UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

July 20, 2023

Mr. Kenneth Michie
Kinder Morgan Inc.
1001 Louisiana Street
Suite 1000
Houston, Texas 77002

Re: Monitoring, Reporting and Verification (MRV) Plan for Kinder Morgan CCS Complex

Dear Mr. Michie:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Kinder Morgan CCS Complex, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Kinder Morgan CCS Complex on June 14, 2023, as the final MRV plan. The MRV Plan Approval Number is 1014543-1. This decision is effective July 25, 2023 and is appealable to the EPA's Environmental Appeals Board, under 40 CFR Part 78.

If you have any questions regarding this determination, please contact me or Melinda Miller of the Greenhouse Gas Reporting Branch at miller.melinda@epa.gov.

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the Kinder Morgan CCS Complex

July 2023

Contents

1 Overview of Project 1

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA) 2

3 Identification of Potential Surface Leakage Pathways 3

4 Strategy for Detection and Quantifying Surface Leakage of CO_2 and for Establishing Expected Baselines for Monitoring..7

6 Summary of Findings 14

<u>Appendices</u>

Appendix A: Final MRV Plan

Appendix B: Submissions and Responses to Requests for Additional Information

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by Kinder Morgan Permian CCS, LLC (Kinder Morgan) for its Kinder Morgan CCS Complex (KMCC) treated acid gas (TAG) injection project into the Ellenburger and Cambrian formations. Note that this evaluation pertains only to the Subpart RR MRV plan for the KMCC, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

KMCC states in Section 1 of the MRV plan that it currently has a Class II disposal permit issued by the Texas Railroad Commission (TRRC) for the Katz Strawn Unit 2361 well (KSU 2361), API# 42-433-33712, UIC #000104281. The permit was originally issued in November 2011 for saltwater disposal operations, and the well has actively injected saltwater since 2013. This permit currently authorizes Kinder Morgan to inject up to 30,000 barrels saltwater per day (bbls/d), equating to 65 million standard cubic feet per day (MMscf/day) of carbon dioxide, into the Ellenburger and Cambrian formations at a depth of 5,800' to 6,800' with a maximum allowable surface pressure of 2,900 psi. KMCC is currently seeking TRRC approval to amend the existing KSU 2361 Class II saltwater disposal permit to inject treated acid gas (TAG), including CO_2. The MRV plan states that KMCC may provide surplus injection capacity to dispose oil and gas waste derived TAG from similar third-party gas processing facilities. Of the 62 MMscf/day total injection volume, KMCC states in the MRV plan that it has 22 MMscf/day committed and proposals to accept 40 MMscf/day more for injection. KMCC intends to inject into this well for 21 years at an injection rate up to 65 MMscf/d. The source of this injected CO_2 is the Red Cedar natural gas processing plants in southern Colorado. The KSU 2361 well is located in a rural, sparsely populated area of Stonewall County, Texas, approximately twelve miles west of the town of Knox City.

KMCC states in the MRV plan that the location, the facility, and the well design of the KSU 2361 are planned to protect against the migration of CO_2 out of the injection interval, protect against contamination of subsurface resources, and most importantly, to prevent surface releases. The MRV plan states that the injection interval for the KSU 2361, the Ellenburger and Cambrian sandstones, is located approximately 5,900 ft below the base of the lowest useable-quality aquifer. As stated in the MRV plan, the KSU 2361 will inject a CO_2 stream containing 99.2% CO_2, 0.00% H_2S, and 0.8% other gases. The MRV plan states that the well and the facility are designed to minimize any leakage of CO_2 to the surface.

In Section 2 of the MRV plan, KMCC describes the geologic setting and injection process for the KSU 2361 well. The MRV plan states that the upper target injection interval is the lower Ordovician-age Ellenburger Group, which is subdivided into the Honeycut, Gorman, and Tanyard Formations. As stated in the MRV plan, the Ellenburger is a widespread lower Ordovician carbonate deposited over the entire north Texas area. The MRV plan describes how the dolomitization and karsting of the Ellenburger formation has created sufficient porosity within the Ellenburger for injection. The lower target injection interval is the Upper Cambrian-age sandstone units of the Wilberns Formation. As stated in the MRV plan, the deposition of the Cambrian and lower Ordovician strata on the early Paleozoic shelf was initiated by a transgressing sea which, entering the area from the south, first laid down a clastic sequence. As explained in the MRV plan, the KSU 2361 open-hole log and injection data determined that the porosity and permeability of the Cambrian sands were sufficient for injection.

The MRV plan states that the Mississippian Lime Formation will serve as the upper confining interval. The MRV plan describes the formation as the product of an extensive shallow water carbonate platform that covered much of southern and western Laurussia. KMCC states in the MRV plan that open-hole logging at the KSU 2361 showed the Mississippian Lime as a predominately cherty limestone. KMCC also determined that the Desmoinesian-age Lower Strawn Shale will act as a secondary confining interval. The MRV plan states that the Lower Strawn Shale is associated with a back-barrier estuary embayment depositional environment, evidenced by the abundance of mudstone. KMCC states in the MRV plan that open-hole logging at the KSU 2361 showed the lithology of the Lower Strawn Shale to be predominately shale.

As stated in the MRV plan, the Precambrian metamorphic rocks will act as the lower confining interval. The Precambrian metamorphic rocks consist of granite, schist, and gneiss. KMCC states in the MRV plan that open-hole log at the KSU 2361 showed that Precambrian metamorphic rocks had a very high resistivity reading, which would indicate little to no porosity.

The description of the project provides the necessary information for 40 CFR 98.448(a)(6).

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines maximum monitoring area as “the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile.” Subpart RR defines active monitoring area as “the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) the area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) the area projected to contain the free phase CO_2 plume at the end of year t + 5.” See 40 CFR 98.449.

As stated in the MRV plan, the reservoir modeling calculated that, after 21 years of injection followed by 30 additional years of density drift, the areal extent of the projected plume will be 3,384 acres. The plume stabilizes and does not migrate any further after the 30-year post-injection period according to the MRV plan. KMCC found that the maximum distance to the edge of the forecasted plume to be approximately 6,850’ after the 30-year post-injection period. Since the stabilized plume shape is relatively circular, KMCC used the maximum distance plus a one-half mile buffer from the injection well after density drift to define the circular boundary of the MMA equal to 9,500’.

The MRV plan states that KMCC established the AMA boundary by superimposing two different boundary conditions. For the first condition, KMCC defines year t as occurring 30 years after the cessation of injection, when the modeled plume has stabilized with a maximum extent radius of 6,850’. KMCC states that the addition of a half-mile buffer results in a maximum extent of 9,500’, satisfying the first condition. For the second condition, since KMCC defines year t as when the plume stabilizes, 30 years after the cessation of injection, the projected radius of the plume for t+5 is also 6,850’. Therefore, after superimposing the results of these two conditions, KMCC defines the AMA with a radius of 9,500’ or 3,384 acres. The MMA and AMA are displayed in Figure 39 of the plan.

The delineations of the MMA and AMA were determined to be acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly delineated in the plan and are consistent with the definitions in 40 CFR 98.449.

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). KMCC identified the following as potential leakage pathways in section 4 of their MRV plan that required consideration:

- Leakage from Surface Equipment
- Leakage through Existing Wells within the MMA
- Leakage through Faults and Fractures
- Leakage through the Confining Layer
- Leakage from Natural or Induced Seismicity

3.1 Surface Equipment

Section 4.1 of the MRV plan states that the surface facilities at the KSU 2361 well are designed to minimize leakage and failure points while injecting acid gas primarily consisting of CO_2. As stated in the MRV plan, the CO_2 stream injected into KSU 2361 could include small amounts of methane and nitrogen. One additional pipeline will be constructed to carry the acid gas from the custody transfer meter to the KSU 2361 wellhead. CO_2 monitors are located around the facility and the well site. The MRV plan states that these gas monitor alarms will be triggered at levels set upon completion of a baseline study of the ambient air quality, followed by a gas dispersion model. Additionally, an emergency shutdown valve (ESD) is located at the wellhead and is locally controlled by pressure, with a high-pressure and low-pressure shut-off.

KMCC states that these facilities have been designed and constructed with other safety systems to provide for safe operations. These systems include ESD valves to isolate portions of the pipeline, pressure relief valves along the pipeline to prevent over-pressurization, and venting to allow piping and equipment to be de-pressured under safe and controlled operating conditions in the event of a leak. The MRV plan states that should KMCC construct additional CO_2 facilities, other meters will be installed as needed to comply with the 40 CFR §98.448(a)(5) measurement. These meters will be near the existing facilities and utilize the existing monitoring programs discussed previously. Furthermore, CO_2 monitors will be installed near the new meters and tied into the facility monitoring systems. No additional wells are included within this MRV facility. For these reasons, KMCC concludes that leakage of CO_2 through the surface equipment is unlikely.

The MRV plan states that with the level of monitoring implemented at the KSU 2361 well, a release of CO_2 would be quickly identified, and the safety systems would minimize the release volume. The CO_2 injected into the KSU 2361 well is supplied by several different sources into the pipeline system and the composition is not expected to change over time. KMCC also states that if any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR §98.448(a)(5).

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through surface equipment at KMCC.

3.2 Existing Wells Within the MMA

Oil and Gas Operations within the Monitoring Area

According to the MRV plan, a significant number of wells have been drilled within the area of the KSU 2361 well, but production has primarily been from the shallower Strawn formation in the Katz field. The Strawn is separated from the Ellenburger-Cambrian interval by 665’ in this area. In addition to the primary Strawn production, a few wells have produced from the Mississippian Lime. The mid-Mississippian is separated from the Ellenburger-Cambrian interval by 133’. The MRV plan states that the KSU 2361 well is the only well that penetrates the injection interval within the projected plume area of the MMA for the KSU 2361. Therefore, it is the only well that will be monitored for surface leakage. The KSU 2361 well is designed to handle and inject acid gas, which reduces the risk and likelihood of leakage through the existing well to near-zero.

The MRV plan states that the KSU 2361 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well. Mechanical integrity tests (MIT), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23 (b)(3)], will take place every five years to verify that the well and wellhead can contain the appropriate operating pressures. The MRV plan also states that if a MIT were to indicate a leak, the well would be isolated, and the leak mitigated to prevent leakage of the injectate to the atmosphere.

Future Drilling

The MRV plan states that potential leakage pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Pre-Cambrian, have proven to date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC around KSU 2361 include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled “Casing, Cementing, Drilling, Well Control, and Completion Requirements”), 16 TAC §3.13. The Ellenburger and Cambrian Sands are among the formations listed for which operators in Stonewall County and district 7B (where the KSU 2361 is located) are required to comply with TRCC Rule 13. TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. The MRV plan also states that in this instance, any new well permitted and drilled to the KSU 2361 well’s injection zone and located within a one-quarter-mile radius of the KSU 2361 well, will be required under TRRC Rule 13 to set steel casing and cement above the KSU 2361 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above all potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued.

Groundwater Wells

The MRV plan states that a groundwater well search resulted in zero groundwater wells found within the MMA, as identified by the Texas Water Development Board. The surface and intermediate casings of the KSU 2361 well, as shown in Figure 41 of the MRV plan, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the Groundwater Advisory Unit (GAU) letter issued for this location. The MRV plan also states that the wellbore casings and cements also prevent CO_2 leakage to the surface along the borehole. For these reasons, KMCC concludes that leakage of the sequestered CO_2 to the groundwater is unlikely.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through existing wells within the MMA.

3.3 Faults and Fractures

Section 4.3 of the MRV plan states that one fault was interpreted within the seismic coverage projecting 12,000’ east of the KSU 2361 location. Initial plume models do not indicate an interaction between the injectate and the fault plane. Additionally, this fault dies within the Mississippian Lime and does not penetrate the Lower Strawn Shale, which acts as the upper confining unit. In the unlikely scenario in which the injection plume reaches the fault, and the fault acts as a transmissive pathway, the MRV plan explains that the upper confining shale above the fault will act as an ideal seal for injectate leaking outside of the permitted injection zone.

The MRV plan states that should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Lower Strawn Shale, juxtaposing it against itself, preventing vertical migration.

The MRV plan states that fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open-hole logs show little to no porosity development indicating that the Lower Strawn Shale and Mississippian Lime were not exposed at this location. Therefore, upward migration of injected gas through confining bed fractures is unlikely.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through faults and fractures.

3.4 Through the Confining Layer

Section 4.4 of the MRV plan states that the Ellenburger and Cambrian injection zones have competent sealing rocks above and below the sand and carbonate formations. The properties of the overlying Lower Strawn Shale and its high composition of shale and mudstone make it an excellent sealing rock to the underlying Ellenburger formation. Tight Mississippian Lime roughly 266' thick lies between the Ellenburger and Lower Strawn Shale formations forming an impermeable upper buffer seal from the injection interval to the upper confining zone. Above this confining unit, KMCC states that shales found within the Homecreek Shale above the Desmoinesian formation will act as additional sealants between the injection interval and the underground source of drinking water (USDW). The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. Precambrian basement rock's underlying the injection zone with low porosity and permeability minimizes the likelihood of downward migration of injected fluids. The MRV plan also states that the relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through the confining layer.

3.5 Natural or Induced Seismicity

Section 4.5 of the MRV plan states that the location of KSU 2361 is in an area of the Midland Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (1971 to present) and the Bureau of Economic Geology's TexNet catalog (2017 to present), as shown in Figure 44 of the MRV plan, indicates the nearest seismic event (unspecified whether natural or induced) occurred more than 40 miles away.

KMCC states that there is no indication of seismic activity posing a risk for loss of CO_2 to the surface within the MMA. Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismic event. For these reasons, KMCC concludes in their MRV plan that leakage of the sequestered CO_2 through seismicity is unlikely.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through natural or induced seismicity.

4 Strategy for Detection and Quantifying Surface Leakage of CO_2 and for Establishing Expected Baselines for Monitoring

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 5 of the MRV plan discusses the strategy that KMCC will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in the previous sections to meet the requirements of 40 CFR §98.448(a)(3). Section 5 of the MRV plan also summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur. Monitoring will occur during the planned 21-year injection period, or otherwise the cessation of operations, plus a proposed 5-year post-injection period. A summary table of KMCC's monitoring strategies can be found in Table 10 of the MRV plan (copied below).

- Leakage from Surface Equipment Failure
- Leakage through Existing and Future Wells within MMA
- Leakage through Faults, Fractures, or Confining seals
- Leakage through Natural or Induced Seismicity

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed CO_2 monitors throughout the Acid Gas Injection (AGI) facility
	Daily visual inspections
	Supervisory Control and Data Acquisition (SCADA)
Leakage through existing wells	Fixed CO_2 monitor at the AGI well
	SCADA continuous monitoring at the AGI Well
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Quarterly atmospheric CO_2 measurements at well locations within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	CO_2 monitoring during offset drilling operations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage through confining layer	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage from natural or induced seismicity	Existing TexNet seismic monitoring station to be implemented

As stated in the MRV plan, the potential for pathways for all previously mentioned forms of leakage are unlikely. Section 7 of the plan explains that given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, KMCC believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. The MRV plan states that any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, history-matching of the sequestering reservoir performance, among others. KMCC states that in the unlikely event that a leak it will be addressed, quantified, and documented within the appropriate timeline.

4.1 Detection of Leakage Through Surface Equipment Failure

Section 5.1 of the MRV plan states that as the facility and the KSU 2361 well are designed to handle CO_2, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used, and the connections are designed to minimize corrosion points. A baseline atmospheric CO_2 concentration will be established before injection operations begin. The facility and well site contain several CO_2 alarms with locations in close proximity.

According to the MRV plan, the AGI complex is continuously monitored through automated systems. Additionally, the MRV plan states that field personnel conduct daily visual field inspections of gauges, monitors, and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the surface equipment associated with the sequestered CO_2 and inspection of the cathodic protection system. These inspections and the automated systems allow KMCC to respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5).

The MRV plan states that pressures and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak.

Thus, the MRV plan provides adequate characterization of KMCC's approach to detect potential leakage through surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage Through Existing and Future Wells Within MMA

Section 5.2 of the MRV plan states that KMCC continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems for the KSU 2361 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. KSU 2361 has a pressure and temperature gauge placed in the injection stream at its wellhead and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. In addition, MIT performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. The MRV plan explains that upon a negative MIT, the well would be isolated, and the leak mitigated.

As discussed previously in the MRV plan, Rule 13 would ensure that new wells in the field would be constructed to prevent migration from the injection interval.

In addition to the fixed monitors described previously, the MRV plan states that KMCC will also establish and operate an in-field monitoring program to detect CO_2 leakage within the MMA. The scope of work will include CO_2 monitoring at the AGI well site and, at minimum, quarterly atmospheric monitoring near any wells identified that penetrate the injection interval within the MMA. The collection of these measurements will be carried out using a qualified third party. The MRV plan states that upon approval of the MRV plan and through the post-injection monitoring period, KMCC will have these monitoring systems in place. No wells have been identified within the MMA that penetrate the injection interval. Additional monitoring will be added as the MMA is updated over time.

Groundwater Quality Monitoring

The MRV plan states that KMCC will monitor the groundwater quality in fluids above the confining interval by sampling from groundwater wells around the facility and analyzing the samples using a third-party laboratory on an annual basis. In the case of KSU 2361, no existing groundwater wells have been identified within the MMA. At least two groundwater monitoring wells will be drilled within 1500' of KSU 2361 at a depth of approximately 100'. The final number, locations, and depths of the wells will be determined by a study completed by a certified third-party firm. A baseline sampling from these wells will occur before injection starts. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature, and other standard laboratory measurements. The MRV plan also states that any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

Thus, the MRV plan provides adequate characterization of KMCC's approach to detect potential leakage through existing and future wells within the MMA as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage Through Faults, Fractures, or Confining Seals

Section 5.3 of the MRV plan states that KMCC continuously monitors the operations of the KSU 2361 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal, would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. The MRV plan also states that a field monitoring system is proposed to measure the shallow topsoil CO_2 concentrations across the MMA. These measurements will be taken quarterly by in-field gas sensors. The field CO_2 monitoring systems would alert field personnel for any release of CO_2 caused by such leakage.

Thus, the MRV plan provides adequate characterization of KMCC's approach to detect potential leakage through faults, fractures, or confining seals as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage Through Natural or Induced Seismicity

The MRV plan states that while the likelihood of a natural or induced seismicity event is extremely low, KMCC plans to use the nearest TexNet seismic monitoring station to monitor the area of the KSU 2361 well. This station is 7.29 miles southwest of the well location, as shown in Figure 46 of the MRV plan. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding KSU 2361. KMCC will monitor this station for any seismic activity that occurs near the well. The MRV plan also states if a seismic event of 3.0 magnitude or greater is detected, KMCC will review the injection volumes and pressures at the KSU 2361 well to determine if any significant changes that would indicate potential leakage had occurred.

Thus, the MRV plan provides adequate characterization of KMCC's approach to detect potential leakage through natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.5 Determination of Baselines

Section 6 of the MRV plan identifies the strategies that KMCC will undertake to establish the expected baselines for monitoring CO_2 surface leakage per §98.448(a)(4). KMCC will use existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. The MRV plan states that once the baseline concentrations are determined over a 12-month period prior to injection, the CO_2 monitors will be set to alarm at concentrations that are a statistically significant deviation from baseline. KMCC identifies the following strategies for determining baselines:

Visual Inspections

The MRV plan states daily inspections will be conducted by field personnel at the facility and the KSU 2361 well. These inspections will aid in identifying and addressing possible issues to minimize the potential leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken to address such issues.

CO_2 Detection

The MRV plan states that in addition to the well site fixed monitors described previously, Kinder Morgan will establish and operate an in-field monitoring program to detect any CO_2 leakage within the MMA. The scope of baseline determination will include atmospheric CO_2 measurements at the AGI well site and near identified penetrations within the MMA. Topsoil CO_2 concentrations will also be measured at pre-determined locations within the MMA, as baseline values before injection activities begin.

Operational Data

The MRV plan states that upon starting injection operations, baseline measurements of injection volumes and pressures will be taken. Any significant deviations over time will be analyzed for indication of leakage of CO_2.

Continuous Monitoring

The MRV plan states that the total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this project is well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. According to the MRV plan, this method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

Groundwater Monitoring

The MRV plan states that initial samples will be taken from the groundwater monitoring wells drilled within 1,500 feet of the KSU 2361 well upon approval of the MRV plan and before commencing injection of CO_2. KMCC also states that a third-party laboratory will analyze the samples to establish the baseline properties of the groundwater.

The MRV plan also states that in the case of a blowdown event, emissions will be sent to vent stacks and will be reported as required for the operation of the well.

Thus, the MRV plan provides adequate characterization of KMCC's approach to establish expected baselines as required by 40 CFR 98.448(a)(4).

5 Considerations Used to Calculate Site-Specific Variables for the Mass Balance Equation

5.1 Determining Mass of CO_2 Received

According to the MRV plan, the CO_2 received for the KSU 2361 well is wholly injected and not mixed with any other supply. Therefore, KMCC concludes that the annual mass of CO_2 injected will equal the amount received. KMCC states that any future streams would be metered separately before being combined into the calculated stream.

KMCC provides an acceptable approach to calculating the mass of CO_2 received in accordance with Subpart RR requirements.

5.2 Determining Mass of CO_2 Injected

Section 7 of the MRV plan states that the mass of CO_2 injected will be measured with a volumetric flow meter. The total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

Where:

CO_{2u} = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,u}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

KMCC provides an acceptable approach to calculating the mass of CO_2 injected in accordance with Subpart RR requirements.

5.3 Mass of CO_2 Produced

KMCC states in the MRV plan that the KSU 2361 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

The MRV plan states that the mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains concentrations well beyond the OSHA PEL 8-hour total weight average (TWA) limit of 5,000 ppm. Any leakage would be detected and managed as an upset event. The MRV plan states that an upset event is any unlikely event that results in the failure of any mass of CO_2 to remain permanently sequestered in the target reservoir. Continuous monitoring systems should trigger an alarm when a release occurs. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak.

Should CO_2 surface leakage occur, KMCC states that the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 below. KMCC further states in the MRV plans that any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, history-matching of the sequestering reservoir performance, among others.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

X = Leakage pathway.

Calculation methods using equations from subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

KMCC provides an acceptable approach for calculating the mass of CO_2 emitted by surface leakage in accordance with Subpart RR requirements.

5.5 Calculation of Mass of CO_2 Sequestered

The MRV plan states that the mass of CO_2 sequestered in subsurface geologic formations will be calculated based off Equation RR-12, assuming an expected injection start date of June 1, 2024, as this well will not actively produce oil or natural gas, or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

The MRV plan states that CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required, and those emissions sent to flares and reported as part of the required GHG reporting for the gas plant.

KMCC provides an acceptable approach for calculating the mass of CO_2 sequestered in accordance with Subpart RR requirements.

6 Summary of Findings

The Subpart RR MRV plan for the Kinder Morgan CCS Complex meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the Kinder Morgan CCS Complex MRV plan.

Subpart RR MRV Plan Requirement	Kinder Morgan CCS Complex MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV plan describes the MMA and AMA. The AMA boundary was established by superimposing the area based on a half-mile buffer around the anticipated plume location at the end of injection (2044) with the area of the projected free-phase CO_2 plume at five additional years (2049). Since the AMA boundary was determined to fall within the MMA boundary, the defined MMA was also used to define the effective AMA.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: leakage from surface equipment; leakage through existing wells within the MMA; leakage through faults and fractures; leakage through the confining layer; and leakage from natural or induced seismicity. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 5 and Section 7 of the MRV plan describe the strategy for how the facility would detect CO_2 leakage to the surface and how the leakage would be quantified, should leakage occur. Leaks would be detecting using methods such as SCADA systems, MITs, groundwater sampling, and in-field monitors.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 6 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 7 of the MRV plan describes KMCC's approach to determining the amount of CO_2 sequestered using the Subpart RR mass balance equation, including as related to calculation of total annual mass emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 of the MRV plan provides the well identification numbers for the KSU 2361 injection well. The MRV plan specifies that the wells have been issued a UIC Class II permit under TRRC Rule 9 and Rule 36.

40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 7 of the MRV plan states that the mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12, assuming an expected injection start date of June 1, 2024.

Appendix A: Final MRV Plan

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan Kinder Morgan Permian CCS LLC

Prepared for *Kinder Morgan Permian CCS LLC*
Houston, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 4.0
June 2023

INTRODUCTION

Kinder Morgan Production Co. LLC (Kinder Morgan) currently has a Class II disposal permit issued by the Texas Railroad Commission (TRRC) for the Katz Strawn Unit 2361 well (KSU 2361), API# 42-433-33712. The permit was originally issued in November 2011 for saltwater disposal operations, and the well has actively injected saltwater since 2013. This permit currently authorizes Kinder Morgan to inject up to 30,000 barrels saltwater per day (bbls/d), equating to 65 million standard cubic feet per day (MMscf/day) of carbon dioxide, into the Ellenburger and Cambrian formations at a depth of 5,800’ to 6,800’ with a maximum allowable surface pressure of 2,900 psi. The KSU 2361 well is located in a rural, sparsely populated area of Stonewall County, Texas, approximately twelve miles west of the town of Knox City, as shown in Figure 1.

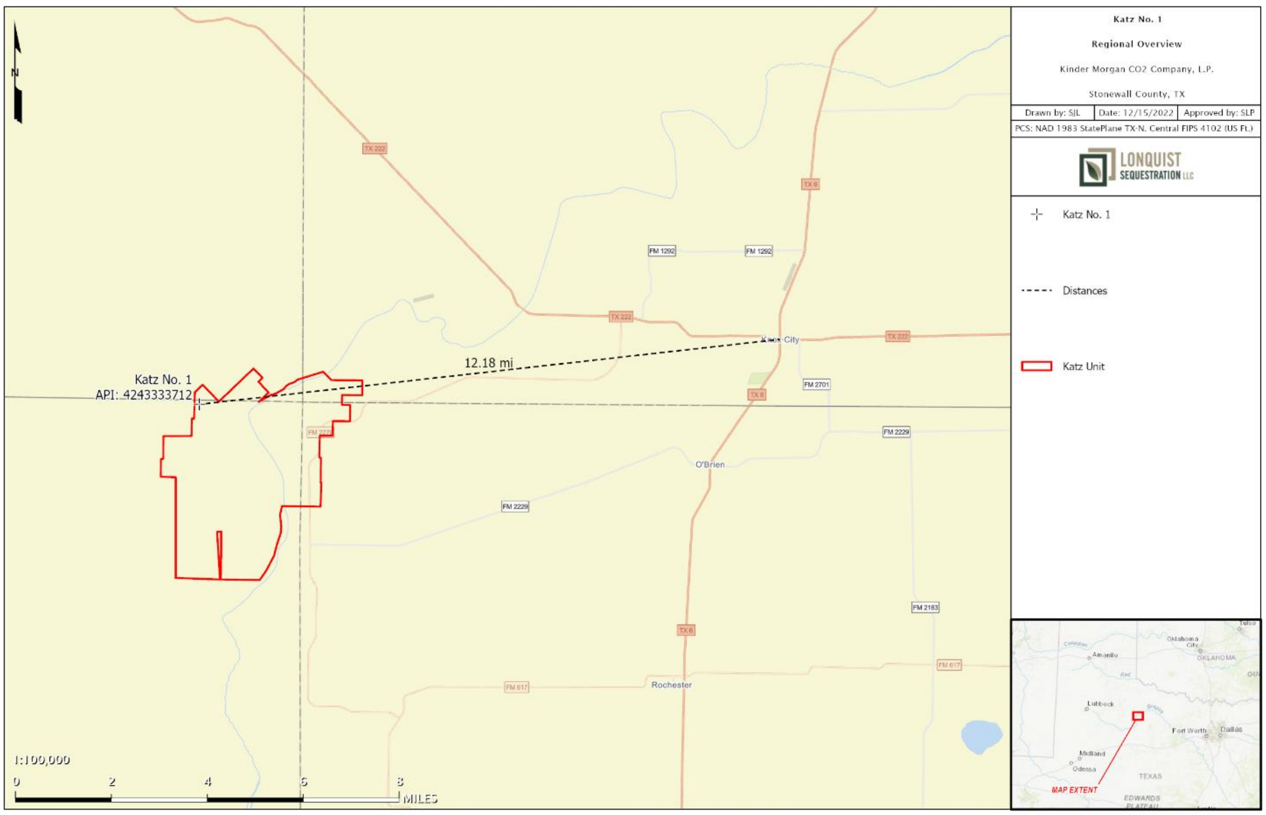


Figure 1 – Location of KSU 2361 Well

Kinder Morgan is seeking TRRC approval to amend the existing KSU 2361 Class II saltwater disposal permit to inject treated acid gas (TAG), including CO_2. In the future, Kinder Morgan may provide surplus injection capacity to dispose oil and gas waste derived TAG from similar third-party gas processing facilities. Kinder Morgan intends to inject into this well for 21 years at a capacity ranging up to 65 million standard cubic feet per day (MMSCF/d). The source of this injected CO_2 gas is from Red Cedar natural gas processing plants in southern Colorado. Table 1 below shows the expected composition of the gas stream to be injected. Table 2 shows the expected average volume of CO_2 gas commitments from similar type emission sources in the same area, along with the contract status as of March 2023.

Table 1 – Expected Gas Composition at KSU 2361

Component	**Mol Percent**
Carbon Dioxide	99.20%
Methane	0.25%
Ethane	0.03%
Propane	0.04%
Nitrogen	0.48%
Hydrogen Sulfide	0.00%

Table 2 – Expected Sequestered Gas Volumes for KSU 2361

Contract Status	**Avg. Rate (MMcfd)**
Committed	22
Proposal	8
Proposal	23
Proposal	9
Total	62

Kinder Morgan is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

ACRONYMS AND ABBREVIATIONS

‘	Feet
%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group’s GEM 2020.11
GHGs	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	MilliDarcy(ies)
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million

MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MMSCF	Million Standard Cubic Feet
MSCF/D	Thousand Cubic Feet per Day
MMSCF/d	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

INTRODUCTION 1
ACRONYMS AND ABBREVIATIONS 3
SECTION 1 – UIC INFORMATION 8
1.1 Underground Injection Control (UIC) Permit Class: Class II 8
1.2 UIC Well Identification Number: 8
SECTION 2 – PROJECT DESCRIPTION 9
2.1 Regional Geology 10
2.1.1 Regional Faulting 18
2.2 Site Characterization 19
2.2.1 Stratigraphy and Lithologic Characteristics 19
2.2.2 Upper Confining Zone – Mississippian Lime 21
2.2.3 Secondary Confining Interval – Lower Strawn Shale 22
2.2.4 Injection Interval – Ellenburger/Cambrian Sands 25
2.2.5 Lower Confining Zone – Precambrian 29
2.3 Fracture Pressure Gradient 31
2.4 Local Structure 32
2.5 Injection and Confinement Summary 37
2.6 Groundwater Hydrology 37
2.6.1 Reservoir Characterization Modeling 43
SECTION 3 – DELINEATION OF MONITORING AREA 56
3.1 Maximum Monitoring Area 56
3.2 Active Monitoring Area 57
SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE 58
4.1 Leakage from Surface Equipment 58
4.2 Leakage from Existing Wells within MMA 59
4.2.1 Oil and Gas Operations within Monitoring Area 59
4.2.2 Groundwater wells 64
4.3 Leakage Through Faults and Fractures 65
4.4 Leakage Through the Confining Layer 65
4.5 Leakage from Natural or Induced Seismicity 65
SECTION 5 – MONITORING FOR LEAKAGE 67
5.1 Leakage from Surface Equipment 68
5.2 Leakage From Existing and Future Wells within MMA 68
5.3 Leakage through Faults, Fractures or Confining Seals 71
5.4 Leakage through Natural or Induced Seismicity 71
SECTION 6 – BASELINE DETERMINATIONS 73
6.1 Visual Inspections 73
6.2 CO_2 Detection 73
6.3 Operational Data 73
6.4 Continuous Monitoring 73
6.5 Groundwater Monitoring 74
SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION 75
7.1 Mass of CO_2 Received 75
7.2 Mass of CO_2 Injected 75

7.3 Mass of CO_2 Produced 76
7.4 Mass of CO_2 Emitted by Surface Leakage 76
7.5 Mass of CO_2 Sequestered 77
SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN 78
SECTION 9 – QUALITY ASSURANCE 79
9.1 Monitoring QA/QC 79
9.2 Missing Data 79
9.3 MRV Plan Revisions 80
SECTION 10 – RECORDS RETENTION 81
SECTION 11 - REFERENCES 82
SECTION 12 - APPENDICES 84

LIST OF FIGURES

Figure 1 – Location of KSU 2361 Well 1
Figure 2 – Regional Map of the Permian Basin. 10
Figure 3 – Stratigraphic Column of the Eastern Shelf 11
Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations 12
Figure 5 – Top of Structure Map of the Ellenburger Group in West Texas 13
Figure 6 – Generalized Isopach Map of the Ellenburger Group in West Texas 14
Figure 7 – Thickness of Cambrian and Lower Ordovician Strata 15
Figure 8 – Formation Tops at KSU 2361. 16
Figure 9 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma. 18
Figure 10 – KSU 2361 Type Log 19
Figure 11 – Type Log of Zones of Interest 20
Figure 12 – Depositional Map of the Mississippian 21
Figure 13 – Core Description 23
Figure 14 – Cross Section Depicting Corelative Offset Core with Lower Strawn Shale 24
Figure 15 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003) 25
Figure 16 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003) 27
Figure 17 – Offset Wells used for Formation Fluid Characterization. 28
Figure 18 – Pre-Cambrian Distribution Map 30
Figure 19 – Ellenburger Structure Map 33
Figure 20 – Structural Northwest-Southeast Cross Section 34
Figure 21 – Structural West to East Seismic Profile 35
Figure 22 – Structural Northwest to Southeast Seismic Profile 36
Figure 23 – Generalized Stratigraphy of the Seymour Aquifer 38
Figure 24 – Regional Extent of the Seymour Aquifer Pods 40
Figure 25 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer 41
Figure 26 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer 42
Figure 27 – Geomodel Dimensions 46
Figure 28 – Structural Horizons of the Geomodel 47
Figure 29 – Porosity Distribution in Plume Model 48
Figure 30 – NTG Ratio Applied to the Plume Model 49
Figure 31 – CO_2-Water Relative Permeability Curves 50
Figure 32 – History Match for KSU 2361 51
Figure 33 – History Match for KSU #3471 51
Figure 34 – Simulated Wellhead Pressure During Active Injection 52

Figure 35 – Forecasted Injection Rate and BHP 53
Figure 36 – Annualized Growth Rate of CO_2 Plume 54
Figure 37 – Aerial View of CO_2 Plume........55
Figure 38 – Cross-Sectional View of CO_2 Plume 55
Figure 39 – Stabilized Plume Boundary, Active Monitoring Area and Maximum Monitoring Area........57
Figure 40 – Site Plan 59
Figure 41 – KSU 2361 Wellbore Schematic 61
Figure 42 – All Oil and Gas Wells within the MMA........62
Figure 43 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA 63
Figure 44 – Seismicity Review (TexNet – 06/01/2022)........66
Figure 45 – Groundwater Monitoring Wells........70
Figure 46 – Nearest TexNet Seismic Station........72

LIST OF TABLES

Table 1 – Expected Gas Composition of Sequestered Gas Stream........2
Table 2 – Expected Gas Volumes of Sequestered Gas Stream........2
Table 3 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples 29
Table 4 – Fracture Gradient Assumptions 31
Table 5 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas 38
Table 6 – CO_2 Solubility Table........45
Table 7 – Rock Properties........47
Table 8 – Initial Conditions Summary........48
Table 9 – Plume Model Radius and Area........54
Table 10 – Summary of Leakage Monitoring Methods 67

SECTION 1 – UIC INFORMATION

This section contains key information regarding the UIC Permit.

1.1 Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. TRRC classifies the KSU 2361 well as UIC Class II. A Class II permit was issued to Kinder Morgan under TRRC Rule 9 (entitled "Disposal into Non-Productive Formations") and Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").

1.2 UIC Well Identification Number:

Katz Strawn Unit 2361, API No. 42-433-33712, UIC #000104281.

SECTION 2 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the KSU 2361 well.

The injection interval for KSU 2361 is approximately 670' below the base of the Strawn formation, the primary producing formation in the area, and approximately 5,900' below the base of the lowest useable-quality aquifer. Therefore, the location, facility, and the well design of the KSU 2361 well are planned to protect against the migration of CO_2 out of the injection interval, protect against contamination of subsurface resources and, most critical, to prevent surface releases.

2.1 Regional Geology

The KSU 2361 well is located on the Eastern Shelf, a broad marine shelf located in the eastern portion of the Permian Basin, shown in Figure 2. Figure 3 depicts an Eastern Shelf stratigraphic column representative of the strata found at the KSU 2361 well location. The red stars reference the injection formations, and a green star indicates the historically productive interval in the area.

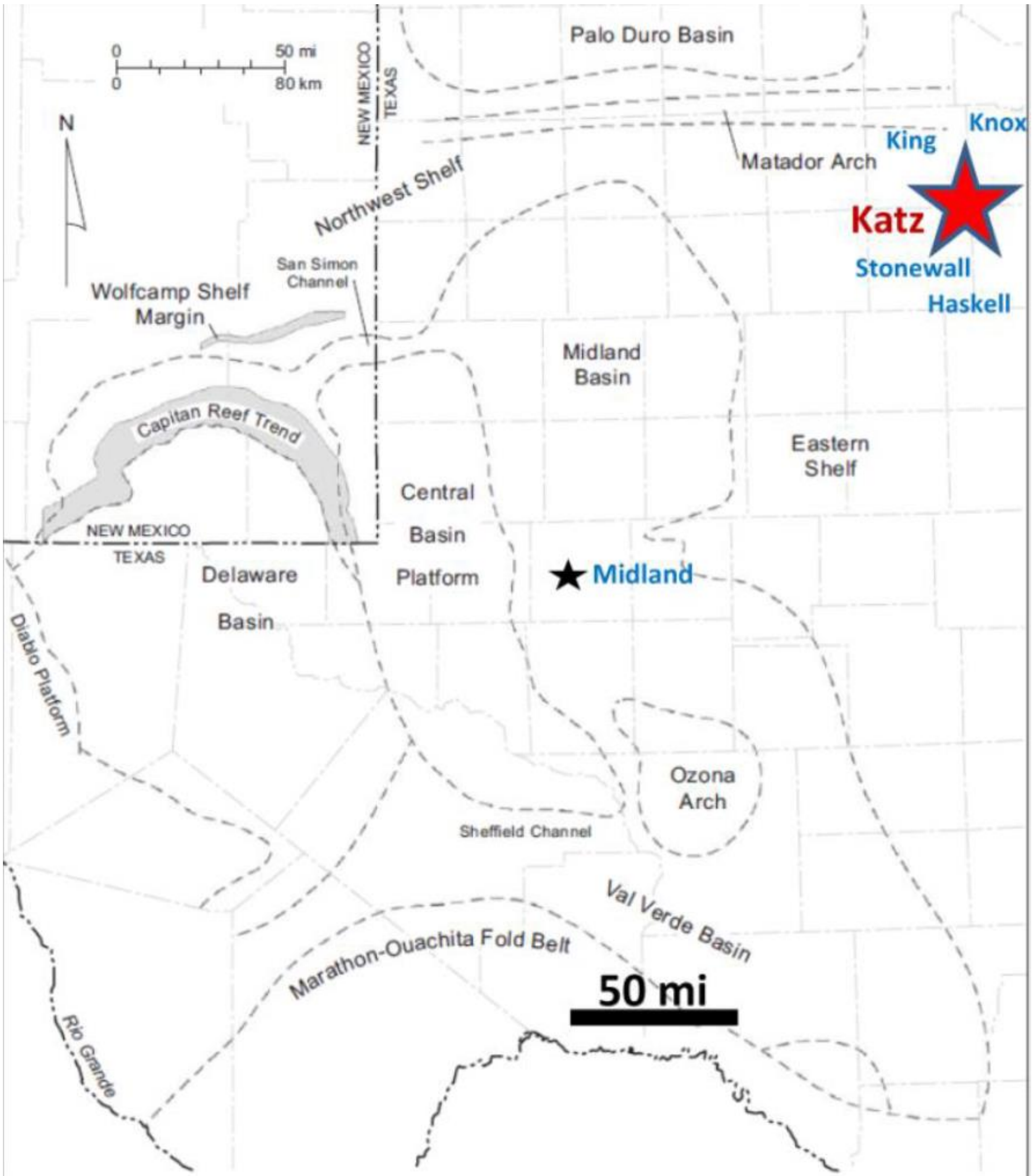


Figure 2 – Regional Map of the Permian Basin. The red star is the approximate location of KSU 2361 well.

SYSTEM	SERIES OR EPOCH FORMATION NAME	STONEWALL CO, TX LITHOLOGIES	
QUATERNARY	Holocene	Alluvium (sand, shale)	
	Pleistocene	ABSENT	
TERTIARY			
CRETACEOUS			
TRIASSIC			
PERMIAN	Guadalupe	gypsum, shale, dolomite	
	Wichita Gp	shale	
	Wolfcamp	shale, sandstone, limestone	
PENNSYLVANIAN	Virgil (Cisco)	shale, limestone, sandstone	
	Missouri (Canyon)	shale, limestone	
	Des Moines (Strawn)	sandstone, shale, limestone	Oil
	Atoka (Bend)	shale, sandstone	
	Morrow	ABSENT	
MISSISSIPPIAN	Chester	limestone	
	Meramec-Osage		
DEVONIAN		ABSENT	
SILURIAN			
ORDOVICIAN	Ellenburger	dolomite	Disposal Zone
CAMBRIAN	Wilberns	shale, sandstone, limestone	Disposal Zone
PRECAMBRIAN		granite	

Figure 3 – Stratigraphic Column of the Eastern Shelf.

The upper target injection interval is the lower Ordovician-age Ellenburger Group, which is subdivided into the Honeycut, Gorman, and Tanyard Formations, as seen in Figure 4. Upper Cambrian-age sandstone units of the Wilberns Formation, comprise the lower target injection interval.

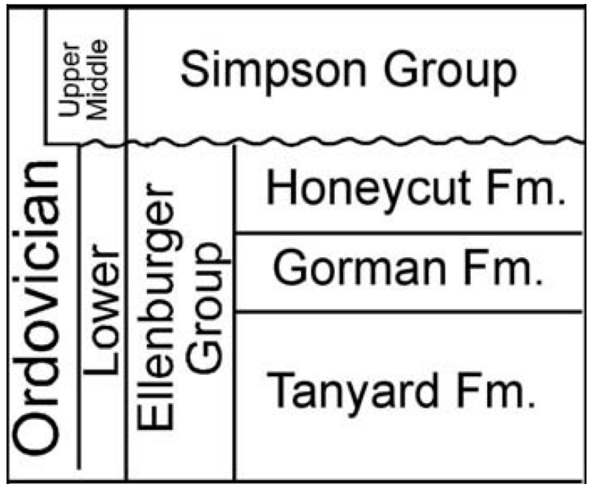


Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations (Kupecz, 1992).

The Ellenburger Group is present at varying depths in each of the provinces of the Permian Basin. In the Midland Basin area, the top of Ellenburger carbonate is as deep as 11,000' (GL) (Loucks, 2003). Due to regional structural dip of the Eastern Shelf, in northeast Stonewall County, the top of Ellenburger is found at only approximately 6,000' deep (GL). The depositional environment over the Stonewall, King, Knox, and Haskell County intersection during the Ordovician Period was a broad, shallow water carbonate platform with an interior of dolomite and an outer area of limestone. This was interpreted by Kerans (1990) as the dolomite being a restricted shelf interior and the limestone being an outer rim of more open-shelf deposits (Loucks, 2003).

Kerans (1990) performed the most complete regional analysis on Ellenburger depositional systems and facies. He recognized six general lithofacies as follows: litharenite: fan delta – marginal marine depositional system; mixed siliciclastic-carbonate packstone/grainstone: lower tidal-flat depositional system; ooid and peloid grainstone: high-energy restricted-shelf depositional system; mottled mudstone: low-energy restricted-shelf depositional system; laminated mudstone: upper tidal-flat depositional system; and gastropod-intraclast-peloid packstone/grainstone: open shallow-water-shelf depositional system.

According to Loucks, the diagenesis of the Ellenburger Group is complex, and the processes that produced the diagenesis spanned millions of years. The three major diagenetic processes of note are dolomitization, karsting, and tectonic fracturing. Dolomitization favors the preservation of fractures and pores due to its greater chemical and mechanical stability relative to limestone. Kupecz and Land (1991) delineated generations of dolomite into early-stage and late-stage. They attributed 90% of the dolomite as early-stage, wherein the source of magnesium was probably seawater. The other 10% of dolomite was attributed as late-stage, in which warm, reactive fluids were expelled from basinal shales during the Ouachita Orogeny. Karsting can affect only the surface of a carbonate terrain, forming terra rosa, or it can extensively dissolve the carbonate surface,

forming karst towers (Loucks, 2003). It can also produce extensive subsurface dissolution in the form of caves and other structures, which increases porosity and permeability. Fracturing can be tectonic or karst-related. Tectonic fractures are commonly the youngest fractures in the rock and generally crosscut karst-related fractures (Kerans, 1989). Holtz and Kerans (1992) divided Ellenburger reservoirs into three groups based on these fracture types. The Eastern Shelf of the Permian Basin falls within the ramp carbonates group, in which predominant pore types are intercrystalline and interparticle. These reservoirs are characterized by the thinnest net pay, highest porosity, moderate permeability, highest initial water saturation, and highest residual oil saturation.

Figures 5 and 6 show the regional structure contours and isopachs of the Ellenburger Group, respectively. Figure 7 shows isopachs of Cambrian and lower Ordovician strata. Stars depict the KSU 2361 well location in each of these figures. In Figure 8, formation tops from gamma-ray data indicate the net pay thickness of the Ellenburger and Cambrian is approximately 223' within this interval in the KSU 2361 well location.

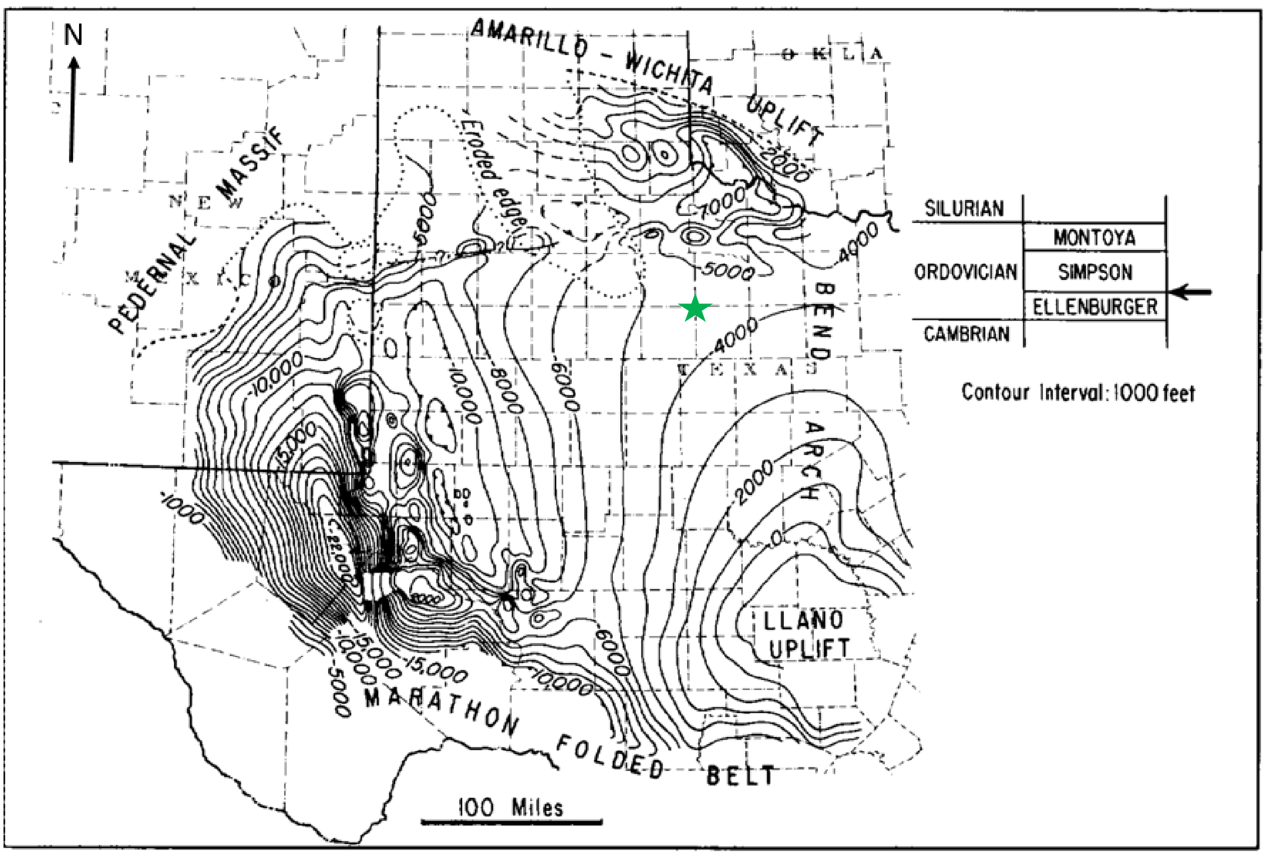


Figure 5 – Top of Structure Map of the Ellenburger Group in West Texas (Subsea Values) (Galley, 1955).

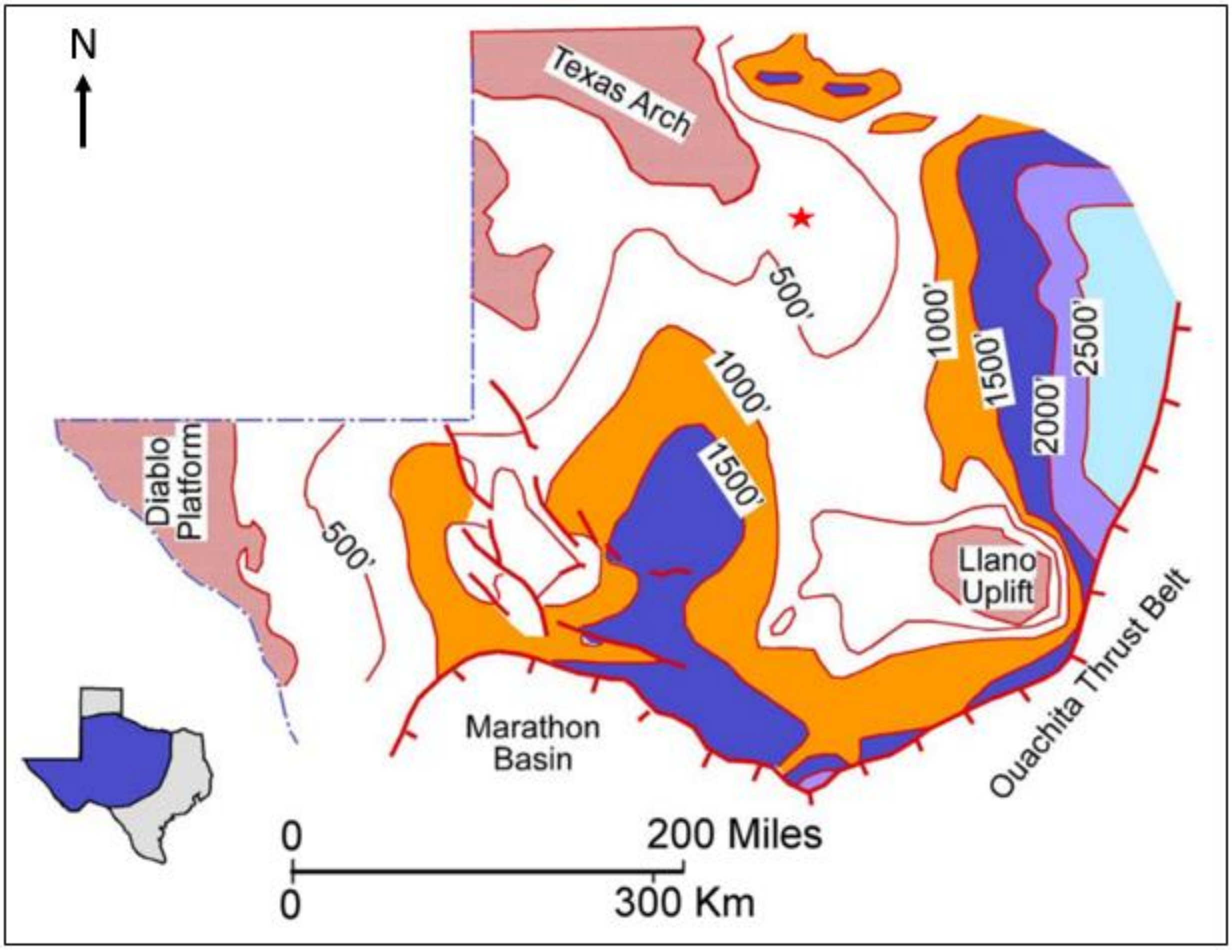


Figure 6 – Generalized Isopach Map of the Ellenburger Group in West Texas (Kerans, 1989).

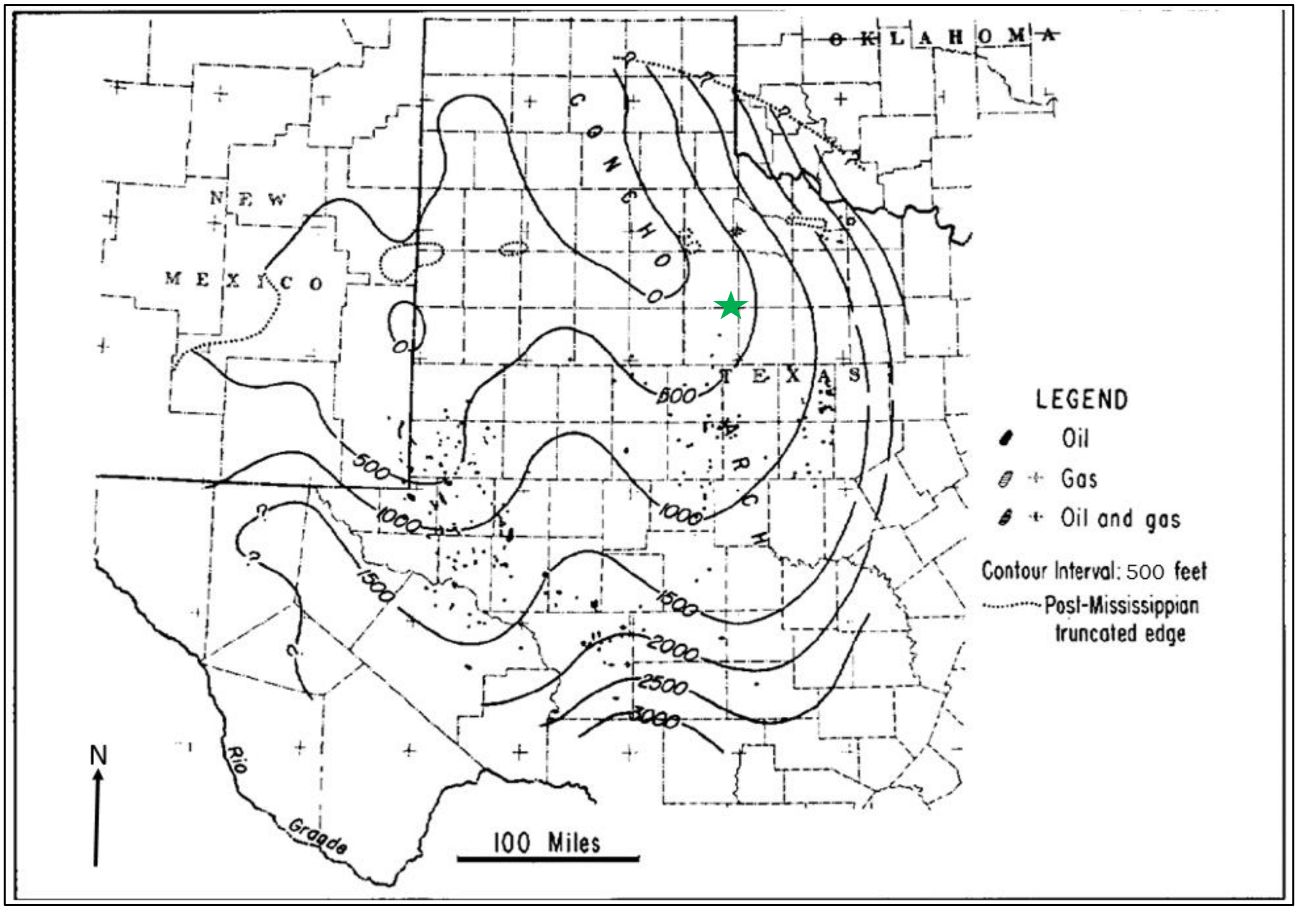


Figure 7 – Thickness of Cambrian and Lower Ordovician Strata
(Galley, 1955).

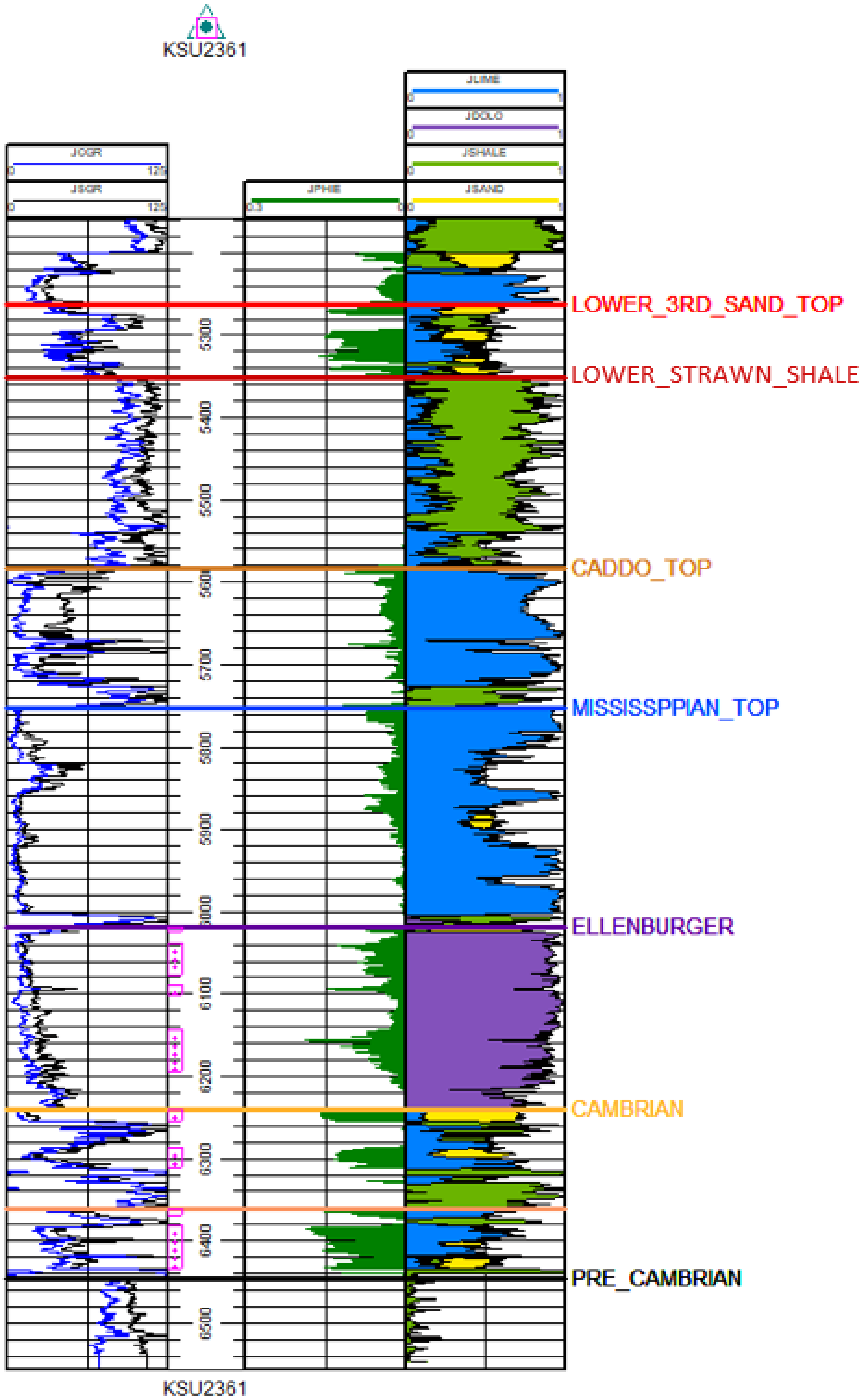


Figure 8 – Formation Tops at KSU 2361. Purple represents dolomite and the upper injection interval. Yellow represents sandstone, which is present in the pay interval. Pink boxes within depth column indicate active perforated intervals.

Cambrian-age strata consist of interbedded sandstone, limestone, and shale members. The initial deposits laid down on the eroded surface of Precambrian rocks were sandstone and arenaceous carbonates. Shale members are thickest in the southeast and nonexistent on the west side of the Permian Basin (Galley, 1955).

Overlying the Precambrian basement rock is the Riley Formation. This, in turn, is overlain by transgressive and progradational shallow-water marine sandstone, siltstone, limestone, and dolomite of the Wilberns Formation. The Riley Formation consists of sandstone packages whose thicknesses vary from place to place in response to the paleotopography of the underlying Precambrian surface (Kyle and McBride, 2014). The depositional environment in this area during the Cambrian was influenced by the sea, which advanced from the southeast (Galley, 1955). This led to the formation of a complex succession of transgressive and regressive sandstone units, both glauconitic and non-glauconitic (Kyle and McBride, 2014).

The Riley Formation is probably thickest south of the Llano region and laps out about 100 miles west and a slightly greater distance northwestward from the Llano region. It has accumulated in a northwestward-extending arm of the sea and likely extended beyond its present limits since there is a disconformity at its top. The Wilberns Formation thins appreciably northwestward from the Llano region to about 230’ in Nolan County and to 70’ in Lubbock County. West and north of the Llano region, usage suggested by Cloud and Barnes and adopted by petroleum geologists places the Tanyard-Wilberns boundary in the vicinity of the first appearance downward of glauconite (Barnes et al., 1959).

Figure 9 indicates that the Riley Formation’s northwestern extent ends in Jones and Fisher counties, which implies that Cambrian strata at KSU 2361 may be limited to the Wilberns Formation only.

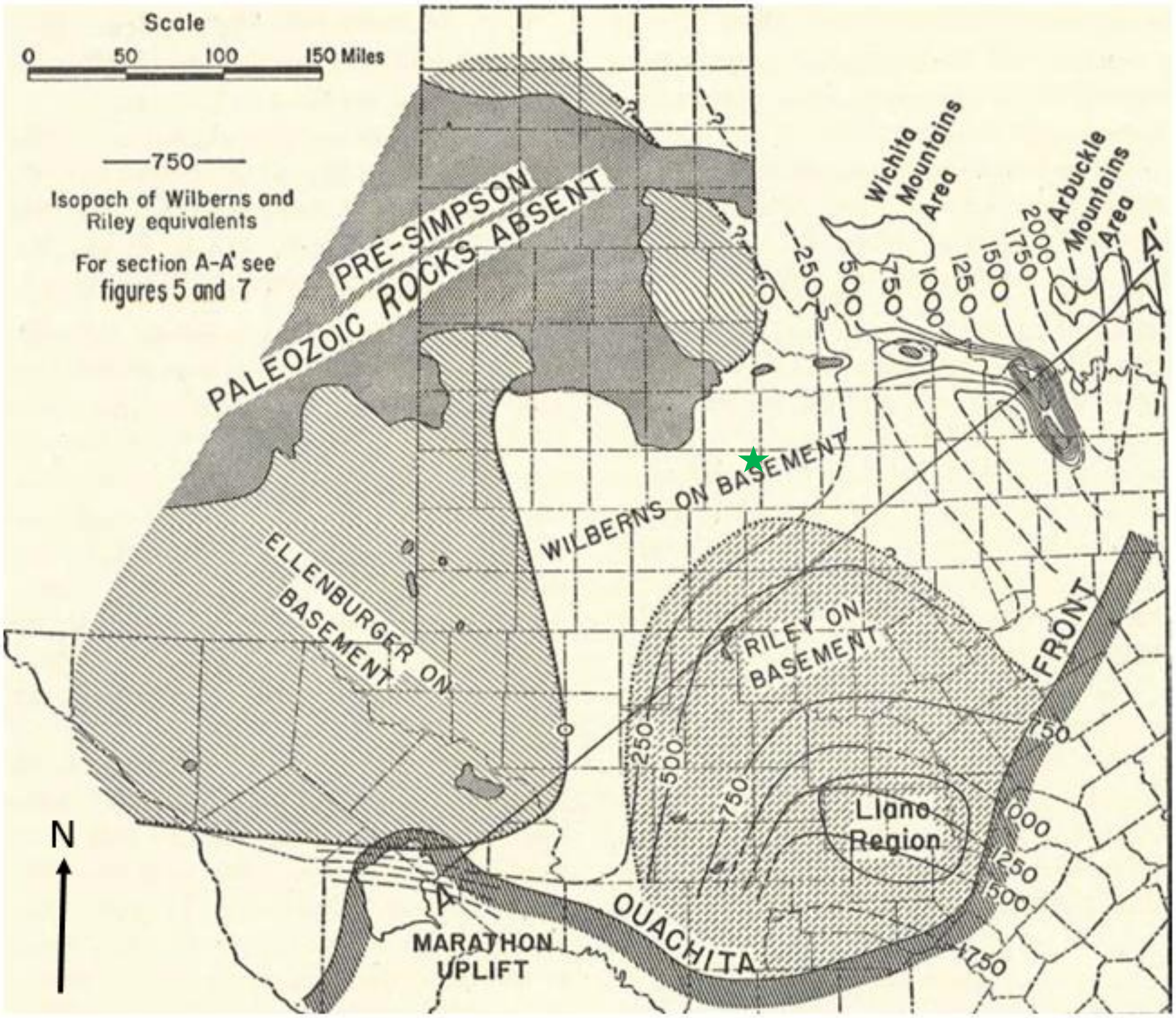


Figure 9 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma.
The green star approximates the location of KSU 2361 (Barnes et al., 1959).

2.1.1 Regional Faulting

Regional faulting in the KSU 2361 area trends primarily N-S in direction. This is the result of the dip rotation from a SW-NE trend seen in the Fort Worth basin to the east that rotates N-S as you move west towards the Bend-Arch and the edge of the basin (Hornhach, 2016). This trend then carries towards the Eastern Shelf closer to the KSU 2361 location. The most common faults are high-angle basement faults that primarily die within the Pennsylvanian in the KSU 2361 well area. Faulting is discussed in more detail in the Site characterization.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the KSU 2361 well.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 depicts an annotated open hole log from the surface to the total depth of the KSU 2361 well, with regional formation tops indicating the injection and primary upper confining units. Figure 11 provides a magnified view of the zones of interest, from above the Lower Strawn to the Precambrian, with general lithologic descriptions along the right edge of the figure.

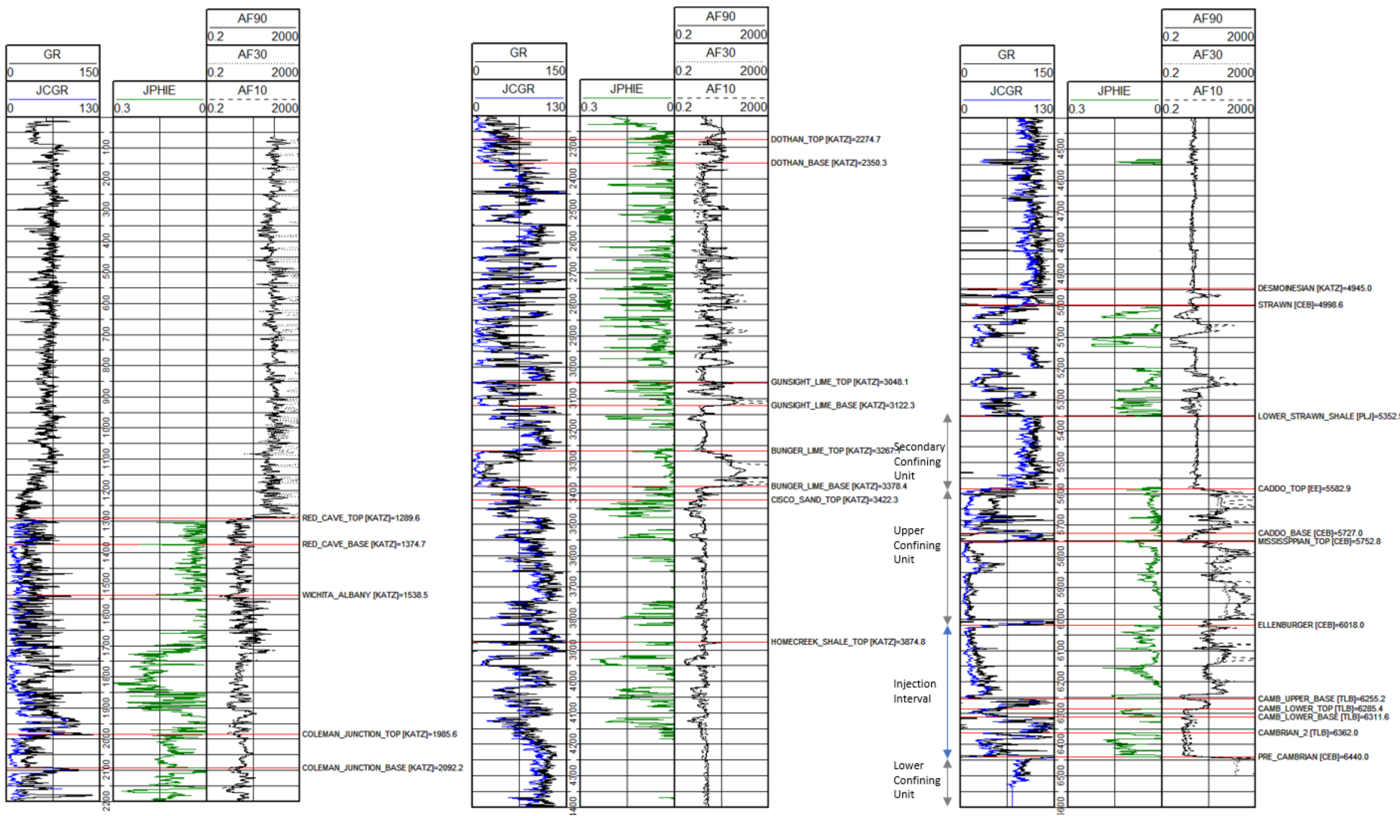


Figure 10 – KSU 2361 Type Log

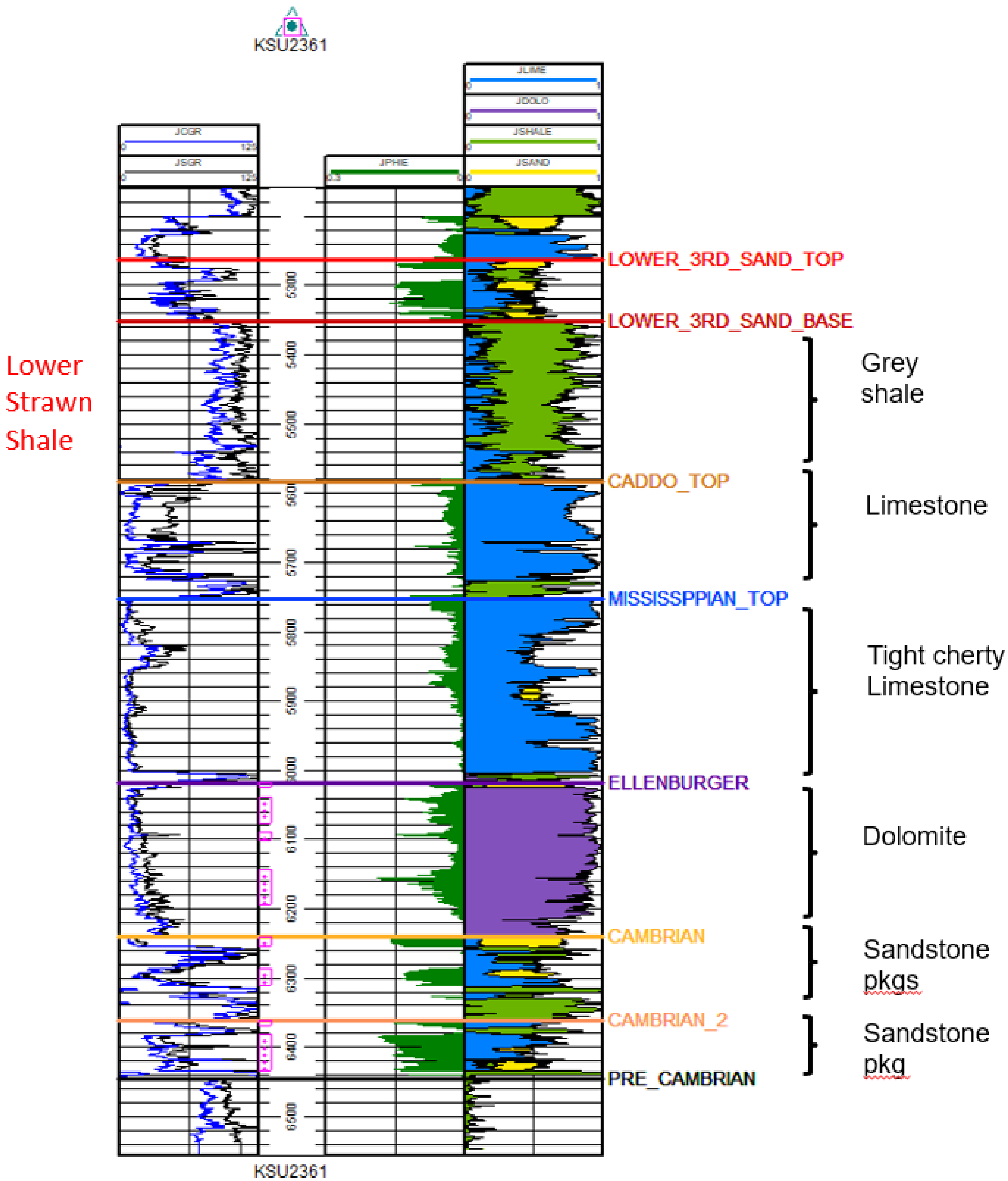


Figure 11 – Type Log of Zones of Interest

2.2.2 Upper Confining Zone – Mississippian Lime

The Mississippian Lime is the primary confining unit for the KSU 2361. This formation is the product of a large extensive shallow water carbonate platform that covered much of the southern and western Laurussia (Kane). Figure 12 shows the location of the KSU 2361 well to be found within the Chappel Shelf of the Mississippian Age. Representative cores of the Mississippian Lime formation found on the Chappel Shelf in the Llano uplift area consist of light-colored, fine- to coarse-grained, skeletal packstone (Kane). The open hole log seen in Figure 11 depicts the Mississippian Lime as predominantly cherty limestone. The basal carbonate section has little to no effective porosity development, which should translate to no permeability development. The Mississippian Platform Carbonate play is the smallest oil-producing play in the Permian Basin, which is tied to the abundance of crinoidal, grain-rich facies in platform successions. Most production from Mississippian reservoirs comes from more porous upper Mississippian ooid grainstones (Kane). This indicates that little to no reservoir characteristics are developed within the lower Mississippian Lime, creating an optimal seal.

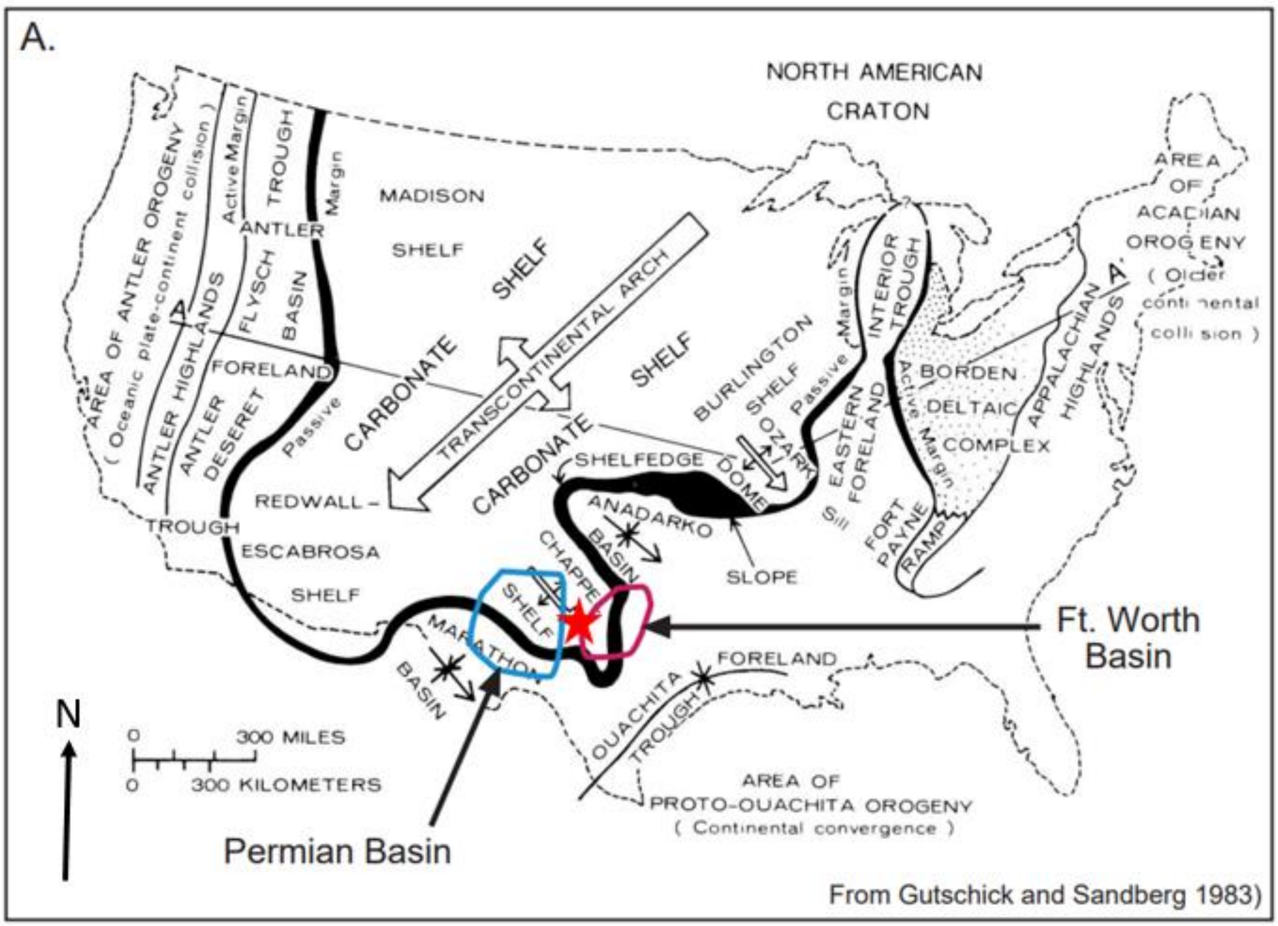


Figure 12 – Depositional Map of the Mississippian (Kane)

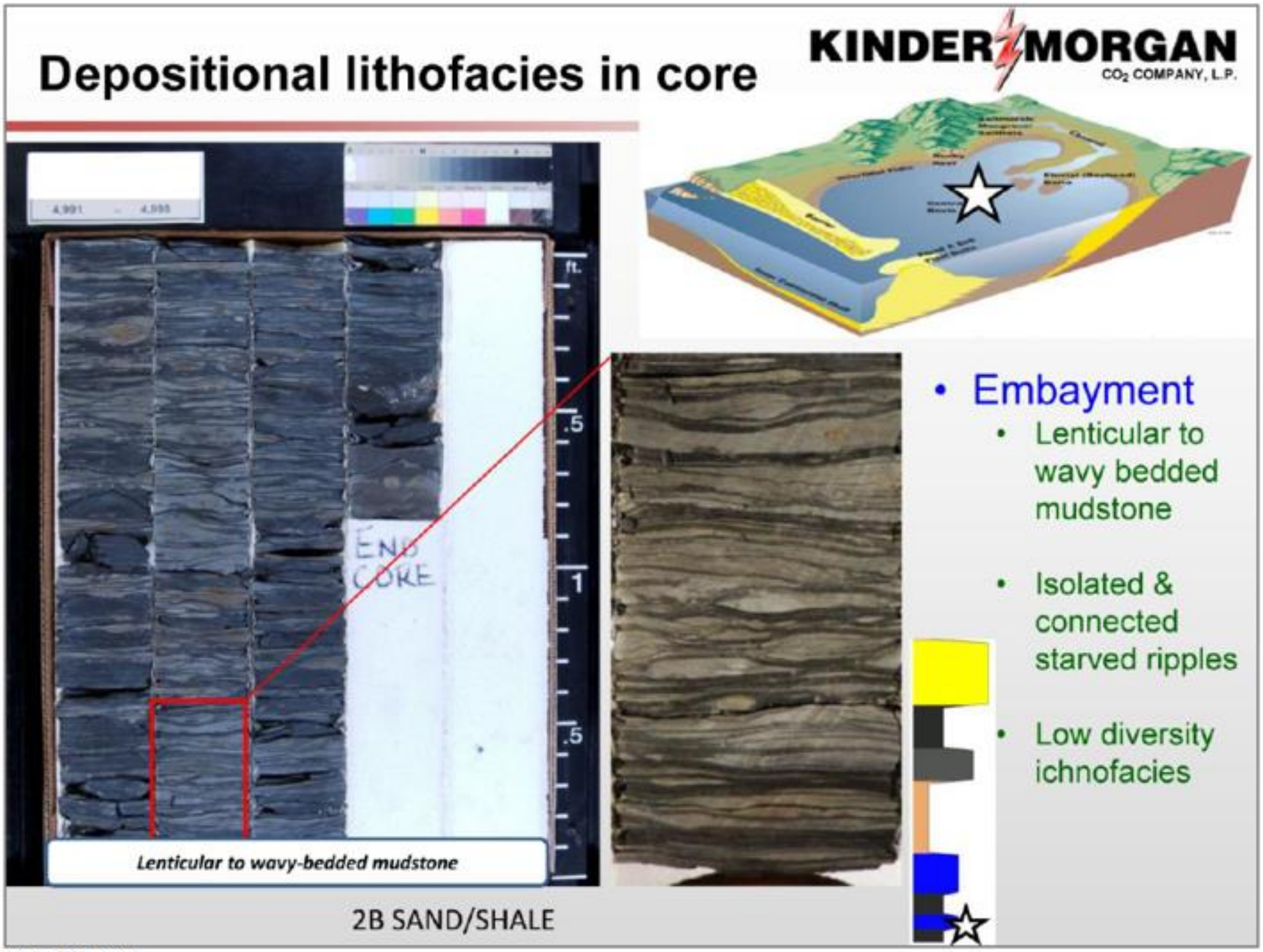
2.2.3 Secondary Confining Interval – Lower Strawn Shale

The Lower Strawn Shale (LSS) is Desmoinesian in age and was heavily influenced by the Knox Baylor Trough, which is near the KSU 2361 location and is late-Desmoinesian in age. The trough resulted from the Ouachita-Marathon overthrust movement that disrupted the Fort Worth basin depositional center, moving the Desmoinesian depocenter further to the west to form the Knox Baylor Trough. This trough allowed sediments to be transported west to the Midland Basin. These sediments were derived from the destruction of the elongated Bowie Delta System, which derived its sediments from the Muenster-Wichita Mountain system (Gunn, 1982).

Depositional facies within the Strawn unit resemble assemblages typical of a mixed siliciclastic-carbonate continental-to-shelf transitional succession found along a complex embayed coastline. Six petrophysically distinct lithofacies were identified: (1) lenticular to wavy-bedded mudstone, (2) flaser to wavy-bedded sandstone, (3) carbonate-rich sandstone, (4) ripple-to-trough cross-laminated sandstone with common convolute bedding, (5) trough cross-laminated sandstone with abundant mud rip ups and mud balls, and (6) heavily bioturbated sandstone. Combined lithofacies and ichnofacies observations suggest that paleoenvironments of the Katz Field included a bayhead delta, back-barrier estuary embayment, tidal flood delta, tidal flat, and upper to middle shoreface (Jesse G. White, 2014). The LSS is associated with the back-barrier estuary embayment depositional environment, evidenced by the abundance of mudstone.

Figure 13 provides core photos and associated descriptions of a core sample taken in the Katz field within an embayment environment. Core descriptions of this core sample observed characteristics that serve as excellent sealant properties to prohibit the migration of injection fluids above the injection zone. Conventional core data was collected in an offset well near the LSS depths in the API #42-433-33534 well, 5,089' away from the KSU 2361 well. Figure 14 is a cross-section relating the KSU 2361 well and the API #42-433-33534 well, indicating the cored interval alongside pictures of the lower portion of the core that most closely resembles the LSS. Horizontal permeabilities within the pictured core data range from 0.05 to 0.3 mD, with a vertical permeability value of less than 0.01 mD.

Along with the core reports and descriptions, Figure 14 plots calculated log curves from petrophysical analyses run on open-hole log data from the KSU 2361 well. Figure 14 indicates no effective porosity within the LSS (JPHIE green curve, 2nd track from the left) with a shale lithology reading (JHSHALE, green shading, 3rd track from the left). The petrophysical properties and lithology indicated by core and log data demonstrate that the LSS possesses characteristics of an excellent sealing formation.



<u>4991 TO 4998</u>:

4991.00 – 4997.4: Black to dark gray lenticular to wavy bedded mudstone encasing light gray lenticular siltstone to muddy very-fine sandstone. Abundant light gray calcareous horizons. Note zones of reddish color.

4997.4 – 4997.5: Burrowed transgressive bioclastic lag deposit? Abundant crinoid and bioclastic debris over burrowed laminated to contorted black shale.

4997.5 - 4997.7: Black laminated shale

4997.7 - 4998.0: Dark gray to gray black crinoid mudstone interbedded with a single tan algal mudstone-wackestone hardground exhibiting mudcracks.

Trace fossils shown in blow-ups include *Paleophycus, Planolites, Thalassinoides* and *Teichichnus*.

Sedimentology infers **brackish water deposits** (Brackish water is water that has more salinity than fresh water, but not as much as seawater. It may result from mixing of seawater with fresh water, as in estuaries.

4991 - 4998: Estuary – embayment. Brackish water deposit. Muddy.

Figure 13 – Core Description

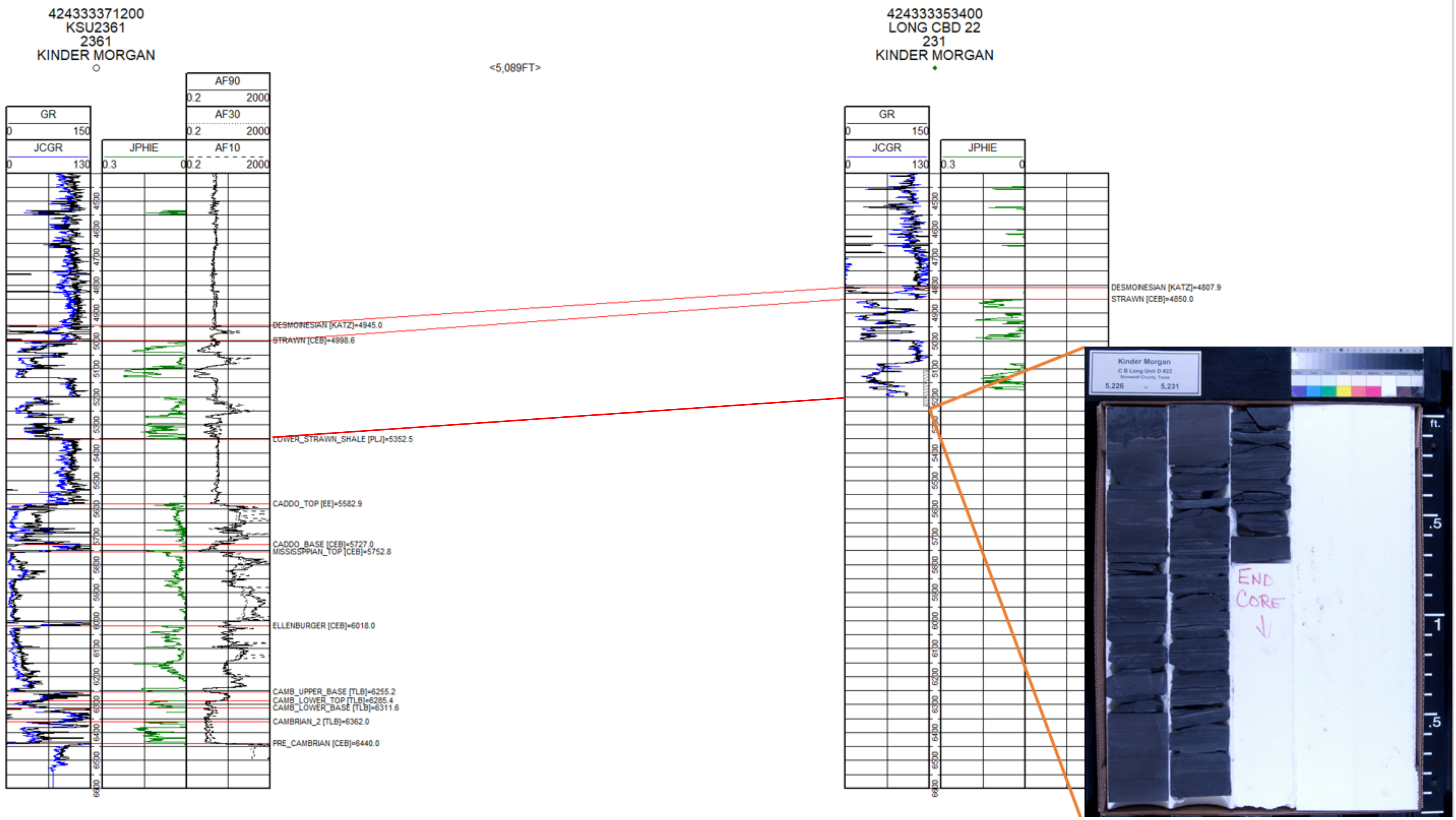


Figure 14 – Cross Section Depicting Correlative Offset Core with Lower Strawn Shale

2.2.4 Injection Interval – Ellenburger/Cambrian Sands

Ellenburger

The Ellenburger is a widespread lower Ordovician carbonate deposited over the entire north Texas area, indicating a relatively uniform depositional condition (Hendricks, 1964). North Central Texas experienced a low-energy, restricted shelf environment comprised of a homogeneous sequence of gray to dark-gray, fine to medium crystalline dolomite containing irregular mottling (probable bioturbation structures) and lesser parallel-laminated mudstone and peloid-wackestone (Kerans, 1990). Figure 15 is a map depicting the different depositional environments of the lower Ordovician, with associated lithologies. This map confirms the inferred dolomite lithology of the open hole log analysis in Figure 11 of the KSU 2361 well.

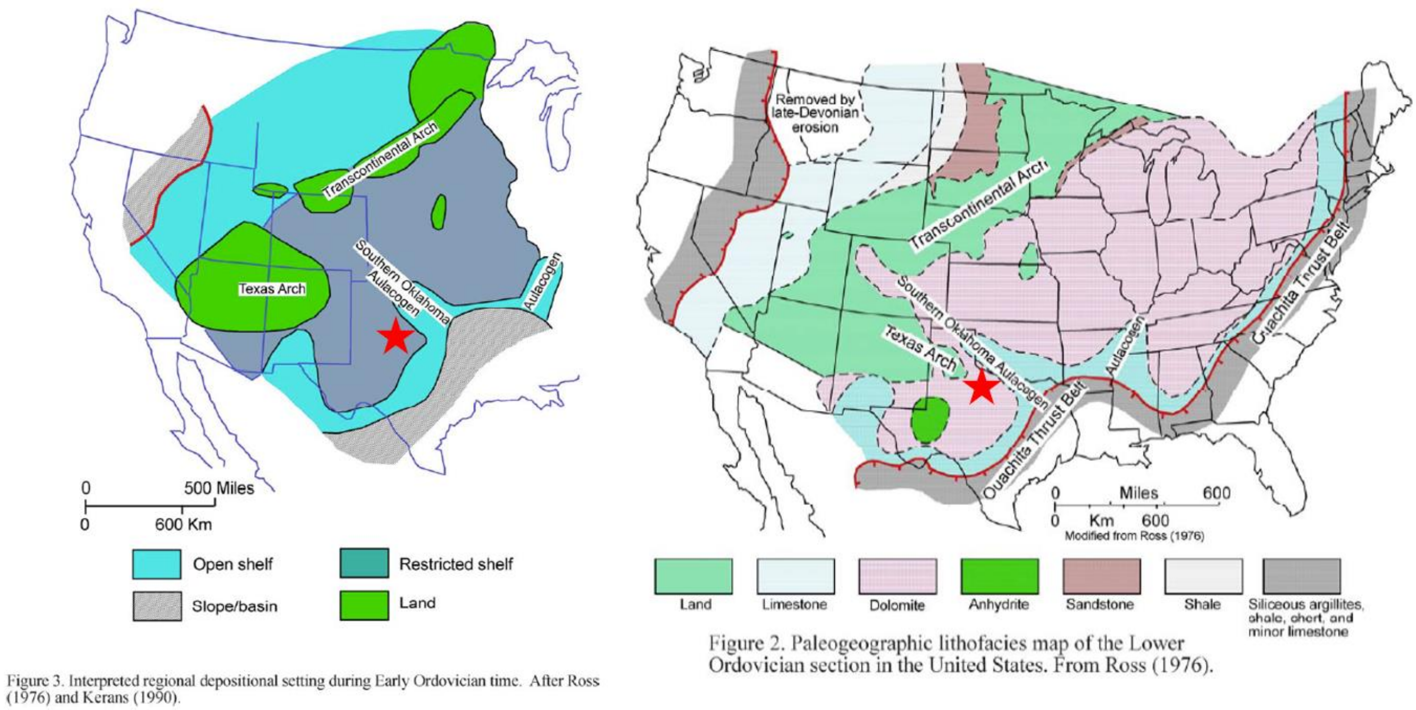


Figure 15 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

Ellenburger Porosity/Permeability Development

Within the low-energy, restricted shelf environment, facies are highly dolomitized and have a heavy presence of bioturbation resulting in mottling (Loucks, 2003). The dolomitization led to porosity development within the Ellenburger, along with diagenetic leaching processes and other secondary porosity features such as karsts and vugs. The tables in Figure 16 show permeability and porosity values tabulated from Ellenburger reservoirs within Texas, categorized by their diagenetic facies into three groups: Karst Modified, Ramp Carbonates, and Tectonically Fractured Dolostones. Based on the descriptions in Figure 16, the Ellenburger of the KSU 2361 would fall within the Karst Modified Reservoirs category outlined in red with average porosity and permeability values of 3% and 32 mD, respectively. This corresponds with the data collected from the KSU 2361 well. As shown in Figure

11 above, the calculated effective porosity curve in green (JPHIE) is an average of roughly 3% over the Ellenburger formation. Permeability was estimated from volumes injected plotted against pressure responses within the KSU 2361 well; these permeabilities ranged from 12-20 mD. Similarities between these two datasets validate reservoir characteristics used for model inputs.

Cambrian

The deposition of Cambrian and lower Ordovician strata on the early Paleozoic shelf was initiated by a transgressing sea which, entering the area from the south, first laid down a clastic sequence. Initial deposits were sandstone and arenaceous carbonates that grade upward into the slightly cherty carbonates of the Ellenburger group (Galley, 1958). Lithologies include glauconitic and phosphatic to clean sandstones of various textures, intergrading and alternating with chemical, clastic, and even local limestones and dolomites, together with intercalated thin shales (Conselman, 1954).

Cambrian Porosity/Permeability Development

Few reservoir characteristics have been published on the Cambrian sands. Porosity and permeability were estimated based on the KSU 2361 wells open hole log and injection data. There are three discreet sandstone intervals within the Cambrian at this location. The upper two sands identified in the CAMBRIAN package have an average effective porosity of 12.9% and 8.8%. The average effective porosity of the third sand is 8.4%. These effective porosity values are plotted as the JPHIE (effective porosity) curve in Figure 11. Due to nature of the Ellenburger and Cambrian zones being commingled during injection tests, modeling makes the assumption of 12-20mD average permeability for the interval, for history matched injection volumes and pressures.

Table 2. Geologic characteristics of the three Ellenburger reservoir groups. From Holtz and Kerans (1992).

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 16 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

Formation Fluid

Four wells were identified within approximately 20 miles of the KSU 2361 well through a review of oil-field brine compositions of the Ellenburger formation from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3. None of these four wells are salt water disposal wells. The location of these wells is shown in Figure 17. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids. Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger Formation is compatible with the proposed injection fluids.

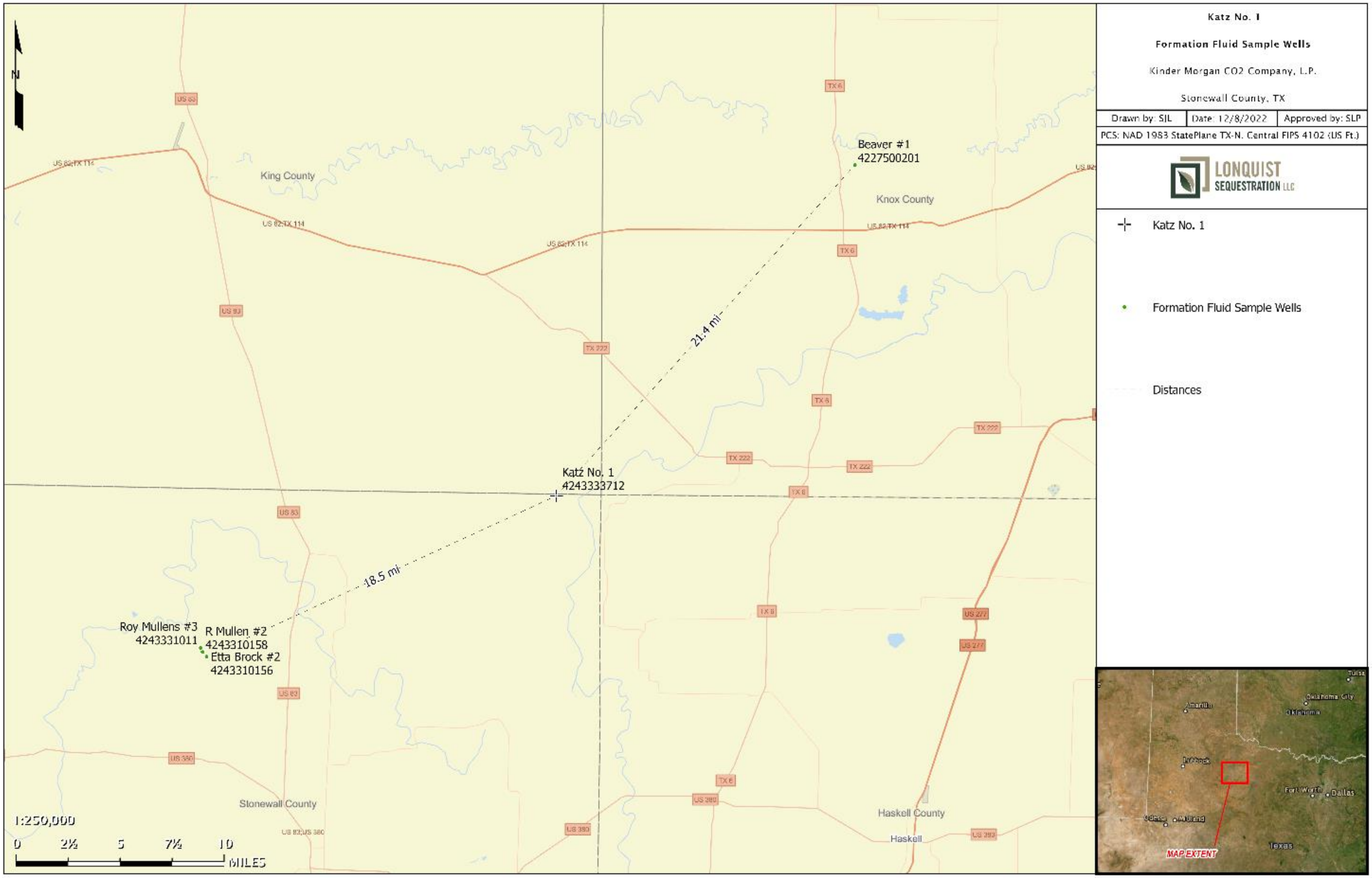


Figure 17 – Offset Wells used for Formation Fluid Characterization.

Table 3 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples

	Average	Low	High
Total Dissolved Solids (ppm)	144065	98802	210131
pH	6.15	5	7
Sodium (ppm)	43391	30833	64222
Calcium (ppm)	9275	5128	13200
Chlorides (ppm)	88355	60061	128685

2.2.5 Lower Confining Zone – Precambrian

The Precambrian outcrops to the south at the Llano uplift and the west in the Trans-Pecos regions of Texas and central New Mexico. Outcrops near the Llano Uplift in McCulloch County consist of highly weathered granite, schist, and gneiss. The granite is fine- to coarse-grained and contains numerous pegmatite veins. The schist has a high percentage of biotite, which gives it a dark-gray color, and it is often referred to as "gray shale" or "blue mud" by well drillers. The gneiss is pinkish and fine-grained (Mason, 1961). A study in 1996 was performed by Adams and Keller to better understand the Precambrian distribution in Texas indicates that Precambrian at the Katz 2361 location should contain an average metamorphic rock, as seen in Figure 18. This agrees with the open hole log response in the Precambrian formation in the open hole log section of Katz 2361. Gamma-ray log values of the Precambrian section are consistently above 90 GAPI (Gamma Units of the American Petroleum Institute), indicating a high radioactive response. A very high resistivity reading within this section indicates little to no porosity, as shown in the JPHIE, validating the characteristics described above. These traits are ideal attributes of a tight, lower confining basement.

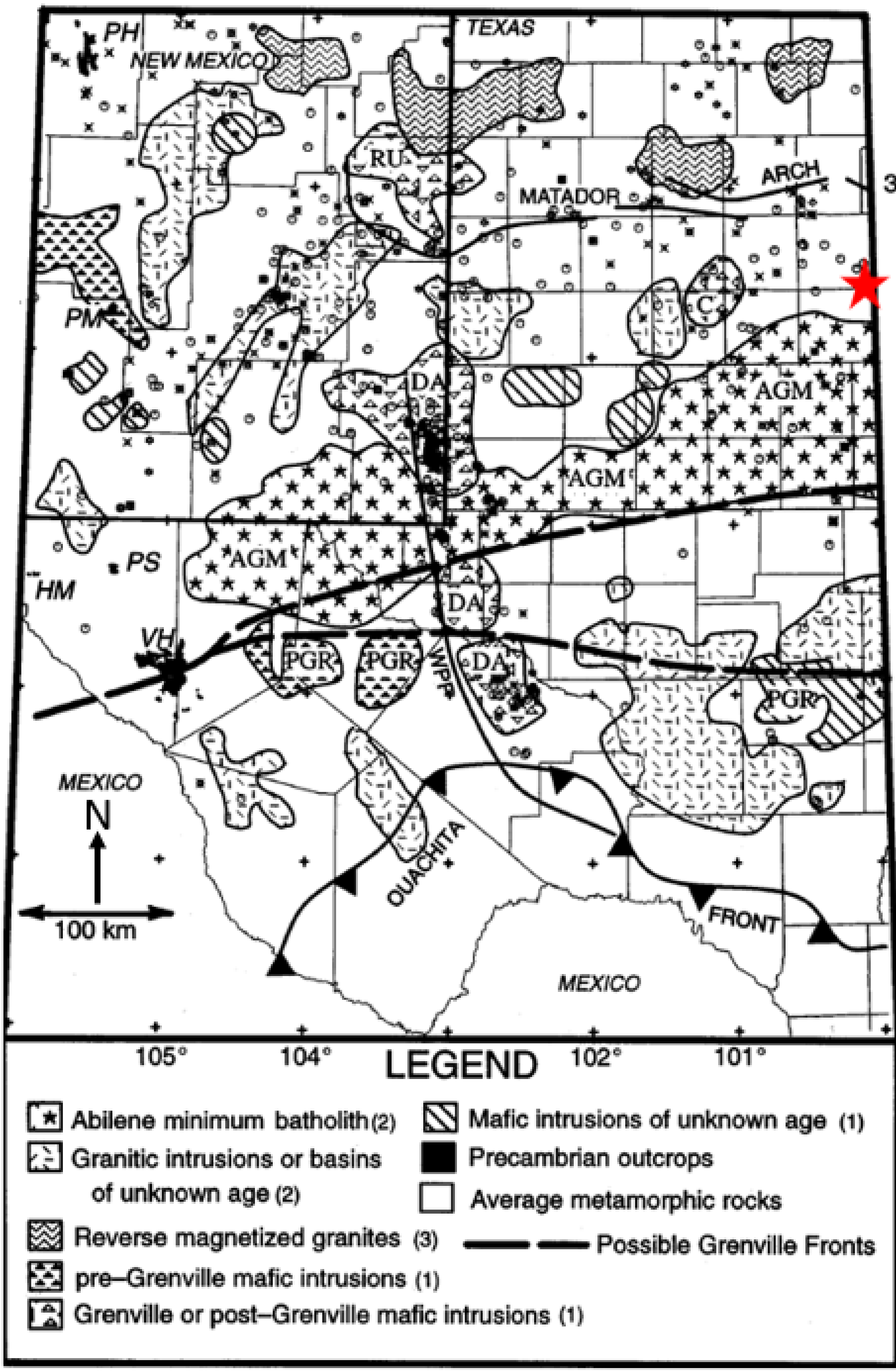


Figure 18 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Fracture Pressure Gradient

Fracture pressure gradients were estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for determining fracture gradients. Poisson's ratio (ν), overburden gradient (OBG), and pore gradient (PG) are all variables that can be changed to match the site-specific injection zone. The expected fracture gradient was determined using industry standards and a literature review. The overburden gradient was assumed to be 1.05 psi/ft. This value is considered best practice when there are no site-specific numbers available. The pore pressure gradient was calculated to be 0.43 psi/ft from the bottom hole pressure data. For limestone/dolomite rock in the injection zone, the Poisson's ratio was assumed to be 0.3 through literature review (Molina, Vilarras, Zeidouni 2016). Using these values in the equation below, a fracture gradient of 0.70 psi/ft was calculated for the injection zone.

For the upper confining interval, a similar fracture gradient was calculated. The upper confining shale has an increased chance to vertically fracture if the injection interval below is fractured (Molina, Vilarras, Zeidouni 2016). Therefore, a Poisson's ratio equal to that of the injection interval was used as a conservative estimate. The lower confining zone was assumed to be of a similar matrix to the injection interval, with the key difference being that the formation is much tighter (lower porosity/permeability). Therefore, the Poisson's ratio was assumed to be slightly higher in this rock. As seen in Table 4, the fracture gradient of .64 psi/ft is slightly higher in the lower confining zone.

Multiple approaches can be taken to manage reservoir pressure. Current engineering practices for acid gas CO_2 injection recommend applying a 10% safety factor to the fracture pressure of the geology being injected into, resulting a 0.63 psi/ft gradient. This new value represents the maximum allowable bottom-hole pressure during injection. Another approach is to maintain a maximum wellhead pressure (WHP). In the reservoir model, a WHP of 1,850 psi was used to constrain the simulated well. This translates to a value that is 84% of the frac gradient or a 16% safety factor. By using either approach, there is a reduced risk of fracture propagation in the injection zone.

A conservative maximum pressure constraint of 0.60 psi/ft was used for injection modeling, which is well below the calculated fracture gradient for each zone. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

Table 4 – Fracture Gradient Assumptions

	Injection Interval	Upper Confining	Lower Confining
Overburden Gradient (psi/ft)	1.05	1.05	1.05
Pore Gradient (psi/ft)	0.43	0.43	0.43
Poisson's Ratio	0.30	0.30	0.31
Fracture Gradient (psi/ft)	0.70	0.70	0.71
FG + 10% Safety Factor (psi/ft)	**0.63**	**0.63**	**0.64**

The following calculations were used to obtain fracture gradient estimates:

$$FG = \frac{\mathrm{n}}{1-\mathrm{n}}(OBG - PG) + PG$$

$$FG = \frac{0.3}{1-0.3}(1.05 - 0.43) + 0.43 = 0.70$$

$FG\ with\ SF = 0.70\ \times (1 - 0.1) = \mathbf{0.63}$ **(Injection and Upper Confining intervals)**

$FG\ with\ SF = 0.71 \times (1 - 0.1) =$ **.64 (Lower Confining interval)**

2.4 Local Structure

Regional structure in the area of the KSU 2361 well is influenced by a shallow angle ramp down dip to the southwest towards the Midland Basin, which is set up by a north-south regional fault to the east. Specifically, the KSU 2361 well is located on the western portion of a shelf-like feature that dips slightly away from the fault to the east. Figure 19 is a structure map on the top of the Ellenburger with the KSU 2361 well indicated by the black star.

Subsurface interpretations of the Ellenburger formation heavily relied on 3D seismic coverage in the area. The seismic coverage outline is represented by the purple boundary seen in Figure 19. Only two wells penetrated the Ellenburger formation within the 3D seismic data volume and are shown in the northwest to southeast seismic profile along with the cross-section in Figure 22. These two wells are active injection wells within the proposed injection interval operated by Kinder Morgan, one being the Katz 2361 well while the other is the Katz #3741 well. Both wells were used to create time-to-depth conversions for the Ellenburger horizon. Shallower formations provide additional well control to assist in creating time-to-depth conversions displayed in the seismic profiles in Figures 21 and 22.

The KSU 2361 well is located roughly 12,000’ west of the mapped fault seen in Figure 19. This distance provides a buffer between the injection plume and the fault that alleviates concerns regarding the interaction between the injectate and the fault. As shown in the seismic profile, this fault does not project above the Caddo formation and is not present in the LSS. As this fault does not project into the upper confining shale layer, there is little risk of the fault acting as a conduit for the injectate to leak outside the proposed injection interval.

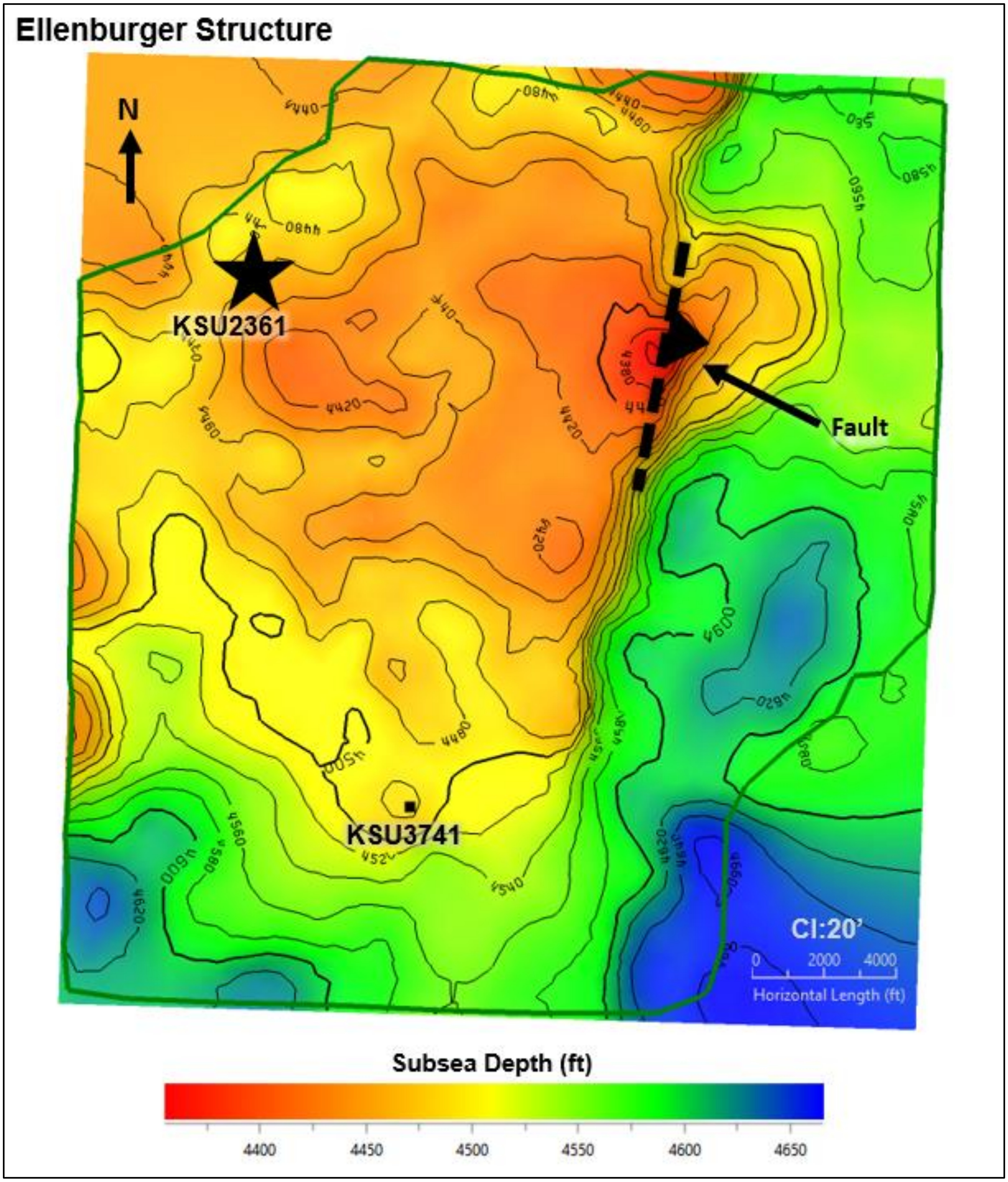


Figure 19 – Ellenburger Structure Map (Subsea Depths). Contour Interval (CI) on Ellenburger Structure map is 20'. The green outline is the boundary of the seismic data.

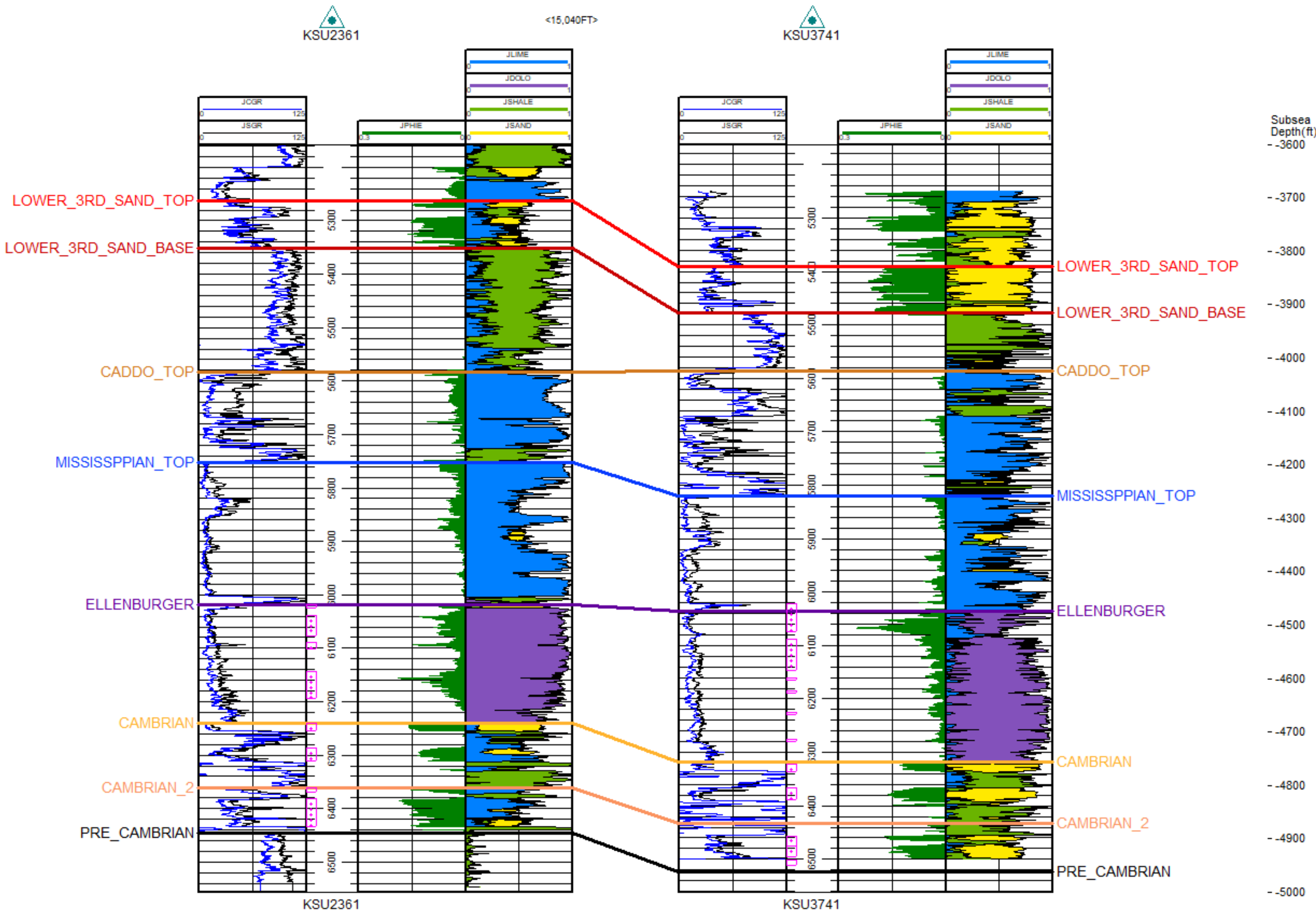


Figure 20 – Structural Northwest-Southeast Cross Section

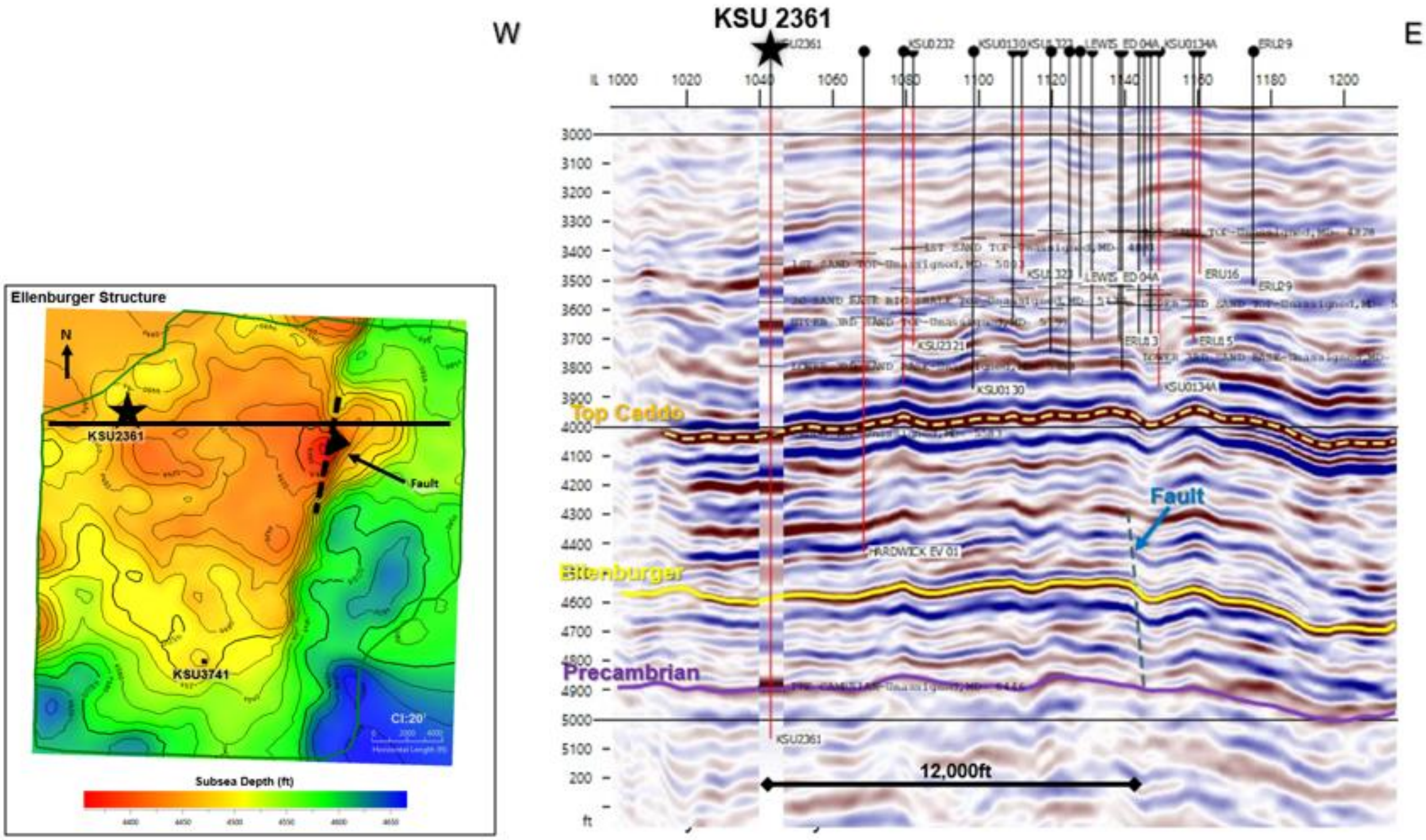
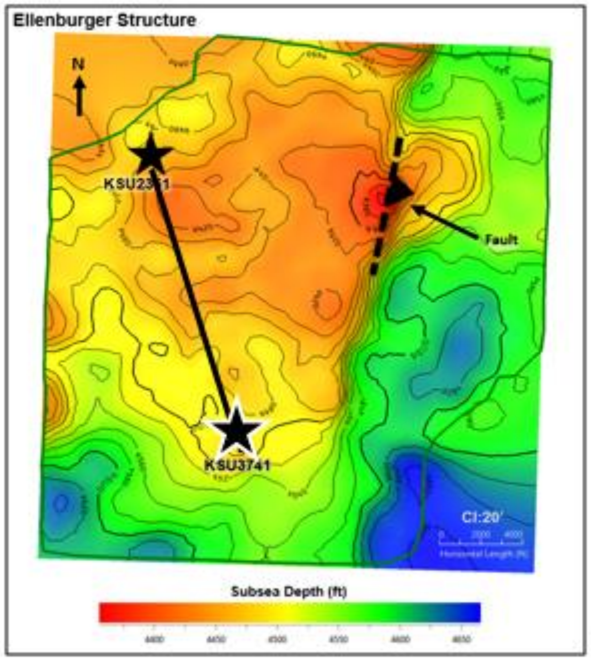


Figure 21 – Structural West to East Seismic Profile. Ellenburger structure map modified from Figure 19.



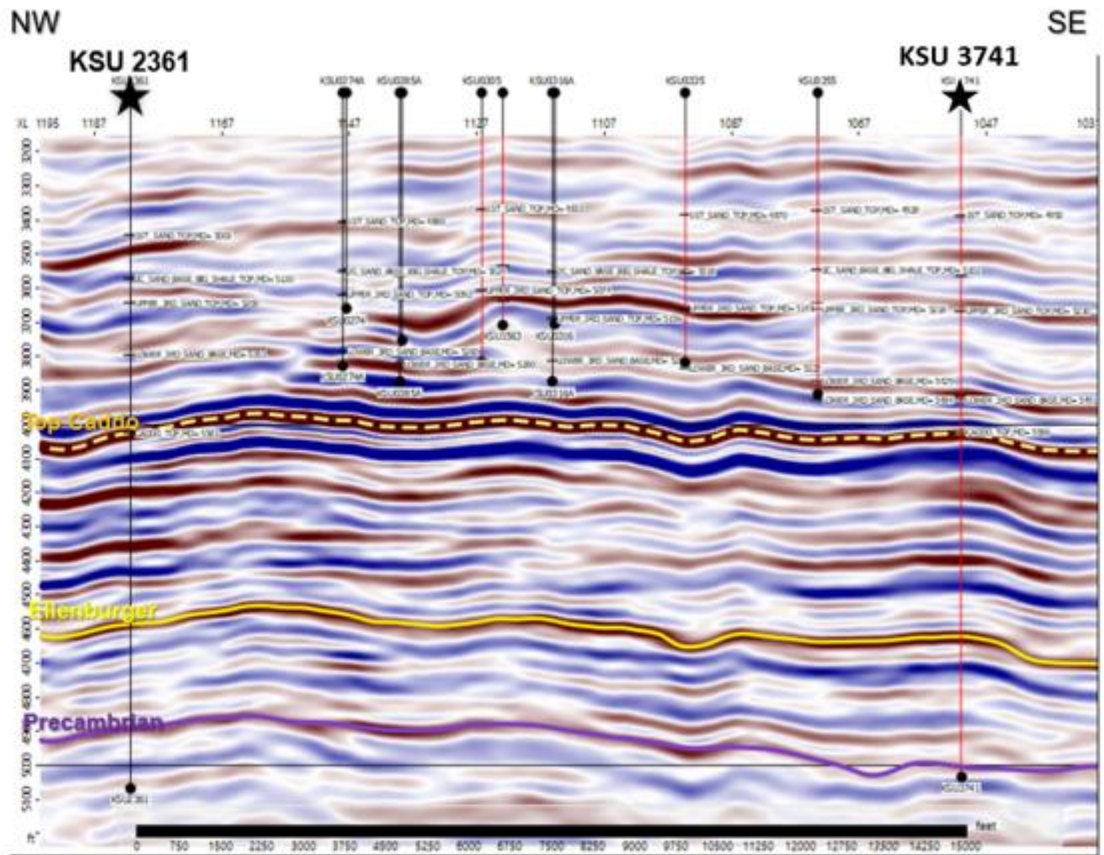


Figure 22 – Structural Northwest to Southeast Seismic Profile between the two wells that penetrate the Ellenburger within the seismic volume. Ellenburger structure map modified from Figure 19.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger and Cambrian sand formations at the KSU 2361 well location indicate that the formations have sufficient thickness, porosity, permeability, and lateral continuity to accept the proposed injection fluids. The Mississippian Lime formation at the KSU 2361 well has low permeability. It is of sufficient thickness and lateral continuity to serve as the upper confining zone, with the Lower Strawn Shale acting as a secondary confining unit. Beneath the injection interval, the low permeability, low porosity Precambrian formation is unsuitable for fluid migration and serves as the lower confining zone.

The area of review has been studied to identify potential subsurface features that may affect the ability of these injection and confinement units to retain the injectate within the requested injection interval. Faults have been identified, characterized, and determined to be low risk to the containment of injectate and do not increase the risk of migration of fluids above the injection interval.

2.6 Groundwater Hydrology

Stonewall, Haskell, Knox, and King Counties fall within the boundary of the Texas Water Development Board's (TWDB) Groundwater Management Area 6. The Seymour Aquifer is identified by the TWDB's *Aquifers of Texas* report in the vicinity of the KSU 2361 well (George et al., 2011). Table 5 references the Seymour Aquifer's position in geologic time and the associated geologic formations, which include the Seymour Formation, Lingos Formation, and Quaternary alluvium (Ewing et al., 2004). A depiction of the general stratigraphy of the Seymour Aquifer is shown in Figure 23.

Table 5 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas (Ewing et al., 2004).

System	Series	Group	Formation
Quaternary	Recent to Pleistocene		Alluvium
			Seymour
Tertiary	missing		
Cretaceous			
Jurassic			
Triassic			
Permian	Ochoa		Quartermaster
	Guadalupe	Whitehorse	
		Pease River	Dog Creek Shale
			Blaine Gypsum
			Flowerpot Shale
			San Angelo
	Leonard	Clear Fork	Choza
			Vale
			Arroyo
		Wichita (upper portion only)	Lueders
			Clyde

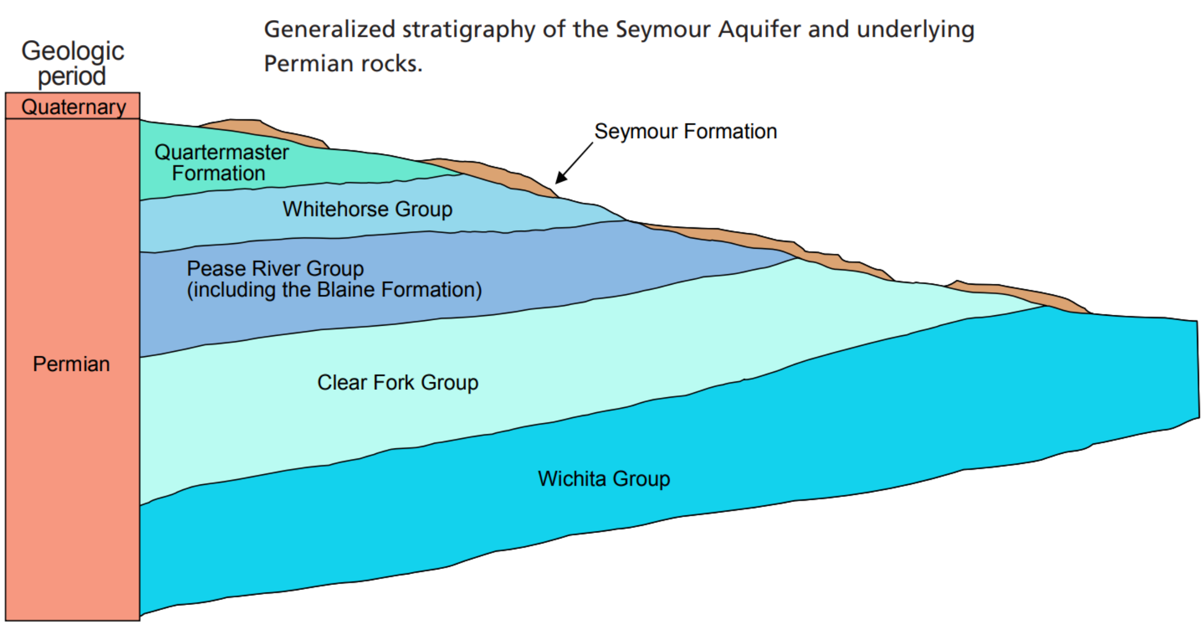


Figure 23 – Generalized Stratigraphy of the Seymour Aquifer (George et al., 2011)

The Seymour Aquifer, as defined by the TWDB, consists of isolated pods of alluvium deposits of Quaternary age, depicted in Figure 24. It extends from the southern Brazos River watershed northward to the border of Oklahoma. The Seymour Aquifer overlies Permian-age deposits that generally dip to the west. Topography, structure, and permeability variation control groundwater flow within the pods. The aquifer generally follows the topographical gradient along the major axis of the pod and discharges laterally to springs, seeps, and alluvium. Similar mechanisms can be expected within the majority of the other pods (Ewing et al., 2004).

A map showing the inferred groundwater flow pattern within a portion of one of the pods in Haskell and Knox counties is shown in Figure 25. The map approximates the natural direction of flow unaffected by pumping from wells. North of the Rule, TX, groundwater divide, the flow is toward the north, northwest, or northeast. Based on the contours of the water table and the permeabilities for the formation indicated by pumping tests, the estimated natural rate of water movement in the Seymour Aquifer, unaffected by pumping, ranges locally from approximately 200’ to 5,000’ per year. Over several miles, the estimated average rate of movement is typically between 800’ and 1,200’ per year (R.W. Harden and Associates, 1978).

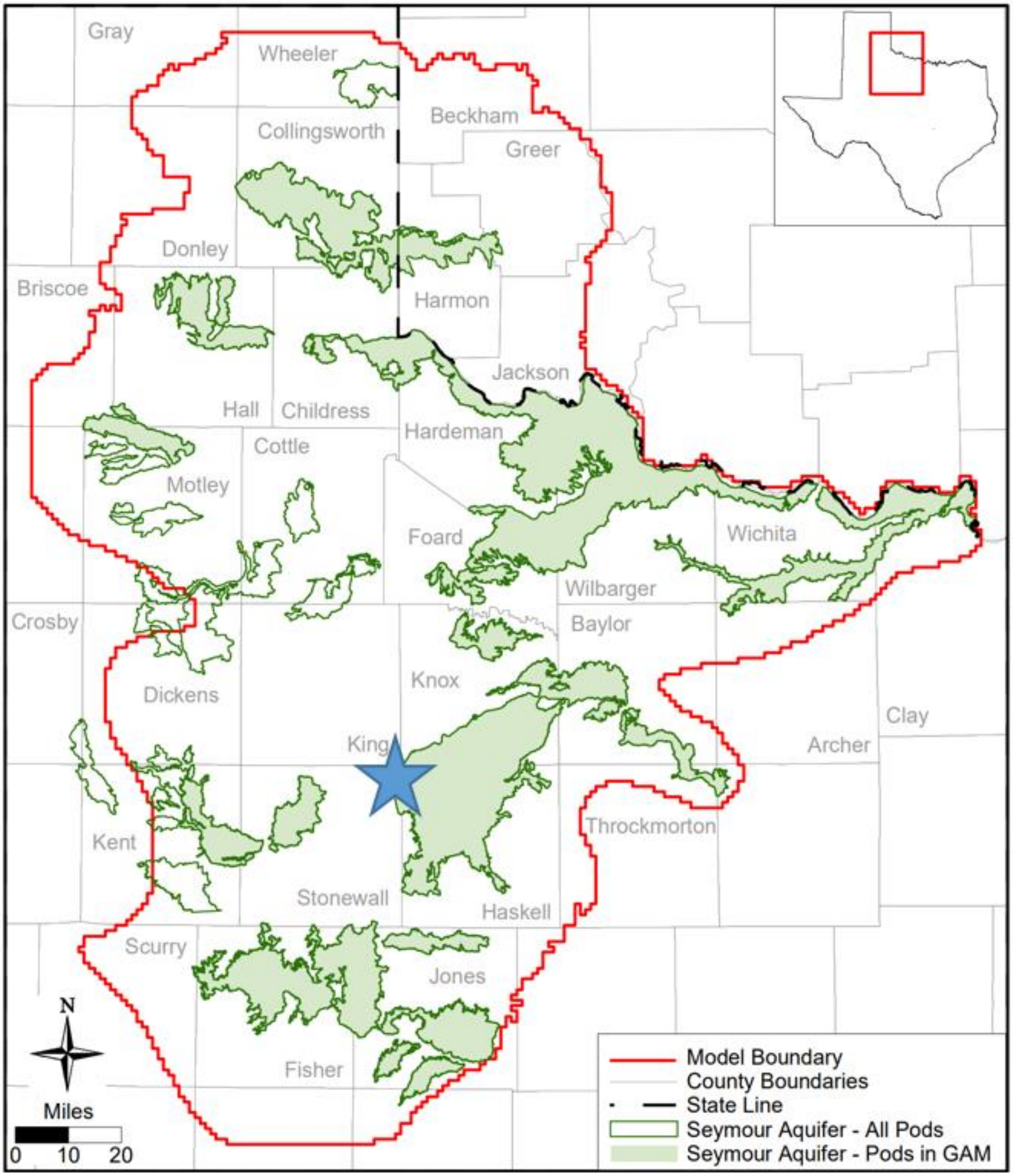


Figure 24 – Regional Extent of the Seymour Aquifer Pods (Ewing et al., 2004)

Figure 25 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer
(R.W. Harden and Associates, 1978).

Total dissolved solids (TDS) are a measure of water saltiness, the sum of concentrations of all dissolved ions (such as sodium, calcium, magnesium, potassium, chloride, sulfate, and carbonates) plus silica. As shown in Figure 26, the total dissolved solids in 41% of the wells within the Seymour Aquifer exceed 1,000 milligrams per liter (mg/L), Texas' secondary maximum contaminant level (MCL). Therefore, the utility of water from the Seymour Aquifer as a drinking water supply is limited in many areas for health reasons, primarily due to elevated nitrate concentrations, and for taste reasons due to saltiness (Ewing et al., 2004).

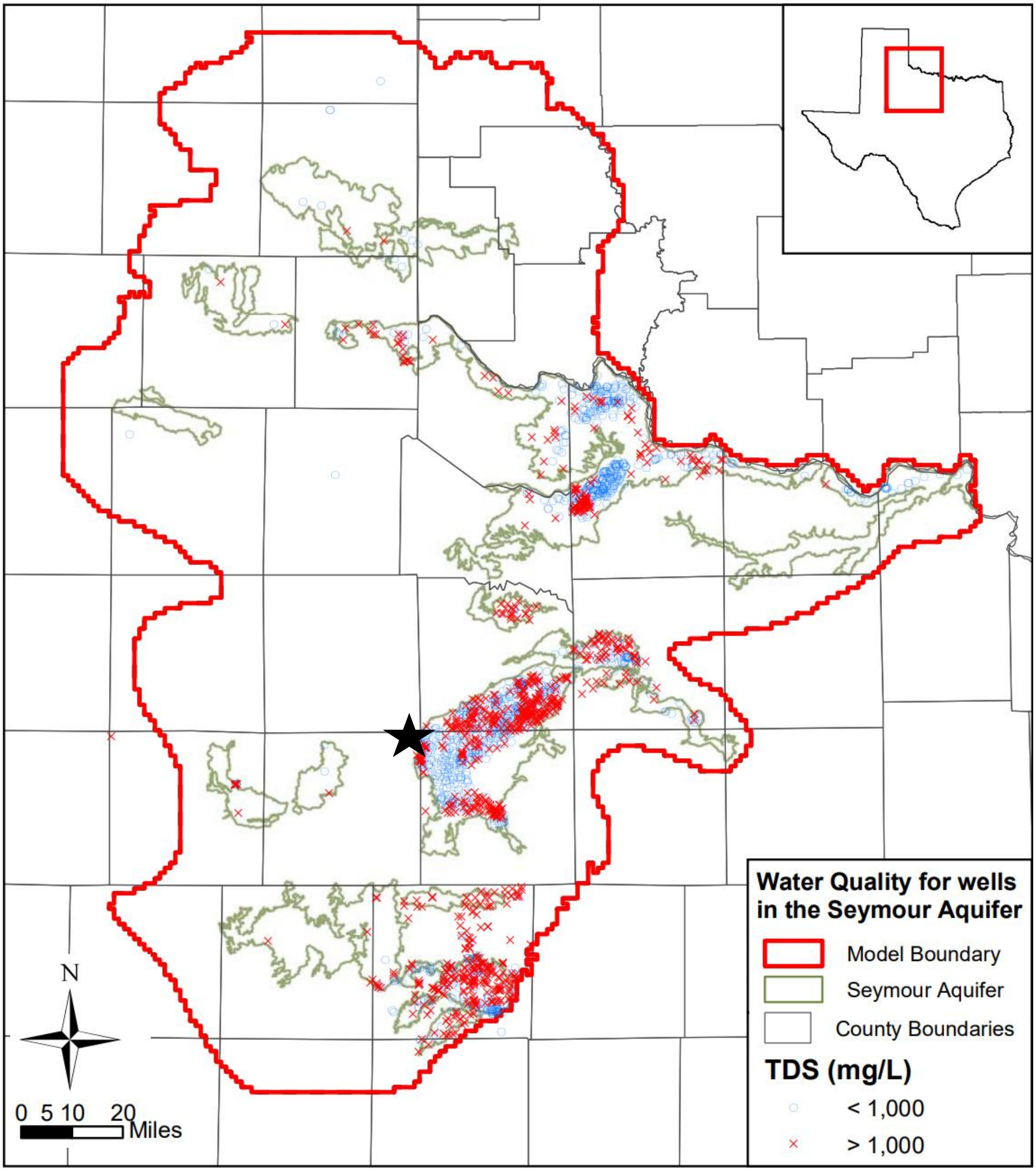


Figure 26 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer (Ewing et al., 2004)

The TRRC's Groundwater Advisory Unit (GAU) specified for the KSU 2361 well that the interval from the land surface to a depth of 100' must specifically protect usable-quality groundwater. Therefore, the base of Underground Sources of Drinking Water (USDW) can be approximated at 100' at the location of the KSU 2361 well, and there is approximately 5,920' separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued

by the TRRC as part of the Class II permitting process for the KSU 2361 well is provided in Appendix A. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Mississippian limestone, thousands of feet of tight limestone and shale beds occur between the injection interval and the lowest water-bearing aquifer.

2.6.1 Reservoir Characterization Modeling

Introduction

KSU 2361 is located in Kinder Morgan's Katz Oil Field in northeast Stonewall County. A geologic model was constructed of this area to forecast the movement of CO_2 and any pressure increases. The model is comprised of the Ellenburger and Cambrian formations, which cover 13,774 acres (~22 square miles). A single CO_2 injector was simulated for 100 years, where approximately 25 million metric tons (MMT) of CO_2 was safely stored.

Software

Paradigm's software suite was used to build the geologic and dynamic models. SKUA-GOCAD™ was utilized in building the geomodel, while Tempest™ designed the dynamic model. The EPA recognizes these software packages for an area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

SKUA-GOCAD™ is a software tool for geology that offers a range of features for structure and stratigraphy, structural analysis, fault seal, well correlation, facies interpretation, 2D/3D restoration, and basin modeling. The structure and stratigraphy module allows users to construct fully sealed structural models, while the structural analysis module provides tools for analyzing fracture probability, stress, and strain. The fault seal module enables the computation of fault displacement maps and fault SGR properties, and the well correlation module allows users to create well sections and digitize markers. The facies interpretation module offers tools for paleo-facies interpretation, and the 2D/3D restoration module provides tools for restoring 3D basin and reservoir models. Finally, the basin modeling module enables users to construct 4D basin models for transfer to basin model simulation software.

Tempest™ is another of Paradigm's industry-leading software packages for reservoir engineering. Tempest™ has history-matching capabilities, allowing for more accurate reservoir characterization modeling. In addition, this software is used to build dynamic models for CO_2 injection. Tempest™ is comprised of three modules: Tempest™ VIEW, Tempest™ ENABLE and Tempest™ MORE. Tempest™ MORE is a black oil simulator with many features and applications to simulate CO_2 injection. The Tempest™ MORE module can accept data in standard GRDECL (RMS, Petrel) file formats. It can also produce output in the ECLIPSE, Nexus/VIP, Intersect, and IMEX/GEM/STARS formats. This allows users to easily import data into the software and export it in a format compatible with other tools and systems. The standard file formats improve the interoperability and compatibility of the MORE software with other systems and tools used in the oil and gas industry

Trapping Mechanisms

To accurately simulate the CO_2 injection and predict the subsequent plume migration, Tempest™ models CO_2 trapping mechanisms in the injection zone. There are five primary trapping mechanisms: structural, hydrodynamic, residual gas (hysteresis), solubility, and geochemical. For this simulation, geochemical reactions were not considered. Each of the five mechanisms is described in further detail below.

Structural Trapping
Structural traps, a physical trapping mechanism, are underground rock formations that trap and store the injected supercritical CO_2. These traps are created by the physical properties of the cap rock, such as its porosity and permeability. For example, a structural trap may be formed by a layer of porous rock above a layer of non-porous rock, with the CO_2 being trapped in the porous rock. Some other examples of structural traps are faults or pinch-outs. Faults can limit the horizontal migration of the plume in the injected formation. The injected CO_2 is lighter than the connate brine found already in the formation. Because of this, the CO_2 floats to the top of the formation and is stored underneath the impermeable cap rock. In this model, CO_2 mass density ranges between 34.9 to 38.5 lb/ft^3 from the shallow to deep injection intervals, whereas the formation brine density is approximately 63.3 lb/ft^3.

Hydrodynamic Trapping
Hydrodynamic traps are another form of physical trapping caused by the interaction between CO_2 and the formation brine. Hydrodynamic trapping is caused by supercritical CO_2 traveling vertically upwards until it reaches the impermeable cap rock and spreads laterally through the unconfined sand layers, driven by the buoyancy and higher density of the brine in the reservoir. Once the CO_2 reaches a caprock with a capillary entry pressure greater than the buoyancy, it is effectively trapped. This type of trapping works best in laterally unconfined sedimentary basins with little to no structural traps.

Equation-of-state (EOS) calculations are performed to determine the phase of CO_2 at any given location based on pressure and temperature for structural and hydrodynamic trapping mechanisms. Several well-known EOS formulae are used within the oil and gas industry for reservoir modeling. These formulae include the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong (SRK) method. The Peng-Robinson is better suited for gas systems than the SRK method. The EOS implemented within the KSU 2361 well model was the Peng-Robinson method.

Residual Gas Trapping
Residual gas traps are also a physical form of trapping CO_2 within pore space by surface tension. This occurs when the porous rock acts as a sponge and traps the CO_2 as the displaced fluid is forced out of the pore space by the injected CO_2. As the displaced brine reenters the pore space once injection stops, small droplets of CO_2 remain in the pore space as residuals and become immobile.

Solubility Trapping
Solubility traps are a form of chemical trapping between the injected CO_2 and connate formation brine. Solubility trapping occurs when the CO_2 is dissolved in a liquid, such as the formation brine.

CO_2 is highly soluble in brine, with the resulting solution having a higher density than the connate brine. This feature affects the reservoir by causing the higher-density brine to sink within the formation, trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration. Table 6 was designed to guide the model to determine the solubility of CO_2 at various pressures and a specified salinity.

Table 6 – CO_2 Solubility Table

Pressure (psi)	CO2 Solubility (Mscf/Stb)	Salinity (ppm)
14	0.00	66,000
50	0.00	66,000
150	0.01	66,000
500	0.0198	66,000
1000	0.0297	66,000
1500	0.0388	66,000
3000	0.0660	66,000

Geochemical Trapping

Geochemical trapping is another form of chemical trapping which refers to storing CO_2 in underground rock formations by using chemical reactions to transform the CO_2 into stable, solid minerals. This process is known as mineral carbonation, and it involves the reaction of CO_2 with the minerals and rocks in underground formations to form stable carbonates. During the process of injecting CO_2 into a disposal reservoir, four (4) primary chemical compounds may be present: CO_2 in the supercritical phase, the hydrochemistry of the naturally occurring brine in the reservoir, aqueous CO_2 (an ionic bond between CO_2 gas and the brine), and the geochemistry of the formation rock. These compounds can interact, leading to the precipitation of CO_2 as a new mineral, often calcium carbonate (limestone). This process is known as mineral carbonation, a key mechanism for the long-term storage of CO_2 in underground rock formations.

Mineral trapping can also occur through the adsorption of CO_2 onto clay minerals. When modeling this process, it is important to consider both hysteresis and solubility trapping. Geochemical formulae can be included in the model using an internal geochemistry database to describe the mineral trapping reactions. These formulae can describe aqueous reactions, such as those involving CO_2 and clay minerals. For aqueous reactions, the following chemical reactions are standard formulae used in CO_2 simulation:

$$CO_2(aq) + H_2O = H^+ + HCO_3^-$$
$$CO_3^{-2} + H^+ = HCO_3^-$$
$$OH^- + H^+ = H_2O$$

The following three formulae represent three common ionic reactions that can occur between water and CO_2 within a reservoir. These reactions involve the formation of solid minerals that can be found in sandstone aquifers, and they result in the precipitation of carbon oxides. These reactions are commonly included in modeling efforts to understand and predict the behavior of CO_2 in underground storage reservoirs:

$$Anorthite\ (CaAl_2Si_2O_8) + 8H^+ = 4\ H_2O + Ca^{2+} + 2Al^{4+}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO3^-$$
$$Kaolinite\ \left(Al_2Si_2O_5(OH_4)\right) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO$$

Geochemical trapping has the potential to store CO_2 for hundreds or thousands of years, but the short-term effects of this method are relatively limited. Instead, the short-term movement and storage of CO_2 are more strongly influenced by hydrodynamic and solubility trapping mechanisms. These mechanisms involve the movement of fluids, such as water or oil, through porous rock formations and the solubilization of CO_2 in liquids, such as water or oil. As a result, these processes can be more effective in the short term at storing CO_2, although they may not have the same long-term stability as geochemical trapping.

Static Model

The geomodel was constructed to simulate the geologic structure of the Ellenburger and Cambrian formations. The grid contains 600 cells in the X-direction (East-West) and 400 cells in the Y-direction (North-South), totaling 240,000 cells per layer. Therefore, 55 layers were utilized in the model representing the gross thickness of the injection interval, totaling 13,200,000 grid blocks. The Ellenburger is comprised of 25 layers and the Cambrian is comprised of 30 layers. Each grid block is 50' by 50' by 10', resulting in a model size of 5.7 miles by 3.8 miles by 550,' as shown in Figure 27. This covers approximately 22 square miles (13,774 acres).

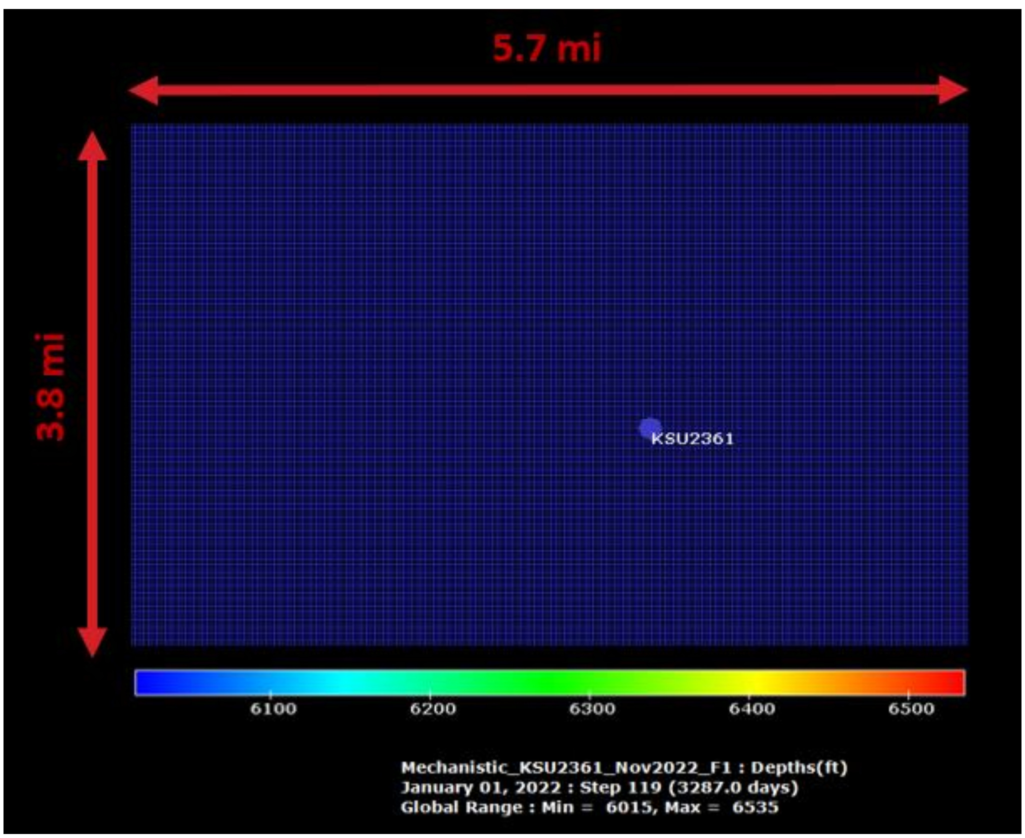


Figure 27 – Geomodel Dimensions

Well log analysis tied into seismic interpretation was used to identify any major formations tops. Four geologic units were identified and incorporated into the geomodel. Each geologic unit was used to determine the geologic structure of the injection zone. First, the Ellenburger is a carbonate formation comprised of dolomite/limestone matrix. Underlying the Ellenburger formation is the Cambrian sandstone. This sandstone was split into two geologic units, the Cambrian 1 and Cambrian 2. The Precambrian formation is at the bottom of the model. The Precambrian, comprised of granite, is the lower confining zone. Figure 28 highlights the overall structure of the target zone.

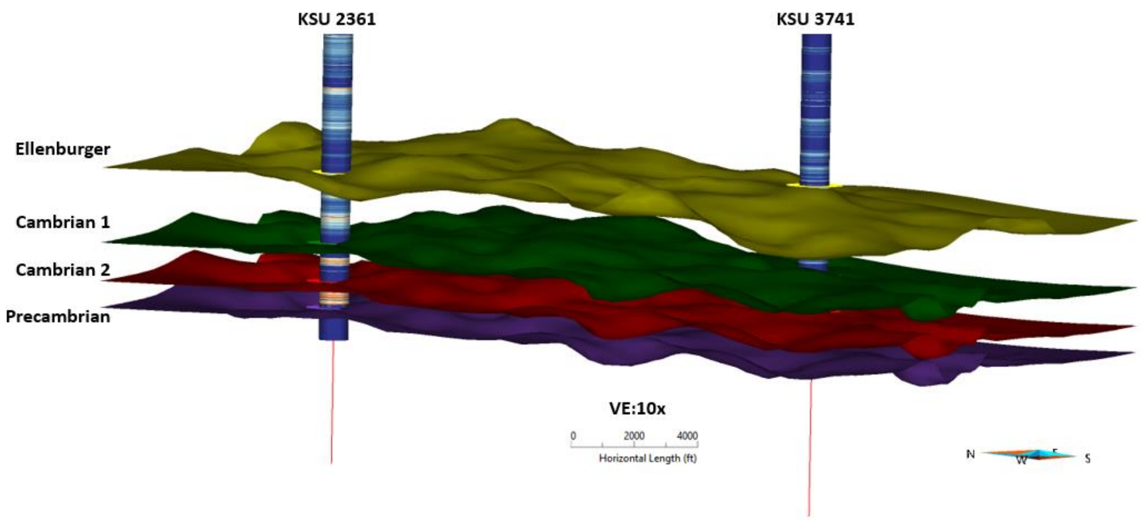


Figure 28 – Structural Horizons of the Geomodel

Permeability and porosity were distributed through the geomodel based on the formation. These rock properties were considered to be laterally homogenous in the simulation. However, vertical heterogeneity was incorporated into the model. Based on well log analysis, porosity was determined to be 10% in the Ellenburger carbonate and 12% in the Cambrian sandstone, as shown in Figure 29. Permeability was determined from history matching two wells. From this exercise, it was determined that the horizontal permeability (K_H) is 20 milliDarcy (mD) and vertical permeability (K_V) was assumed to be 10% of K_H or 2 mD. Table 7 summarizes the rock properties in the model.

Table 7 – Rock Properties

Assumptions	Values
Ellenburger Porosity (%)	10
Cambrian Porosity (%)	12
K_H (mD)	20
K_V/K_H Ratio	0.1

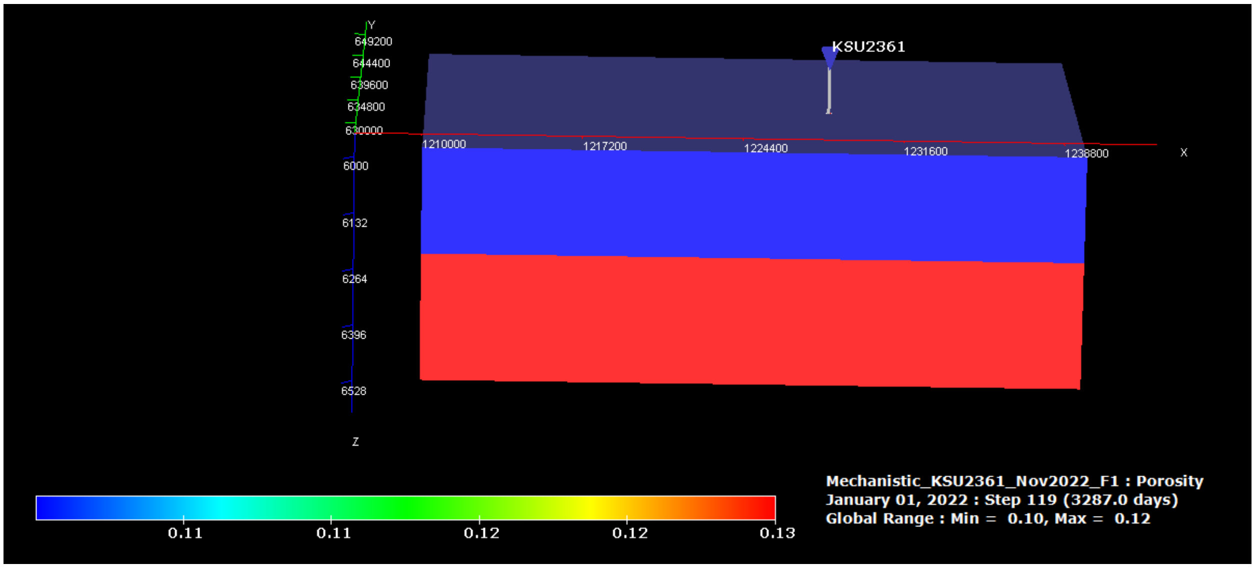


Figure 29 – Porosity Distribution in Plume Model

Dynamic Model

The primary objectives of the CO_2 plume model are as follows:

1. Determine the maximum possible injection rate without fracturing the target zone
2. Determine land acquisition strategy (i.e., maximum plume size)
3. Assess the likelihood of CO_2 leakage through potential conduits that may contaminate the Underground Source of Drinking Water (USDW)

Using the geomodel as an input, an infinite-acting model was built to simulate boundary conditions. The model assumes that the reservoir is 100% filled with brine. The formation fluid was estimated to have a salinity of 66,000 ppm. An offset step-rate test was utilized to estimate initial reservoir pressure and fracture pressure. Reservoir pressure was determined to be 2,600 psi which translates to a 0.435 psi/ft gradient. While pressure never reached high enough to propagate any fractures during the step-rate test, the fracture pressure was estimated to be approximately 4,390 psi. This translates to a fracture gradient of 0.683 psi/ft. Based off this data, a wellhead pressure of 1,850 psi was used to constrain the modelled well. An average temperature of 260 °F was also applied to the reservoir. Table 8 provides a summary of the initial conditions included in the simulation.

Table 8 – Initial Conditions Summary

Assumptions	Values
Permeability (mD)	20
Porosity (%)	10-12
Pore Gradient (psi/ft)	0.435
Frac Gradient (psi/ft)	0.683
Reservoir Temperature (°F)	260

To accurately and conservatively model the effective pore space of the rock, a net-to-gross (NTG) ratio was applied to the Ellenburger and Cambrian formations. The lateral plume extent is increased by reducing the total pore space CO_2 can flow through. Reducing the available pore space also limits

the CO_2 injection rate of the well due to higher increases in pressure. The Ellenburger had an NTG ratio of 0.5 applied, while the Cambrian formation had a 0.6 NTG ratio. This is further highlighted in Figure 30.

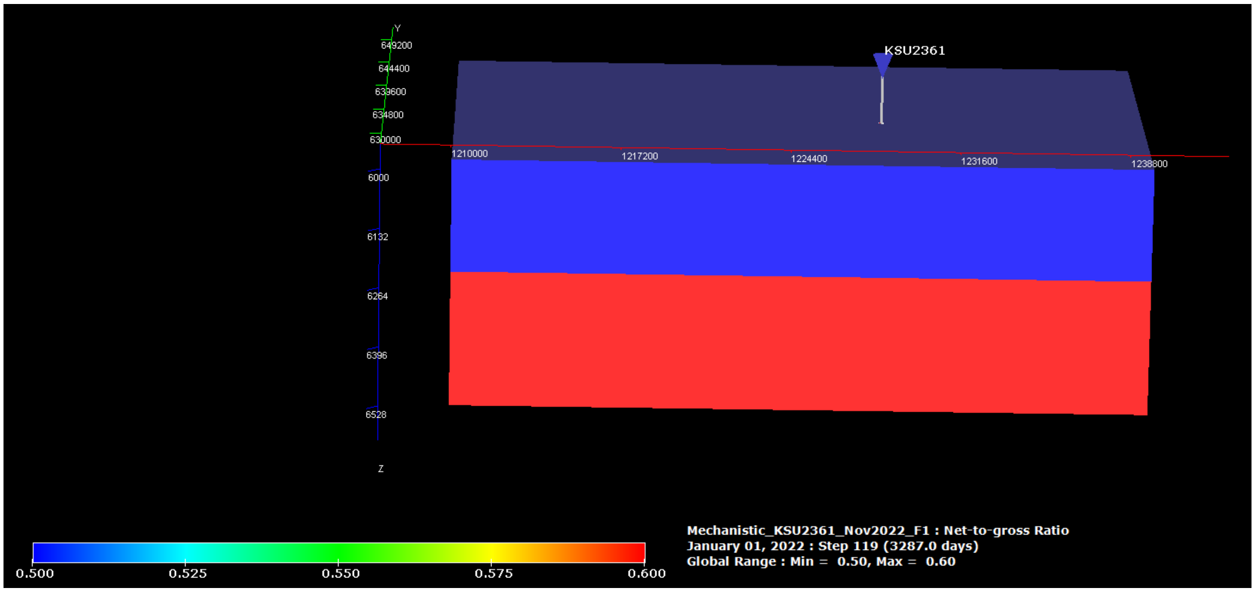


Figure 30 – NTG Ratio Applied to the Plume Model

Relative Permeability

Relative permeability curves were generated to represent a CO_2-brine system and how supercritical CO_2 will flow through a 100% brine-filled rock. Data from Kinder Morgan's McElmo Dome source models were utilized to create the relative permeability curves. The key inputs include a 9% irreducible water saturation and a 9% maximum residual gas saturation. Figure 31 shows the curves included in the simulation model.

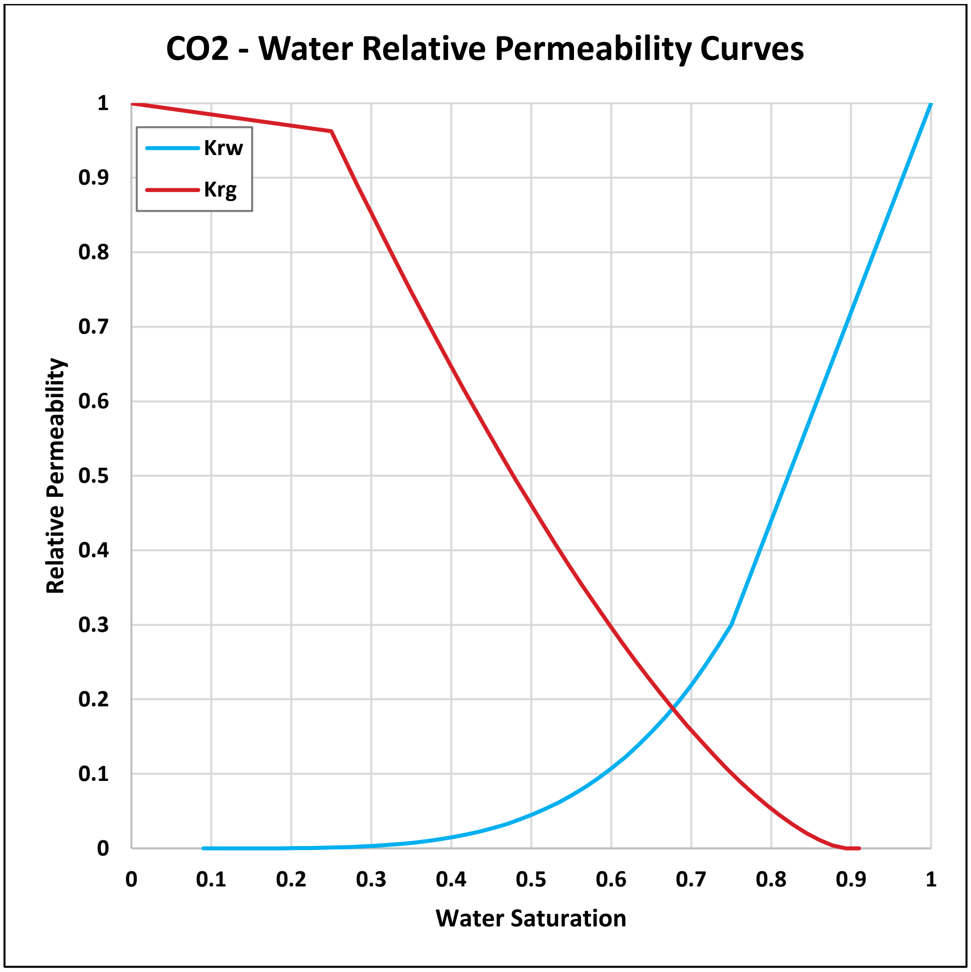


Figure 31 – CO_2-Water Relative Permeability Curves

History Matching

Two SWD wells were history-matched to determine permeability estimates. Historical injection rates were set in the model, and the simulated pressure response was compared to the recorded pressure data. This process was iterated multiple times until the simulated and real-life data matched. Monthly data points KSU 2361 (Figure 32) and KSU #3471 (Figure 33) were used to vary the injection rate in the model. These same intervals were used to compare the simulated results.

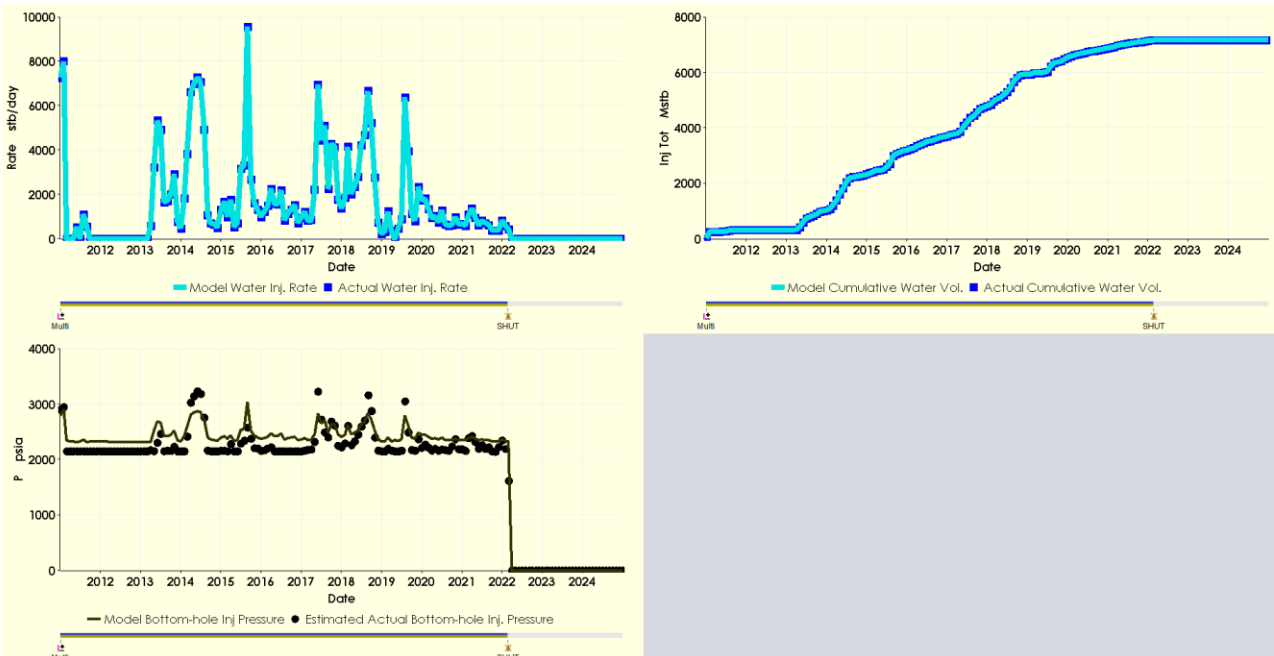


Figure 32 – History Match for KSU 2361

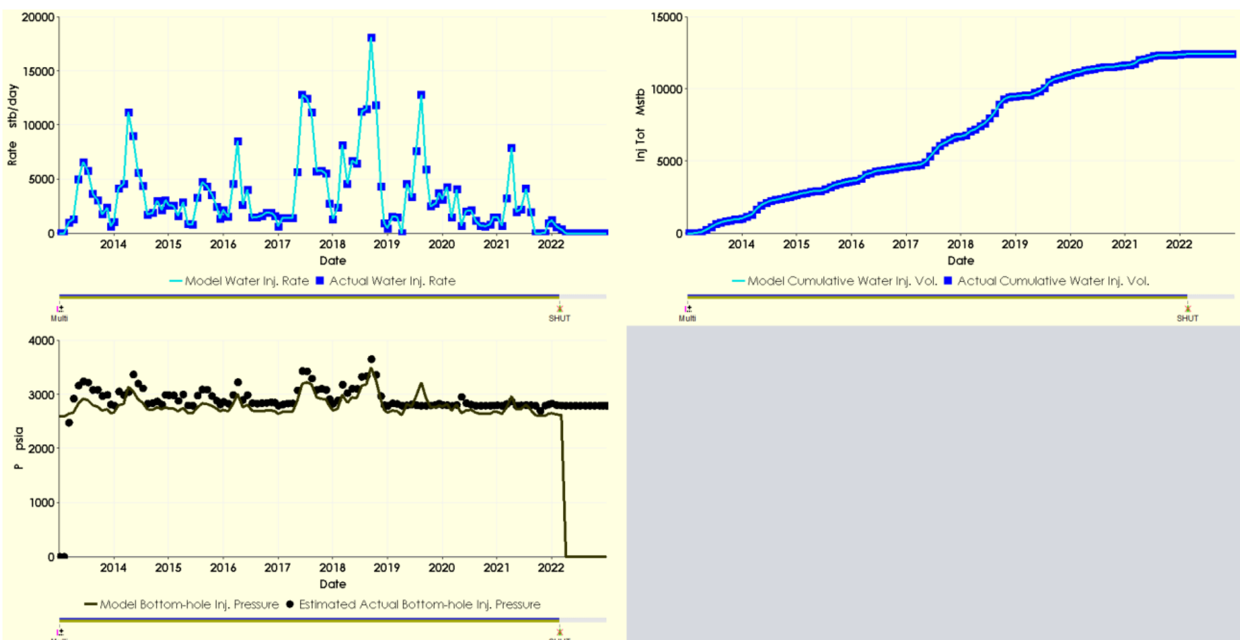


Figure 33 – History Match for KSU #3471

CO_2 Injection Operations

KSU 2361 was simulated to inject supercritical CO_2 for 21 years. A maximum wellhead pressure (WHP) was used to limit the injection rate. This value was determined from the fracture gradient estimation, and an equivalent wellhead pressure was calculated. The WHP constraint was set to 1,850 psi, equal to 84% of the fracture pressure. The injection rate was then maximized to stay

below the expected frac gradient. Figure 34 shows the simulated WHP during active injection operations.

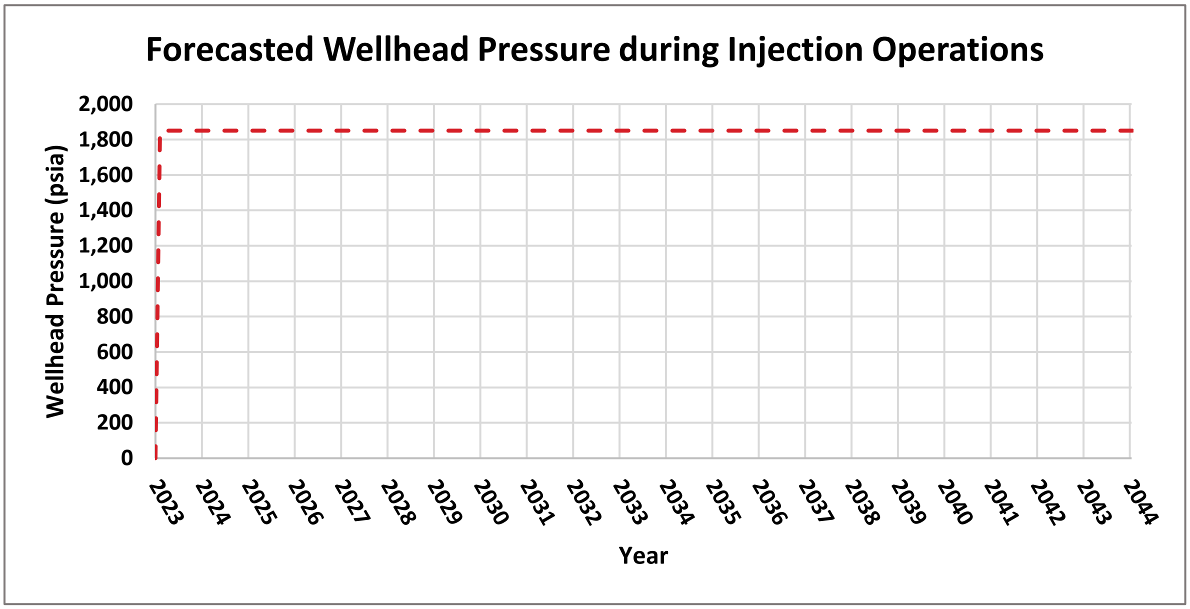


Figure 34 – Simulated Wellhead Pressure During Active Injection

During active injection, KSU 2361 achieved a maximum rate of approximately 1.22 MMT/yr. (~65 million cubic feet (MMscf)/day). During injection, the bottom hole pressure (BHP) reaches a maximum of 3,493 psi, which is safely below the fracture pressure. This is an 893-psi increase from the initial reservoir pressure. After injection ceases, the reservoir pressure decreases, reaching 65 psi buildup from the initial reservoir pressure. Figure 35 summarizes these results. The decreasing bottom-hole pressure from 2023 to 2044 is due to the relative permeability increasing over time.

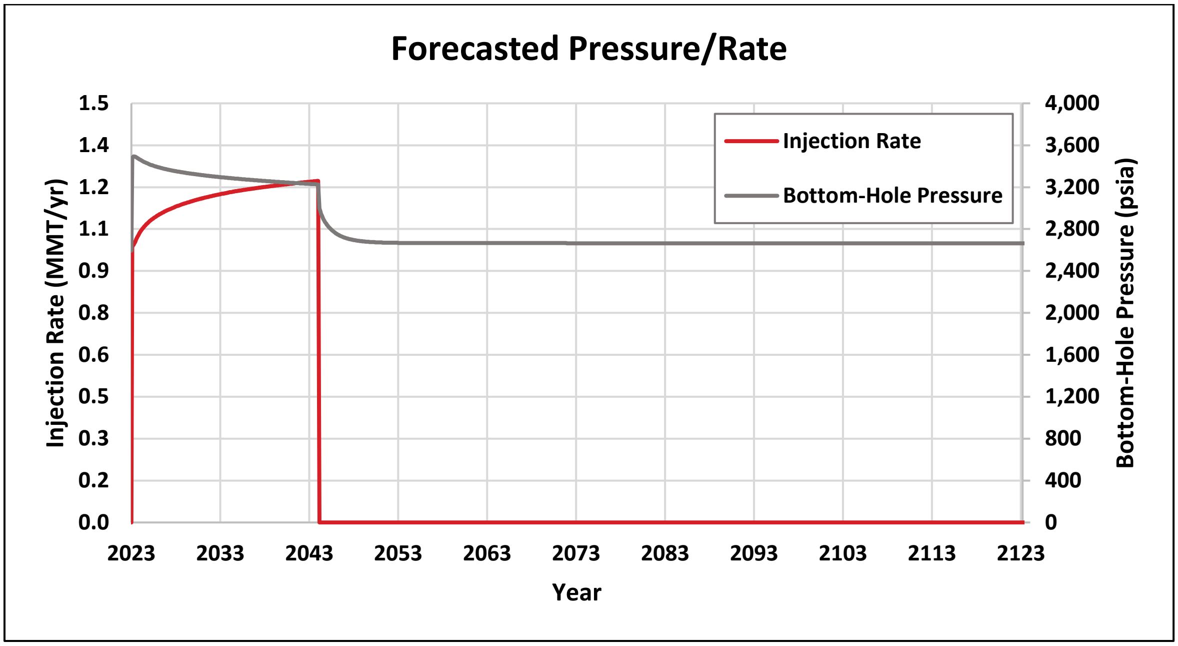


Figure 35 – Forecasted Injection Rate and BHP

Model Results

The maximum plume was determined once the plume was considered stabilized and by using a gas saturation cutoff of 3%. The plume is considered stabilized once all lateral and vertical movement of CO_2 has stopped, which also marks the end of the initial monitoring period. Aerial plume sizes were taken at 10-year intervals to determine a growth rate. As seen in Figure 36, an annualized growth rate is determined at each interval. The plume is delineated based on the maximum extent of the plume when the growth rate reaches 0%. In this model, the plume stabilizes in 2074, 30 years after the end of the injection period.

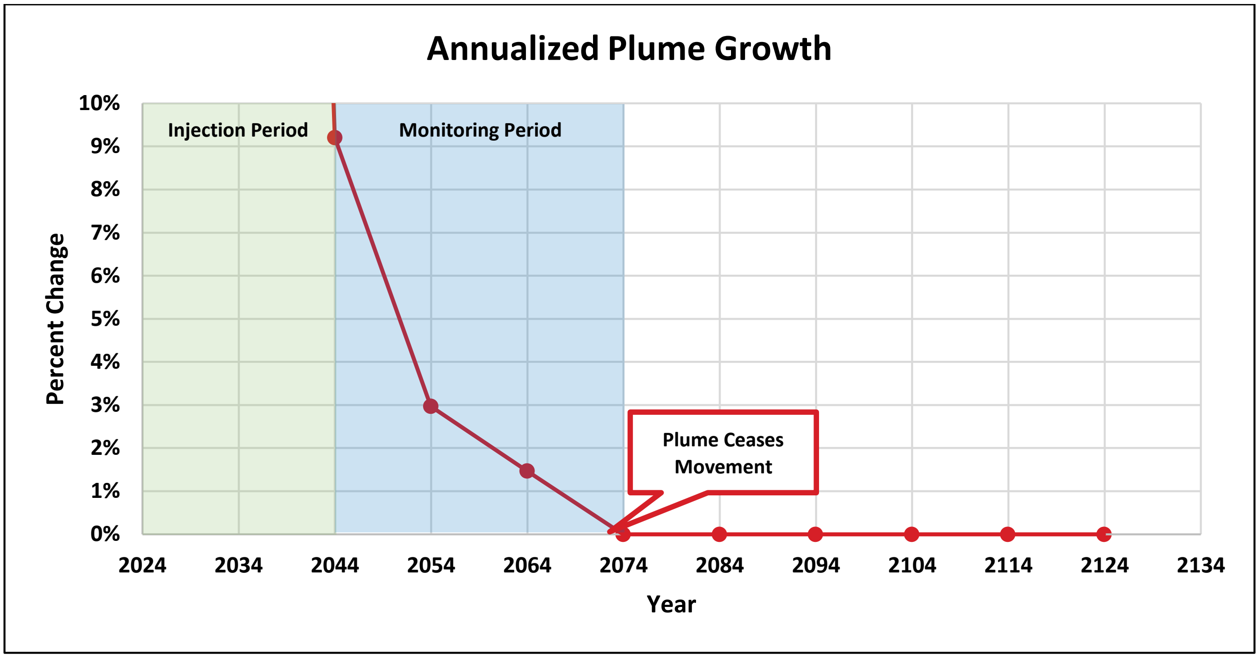


Figure 36 – Annualized Growth Rate of CO_2 Plume

The stabilized plume reaches a maximum of 3,384 ac (~5.3 sq mi). The furthest extent of this plume is to the South, as seen in Figure 37. The largest radius of the plume is 6,850' (~1.2 mi) from the wellbore. Due to the heterogeneity included in the model, the plume is not uniform from layer to layer, as seen in Figure 48. The maximum plume was chosen from the layer with the largest lateral extent of CO_2. Table 9 shows the plume radius and plume compared to time since injection starting in year zero. The results in Table 9 show that the modeled plume boundary is expected to stabilize 30 years after injection has ended. Additionally, the model was run a further 50 years to ensure the final plume boundary was stabilized, as shown in the table below.

Table 9 – Plume Model Radius and Area

Date	Year	Plume Radius (ft.)	Plume Area (Acres)
Jan-23	0	0	0
Jan-34	10	4650	1559
Jan-44	20	6400	2954
Jan-54	30	6700	3238
Jan-64	40	6800	3335
Jan-74	50	6850	3384
Jan-84	60	6850	3384
Jan-94	70	6850	3384
Jan-04	80	6850	3384
Jan-14	90	6850	3384
Jan-24	100	6850	3384

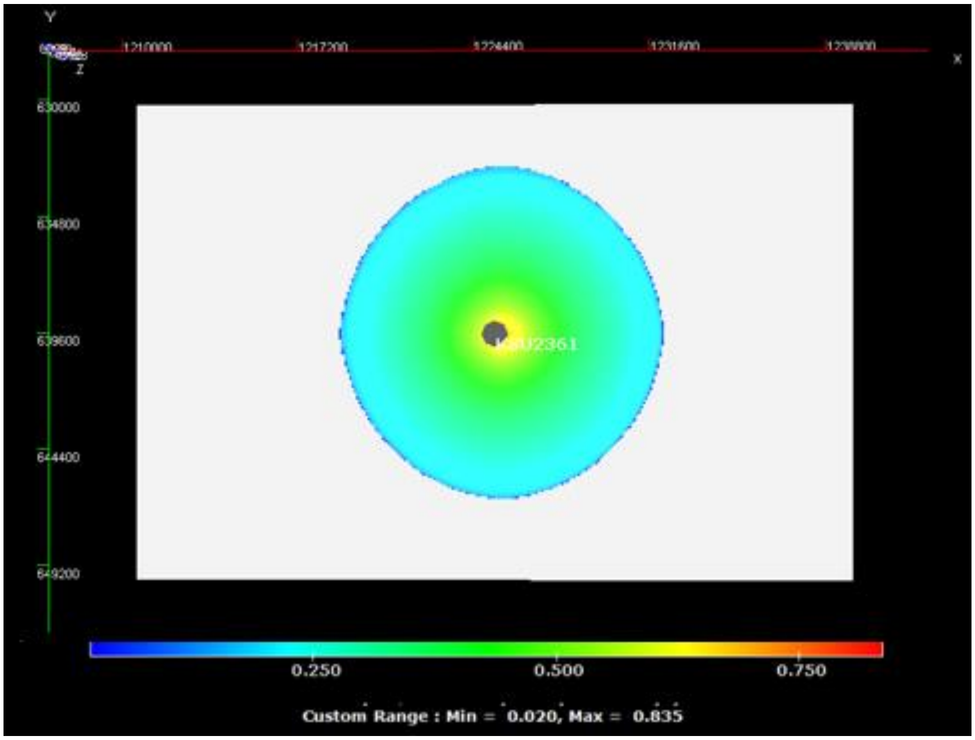


Figure 37 – Aerial View of CO_2 Plume

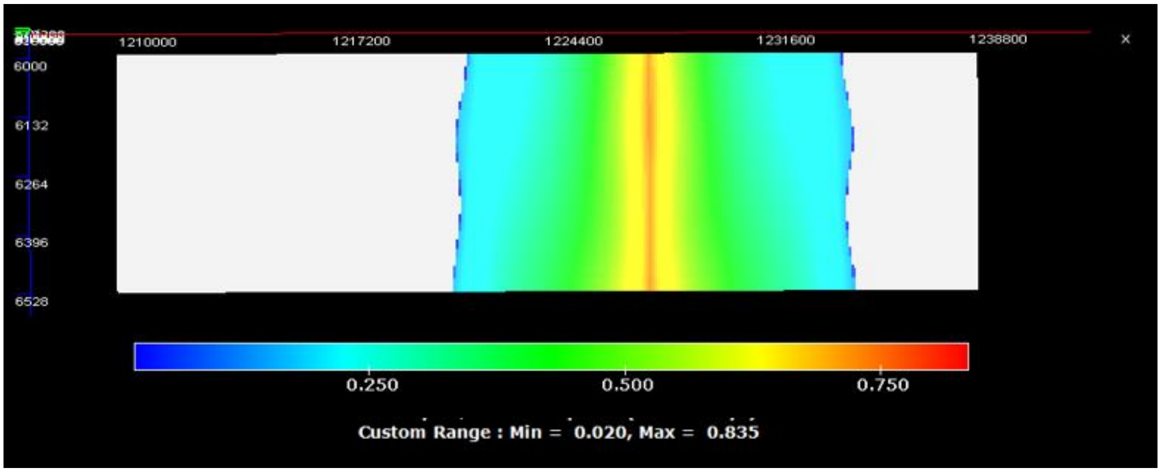


Figure 38 – Cross-Sectional View of CO_2 Plume

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA) as described in EPA 40 CFR §**98.448(a)(1**).

3.1 Maximum Monitoring Area

The EPA defines the MMA as equal to, or greater than, the area expected to contain the free-phase CO_2-occupied plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one-half mile. A numerical computer simulation was used to determine an estimate for the size and drift of the plume. Using a combination of Paradigm's SKUA-GOCAD and Aspen Technology's Tempest software packages, a geomodel, and reservoir model were used to determine the areal extent and density drift of the plume. The model accounts for the following considerations:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Kinder Morgan's pipeline gas specifications were used for the initial composition of the injectate in the model, as provided in Appendix B. The molar composition of the gas is mostly carbon dioxide, with some small amounts of nitrogen and hydrocarbons, and contained no H_2S. The molar composition was incorporated into the model as future CO_2 streams could be added for injection. As discussed in Section 2, the gas was modeled to be injected primarily into the Ellenburger and both Cambrian formations. The geomodel was created based on the rock properties seen in the Ellenburger and Cambrian rocks.

The weighted average gas saturation defined the plume boundary in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in 2044, the areal expanse of the plume will be 2,954 acres. After 30 additional years of density drift, the areal extent of the plume is 3,384 acres, with a maximum distance to the edge of the plume of approximately 6,850'. Since the stabilized plume shape is relatively circular, the maximum distance plus a one-half mile buffer from the injection well, was used to define the circular boundary of the MMA equal to 9500'.

The plume is expected to stabilize 30 years after injection ceases and does not migrate after 2050, the monitoring program of the MMA will remain active for the required amount of time.

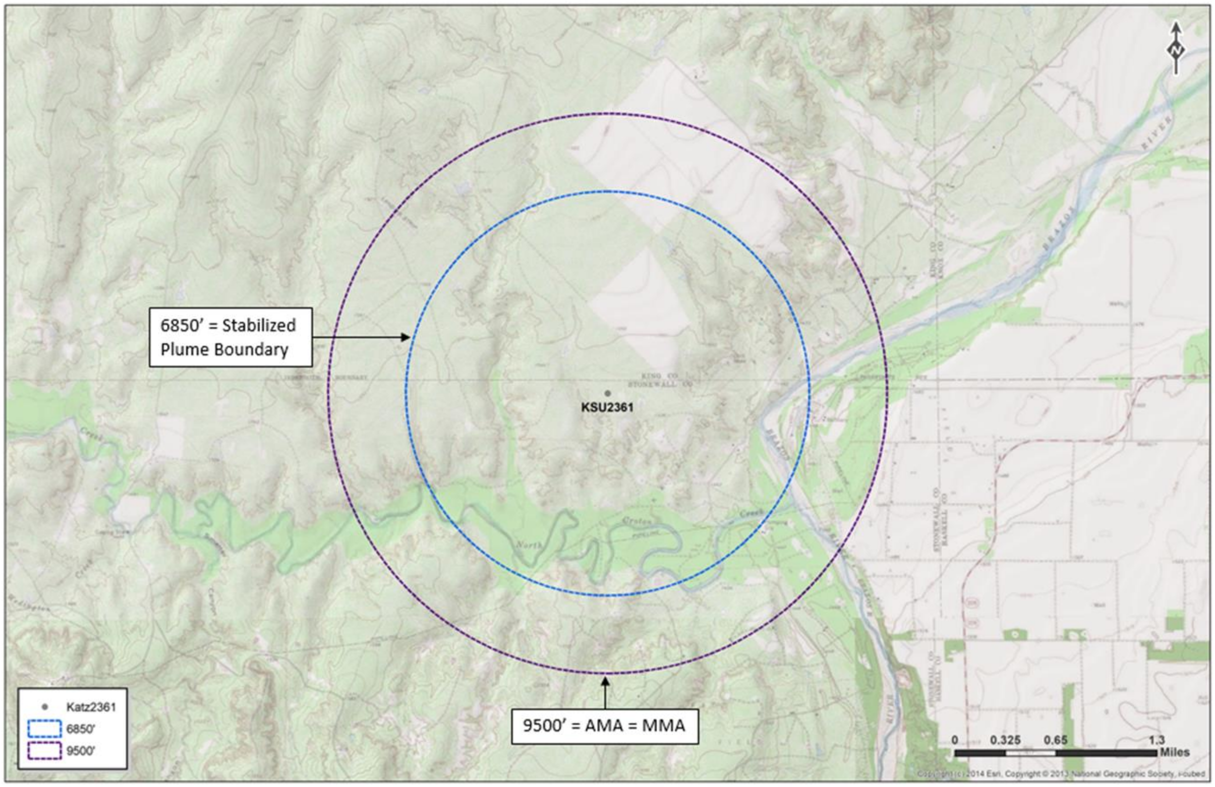


Figure 39 – Stabilized Plume Boundary, Active Monitoring Area and Maximum Monitoring Area

3.2 Active Monitoring Area

Per 40 CFR 98.449, the boundary of the AMA is established by superimposing two different boundary conditions. For the first condition, Kinder Morgan defines year t as occurring 30 years after the cessation of injection, when the modeled plume has stabilized with a maximum extent radius of 6,850'. The addition of a half-mile buffer results in a maximum extent of 9,500', satisfying the first condition. For the second condition, since Kinder Morgan defines year t as when the plume stabilizes, 30 years after the cessation of injection, the projected radius of the plume for t + 5 is also 6,850'. Superimposing the results of these two conditions results in Kinder Morgan defining the AMA with a radius of 9,500', or 3,384 acres, as shown in Figure 39.

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from Natural or Induced Seismicity

4.1 Leakage from Surface Equipment

The surface facilities at the KSU 2361 well are designed for injecting acid gas primarily consisting of CO_2. One additional pipeline will be constructed to carry the acid gas from the custody transfer meter to the KSU 2361 wellhead, as shown in Figure 40. The wellbore of the KSU 2361 is designed for acid gas, as seen in the wellbore schematic in Figure 41. The facilities have been designed to minimize leakage and failure points. The design and construction of these facilities followed industry standards and best practices. CO_2 monitors are located around the facility and the well site. These gas monitor alarms will be triggered at levels set upon completion of a baseline study of the ambient air quality, followed by a gas dispersion model. An emergency shutdown valve (ESD) is located at the wellhead and is locally controlled by pressure, with a high-pressure and low-pressure shut-off.

The facilities have been designed and constructed with other safety systems to provide for safe operations. These systems include ESD valves to isolate portions of the pipeline, pressure relief valves along the pipeline to prevent over-pressurization, and venting to allow piping and equipment to be de-pressured under safe and controlled operating conditions in the event of a leak. More information on these systems and be found in Appendix C. Should Kinder Morgan construct additional CO_2 facilities other meters will be installed as needed to comply with the 40 CFR **§98.448(a)(5**) measurement. These meters will be near the existing facilities and utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meters and tied into the facility monitoring systems. No additional wells are included within this MRV facility.

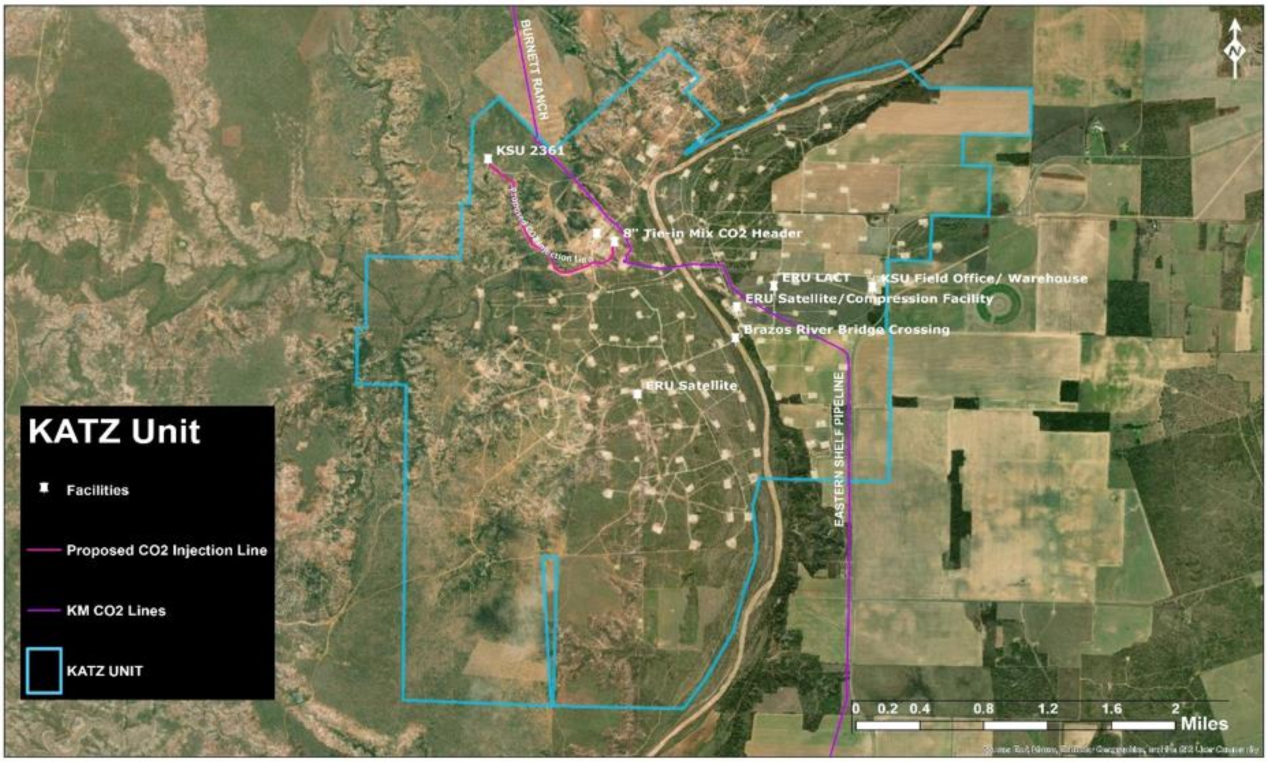


Figure 40 – Site Plan

With the level of monitoring implemented at the KSU 2361 well, a release of CO_2 would be quickly identified, and the safety systems would minimize the release volume. The CO_2 stream injected into KSU 2361 could include small amounts of methane and nitrogen, as seen in Appendix B. The CO2 injected into the Katz 2361 well is supplied by a number of different sources into the pipeline system and the composition is not expected to change over time. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR **§98.448(a)(5)**. Kinder Morgan concludes that leakage of CO_2 through the surface equipment as unlikely.

4.2 Leakage from Existing Wells within MMA

4.2.1 Oil and Gas Operations within Monitoring Area

A significant number of wells have historically been drilled within the area of the KSU 2361 well. However, production has primarily been from the shallower Strawn formation in the Katz Field. The Strawn is separated from the Ellenburger-Cambrian interval by 665' in this area. In addition to the primary Strawn production, a few wells have produced from the Mississippian. The mid-Mississippian is separated from the Ellenburger-Cambrian interval by 133'. KSU 2361 is the only well penetrating the injection interval within the projected plume area of the MMA for the KSU 2361. Therefore, it is the only well that will be monitored for surface leakage. This well is designed to handle and inject acid gas, which reduces the risk and likelihood of leakage through the existing well to near-zero.

The KSU 2361 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as depicted in the schematic denoted in Figure 41. Mechanical integrity tests (MIT), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every five years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 42. The MMA review map and a summary of all the wells in the MMA are provided in Appendix D. Figure 43 highlights that no wells penetrate the MMA's gross injection zone.

KINDER MORGAN

Schematic - Current

Well Name: KSU #2361

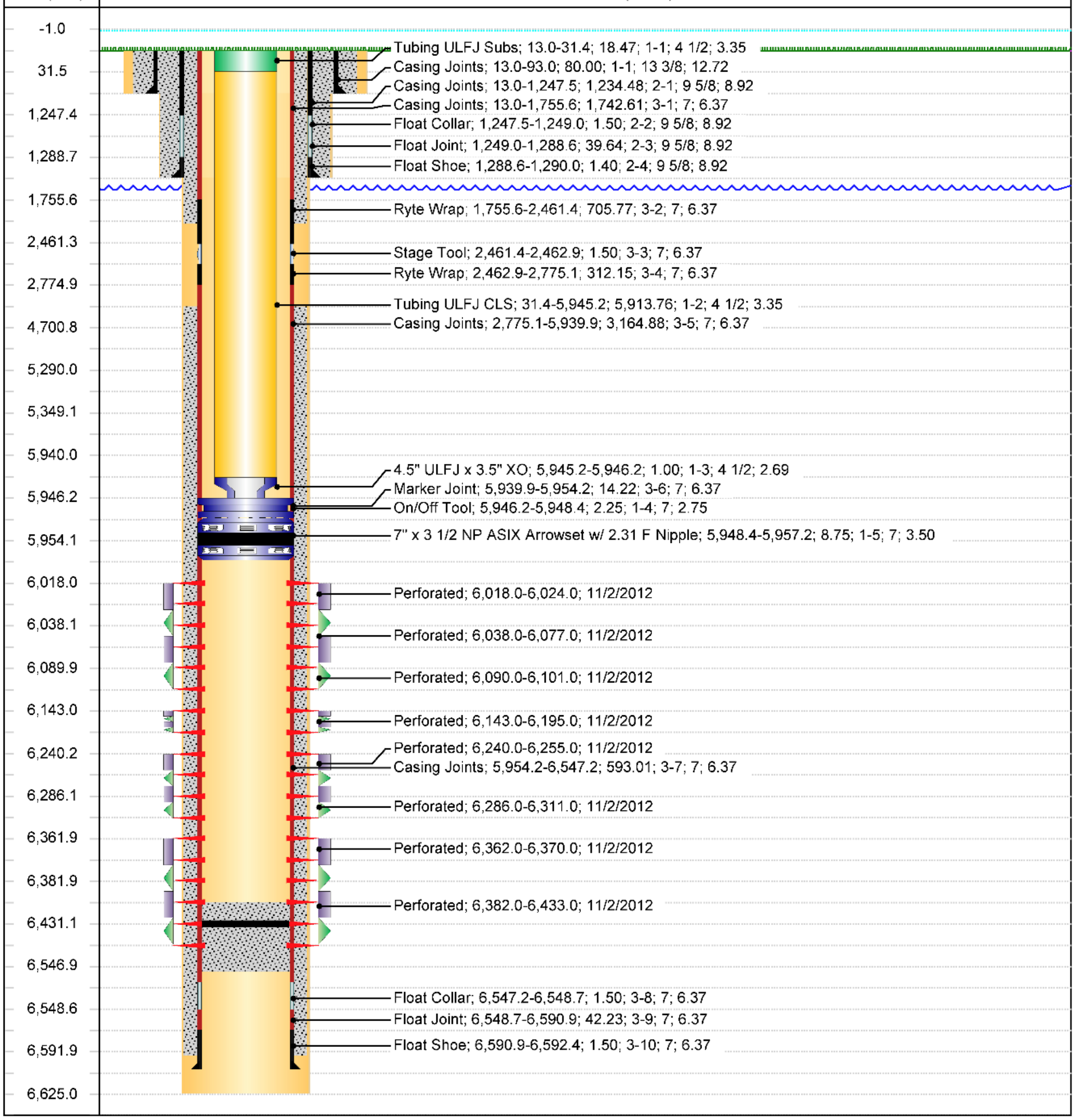
API/UWI	Surface Location	Field Name	State	Well Configuration Type	RRC/COGC...	Account Cat/Prop...
42-433-33712	SEC 2 LONG, CB	KATZ	Texas	Vertical		26039
Estimated KB Elevation (ft)	**KB-Tubing Head Distance (ft)**	**Original Well Spud Date**	**Rig Release Date**	**PBTD (All) (ftKB)**	**Total Depth All (TVD) (ftKB)**	
1,531.00	13.00	8/23/2012 18:00	9/13/2012 06:00	Original Hole - 6,431.0		

Most Recent Job

Job Category	Primary Job Type	Secondary Job Type	Start Date	End Date
Non-Rig Activity	Coil Tubing		4/2/2019	4/4/2019

TD: 6,625.0 Vertical, Original Hole, 2/21/2022 10:06:22 AM

MD (ftKB)	Vertical schematic (actual)



Page 1/1 **Report Printed: 2/21/2022**

Figure 41 – KSU 2361 Wellbore Schematic

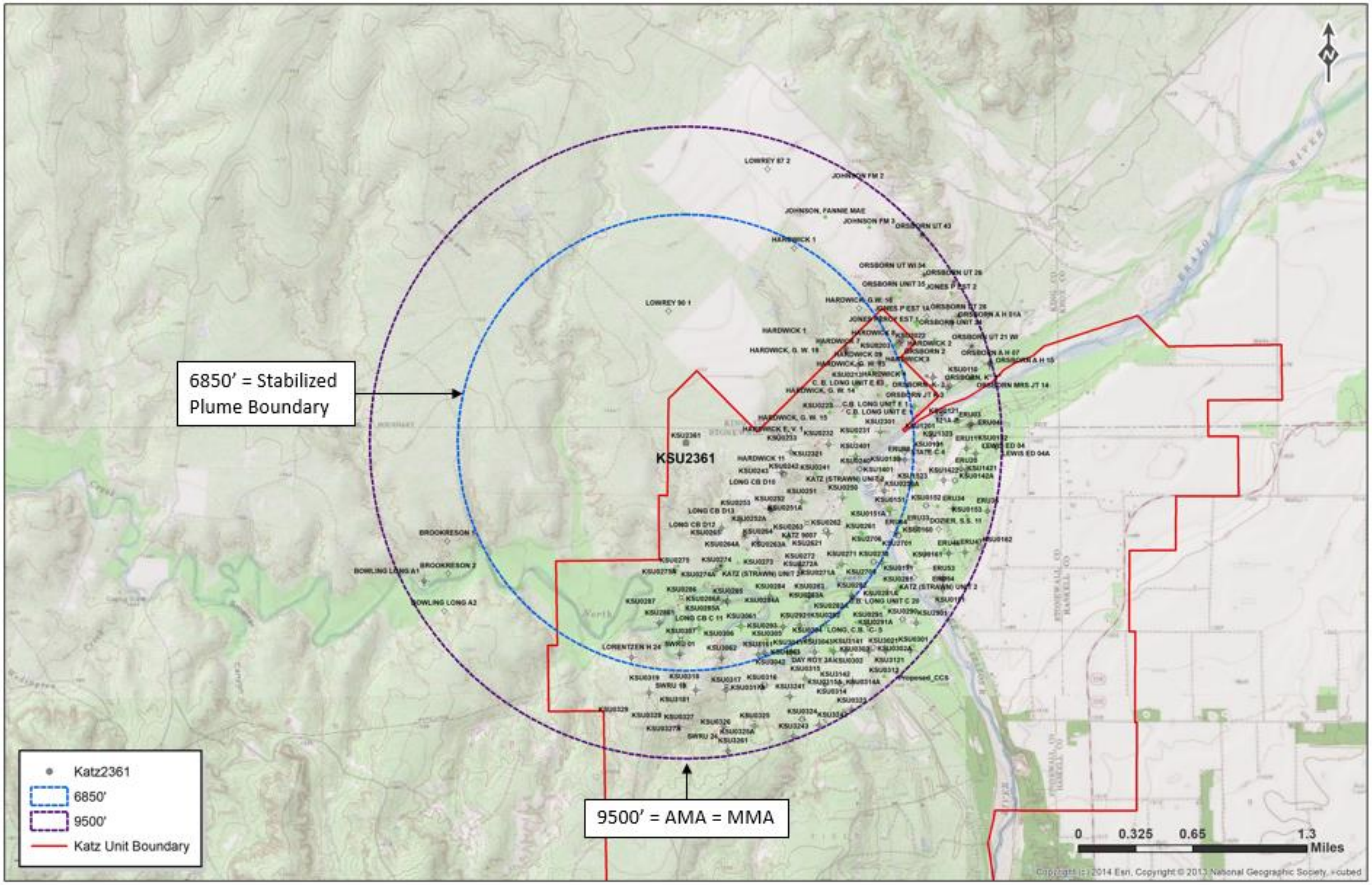


Figure 42 – All Oil and Gas Wells within the MMA

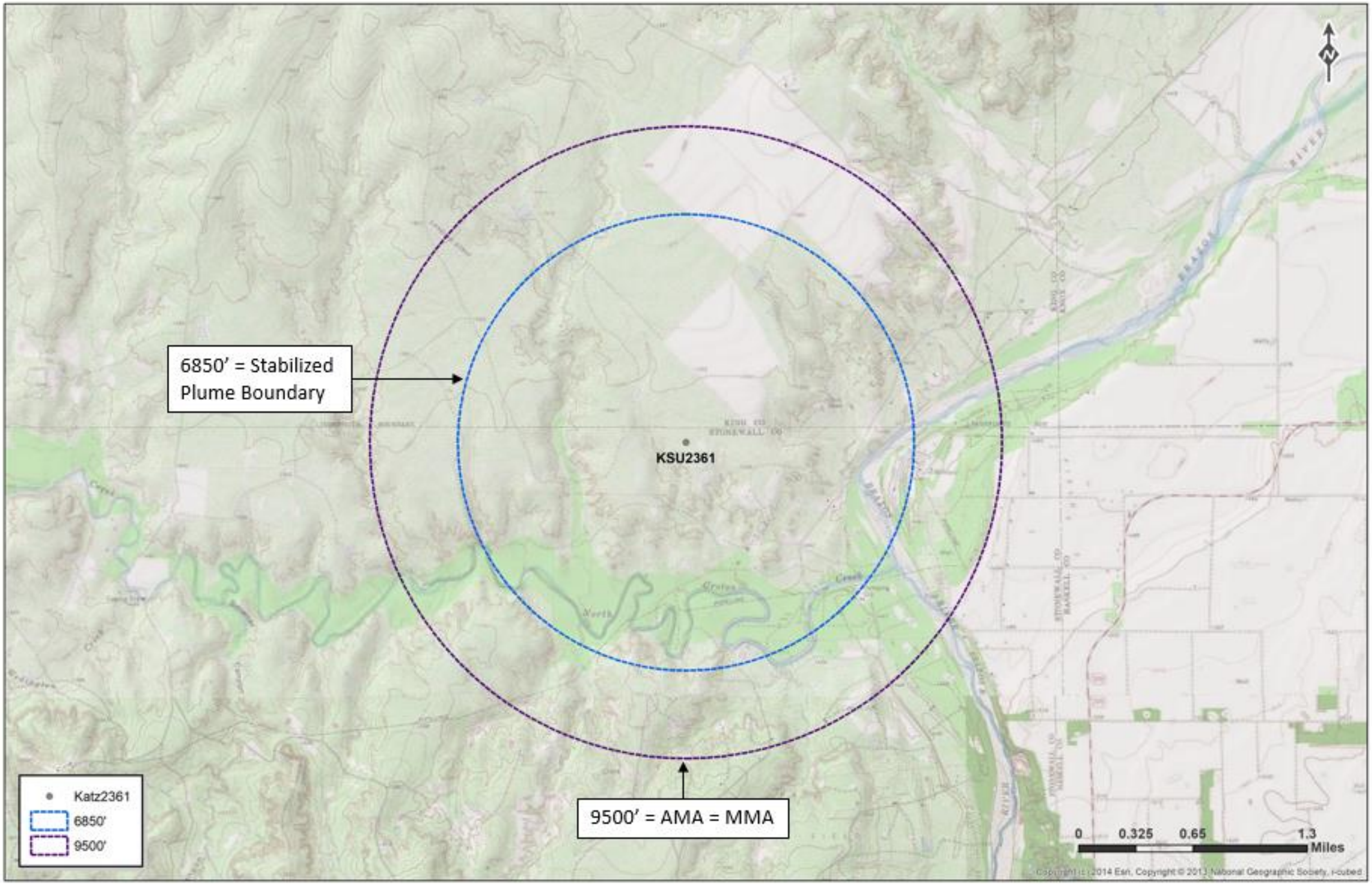


Figure 43 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA

Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Pre-Cambrian, have proven to date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC in the area of KSU 2361 include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"), 16 TAC **§3.13**. By way of example, see the KSU 2361 well drilling permit provided in Appendix A. The Ellenburger and Cambrian Sands are among the formations listed for which operators in Stonewall County and district 7B (where the KSU 2361 is located) are required to comply with TRCC Rule 13. TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. In this instance, any new well permitted and drilled to the KSU 2361 well's injection zone, and located within a one-quarter-mile radius of the KSU 2361 well, will be required under TRRC Rule 13 to set steel casing and cement above the KSU 2361 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above *all* potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued, which is also shown in the permit mentioned above in Appendix A.

4.2.2 Groundwater wells

A groundwater well search resulted in zero groundwater wells found within the MMA, as identified by the Texas Water Development Board.

The surface and intermediate casings of the KSU 2361 well, as shown in Figure 41, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See the GAU letter included in Appendix A. The wellbore casings and cements also prevent CO_2 leakage to the surface along the borehole. Kinder Morgan concludes that leakage of the sequestered CO_2 to the groundwater wells as unlikely.

4.3 Leakage Through Faults and Fractures

One fault was interpreted within the seismic coverage projecting 12,000' east of the KSU 2361 location. Initial plume models do not indicate an interaction between the injectate and the fault plane. Additionally, this fault dies within the Mississippian formation and does not penetrate the Lower Strawn Shale that acts as the upper confining unit. In the unlikely scenario in which the injection plume reaches the fault, and the fault acts as a transmissive pathway, the upper confining shale above the fault will act as an ideal sealant from injectate leaking outside of the permitted injection zone.

Should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Lower Strawn Shale, juxtaposing it against itself, preventing vertical migration.

Fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open hole logs show little to no porosity development indicating the Lower Strawn Shale or Mississippian Lime were not exposed at this location. Therefore, upward migration of injected gas through confining bed fractures is unlikely.

4.4 Leakage Through the Confining Layer

The Ellenburger and Cambrian injection zones have competent sealing rocks above and below the sand and carbonate formations. The properties of the overlying Lower Strawn Shale and its high composition of shale and mudstone make an excellent sealing rock to the underlying Ellenburger formation. Tight Mississippian Lime of roughly 266' lies between the Ellenburger and Lower Strawn Shale formations forming an impermeable upper buffer seal from the injection interval to the upper confining zone. Above this confining unit, shales found within the Homecreek Shale above the Desmoinesian formation will act as additional sealants between the injection interval and the USDW. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. Precambrian basement rock's underlying low porosity and permeability minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

4.5 Leakage from Natural or Induced Seismicity

The location of KSU 2361 is in an area of the Midland Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 44, indicates the nearest seismic event (unspecified whether natural or induced) occurred more than 40 miles away.

There is no indication of seismic activity posing a risk for loss of CO_2 to the surface within the MMA. Therefore, Kinder Morgan concludes that leakage of the sequestered CO_2 through seismicity as unlikely.

Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

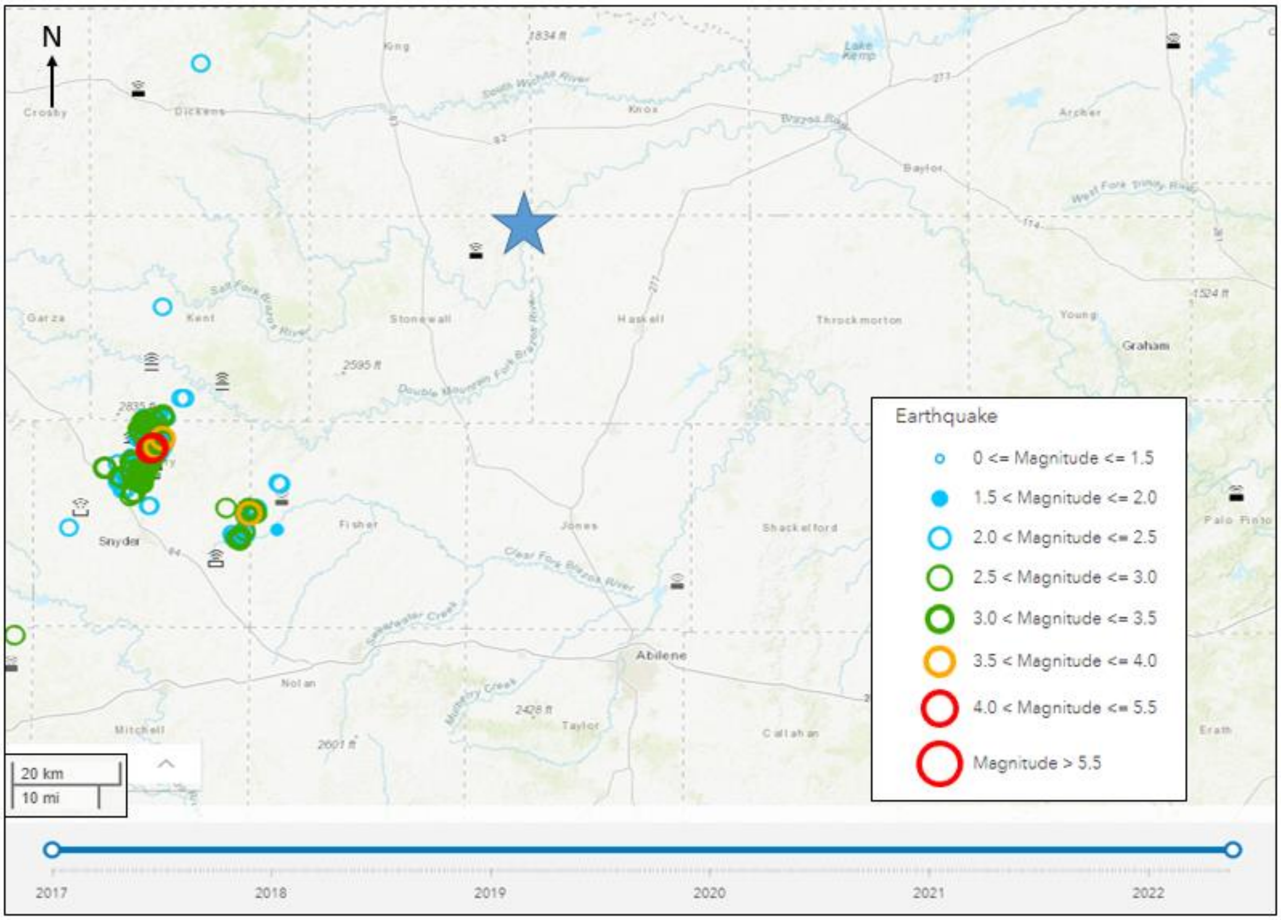


Figure 44 – Seismicity Review (TexNet – 06/01/2022)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Kinder Morgan will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 to meet the requirements of 40 CFR **§98.448(a)(3)**. Table 10 summarizes the monitoring of potential leakage pathways to the surface. Monitoring will occur during the planned 21-year injection period or cessation of injection operations, plus a proposed 5-year post-injection period.

- Leakage from surface equipment failure
- Leakage through existing and future wells within MMA
- Leakage through faults, fractures, or confining seals
- Leakage through natural or induced seismicity

Table 10 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed CO_2 monitors throughout the AGI facility
	Daily visual inspections
	Supervisory Control and Data Acquisition (SCADA)
Leakage through existing wells	Fixed CO_2 monitor at the the AGI well
	SCADA continuous monitoring at the AGI Well
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Quarterly atmospheric CO_2 measurements at well locations within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	CO_2 monitoring during offset drilling operations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage through confining layer	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage from natural or induced seismicity	Existing TexNet seismic monitoring station to be implemented

5.1 Leakage from Surface Equipment

As the facility and the KSU 2361 well are designed to handle CO_2, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used, and the connections are designed to minimize corrosion points. A baseline atmospheric CO_2 concentration will be established before injection operations begin. The facility and well site contain several CO_2 alarms with locations in close proximity.

The AGI complex is continuously monitored through automated systems. Details surrounding these systems can be found in Appendix C. In addition, field personnel conduct daily visual field inspections of gauges, monitors, and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the surface equipment associated with the sequestered CO2 and inspection of the cathodic protection system. These inspections and the automated systems allow Kinder Morgan to respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)**.

Pressures and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

5.2 Leakage From Existing and Future Wells within MMA

Kinder Morgan continuously monitors and collects injection volumes, pressures and temperatures through their SCADA systems, for the KSU 2361 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. KSU 2361 has a pressure and temperature gauge placed in the injection stream at its wellhead and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. In addition, mechanical integrity tests (MIT) performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 would ensure that new wells in the field would be constructed to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Kinder Morgan will also establish and operate an in-field monitoring program to detect CO_2 leakage within the MMA. The scope of work will include CO_2 monitoring at the AGI well site and, at minimum, quarterly atmospheric monitoring near any wells identified that penetrate the injection interval within the MMA. The collection of these measurements will be carried out by using a qualified third party. Upon approval of the MRV and through the post-injection monitoring period, Kinder Morgan will have these monitoring systems in place. No wells have been identified within the MMA that penetrate the injection interval. Additional monitoring will be added as the MMA is updated over time. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

Groundwater Quality Monitoring

Kinder Morgan will monitor the groundwater quality in fluids above the confining interval by sampling from groundwater wells in the area of the facility and analyzing the sample with a third-party laboratory on an annual basis. In the case of KSU 2361, no existing groundwater wells have been identified within the MMA. At least two groundwater monitoring wells will be drilled within 1500’ of KSU 2361 at a depth of approximately 100’. The final number, locations, and depths of the wells will be determined by a study completed by a certified 3rd party firm. The approximate location and depths of these wells are shown in Figure 45. A baseline sampling from these wells will occur before injection starts. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature, and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

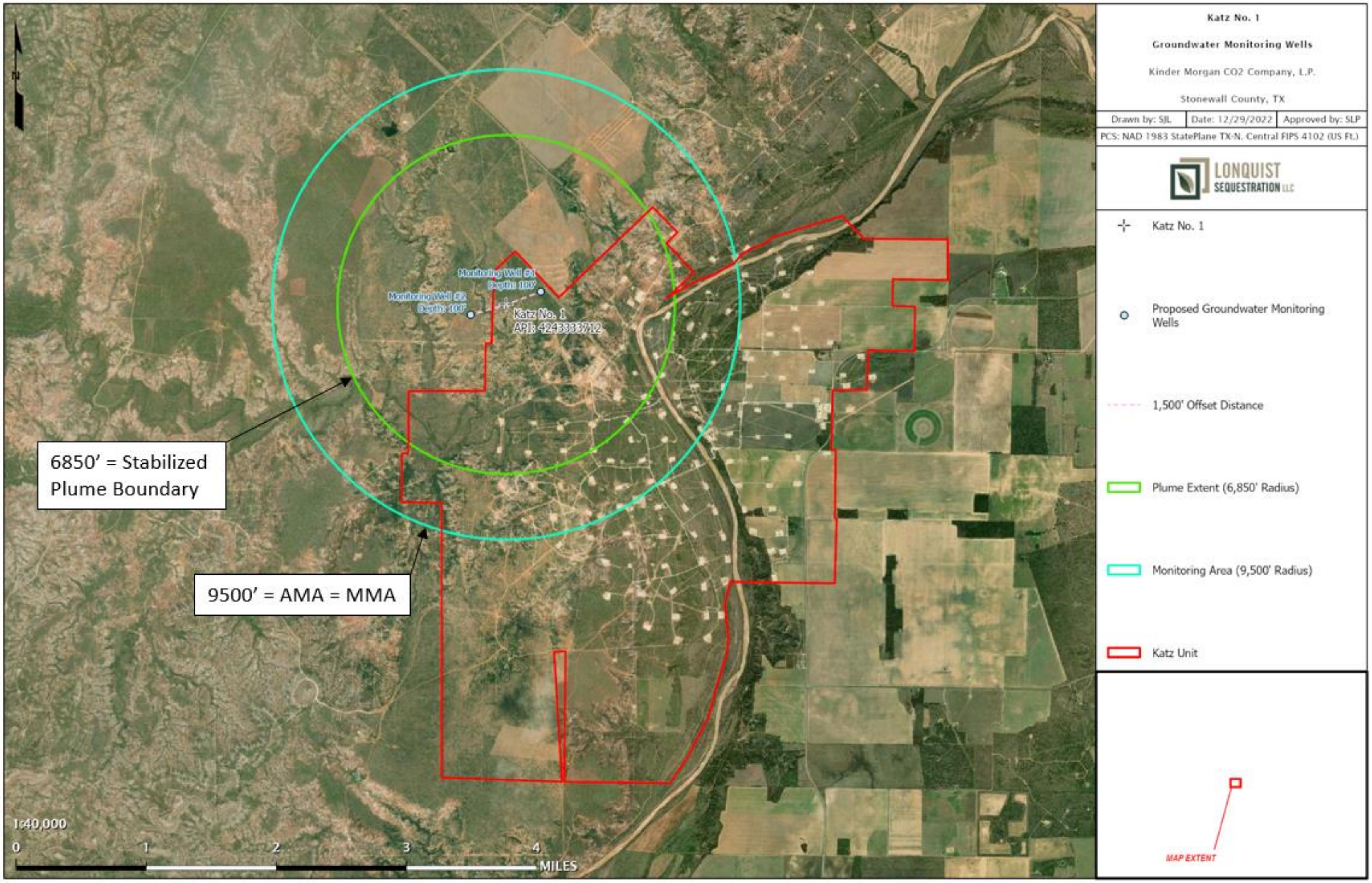


Figure 45 – Groundwater Monitoring Wells

5.3 Leakage through Faults, Fractures or Confining Seals

Kinder Morgan continuously monitors the operations of the KSU 2361 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. In addition, a field monitoring system is proposed to measure the shallow topsoil CO_2 concentrations across the MMA. These measurements will be taken quarterly by in-field gas sensors. The field CO_2 monitoring systems would alert field personnel for any release of CO_2 caused by such leakage. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

5.4 Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Kinder Morgan plans to use the nearest TexNet seismic monitoring station to monitor the area of the KSU 2361 well. This station is 7.29 miles southwest of the well location, as shown below in Figure 46. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Katz Unit. Kinder Morgan will monitor this station for any seismic activity that occurs near the well. If a seismic event of 3.0 magnitude or greater is detected, Kinder Morgan will review the injection volumes and pressures at the KSU 2361 well to determine if any significant changes occur that would indicate potential leakage. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

Figure 46 – Nearest TexNet Seismic Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Kinder Morgan will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Kinder Morgan will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Once the baseline concentrations are determined over a 12 month period prior to injection, the CO_2 monitors will be set to alarm at concentrations that are statistically significant deviation from baseline.

6.1 Visual Inspections

Daily inspections will be conducted by field personnel at the facility and the KSU 2361 well. These inspections will aid with identifying and addressing possible issues in order to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken to address such issues.

6.2 CO_2 Detection

In addition to the well site fixed monitors described previously, Kinder Morgan will establish and operate an in-field monitoring program to detect any CO_2 leakage within the MMA. The scope of baseline determination will include atmospheric CO_2 measurements at the AGI well site and near identified penetrations within the MMA. Topsoil CO_2 concentrations will also be measured, at pre-determined locations within the MMA, as baseline values before injection activities begin.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be taken. Any significant deviations over time will be analyzed for indication of leakage of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this project are well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a blowdown event, emissions will be sent to vent stacks and will be reported as required for the operation of the well.

6.5 Groundwater Monitoring

Initial samples will be taken from the groundwater monitoring wells drilled within 1,500 feet of the KSU 2361 well upon approval of Kinder Morgan's MRV and before commencing injection of CO_2. A third-party laboratory will analyze the samples to establish the baseline properties of the groundwater.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

This section identifies how Kinder Morgan will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR **§98.448(a)(5)**.

7.1 Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

Per 40 CFR **§98.444(b)**, since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters per quarter)

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (volume percent CO_2, expressed as a decimal fraction)

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The KSU 2361 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains concentrations well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Any leakage would be detected and managed as an upset event. An upset event is any unlikely event that results in the failure of any mass of CO_2 to remain permanently sequestered in the target reservoir. Continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released as a result of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Kinder Morgan believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in Section 10, below.

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12, assuming an expected injection start date of June 1, 2024, as this well will not actively produce oil or natural gas, or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to flares and reported as part of the required GHG reporting for the gas plant.

- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The KSU 2361 well currently reports GHGs under Subpart UU, but Kinder Morgan has elected to submit an MRV plan under, and otherwise comply with, Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed by March 31st of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Kinder Morgan plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 *Injected*

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated per the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP.

CO_2 *Emissions from Leaks and Vented Emissions*

- Gas monitors will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i) requirements**.**
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Kinder Morgan will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Kinder Morgan will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

Kinder Morgan will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least three years and include the following:

- Quarterly records of the CO_2 injected
    - Volumetric flow at standard conditions
    - Volumetric flow at operating conditions
    - Operating temperature and pressure
    - Concentration of the CO_2 stream
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

Adams, Donald & Keller, Randy. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective. AAPG Bulletin. 80. 410-431. 10.1306/64ED87FA-1724-11D7-8645000102C1865D.

Broadhead, Ronald E., 2005. Regional Aspects of the Wristen petroleum system, southeastern New Mexico: New Mexico Bureau of Geology and Mineral Resources Open File Report, no. 485.

Comer, John B., 1991. Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas and Southeastern New Mexico: Bureau of Economic Geology Report of Investigations, no. 201.

Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.

Ewing et al. (2004). Groundwater Availability Model for the Seymour Aquifer. *Texas Water Development Board.*

Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.

George, Peter G., Mace, Robert E., and Petrossian, Rima, 2011. Aquifers of Texas: Texas Water Development Board Report, no 380.

Gunn, R. D. (1982). Desmoinesian Depositional Systems in the Knox Baylor Trough. *North Texas Geological Society*.

Harding, R.W. and Associates. (1978). THE SEYMOUR AQUIFER: Ground-Water Quality and Availability in Haskell and Knox Counties, Texas. *Texas Department of Water Resources.*

Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.

Hoak, T., Sundberg, K., and Ortoleva, P. Overview of the Structural Geology and Tectonics of the Central Basin Platform, Delaware Basin, and Midland Basin, West Texas and New Mexico: Department of Energy Open File Report.

Holtz, M.H., and Kerans, C. (1992). Characterization and categorization of West Texas Ellenburger reservoirs. *Permian Basin Section SEPM Publication No. 92-22, p. 31-44.*

Hornhach, M. J. (2016). Ellenburger wastewater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.

Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas*.

Kane, S. C. (n.d.). THE MISSISSIPPIAN BARNETT FORMATION: A SOURCE-ROCK, SEAL, AND RESERVOIR PRODUCED BY EARLYCARBONIFEROUS FLOODING OF THE TEXAS CRATON. *BEG*.

Kerans, C. (1989). Karst-controlled reservoir heterogeneity and an example from the Ellenburger Group (Lower Ordovician) of West Texas. *Bureau of Economic Geology.*

Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.

Kupecz, J.A., and L.S. Land. (1991). Late-stage dolomitization of the Lower Ordovician Ellenburger Group, West Texas. *Journal of Sedimentary Petrology.*

Kyle, J.R. and E.F. McBride. (2014). Geology of the Voca Frac Sand District, western Llano Uplift, Texas. *Arizona Geological Survey Special Paper #9, Chapter 2, p. 1-13.*

Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.

Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

Molina, Oscar, Vilarras, Victor, and Zeidouni, Mehdi, 2016. Geologic carbon storage for shale gas recovery: 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18.

Ruppel, Stephen C. and Holtz, Mark H., 1994. Depositional and Diagenetic Facies Patterns and Reservoir Development in Silurian and Devonian Rocks of the Permian Basin: Bureau of Economic Geology Report of Investigations, no. 216.

Snee, Jens-Erik Lund and Zoback, Mark D., 2016. State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity.

Teeple, Andrew P., Ging, Patricia B., Thomas, Jonathan V., Wallace, David S., and Payne, Jason D., 2021. Hydrogeologic Framework, Geochemistry, Groundwater-Flow System, and Aquifer Hydraulic Properties Used in the Development of a Conceptual Model of the Ogallala, Edwards-Trinity (High Plains), and Dockum Aquifers In and Near Gaines, Terry, and Yoakum Counties, Texas: USGS Scientific Investigations Report 2021-5009.

SECTION 12 - APPENDICES

APPENDICES

APPENDIX A – TRRC FORMS KSU #2361

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE

A-1

CHRISTI CRADDICK, CHAIRMAN
RYAN SITTON, COMMISSIONER
WAYNE CHRISTIAN, COMMISSIONER

DANNY SORRELLS
ASSISTANT EXECUTIVE DIRECTOR
DIRECTOR, OIL AND GAS DIVISION
PAUL DUBOIS
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 13453 AMENDMENT

KINDER MORGAN PRODUCTION CO LLC
6 DESTA DRIVE STE 6000
MIDLAND, TX 79705

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated August 27, 2018 for the permitted interval of the ELLENBURGER, and CAMBRIAN formations and subject to the following terms and special conditions:

KATZ (STRAWN) UNIT (30524) LEASE
KATZ (STRAWN) FIELD
STONEWALL COUNTY, DISTRICT 7B

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
2361	43333712	000104281	Salt Water, and Other Non-Hazardous O/G Waste	5,800	6, 435	30,000	N/A	2,900	N/A

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
2361	43333712	**1. According to the cross-section submitted by the operator the Pre-Cambrian top is at 6440 feet and hence the PBTD shall be at 6435 feet (deepest perforations are at 6433 feet per RRC records). Operator agreed to this permit special condition provision in the email dated on 11-29-2018. A copy of Form W-15 Cementing Record must be filed with the Form H-5 Injection Well Pressure Test Report prior to injection documenting compliance with this Special Condition.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON December 31, 2018.

Sean Avitt, Manager
Injection-Storage Permits Unit

Amendment Comments:

Well No.	API No.	Amendment Comments
2361	43333712	1. Amends maximum daily injection volume for liquid from 20000 bbl/day. 2. Amends packer setting depth from 5750 feet. 3. Amends permit dated November 21, 2011.

Note: This document will only be distributed electronically.

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE

A-2

Texas Commission on Environmental Quality
TCEQ
Surface Casing Program

DEPTH OF USABLE-QUALITY GROUND WATER TO BE PROTECTED

Date: July 21, 2010

TCEQ File No.: SC- 5504

API Number: 43333592

Attention: ROSE BURDITT

RRC Lease No. 000000

SC_463316_43333592_000000_5504.pdf

KINDER MORGAN PRODUCTION CO LL
500 W ILLINOIS
STE 500
MIDLAND TX 79701

P-5# 463316

--Measured--

3545 ft FNEL

72 ft FNWL

MRL: SURVEY

Digital Map Location:

X-coord/Long: 1232566

Y-coord/Lat: 638341

Datum: 27 Zone: NC

County: STONEWALL

Lease & Well No.: KATZ (STRAWN) UNIT #232&ALL

Purpose: ND

Location: SUR-EUSTIS J.,SEC-2,--[TD=5500],[RRC 7B],

To protect usable-quality ground water at this location, the Texas Commission on Environmental Quality recommends:

The interval from the land surface to a depth of 100 feet must be protected.

This recommendation is applicable to all wells drilled in this LEASE IN SECTION 2.

Note: Unless stated otherwise, this recommendation is intended to apply only to the subject well and not for area-wide use. Approval of the well completion methods for protection of this groundwater falls under the jurisdiction of the Railroad Commission of Texas. **This recommendation is intended for normal drilling, production, and plugging operations only. It does not apply to saltwater disposal operation into a nonproductive zone (RRC Form W-14).**

If you have any questions, please contact us at 512-239-0515, sc@tceq.state.tx.us, or by mail MC-151.

Sincerely,

T. Wesley McCoy

Digitally signed by Thomas Wesley McCoy
DN: c=US, st=Texas, l=Austin, ou=Surface Casing, o=Texas Commission on Environmental Quality, cn=Thomas Wesley McCoy, email=wmccoy@tceq.state.tx.us
Date: 2010.07.21 11:46:18 -05'00'

T. Wesley McCoy, P.G.

Geologist, Surface Casing Team
Waste Permits Division

GEOLOGIST SEAL

STATE OF TEXAS
T. WESLEY McCOY
GEOLOGY
117
LICENSED
PROFESSIONAL GEOSCIENTIST

The seal appearing on this document was authorized by *T. Wesley McCoy* on 7/21/2010
Note: Alteration of this electronic document will invalidate the digital signature.

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE

A-3

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 718131	DATE PERMIT ISSUED OR AMENDED Jun 14, 2011	DISTRICT * 7B
API NUMBER 42-433-33712	FORM W-1 RECEIVED Jun 09, 2011	COUNTY STONEWALL
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 7194
OPERATOR 463316 KINDER MORGAN PRODUCTION CO LLC 6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (325) 677-3545
LEASE NAME KATZ (STRAWN) UNIT		WELL NUMBER 2361
LOCATION 21.9 miles NE direction from ASPERMONT		TOTAL DEPTH 7500

Section, Block and/or Survey

SECTION ✈ BLOCK ✈ ABSTRACT ✈ 1939

SURVEY ✈ LONG, C B

DISTANCE TO SURVEY LINES 3511 ft. S 539 ft. W	DISTANCE TO NEAREST LEASE LINE 539 ft.
DISTANCE TO LEASE LINES 1751 ft. NE 539 ft. W	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
KATZ (STRAWN) KATZ (STRAWN) UNIT	7194.00 539	7,500	2361 3991	7B

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office. This is a hydrogen sulfide field. Hydrogen Sulfide Fields with perforations must be isolated and tested per State Wide Rule 36 and a Form H-9 filed with the district office. Fields with SWR 10 authority to downhole commingle must be isolated and tested individually prior to commingling production.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

Currently there are no identified formations listed for this county. It is still the operators responsibility to isolate and report any potential flow zones that are encountered in the completion of this well.

A-4

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Approved
Date: 10/04/2013
Tracking No.: 62859

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator KINDER MORGAN PRODUCTION CO LLC **Operator** 463316
Operator 6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000

WELL INFORMATION

API 42-433-33712 **County:** STONEWALL
Well No.: 2361 **RRC District** 7B
Lease KATZ (STRAWN) UNIT **Field** KATZ (STRAWN)
RRC Lease 30524 **Field No.:** 48294600
Location Section: ,Block: , Survey: LONG, C B SVY, Abstract: 1939

Latitude **Longitud**
This well is **miles in a**
direction from 21.9 MILES IN A NE DIRECTION FROM ASPERMONT, TX,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC **Completion or Recompletion** 12/15/2012

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	06/14/2011	718131
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal	11/21/2011	13453
Other:		

COMPLETION INFORMATION

Spud **Date of first production after rig** 12/15/2012
Date plug back, deepening, drilling operation 08/24/2012 **Date plug back, deepening, recompletion, drilling operation** 09/13/2012
Number of producing wells on this lease this field (reservoir) including this 66 **Distance to nearest well in lease & reservoir** 3991.0
Total number of acres in 7194.00 **Elevation** 1518 GL
Total depth TVD 6625 **Total depth MD**
Plug back depth TVD 6547 **Plug back depth MD**
Was directional survey made other inclination (Form W- No **Rotation time within surface casing Is Cementing Affidavit (Form W-15)** Yes
Recompletion or No **Multiple** No
Type(s) of electric or other log(s) Induction only
Electric Log Other Description:
Location of well, relative to nearest lease **Off Lease :** No
of lease on which this well is 1751.0 **Feet from the** NE **Line and**
539.0 **Feet from the** West **Line of the**
KATZ (STRAWN) UNIT **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type

PACKET: N/A

W2: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination	**Depth**	**Date**
SWR 13 Exception	**Depth**	

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		**Production**	
Number of hours	24	**Choke**	
Was swab used during this	No	**Oil produced prior to**	

PRODUCTION DURING TEST PERIOD:

Oil		**Gas**	
Gas - Oil	0	**Flowing Tubing**	
Water			

CALCULATED 24-HOUR RATE

Oil		**Gas**	
Oil Gravity - API - 60.:		**Casing**	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1		9 5/8	12 1/4	1290			C	491	837.0	SURF ACE	
2		7	8 3/4	6592			C	750	1248.0	3256	
3		7	8 3/4	6592	2463		C	450	618.0	SURF ACE	

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	4 1/2	5945	5957 /

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	No	L 6018	6024.0
2	No	L 6038	6077.0
3	No	L 6090	6101.0
4	No	L 6143	6195.0
5	No	L 6240	6255.0
6	No	L 6286	6311.0
7	No	L 6362	6370.0
8	No	L 6382	6433.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1		PUMP 2800 GALLONS 15% HCL, FLUSH WITH 36 BARRELS TREATED WATER.	6018	6101
2		PUMP 2600 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6143	6195
3		PUMP 2440 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6240	6311
4		PUMP 2960 GALLONS 15% HCL, FLUSH WITH 76 BARRELS TREATED WATER.	6362	6433

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
BASE PALO PINTO		3215.2			
ELLENBURGER		6018.0			
CAMBRIAN		6240.0			

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

THE PURPOSE OF THIS FILING IS TO REPORT A DRILLED AND COMPLETED SALT WATER DISPOSAL WELL.

OPERATOR'S CERTIFICATION

Printed	Dorothy Horrell	**Title:**	Administrator
Telephone	(432) 688-2448	**Date**	01/14/2013

APPENDIX B – GAS COMPOSITION

CO2 Pipeline - Gas Quality Specifications

Kinder Morgan CO2 Company

Revision: 2019 11 12

Product delivered at the Origination Point shall meet the following specifications, which herein are called Quality Specifications:

(a) **CO2 Content** Product composition shall be not less than ninety five per cent (95%) CO2 by mole fraction.
(b) **Water** Product shall contain no free water, and shall not contain more than thirty (30) pounds of water per million standard cubic feet (MMscf) in the vapor phase.
(c) **Pressure** Product shall be delivered at a pressure sufficient to get into the pipeline.
(d) **Temperature** Product shall be delivered at a temperature not greater than 120 degrees F, and not less than 65 degrees F.
(e) **H2S** Product shall not contain more than twenty (20) parts per million H2S, by volume.
(f) **Nitrogen** Product shall not contain more than four per cent (4%) nitrogen, by mole fraction.
(g) **Sulphur** Product shall not contain more than thirty five (35) parts per million sulphur, by weight.
(h) **Oxygen** Product shall not contain more than ten (10) parts per million, oxygen, by weight.
(i) **Hydrocarbons** Product shall not contain more than five percent (5%) hydrocarbons, by mole fraction.
(j) **Glycol** Product shall not contain more than 0.3 gallon glycol, per million standard cubic feet, and at no time shall glycol be present in a liquid state at temperature and pressure conditions of the pipeline.
(k) **Carbon Monoxide** Product shall not contain more than 4,250 parts per million, carbon monoxide, by weight.
(l) **NOx** Product shall not contain more than one (1) part per million, NOx, by weight.
(m) **SOx** Product shall not contain more than one (1) part per million, SOx, by weight.
(n) **Particulates** Product shall not contain more than one (1) part per million, particulates, by weight.
(o) **Amines** Product shall not contain more than one (1) part per million, amines, by weight.
(p) **Hydrogen** Product shall not contain more than one per cent (1%) hydrogen, by mole fraction.
(q) **Mercury** Product shall not contain more than five (5) nano grams per liter (ng/l) mercury.
(r) **Ammonia** Product shall not contain more than fifty (50) parts per million, ammonia, by weight.
(s) **Argon** Product shall not contain more than one volume percent (1% by volume) argon.
(t) **Liquids** Product shall be free of liquids at delivery conditions and shall not produce condensed liquids in the pipeline at pipeline pressure and temperature.
(u) **Compressor Lube Oil Carry Over** Compressor lube oil carry over in the product shall not exceed fifty (50) parts per million, by weight, and shall not cause fouling of pipeline, pipeline equipment downstream systems or reservoirs.
(v) **Impurities Deleterious to Pipeline, Equipment, Downstream Systems or Reservoirs** In addition to compositional limits listed above, product shall not contain impurities deleterious to pipeline, equipment, downstream systems or reservoirs.

APPENDIX C – PIPELINE SAFETY PLAN

Kinder Morgan CO_2 pipelines are monitored 24 hours a day, 7 days a week by personnel in control centers using a SCADA computer system. This electronic surveillance system gathers pipeline pressures, volume and flow rates and the status of pumping equipment and valves. Whenever operating conditions change, an alarm warns the operator on duty and the condition is investigated. Both automated and manual valves are strategically placed along the pipeline system to enable the pipeline to be shut down immediately and sections to be isolated quickly, if necessary. Visual inspections of the pipeline right-of-way, a narrow strip of land reserved for the pipeline, are conducted by air and ground on a regular basis.

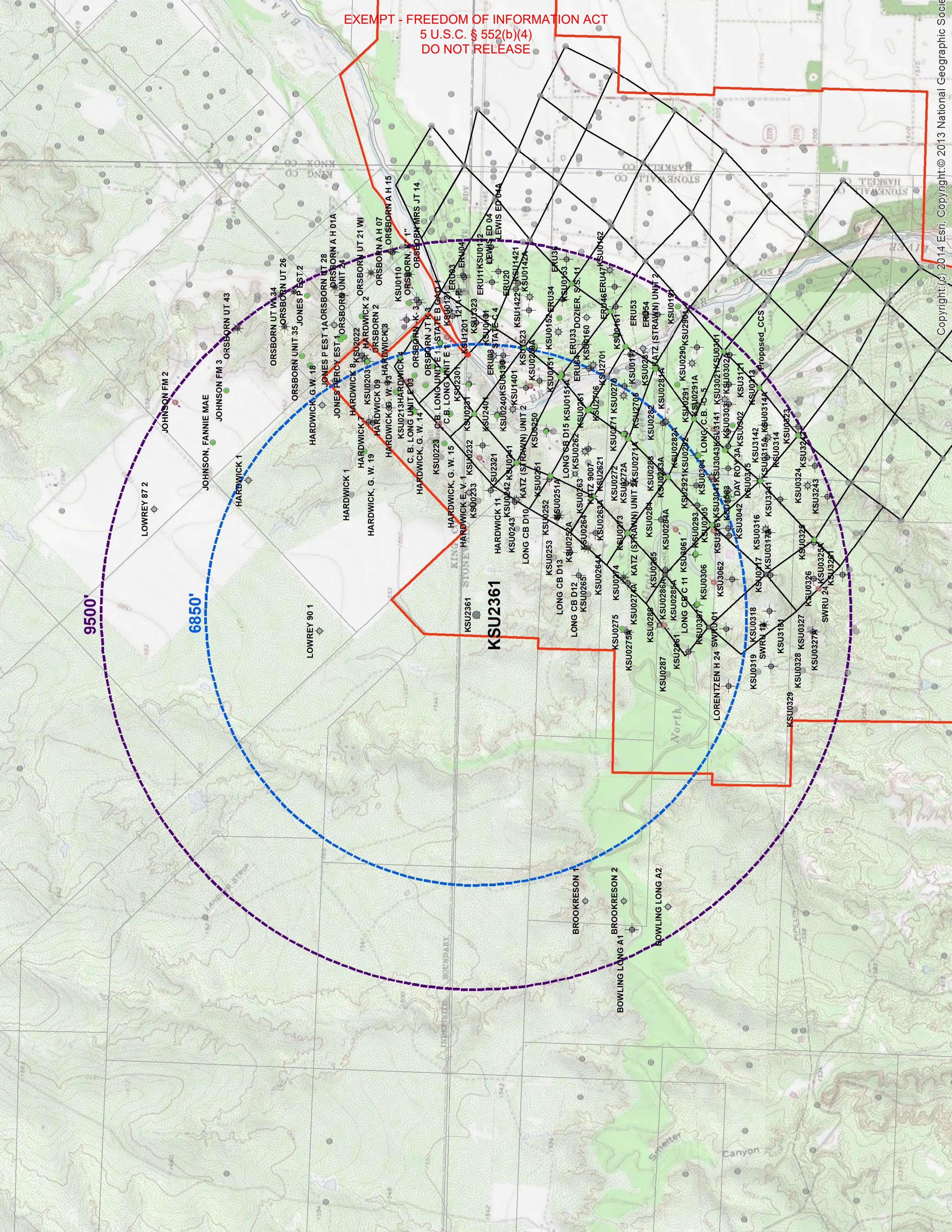
In the event of a CO_2 pipeline rupture, the Kinder Morgan CO_2 Supervisory Control and Data Acquisition (SCADA) computer system will shut down the pipeline and isolate the impacted section with automated valves. Kinder Morgan will notify the appropriate public safety answering point (i.e., 9-1-1 emergency call center) and initiate the internal Emergency Response Line to alert the operations team. An emergency response plan would be initiated with implementation of an incident command system, and Kinder Morgan will work with local emergency responders to isolate the impacted area.

APPENDIX D – MMA/AMA REVIEW MAPS

APPENDIX D-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX D-2: OIL AND GAS WELLS WITHIN THE MMA LIST

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE



Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332238	BOWLING-LONG A	2	P & A	5,815	WILDCAT	4/20/1987	5/7/1987
4243332229	BROOKRESON	1	P & A	5,730	WILDCAT	3/7/1987	5/14/1987
4243332319	BROOKRESON	2	P & A	5,745	WILDCAT	12/2/1987	12/13/1987
4226932003	C. B. LONG UNIT	E 03	P & A	5,300	KATZ	--	--
4243300422	C.B. LONG UNIT	C 11	P & A	5,127	KATZ	7/11/1989	5/15/2009
4243332388	C.B. LONG UNIT	C 16	P & A	5,200	KATZ	11/18/1989	12/8/2010
4243300585	C.B. LONG UNIT	D 10	P & A	5,197	KATZ	6/30/1989	1/13/2009
4243332465	C.B. LONG UNIT	D 13	P & A	5,201	KATZ	12/27/1989	9/23/2005
4243301965	C.B. LONG UNIT	D 4	P & A	5,188	KATZ		11/30/2010
4226900122	C.B. LONG UNIT	E 1	P & A	5,165	KATZ		9/15/2009
4226932006	C.B. LONG UNIT	E 2	P & A	5,200	KATZ	10/11/1990	2/24/2011
4243332116	DOZIER, S.S.	11	P & A	5,950	WILDCAT	6/12/1986	06/23/1986
4226900308	EAST RIVER UNIT	4	INACTIVE	4,931	KATZ		02/21/1995
4243332303	EAST RIVER UNIT	8	P & A	5,200	KATZ	11/17/1987	06/24/2009
4243332302	EAST RIVER UNIT	11	P & A	5,200	KATZ	11/26/1987	3/18/2004
4243300796	EAST RIVER UNIT	18	ACTIVE	5,300	KATZ	7/26/1951	--
4243300802	EAST RIVER UNIT	20	P & A	5,184	KATZ	8/22/1988	7/6/2009
4243300798	EAST RIVER UNIT	21	P & A	4,957	KATZ		12/5/1989
4243300787	EAST RIVER UNIT	33	P & A	5,155	KATZ		10/21/2009
4243300781	EAST RIVER UNIT	34	P & A	5,120	KATZ		10/30/2009
4243332306	EAST RIVER UNIT	36	P & A	5,200	KATZ	12/15/1987	2/28/2006
4243300849	EAST RIVER UNIT	45	P & A	5,167	KATZ		12/7/2010
4243300848	EAST RIVER UNIT	46	INACTIVE	4,875	KATZ		2/15/1990
4243332308	EAST RIVER UNIT	47	P & A	5,200	KATZ	12/5/1987	10/13/2009
4243300780	EAST RIVER UNIT	53	P & A	4,918	KATZ		2/14/1995
4243300788	EAST RIVER UNIT	54	P & A	5,211	KATZ		2/11/2009
4243332417	EAST RIVER UNIT	64	P & A	5,245	KATZ	8/8/1988	1/23/2009
4243333510	EAST RIVER UNIT	105	ACTIVE	5,325	KATZ	11/3/2009	--
4243333368	EAST RIVER UNIT	73H	P & A	4,750	KATZ	8/8/2007	9/3/2007
4243381146	EDD LEWIS		P & A	4,967	KATZ		10/14/2005
4226932269	HARDWICK	1	P & A	5,820	WILDCAT	6/19/1997	7/1/1997
4226900006	HARDWICK	2	P & A	5,147	KATZ		5/15/1975
4226900007	HARDWICK	3	P & A	5,168	KATZ		7/27/1970
4226900008	HARDWICK	4	P & A	5,146	KATZ		1/26/1984
4226900011	HARDWICK	6	P & A	5,152	KATZ		7/24/1970
4226900009	HARDWICK	7	P & A	5,150	KATZ		8/19/1967
4226900010	HARDWICK	8	P & A	5,152	KATZ		6/18/1976
4226980016	HARDWICK	9	P & A	2,171	KATZ		1/27/1984
4243301905	HARDWICK	11	P & A	5,152	KATZ		7/22/1970
4226900005	HARDWICK E. V.	1	P & A	5,960	KATZ		7/14/1951
4226931776	HARDWICK, G. W.	12	P & A	5,200	KATZ	3/10/1988	11/6/2009
4226931777	HARDWICK, G. W.	13	P & A	5,200	KATZ	3/11/1988	11/19/2009
4226931775	HARDWICK, G. W.	14	P & A	5,200	KATZ	5/29/1988	11/16/2009
4226931771	HARDWICK, G. W.	15	P & A	5,200	KATZ	3/15/1988	11/12/2009
4226931774	HARDWICK, G. W.	16	P & A	5,200	KATZ	3/8/1988	5/13/2004
4226931772	HARDWICK, G. W.	17	P & A	5,250	KATZ	3/9/1988	11/10/2009
4226932431	HARDWICK, G.W.	18	P & A	5,300	KATZ	8/13/2001	8/24/2001
4226932178	JOHNSON, FANNIE MAE	1	P & A	5,840	KATZ	4/11/1995	2/2/2016
4226932197	JOHNSON, FANNIE MAE	2	P & A	5,825	KATZ	10/5/1995	2/3/2016
4226932236	JOHNSON, FANNIE MAE	3	P & A	5,830	KATZ	11/2/1996	2/1/2016
4226900420	JONES PERCY EST	1	P & A	5,200	KATZ		1/1/1962
4226900428	JONES PERCY ESTATE	3	P & A	4,940	KATZ		7/1/1958
4226932805	KATZ (STRAWN) UNIT	110	ACTIVE	5,312	KATZ	3/13/2011	--
4226931666	KATZ (STRAWN) UNIT	121	P & A	4,879	KATZ	2/9/1987	10/24/2019
4243300797	KATZ (STRAWN) UNIT	131	ACTIVE	5,200	KATZ	9/24/1951	--
4243333513	KATZ (STRAWN) UNIT	132	ACTIVE	5,320	KATZ	12/2/2009	--
4243332296	KATZ (STRAWN) UNIT	143	P & A	5,200	KATZ	12/13/1987	7/30/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332304	KATZ (STRAWN) UNIT	151	P & A	5,200	KATZ	11/20/1987	7/20/2010
4243300779	KATZ (STRAWN) UNIT	152	ACTIVE	5,255	KATZ		--
4243300783	KATZ (STRAWN) UNIT	153	ACTIVE	5,299	KATZ	4/25/1952	--
4243333511	KATZ (STRAWN) UNIT	160	ACTIVE	5,302	KATZ	11/20/2009	--
4243333518	KATZ (STRAWN) UNIT	161	ACTIVE	5,308	KATZ	1/22/2010	--
4243333512	KATZ (STRAWN) UNIT	162	ACTIVE	5,328	KATZ	12/30/2009	--
4243333521	KATZ (STRAWN) UNIT	171	ACTIVE	5,334	KATZ	2/2/2010	--
4243333580	KATZ (STRAWN) UNIT	180	ACTIVE	5,327	KATZ	6/29/2010	--
4243333665	KATZ (STRAWN) UNIT	191	ACTIVE	5,423	KATZ	5/2/2011	--
4226932789	KATZ (STRAWN) UNIT	211	ACTIVE	5,316	KATZ	11/7/2010	--
4226932795	KATZ (STRAWN) UNIT	212	P & A	5,294	KATZ	8/21/2010	6/8/2022
4226932783	KATZ (STRAWN) UNIT	220	ACTIVE	5,308	KATZ	3/9/2010	--
4226932788	KATZ (STRAWN) UNIT	221	ACTIVE	4,863	KATZ	6/6/2010	--
4226932793	KATZ (STRAWN) UNIT	222	ACTIVE	5,308	KATZ	6/18/2010	--
4243333534	KATZ (STRAWN) UNIT	231	ACTIVE	5,315	KATZ	4/23/2010	--
4243333592	KATZ (STRAWN) UNIT	232	ACTIVE	5,340	KATZ	8/10/2010	--
4243333523	KATZ (STRAWN) UNIT	240	ACTIVE	5,309	KATZ	3/18/2010	--
4243300584	KATZ (STRAWN) UNIT	241	ACTIVE	5,250	KATZ	6/8/1957	--
4243333615	KATZ (STRAWN) UNIT	242	ACTIVE	5,297	KATZ	11/30/2010	--
4243300403	KATZ (STRAWN) UNIT	250	P & A	5,206	KATZ	10/25/1951	12/13/2019
4243300400	KATZ (STRAWN) UNIT	261	ACTIVE	5,150	KATZ		--
4243333573	KATZ (STRAWN) UNIT	262	ACTIVE	5,314	KATZ	5/25/2010	--
4243300583	KATZ (STRAWN) UNIT	264	P & A	5,242	KATZ		4/29/2011
4243333524	KATZ (STRAWN) UNIT	270	ACTIVE	5,300	KATZ	4/13/2010	--
4243300405	KATZ (STRAWN) UNIT	271	P & A	5,150	KATZ		11/4/2010
4243300421	KATZ (STRAWN) UNIT	273	ACTIVE	5,127	KATZ	7/11/1953	--
4243300424	KATZ (STRAWN) UNIT	274	P & A	5,131	KATZ	5/16/1989	12/27/2010
4243301970	KATZ (STRAWN) UNIT	275	P & A	5,185	KATZ		3/14/2011
4243300417	KATZ (STRAWN) UNIT	281	P & A	5,156	KATZ		8/16/2010
4243332387	KATZ (STRAWN) UNIT	282	P & A	5,189	KATZ	11/2/1989	9/20/2010
4243332389	KATZ (STRAWN) UNIT	284	P & A	5,210	KATZ	10/15/1989	1/10/2011
4243332390	KATZ (STRAWN) UNIT	285	P & A	5,219	KATZ		11/3/2010
4243332461	KATZ (STRAWN) UNIT	286	P & A	5,730	KATZ	12/8/1989	4/29/2013
4243333526	KATZ (STRAWN) UNIT	290	ACTIVE	5,315	KATZ	5/6/2010	--
4243333704	KATZ (STRAWN) UNIT	301	ACTIVE	5,365	KATZ	7/27/2011	--
4243301620	KATZ (STRAWN) UNIT	302	P & A	5,138	KATZ	3/28/1953	1/5/2012
4243333738	KATZ (STRAWN) UNIT	304	ACTIVE	5,300	KATZ	12/3/2011	--
4243333778	KATZ (STRAWN) UNIT	305	ACTIVE	5,330	KATZ	4/6/2012	--
4243333569	KATZ (STRAWN) UNIT	306	ACTIVE	5,328	KATZ	5/16/2010	--
4243333813	KATZ (STRAWN) UNIT	307	INACTIVE	5,365	KATZ	6/26/2012	--
4243333746	KATZ (STRAWN) UNIT	313	ACTIVE	5,380	KATZ	11/20/2011	--
4243332561	KATZ (STRAWN) UNIT	314	P & A	5,225	KATZ	12/16/1989	2/7/2012
4243333788	KATZ (STRAWN) UNIT	315	P & A	5,320	KATZ	3/17/2012	7/1/2014
4243332553	KATZ (STRAWN) UNIT	317	P & A	5,200	KATZ	12/11/1989	10/14/2013
4243333822	KATZ (STRAWN) UNIT	318	P & A	5,320	KATZ	7/5/2012	5/24/2021
4243333736	KATZ (STRAWN) UNIT	324	ACTIVE	5,380	KATZ	2/6/2012	--
4243333527	KATZ (STRAWN) UNIT	326	ACTIVE	5,503	KATZ	3/30/2010	--
4243300819	KATZ (STRAWN) UNIT	327	P & A	4,952	KATZ		12/23/2010
4243332509	KATZ (STRAWN) UNIT	1201	P & A	5,295	KATZ	7/1/1989	11/29/2010
4226931752	KATZ (STRAWN) UNIT	1221	P & A	5,200	KATZ	1/23/1988	10/11/2011
4243300800	KATZ (STRAWN) UNIT	1323	P & A	4,930	KATZ		3/23/2010
4243332298	KATZ (STRAWN) UNIT	1401	P & A	5,261	KATZ	1/24/1988	3/19/2010
4243332274	KATZ (STRAWN) UNIT	1422	P & A	5,220	KATZ	9/2/1987	11/16/2009
4243300801	KATZ (STRAWN) UNIT	1523	P & A	5,101	KATZ	5/20/1952	11/24/2009
4243332299	KATZ (STRAWN) UNIT	1801	P & A	4,879	KATZ	2/2/1988	3/31/2011
4226932806	KATZ (STRAWN) UNIT	2022	ACTIVE	5,313	KATZ	3/25/2011	--
4226932345	KATZ (STRAWN) UNIT	2121	P & A	5,800	KATZ	8/8/1999	11/12/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932002	KATZ (STRAWN) UNIT	2221	P & A	5,200	KATZ	10/25/1990	6/1/2010
4243332753	KATZ (STRAWN) UNIT	2321	P & A	5,200	KATZ	12/10/1991	3/3/2011
4243333712	KATZ (STRAWN) UNIT	2361	ACTIVE	6,625	KATZ	8/23/2012	--
4243300406	KATZ (STRAWN) UNIT	2401	P & A	5,173	KATZ	5/23/1989	12/31/2009
4243332541	KATZ (STRAWN) UNIT	2701	INACTIVE	100	KATZ	9/27/1989	--
4243332565	KATZ (STRAWN) UNIT	2702	INACTIVE	100	KATZ	12/7/1989	--
4243300401	KATZ (STRAWN) UNIT	2705	P & A	5,116	KATZ	5/12/1989	3/2/2010
4243333713	KATZ (STRAWN) UNIT	2706	COMPLETED	7,500	KATZ		--
4243300423	KATZ (STRAWN) UNIT	2861	P & A	5,161	KATZ	7/17/1989	11/21/2013
4243300399	KATZ (STRAWN) UNIT	2901	P & A	5,150	KATZ		2/17/2011
4243333160	KATZ (STRAWN) UNIT	2921	P & A	5,725	KATZ	12/10/1998	1/13/2010
4243380198	KATZ (STRAWN) UNIT	3041	P & A	5,113	KATZ	7/18/2005	6/17/2010
4243301606	KATZ (STRAWN) UNIT	3042	P & A	5,113	KATZ	11/6/1989	3/22/2012
4243300838	KATZ (STRAWN) UNIT	3062	P & A	5,240	KATZ	11/16/1989	7/1/2010
4243301610	KATZ (STRAWN) UNIT	3141	P & A	5,115	KATZ		2/16/2012
4243300837	KATZ (STRAWN) UNIT	3161	P & A	5,190	KATZ	2/13/1990	8/18/2010
4243300842	KATZ (STRAWN) UNIT	3181	P & A	4,961	KATZ		2/16/2011
4243301605	KATZ (STRAWN) UNIT	3241	P & A	5,170	KATZ		4/12/2013
4243332570	KATZ (STRAWN) UNIT	3243	P & A	5,240	KATZ	1/14/1990	2/10/2010
4243332588	KATZ (STRAWN) UNIT	3261	P & A	5,150	KATZ	2/12/1990	3/31/2010
4226932987	KATZ (STRAWN) UNIT	121A	ACTIVE	5,337	KATZ	12/3/2019	--
4243333496	KATZ (STRAWN) UNIT	142A	ACTIVE	5,305	KATZ	10/20/2009	--
4243333595	KATZ (STRAWN) UNIT	151A	ACTIVE	5,317	KATZ	9/7/2010	--
4243334217	KATZ (STRAWN) UNIT	250A	INACTIVE	5,314	KATZ	12/19/2019	--
4243333630	KATZ (STRAWN) UNIT	251A	ACTIVE	5,315	KATZ	12/10/2010	--
4243333598	KATZ (STRAWN) UNIT	252A	TA	5,300	KATZ	10/17/2010	--
4243333599	KATZ (STRAWN) UNIT	263A	ACTIVE	5,315	KATZ	9/29/2010	--
4243333639	KATZ (STRAWN) UNIT	264A	P & A	5,333	KATZ	4/5/2011	6/1/2021
4243333627	KATZ (STRAWN) UNIT	271A	ACTIVE	5,302	KATZ	12/20/2010	--
4243333632	KATZ (STRAWN) UNIT	272A	ACTIVE	5,318	KATZ	3/1/2011	--
4243333807	KATZ (STRAWN) UNIT	274A	TA	5,300	KATZ	5/24/2012	7/1/2022
4243333607	KATZ (STRAWN) UNIT	281A	ACTIVE	5,324	KATZ	10/9/2010	--
4243333617	KATZ (STRAWN) UNIT	282A	ACTIVE	5,297	KATZ	11/18/2010	--
4243333735	KATZ (STRAWN) UNIT	283A	ACTIVE	5,380	KATZ	10/7/2011	--
4243333722	KATZ (STRAWN) UNIT	284A	ACTIVE	5,345	KATZ	12/15/2011	--
4243333799	KATZ (STRAWN) UNIT	285A	INACTIVE	5,350	KATZ	4/16/2012	--
4243333927	KATZ (STRAWN) UNIT	286A	TA	5,337	KATZ	3/24/2014	--
4243333730	KATZ (STRAWN) UNIT	291A	ACTIVE	5,364	KATZ	9/24/2011	--
4243333695	KATZ (STRAWN) UNIT	302A	ACTIVE	5,390	KATZ	7/6/2011	--
4243333771	KATZ (STRAWN) UNIT	303A	ACTIVE	5,330	KATZ	2/27/2012	--
4243333753	KATZ (STRAWN) UNIT	314A	ACTIVE	5,375	KATZ	10/27/2011	--
4243334002	KATZ (STRAWN) UNIT	315A	ACTIVE	5,348	KATZ	7/11/2014	--
4243333770	KATZ (STRAWN) UNIT	316A	ACTIVE	5,400	KATZ	1/25/2012	--
4243333820	KATZ (STRAWN) UNIT	317A	INACTIVE	5,336	KATZ	12/29/2013	--
4243333776	KATZ (STRAWN) UNIT	323A	ACTIVE	5,408	KATZ	3/7/2012	--
4243333821	KATZ (STRAWN) UNIT	325A	ACTIVE	5,385	KATZ	12/10/2013	--
4226900309	LEWIS, W. D.	2	P & A	5,090	KATZ		9/29/2008
4243300412	LONG, C. B. -D-	5	P & A	5,165	KATZ		3/12/2010
4243300415	LONG, C. B. -D-	6	P & A	5,188	KATZ		11/8/2010
4243300408	LONG, C.B. -C-	4	P & A	5,214	KATZ		3/9/2011
4243300411	LONG, C.B. -C-	5	P & A	5,165	KATZ		11/30/2010
4243300420	LONG, C.B. -C-	9	INACTIVE	5,163	KATZ		5/13/2010
4243300414	LONG, C.B. -C-	6 T	P & A	5,168	KATZ		11/12/2010
4243300419	LONG, C.B. -C-	8 T	P & A	5,165	KATZ		11/15/2010
4243300418	LONG, C.B. -D-	7	P & A	5,190	KATZ	8/1/1989	8/10/2010
4243300586	LONG, C.B. -D-	11	P & A	5,183	KATZ	6/15/1989	8/30/2010
4243300587	LONG, C.B. -D-	12	P & A	4,896	KATZ		1/13/1986

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932293	LOWERY 87	2	P & A	5,835	WILDCAT	11/11/1997	11/24/1997
4226932268	LOWREY 90	1	P & A	5,800	WILDCAT	5/25/1997	6/4/1997
4226932270	MANGIS	2	P & A	5,770	KAIA	7/10/1997	7/20/1997
4226932325	ORSBORN	2	P & A	5,718	KAIA	10/22/1998	11/4/1998
4226900108	ORSBORN	7	P & A	4,940	KATZ		8/30/2006
4226932955	ORSBORN K	14	INACTIVE	5,235	KATZ	11/5/2015	--
4226900077	ORSBORN -K-	3	P & A	5,091	KATZ		7/19/1993
4226900082	ORSBORN UNIT	1	INACTIVE	5,155	KATZ	8/14/1952	--
4226900081	ORSBORN UNIT	14	P & A	5,077	KATZ		8/30/2018
4226900105	ORSBORN UNIT	15	P & A	5,211	KATZ		8/25/1994
4226910001	ORSBORN UNIT	19	P & A	5,144	KATZ	9/1/1984	9/6/1984
4226931306	ORSBORN UNIT	21	P & A	5,170	KATZ	9/25/1984	11/11/2021
4226931395	ORSBORN UNIT	24	P & A	5,200	KATZ	1/23/1985	3/25/2022
4226931398	ORSBORN UNIT	26	P & A	5,247	KATZ	2/4/1985	5/9/2019
4226931397	ORSBORN UNIT	28	P & A	5,220	KATZ	2/18/1985	3/1/2013
4226931738	ORSBORN UNIT	34	P & A	5,250	KATZ	10/9/1987	8/28/2018
4226932314	ORSBORN UNIT	43	P & A	5,350	KATZ	4/24/1998	4/29/2019
4226932956	ORSBORN UNIT	44	INACTIVE	5,230	KATZ	6/28/2016	--
4226900076	ORSBORN, "K"	1	P & A	5,099	KATZ		7/12/1993
4226900104	ORSBORN, ALMA H.	1	P & A	5,155	KATZ		5/7/1957
4243300841	SOUTHWEST RIVER UNI	1	P & A	4,903	KATZ		7/17/1998
4243301612	SOUTHWEST RIVER UNI	5	P & A	5,115	KATZ		2/20/2012
4243301621	SOUTHWEST RIVER UNI	6	P & A	5,154	KATZ	4/14/1953	1/25/2012
4243301609	SOUTHWEST RIVER UNI	9	P & A	5,150	KATZ		4/13/2011
4243301619	SOUTHWEST RIVER UNI	10	P & A	5,104	KATZ	2/17/1953	12/14/2010
4243300844	SOUTHWEST RIVER UNI	13	P & A	4,987	KATZ		9/18/1995
4243300836	SOUTHWEST RIVER UNI	16	P & A	5,170	KATZ		1/5/2011
4243332587	SOUTHWEST RIVER UNI	18	P & A	5,300	KATZ	2/1/1990	1/27/2010
4243300811	SOUTHWEST RIVER UNI	24	P & A	4,920	KATZ		11/28/2002
4243301444	SOUTHWEST RIVER UNI	28	P & A	4,950	KATZ	8/13/2007	4/13/2011
4243300823	SOUTHWEST RIVER UNI	36	P & A	4,963	KATZ		--
4243300815	SOUTHWEST RIVER UNI	37	P & A	4,972	KATZ		10/15/1991
4243300835	SOUTHWEST RIVER UNI	71	P & A	5,171	KATZ		10/4/1991
4243300809	SOUTHWEST RIVER UNI	25W	P & A	5,230	KATZ		10/22/2013
4243332560	SOUTHWEST RIVER UNI	27W	P & A	5,206	KATZ	1/9/1990	3/12/2013
4226900069	STATE A GAO	1	P & A	5,085	KATZ		4/19/1985
4226900070	STATE B GAO	1	P & A	4,876	KATZ		4/17/1985
4243301761	STATE OF TEXAS -C-	1	P & A	5,296	KATZ		2/11/1983
4243301762	STATE OF TEXAS -C-	2	P & A	5,205	KATZ		12/4/1982
4243301764	STATE OF TEXAS -C-	4	P & A	5,205	KATZ		11/29/1982
4226900012			ACTIVE	5,105			--
4226900016			ACTIVE	5,175			--
4243300005			P & A	3,251			--

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Appendix B: Submissions and Responses to Requests for Additional Information

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Kinder Morgan Permian CCS LLC

Prepared for *Kinder Morgan Permian CCS LLC*
Houston, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 4.0
June 2023

INTRODUCTION

Kinder Morgan Production Co. LLC (Kinder Morgan) currently has a Class II disposal permit issued by the Texas Railroad Commission (TRRC) for the Katz Strawn Unit 2361 well (KSU 2361), API# 42-433-33712. The permit was originally issued in November 2011 for saltwater disposal operations, and the well has actively injected saltwater since 2013. This permit currently authorizes Kinder Morgan to inject up to 30,000 barrels saltwater per day (bbls/d), equating to 65 million standard cubic feet per day (MMscf/day) of carbon dioxide, into the Ellenburger and Cambrian formations at a depth of 5,800' to 6,800' with a maximum allowable surface pressure of 2,900 psi. The KSU 2361 well is located in a rural, sparsely populated area of Stonewall County, Texas, approximately twelve miles west of the town of Knox City, as shown in Figure 1.

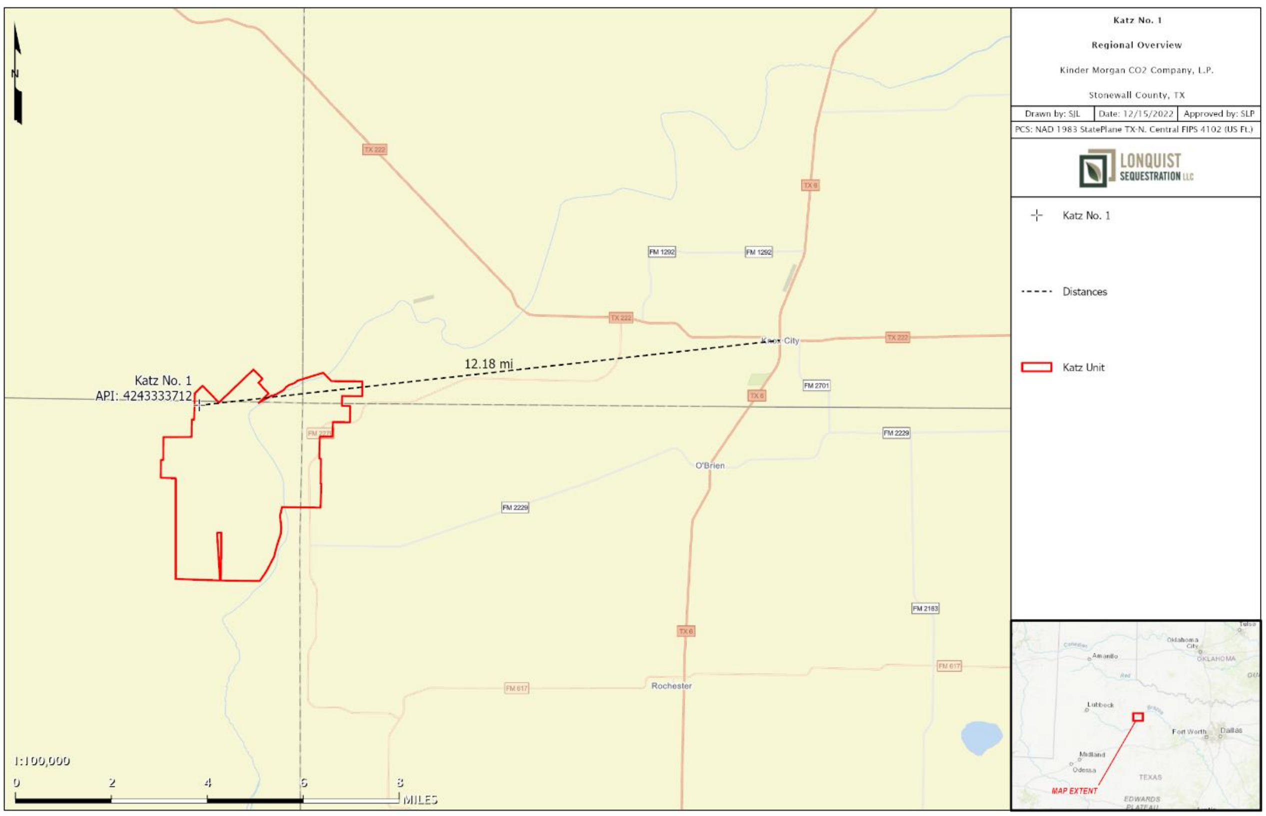


Figure 1 – Location of KSU 2361 Well

Kinder Morgan is seeking TRRC approval to amend the existing KSU 2361 Class II saltwater disposal permit to inject treated acid gas (TAG), including CO_2. In the future, Kinder Morgan may provide surplus injection capacity to dispose oil and gas waste derived TAG from similar third-party gas processing facilities. Kinder Morgan intends to inject into this well for 21 years at a capacity ranging up to 65 million standard cubic feet per day (MMSCF/d). The source of this injected CO_2 gas is from Red Cedar natural gas processing plants in southern Colorado. Table 1 below shows the expected composition of the gas stream to be injected. Table 2 shows the expected average volume of CO_2 gas commitments from similar type emission sources in the same area, along with the contract status as of March 2023.

Table 1 – Expected Gas Composition at KSU 2361

Component	**Mol Percent**
Carbon Dioxide	99.20%
Methane	0.25%
Ethane	0.03%
Propane	0.04%
Nitrogen	0.48%
Hydrogen Sulfide	0.00%

Table 2 – Expected Sequestered Gas Volumes for KSU 2361

Contract Status	**Avg. Rate (MMcfd)**
Committed	22
Proposal	8
Proposal	23
Proposal	9
Total	62

Kinder Morgan is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

ACRONYMS AND ABBREVIATIONS

‘	Feet
%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group’s GEM 2020.11
GHGs	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	MilliDarcy(ies)
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million

MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MMSCF	Million Standard Cubic Feet
MSCF/D	Thousand Cubic Feet per Day
MMSCF/d	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

INTRODUCTION 1
ACRONYMS AND ABBREVIATIONS....3
SECTION 1 – UIC INFORMATION....8
1.1 Underground Injection Control (UIC) Permit Class: Class II....8
1.2 UIC Well Identification Number: 8
SECTION 2 – PROJECT DESCRIPTION 9
2.1 Regional Geology....10
2.1.1 Regional Faulting 18
2.2 Site Characterization 19
2.2.1 Stratigraphy and Lithologic Characteristics....19
2.2.2 Upper Confining Zone – Mississippian Lime....21
2.2.3 Secondary Confining Interval – Lower Strawn Shale....22
2.2.4 Injection Interval – Ellenburger/Cambrian Sands....25
2.2.5 Lower Confining Zone – Precambrian 29
2.3 Fracture Pressure Gradient 31
2.4 Local Structure....32
2.5 Injection and Confinement Summary....37
2.6 Groundwater Hydrology....37
2.6.1 Reservoir Characterization Modeling....43
SECTION 3 – DELINEATION OF MONITORING AREA....56
3.1 Maximum Monitoring Area 56
3.2 Active Monitoring Area 57
SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE....58
4.1 Leakage from Surface Equipment....58
4.2 Leakage from Existing Wells within MMA....59
4.2.1 Oil and Gas Operations within Monitoring Area 59
4.2.2 Groundwater wells 64
4.3 Leakage Through Faults and Fractures....65
4.4 Leakage Through the Confining Layer 65
4.5 Leakage from Natural or Induced Seismicity....65
SECTION 5 – MONITORING FOR LEAKAGE....67
5.1 Leakage from Surface Equipment....68
5.2 Leakage From Existing and Future Wells within MMA....68
5.3 Leakage through Faults, Fractures or Confining Seals....71
5.4 Leakage through Natural or Induced Seismicity....71
SECTION 6 – BASELINE DETERMINATIONS 73
6.1 Visual Inspections 73
6.2 CO_2 Detection 73
6.3 Operational Data 73
6.4 Continuous Monitoring 73
6.5 Groundwater Monitoring 74
SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION 75
7.1 Mass of CO_2 Received....75
7.2 Mass of CO_2 Injected 75

7.3 Mass of CO_2 Produced 76
7.4 Mass of CO_2 Emitted by Surface Leakage 76
7.5 Mass of CO_2 Sequestered 77
SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN 78
SECTION 9 – QUALITY ASSURANCE 79
9.1 Monitoring QA/QC 79
9.2 Missing Data 79
9.3 MRV Plan Revisions 80
SECTION 10 – RECORDS RETENTION 81
SECTION 11 - REFERENCES 82
SECTION 12 - APPENDICES 84

LIST OF FIGURES

Figure 1 – Location of KSU 2361 Well 1
Figure 2 – Regional Map of the Permian Basin. 10
Figure 3 – Stratigraphic Column of the Eastern Shelf 11
Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations 12
Figure 5 – Top of Structure Map of the Ellenburger Group in West Texas 13
Figure 6 – Generalized Isopach Map of the Ellenburger Group in West Texas 14
Figure 7 – Thickness of Cambrian and Lower Ordovician Strata 15
Figure 8 – Formation Tops at KSU 2361. 16
Figure 9 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma. 18
Figure 10 – KSU 2361 Type Log 19
Figure 11 – Type Log of Zones of Interest 20
Figure 12 – Depositional Map of the Mississippian 21
Figure 13 – Core Description 23
Figure 14 – Cross Section Depicting Corelative Offset Core with Lower Strawn Shale 24
Figure 15 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003) 25
Figure 16 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003) 27
Figure 17 – Offset Wells used for Formation Fluid Characterization. 28
Figure 18 – Pre-Cambrian Distribution Map 30
Figure 19 – Ellenburger Structure Map 33
Figure 20 – Structural Northwest-Southeast Cross Section 34
Figure 21 – Structural West to East Seismic Profile 35
Figure 22 – Structural Northwest to Southeast Seismic Profile 36
Figure 23 – Generalized Stratigraphy of the Seymour Aquifer 38
Figure 24 – Regional Extent of the Seymour Aquifer Pods 40
Figure 25 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer 41
Figure 26 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer 42
Figure 27 – Geomodel Dimensions 46
Figure 28 – Structural Horizons of the Geomodel 47
Figure 29 – Porosity Distribution in Plume Model 48
Figure 30 – NTG Ratio Applied to the Plume Model 49
Figure 31 – CO_2-Water Relative Permeability Curves 50
Figure 32 – History Match for KSU 2361 51
Figure 33 – History Match for KSU #3471 51
Figure 34 – Simulated Wellhead Pressure During Active Injection 52

Figure 35 – Forecasted Injection Rate and BHP 53
Figure 36 – Annualized Growth Rate of CO_2 Plume 54
Figure 37 – Aerial View of CO_2 Plume....55
Figure 38 – Cross-Sectional View of CO_2 Plume 55
Figure 39 – Stabilized Plume Boundary, Active Monitoring Area and Maximum Monitoring Area....57
Figure 40 – Site Plan 59
Figure 41 – KSU 2361 Wellbore Schematic 61
Figure 42 – All Oil and Gas Wells within the MMA....62
Figure 43 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA 63
Figure 44 – Seismicity Review (TexNet – 06/01/2022)....66
Figure 45 – Groundwater Monitoring Wells....70
Figure 46 – Nearest TexNet Seismic Station....72

LIST OF TABLES

Table 1 – Expected Gas Composition of Sequestered Gas Stream....2
Table 2 – Expected Gas Volumes of Sequestered Gas Stream....2
Table 3 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples 29
Table 4 – Fracture Gradient Assumptions 31
Table 5 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas 38
Table 6 – CO_2 Solubility Table 45
Table 7 – Rock Properties 47
Table 8 – Initial Conditions Summary 48
Table 9 – Plume Model Radius and Area....54
Table 10 – Summary of Leakage Monitoring Methods 67

SECTION 1 – UIC INFORMATION

This section contains key information regarding the UIC Permit.

1.1 Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. TRRC classifies the KSU 2361 well as UIC Class II. A Class II permit was issued to Kinder Morgan under TRRC Rule 9 (entitled “Disposal into Non-Productive Formations”) and Rule 36 (entitled “Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas”).

1.2 UIC Well Identification Number:

Katz Strawn Unit 2361, API No. 42-433-33712, UIC #000104281.

SECTION 2 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the KSU 2361 well.

The injection interval for KSU 2361 is approximately 670' below the base of the Strawn formation, the primary producing formation in the area, and approximately 5,900' below the base of the lowest useable-quality aquifer. Therefore, the location, facility, and the well design of the KSU 2361 well are planned to protect against the migration of CO_2 out of the injection interval, protect against contamination of subsurface resources and, most critical, to prevent surface releases.

2.1 Regional Geology

The KSU 2361 well is located on the Eastern Shelf, a broad marine shelf located in the eastern portion of the Permian Basin, shown in Figure 2. Figure 3 depicts an Eastern Shelf stratigraphic column representative of the strata found at the KSU 2361 well location. The red stars reference the injection formations, and a green star indicates the historically productive interval in the area.

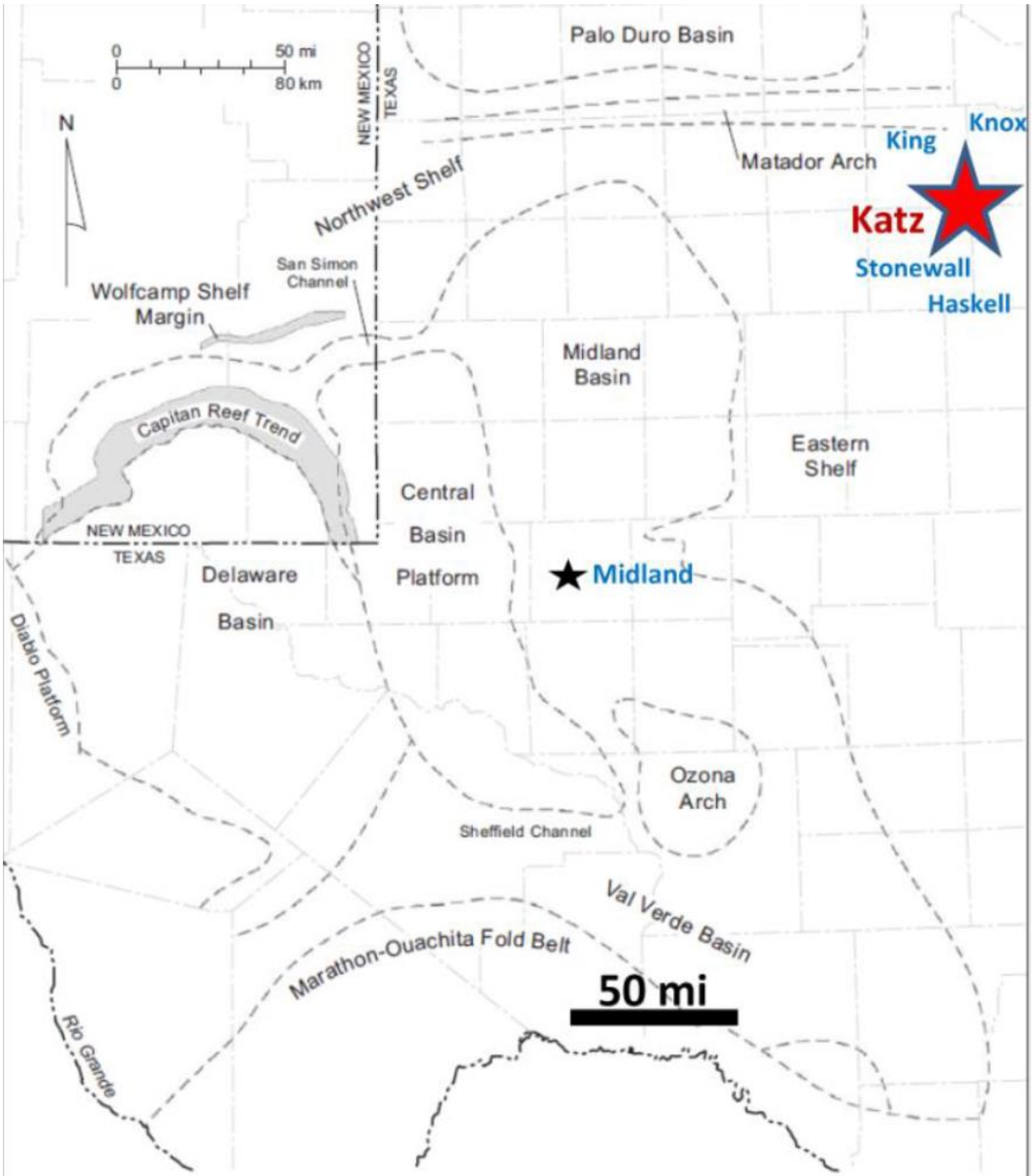


Figure 2 – Regional Map of the Permian Basin. The red star is the approximate location of KSU 2361 well.

SYSTEM	SERIES OR EPOCH FORMATION NAME	STONEWALL CO, TX LITHOLOGIES	
QUATERNARY	Holocene	Alluvium (sand, shale)	
	Pleistocene		
TERTIARY			
CRETACEOUS		*ABSENT*	
TRIASSIC			
PERMIAN	Guadalupe	gypsum, shale, dolomite	
	Wichita Gp	shale	
	Wolfcamp	shale, sandstone, limestone	
PENNSYLVANIAN	Virgil (Cisco)	shale, limestone, sandstone	
	Missouri (Canyon)	shale, limestone	
	Des Moines (Strawn)	sandstone, shale, limestone	★ Oil
	Atoka (Bend)	shale, sandstone	
	Morrow	*ABSENT*	
MISSISSIPPIAN	Chester	limestone	
	Meramec-Osage		
DEVONIAN		*ABSENT*	
SILURIAN			
ORDOVICIAN	Ellenburger	dolomite	★ Disposal Zone
CAMBRIAN	Wilberns	shale, sandstone, limestone	★ Disposal Zone
PRECAMBRIAN		granite	

Figure 3 – Stratigraphic Column of the Eastern Shelf.

The upper target injection interval is the lower Ordovician-age Ellenburger Group, which is subdivided into the Honeycut, Gorman, and Tanyard Formations, as seen in Figure 4. Upper Cambrian-age sandstone units of the Wilberns Formation, comprise the lower target injection interval.

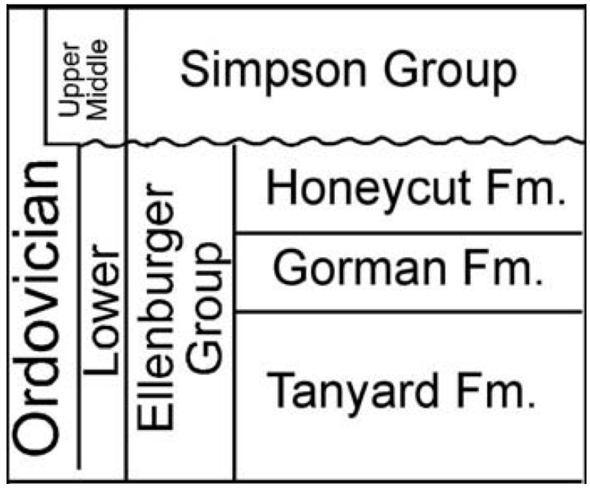


Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations (Kupecz, 1992).

The Ellenburger Group is present at varying depths in each of the provinces of the Permian Basin. In the Midland Basin area, the top of Ellenburger carbonate is as deep as 11,000' (GL) (Loucks, 2003). Due to regional structural dip of the Eastern Shelf, in northeast Stonewall County, the top of Ellenburger is found at only approximately 6,000' deep (GL). The depositional environment over the Stonewall, King, Knox, and Haskell County intersection during the Ordovician Period was a broad, shallow water carbonate platform with an interior of dolomite and an outer area of limestone. This was interpreted by Kerans (1990) as the dolomite being a restricted shelf interior and the limestone being an outer rim of more open-shelf deposits (Loucks, 2003).

Kerans (1990) performed the most complete regional analysis on Ellenburger depositional systems and facies. He recognized six general lithofacies as follows: litharenite: fan delta – marginal marine depositional system; mixed siliciclastic-carbonate packstone/grainstone: lower tidal-flat depositional system; ooid and peloid grainstone: high-energy restricted-shelf depositional system; mottled mudstone: low-energy restricted-shelf depositional system; laminated mudstone: upper tidal-flat depositional system; and gastropod-intraclast-peloid packstone/grainstone: open shallow-water-shelf depositional system.

According to Loucks, the diagenesis of the Ellenburger Group is complex, and the processes that produced the diagenesis spanned millions of years. The three major diagenetic processes of note are dolomitization, karsting, and tectonic fracturing. Dolomitization favors the preservation of fractures and pores due to its greater chemical and mechanical stability relative to limestone. Kupecz and Land (1991) delineated generations of dolomite into early-stage and late-stage. They attributed 90% of the dolomite as early-stage, wherein the source of magnesium was probably seawater. The other 10% of dolomite was attributed as late-stage, in which warm, reactive fluids were expelled from basinal shales during the Ouachita Orogeny. Karsting can affect only the surface of a carbonate terrain, forming terra rosa, or it can extensively dissolve the carbonate surface,

forming karst towers (Loucks, 2003). It can also produce extensive subsurface dissolution in the form of caves and other structures, which increases porosity and permeability. Fracturing can be tectonic or karst-related. Tectonic fractures are commonly the youngest fractures in the rock and generally crosscut karst-related fractures (Kerans, 1989). Holtz and Kerans (1992) divided Ellenburger reservoirs into three groups based on these fracture types. The Eastern Shelf of the Permian Basin falls within the ramp carbonates group, in which predominant pore types are intercrystalline and interparticle. These reservoirs are characterized by the thinnest net pay, highest porosity, moderate permeability, highest initial water saturation, and highest residual oil saturation.

Figures 5 and 6 show the regional structure contours and isopachs of the Ellenburger Group, respectively. Figure 7 shows isopachs of Cambrian and lower Ordovician strata. Stars depict the KSU 2361 well location in each of these figures. In Figure 8, formation tops from gamma-ray data indicate the net pay thickness of the Ellenburger and Cambrian is approximately 223' within this interval in the KSU 2361 well location.

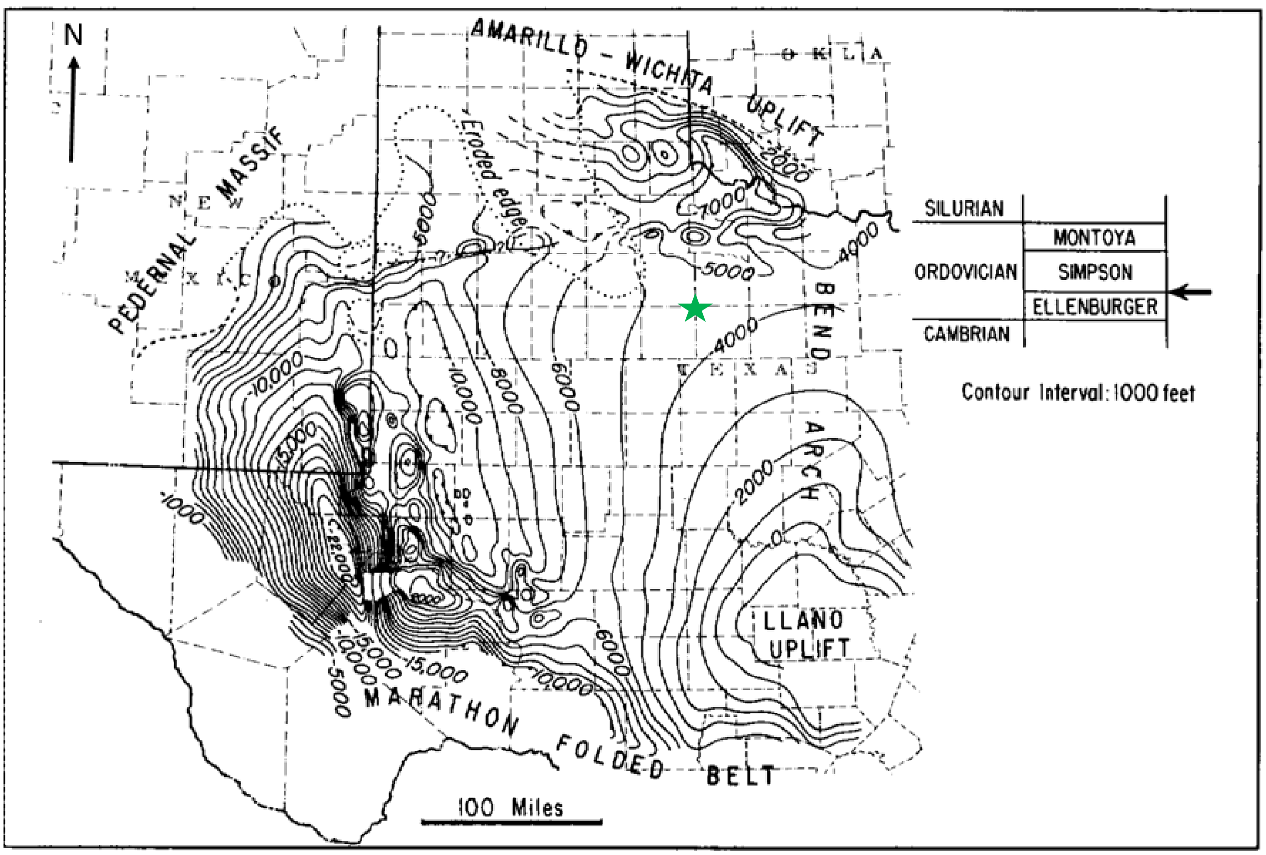


Figure 5 – Top of Structure Map of the Ellenburger Group in West Texas (Subsea Values) (Galley, 1955).

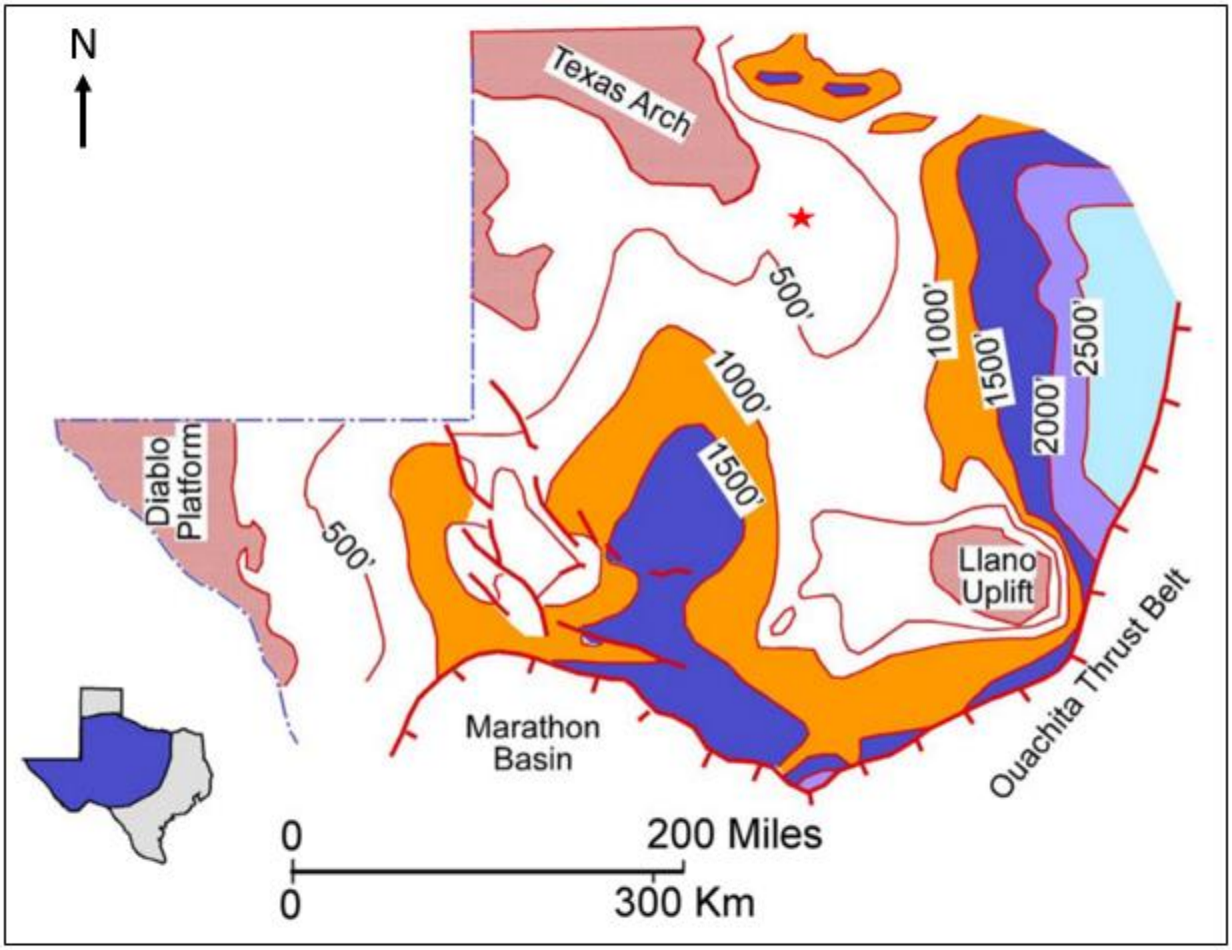


Figure 6 – Generalized Isopach Map of the Ellenburger Group in West Texas
(Kerans, 1989).

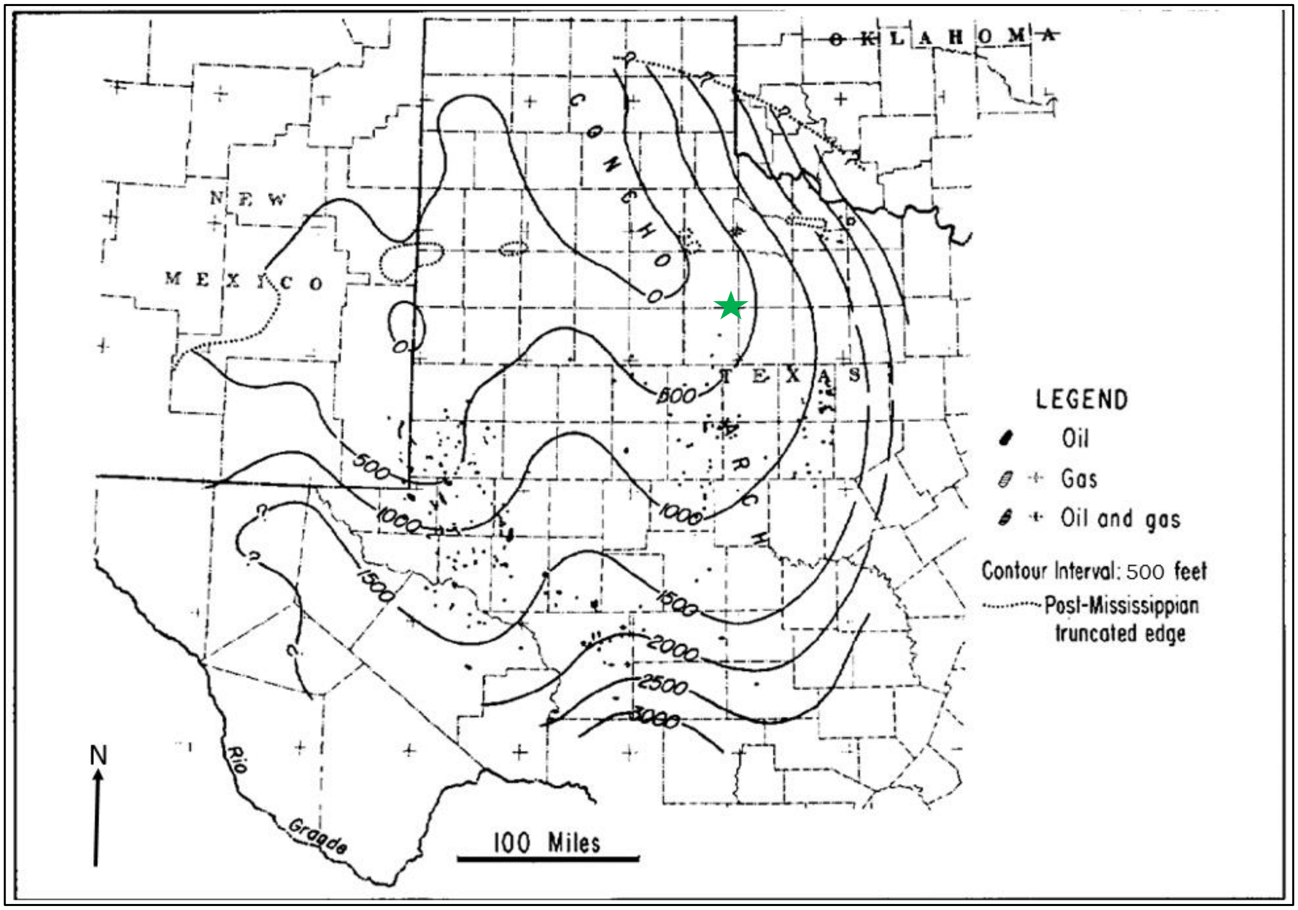


Figure 7 – Thickness of Cambrian and Lower Ordovician Strata (Galley, 1955).

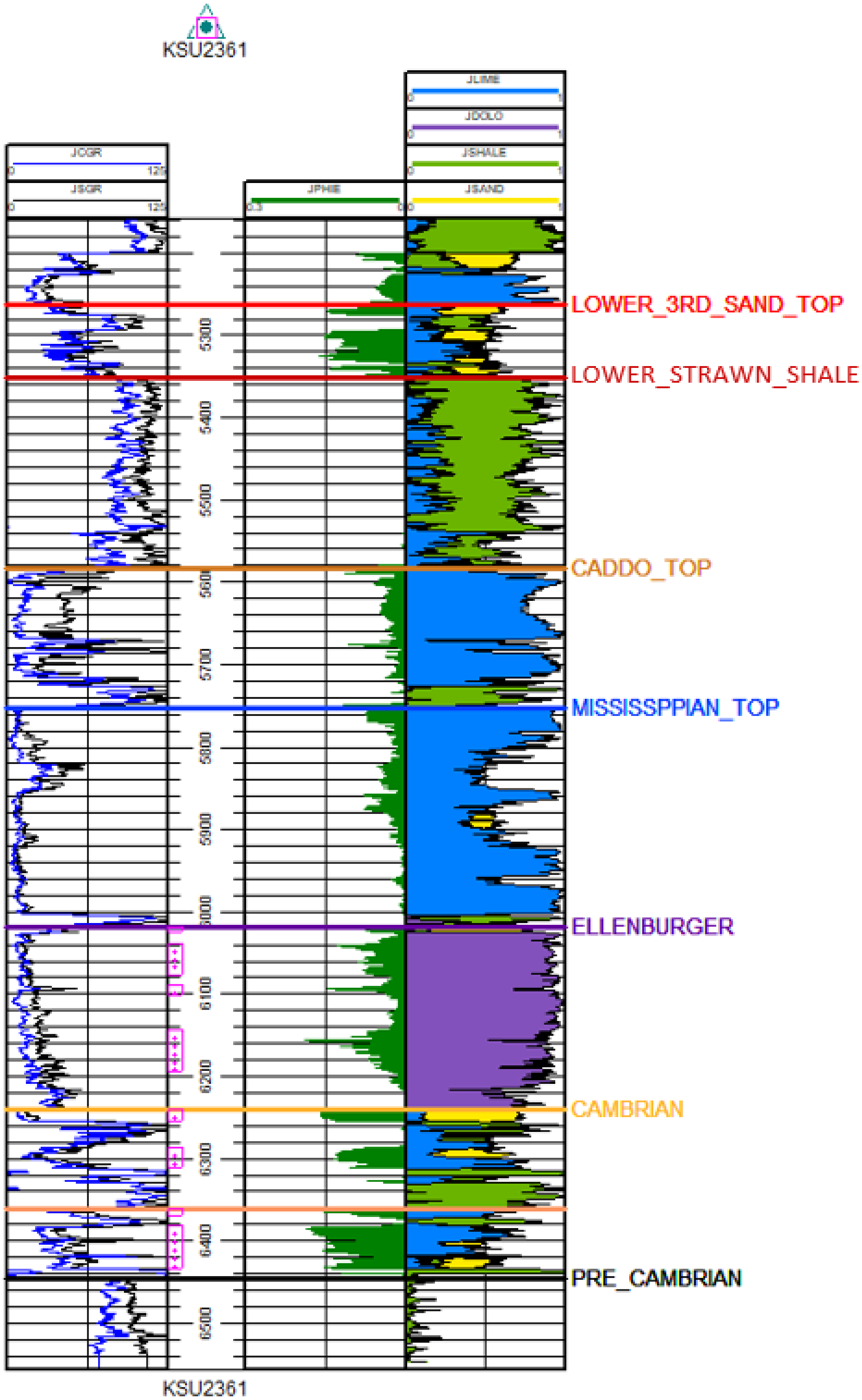


Figure 8 – Formation Tops at KSU 2361. Purple represents dolomite and the upper injection interval. Yellow represents sandstone, which is present in the pay interval. Pink boxes within depth column indicate active perforated intervals.

Cambrian-age strata consist of interbedded sandstone, limestone, and shale members. The initial deposits laid down on the eroded surface of Precambrian rocks were sandstone and arenaceous carbonates. Shale members are thickest in the southeast and nonexistent on the west side of the Permian Basin (Galley, 1955).

Overlying the Precambrian basement rock is the Riley Formation. This, in turn, is overlain by transgressive and progradational shallow-water marine sandstone, siltstone, limestone, and dolomite of the Wilberns Formation. The Riley Formation consists of sandstone packages whose thicknesses vary from place to place in response to the paleotopography of the underlying Precambrian surface (Kyle and McBride, 2014). The depositional environment in this area during the Cambrian was influenced by the sea, which advanced from the southeast (Galley, 1955). This led to the formation of a complex succession of transgressive and regressive sandstone units, both glauconitic and non-glauconitic (Kyle and McBride, 2014).

The Riley Formation is probably thickest south of the Llano region and laps out about 100 miles west and a slightly greater distance northwestward from the Llano region. It has accumulated in a northwestward-extending arm of the sea and likely extended beyond its present limits since there is a disconformity at its top. The Wilberns Formation thins appreciably northwestward from the Llano region to about 230' in Nolan County and to 70' in Lubbock County. West and north of the Llano region, usage suggested by Cloud and Barnes and adopted by petroleum geologists places the Tanyard-Wilberns boundary in the vicinity of the first appearance downward of glauconite (Barnes et al., 1959).

Figure 9 indicates that the Riley Formation's northwestern extent ends in Jones and Fisher counties, which implies that Cambrian strata at KSU 2361 may be limited to the Wilberns Formation only.

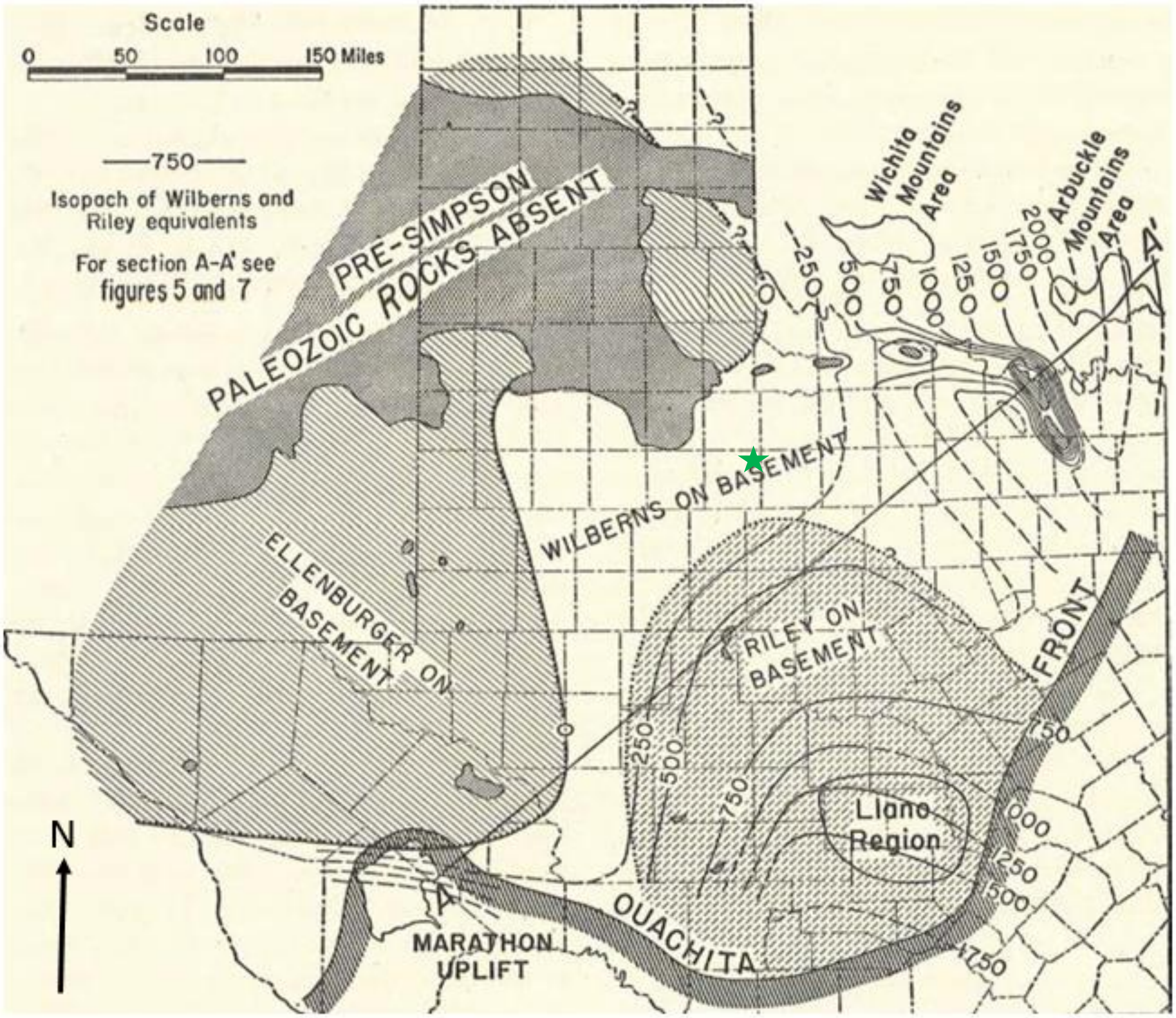


Figure 9 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma. The green star approximates the location of KSU 2361 (Barnes et al., 1959).

2.1.1 Regional Faulting

Regional faulting in the KSU 2361 area trends primarily N-S in direction. This is the result of the dip rotation from a SW-NE trend seen in the Fort Worth basin to the east that rotates N-S as you move west towards the Bend-Arch and the edge of the basin (Hornhach, 2016). This trend then carries towards the Eastern Shelf closer to the KSU 2361 location. The most common faults are high-angle basement faults that primarily die within the Pennsylvanian in the KSU 2361 well area. Faulting is discussed in more detail in the Site characterization.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the KSU 2361 well.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 depicts an annotated open hole log from the surface to the total depth of the KSU 2361 well, with regional formation tops indicating the injection and primary upper confining units. Figure 11 provides a magnified view of the zones of interest, from above the Lower Strawn to the Precambrian, with general lithologic descriptions along the right edge of the figure.

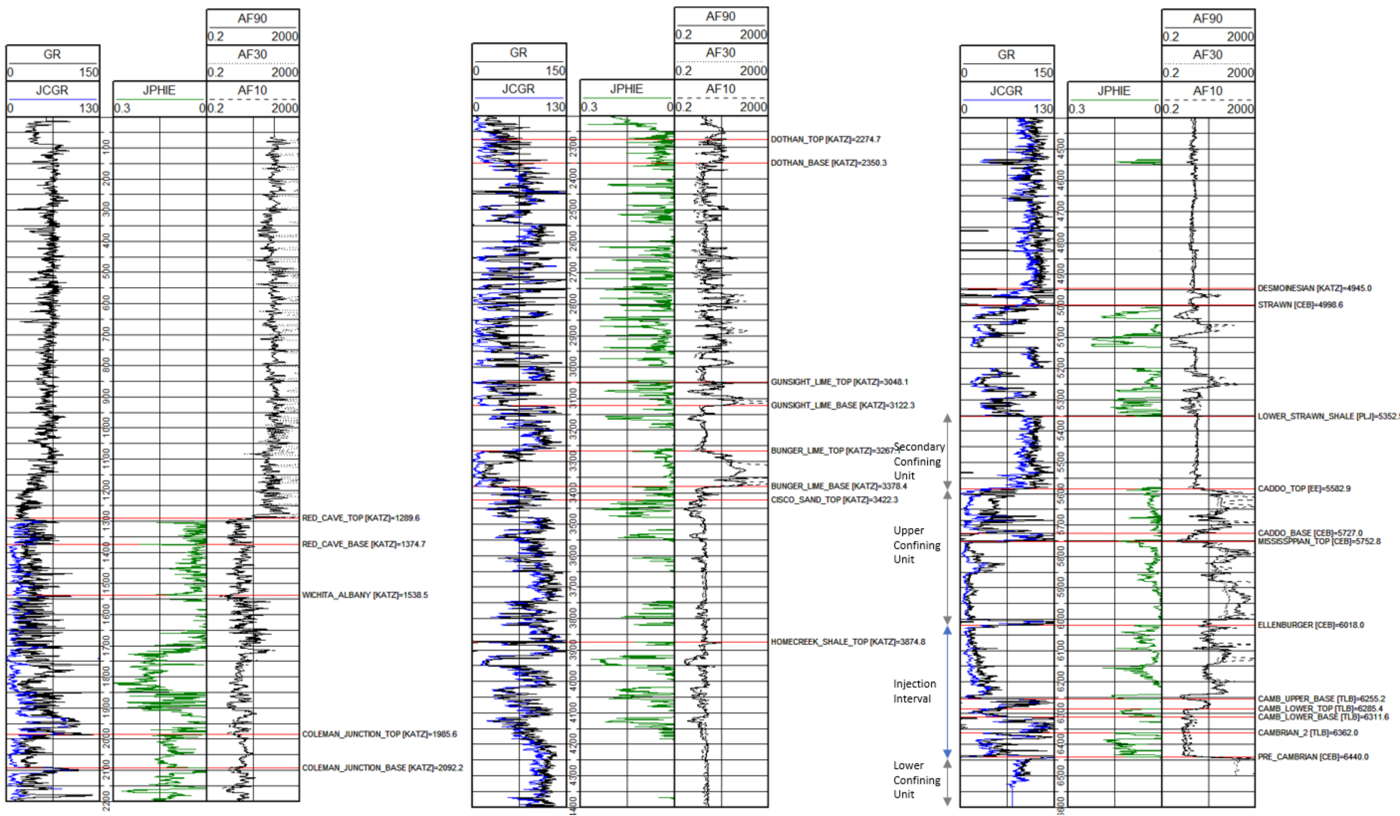


Figure 10 – KSU 2361 Type Log

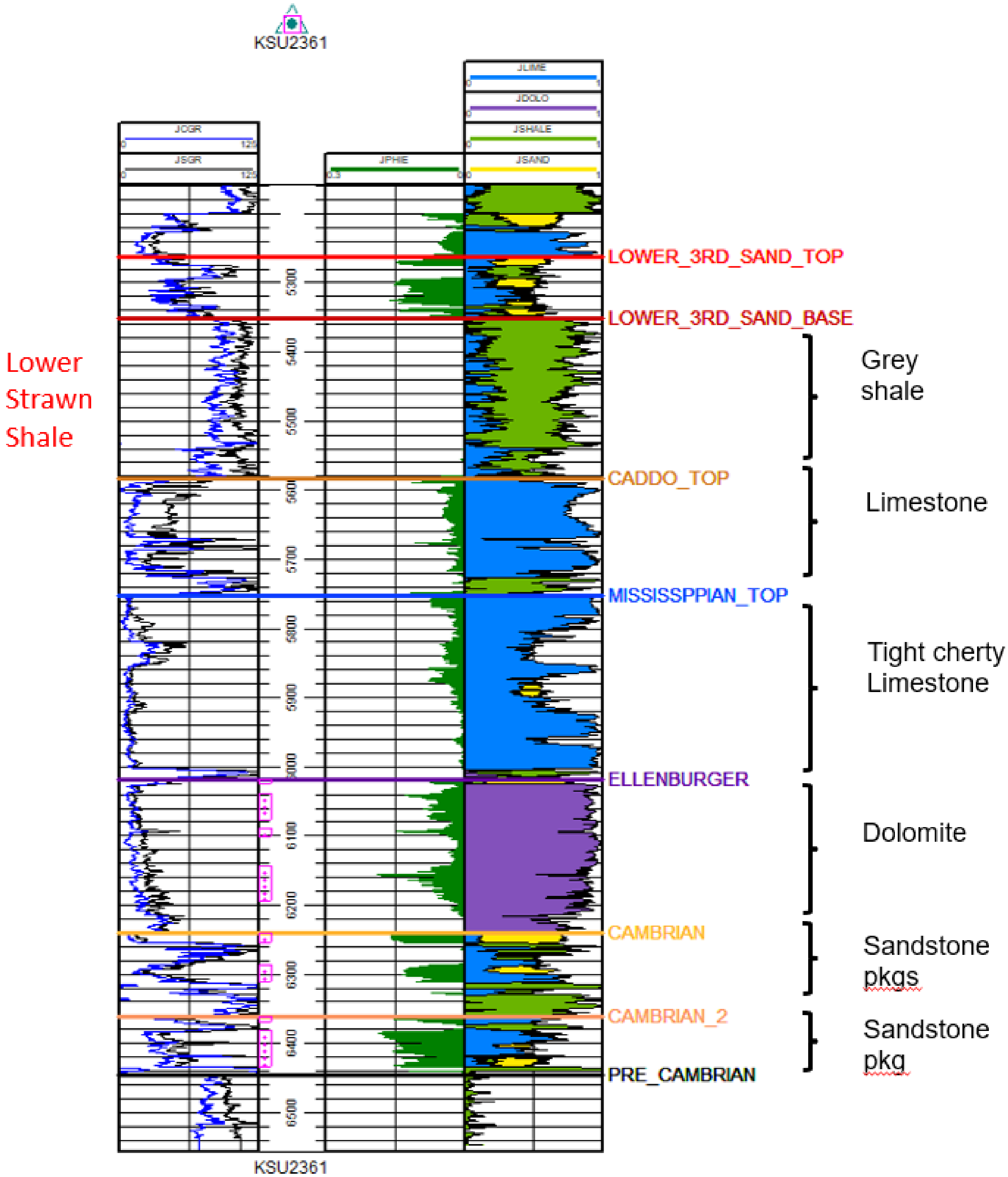


Figure 11 – Type Log of Zones of Interest

2.2.2 Upper Confining Zone – Mississippian Lime

The Mississippian Lime is the primary confining unit for the KSU 2361. This formation is the product of a large extensive shallow water carbonate platform that covered much of the southern and western Laurussia (Kane). Figure 12 shows the location of the KSU 2361 well to be found within the Chappel Shelf of the Mississippian Age. Representative cores of the Mississippian Lime formation found on the Chappel Shelf in the Llano uplift area consist of light-colored, fine- to coarse-grained, skeletal packstone (Kane). The open hole log seen in Figure 11 depicts the Mississippian Lime as predominantly cherty limestone. The basal carbonate section has little to no effective porosity development, which should translate to no permeability development. The Mississippian Platform Carbonate play is the smallest oil-producing play in the Permian Basin, which is tied to the abundance of crinoidal, grain-rich facies in platform successions. Most production from Mississippian reservoirs comes from more porous upper Mississippian ooid grainstones (Kane). This indicates that little to no reservoir characteristics are developed within the lower Mississippian Lime, creating an optimal seal.

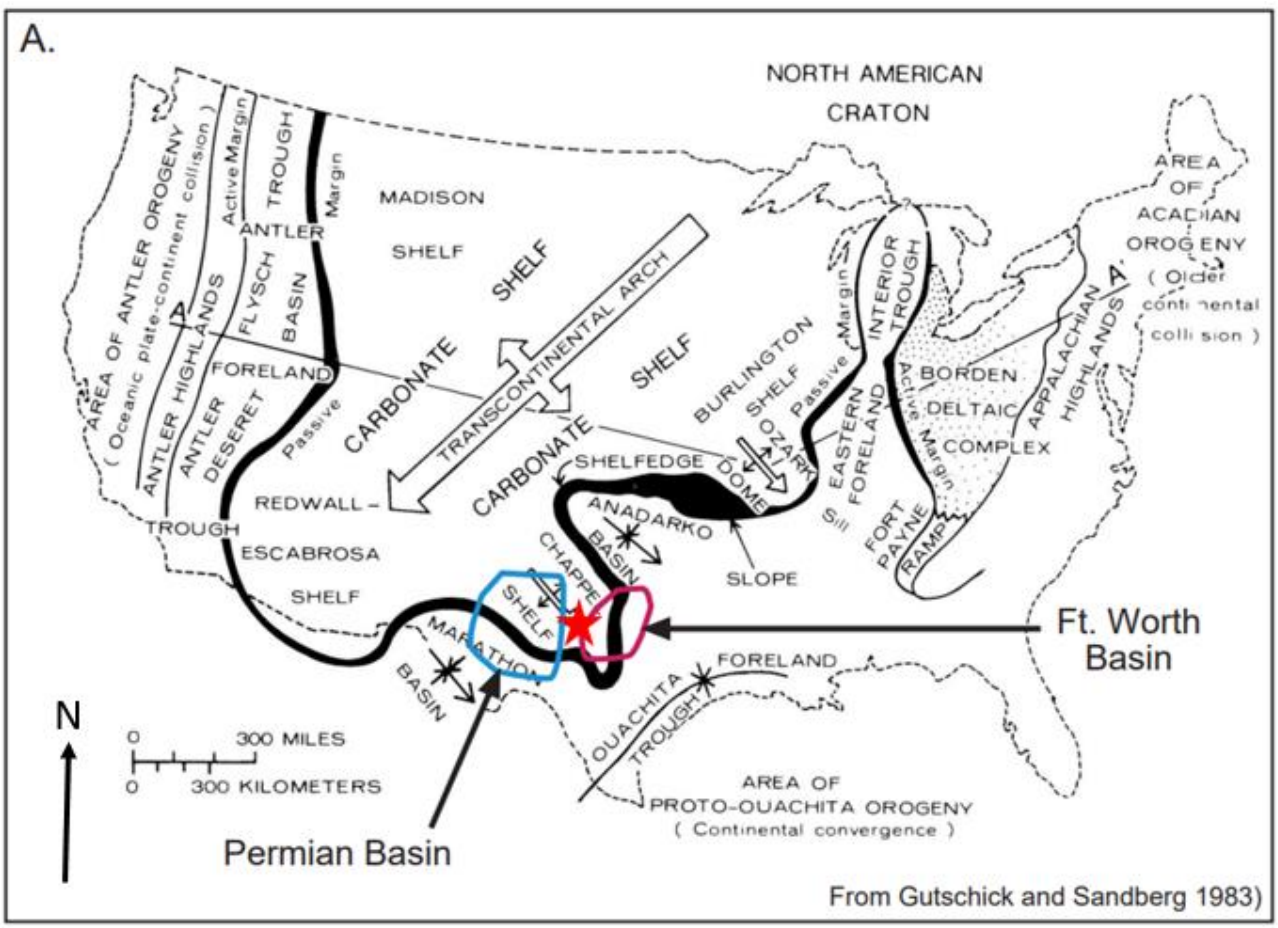


Figure 12 – Depositional Map of the Mississippian (Kane)

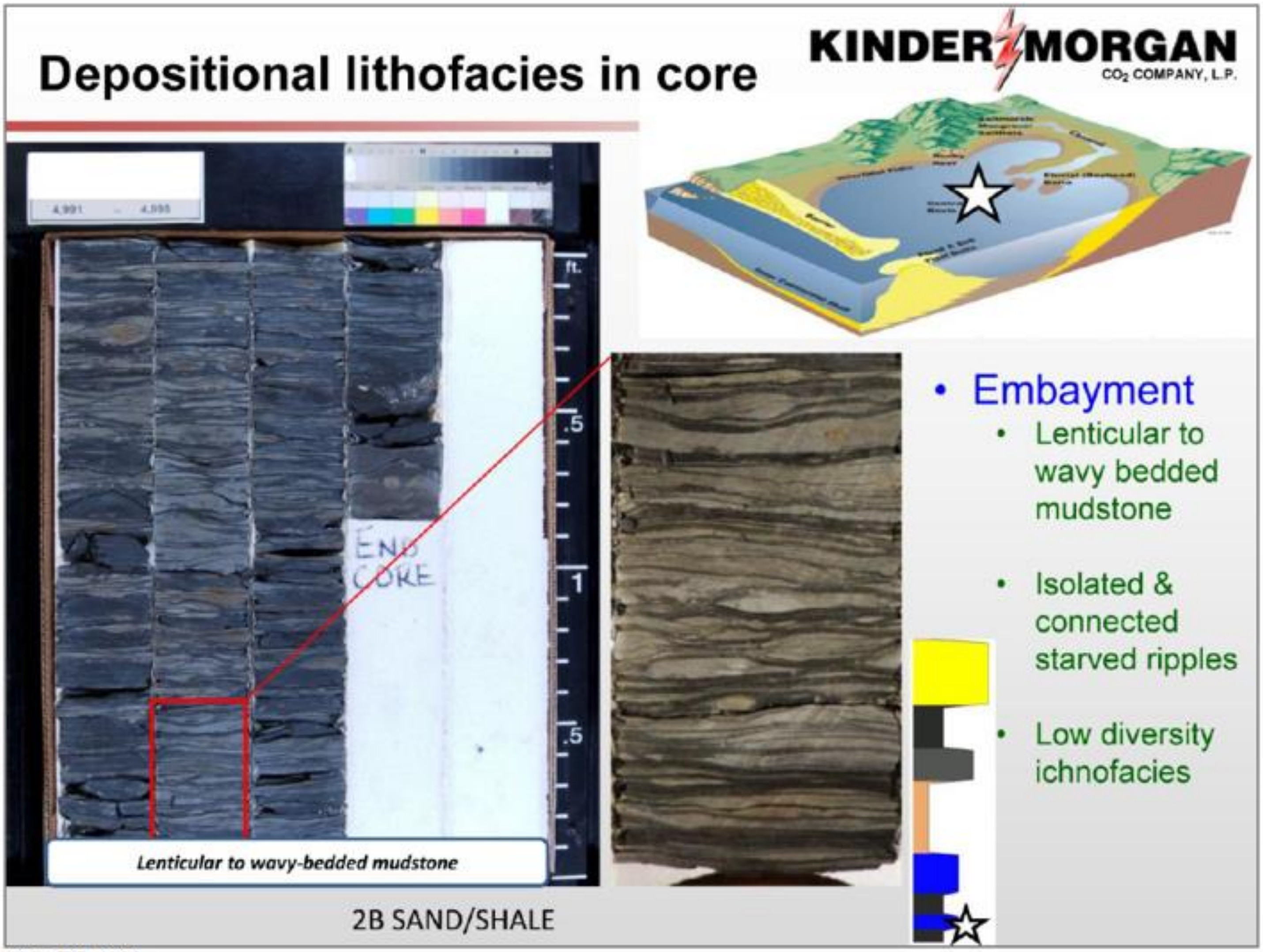
2.2.3 Secondary Confining Interval – Lower Strawn Shale

The Lower Strawn Shale (LSS) is Desmoinesian in age and was heavily influenced by the Knox Baylor Trough, which is near the KSU 2361 location and is late-Desmoinesian in age. The trough resulted from the Ouachita-Marathon overthrust movement that disrupted the Fort Worth basin depositional center, moving the Desmoinesian depocenter further to the west to form the Knox Baylor Trough. This trough allowed sediments to be transported west to the Midland Basin. These sediments were derived from the destruction of the elongated Bowie Delta System, which derived its sediments from the Muenster-Wichita Mountain system (Gunn, 1982).

Depositional facies within the Strawn unit resemble assemblages typical of a mixed siliciclastic-carbonate continental-to-shelf transitional succession found along a complex embayed coastline. Six petrophysically distinct lithofacies were identified: (1) lenticular to wavy-bedded mudstone, (2) flaser to wavy-bedded sandstone, (3) carbonate-rich sandstone, (4) ripple-to-trough cross-laminated sandstone with common convolute bedding, (5) trough cross-laminated sandstone with abundant mud rip ups and mud balls, and (6) heavily bioturbated sandstone. Combined lithofacies and ichnofacies observations suggest that paleoenvironments of the Katz Field included a bayhead delta, back-barrier estuary embayment, tidal flood delta, tidal flat, and upper to middle shoreface (Jesse G. White, 2014). The LSS is associated with the back-barrier estuary embayment depositional environment, evidenced by the abundance of mudstone.

Figure 13 provides core photos and associated descriptions of a core sample taken in the Katz field within an embayment environment. Core descriptions of this core sample observed characteristics that serve as excellent sealant properties to prohibit the migration of injection fluids above the injection zone. Conventional core data was collected in an offset well near the LSS depths in the API #42-433-33534 well, 5,089' away from the KSU 2361 well. Figure 14 is a cross-section relating the KSU 2361 well and the API #42-433-33534 well, indicating the cored interval alongside pictures of the lower portion of the core that most closely resembles the LSS. Horizontal permeabilities within the pictured core data range from 0.05 to 0.3 mD, with a vertical permeability value of less than 0.01 mD.

Along with the core reports and descriptions, Figure 14 plots calculated log curves from petrophysical analyses run on open-hole log data from the KSU 2361 well. Figure 14 indicates no effective porosity within the LSS (JPHIE green curve, 2nd track from the left) with a shale lithology reading (JHSHALE, green shading, 3rd track from the left). The petrophysical properties and lithology indicated by core and log data demonstrate that the LSS possesses characteristics of an excellent sealing formation.



<u>4991 TO 4998</u>:

4991.00 – 4997.4: Black to dark gray lenticular to wavy bedded mudstone encasing light gray lenticular siltstone to muddy very-fine sandstone. Abundant light gray calcareous horizons. Note zones of reddish color.

4997.4 – 4997.5: Burrowed transgressive bioclastic lag deposit? Abundant crinoid and bioclastic debris over burrowed laminated to contorted black shale.

4997.5 - 4997.7: Black laminated shale

4997.7 - 4998.0: Dark gray to gray black crinoid mudstone interbedded with a single tan algal mudstone-wackestone hardground exhibiting mudcracks.

Trace fossils shown in blow-ups include *Paleophycus, Planolites, Thalassinoides* and *Teichichnus*.

Sedimentology infers **brackish water deposits** (Brackish water is water that has more <u>salinity</u> than <u>fresh water</u>, but not as much as <u>seawater</u>. It may result from mixing of seawater with fresh water, as in <u>estuaries</u>.

4991 - 4998: Estuary – embayment. Brackish water deposit. Muddy.

Figure 13 – Core Description

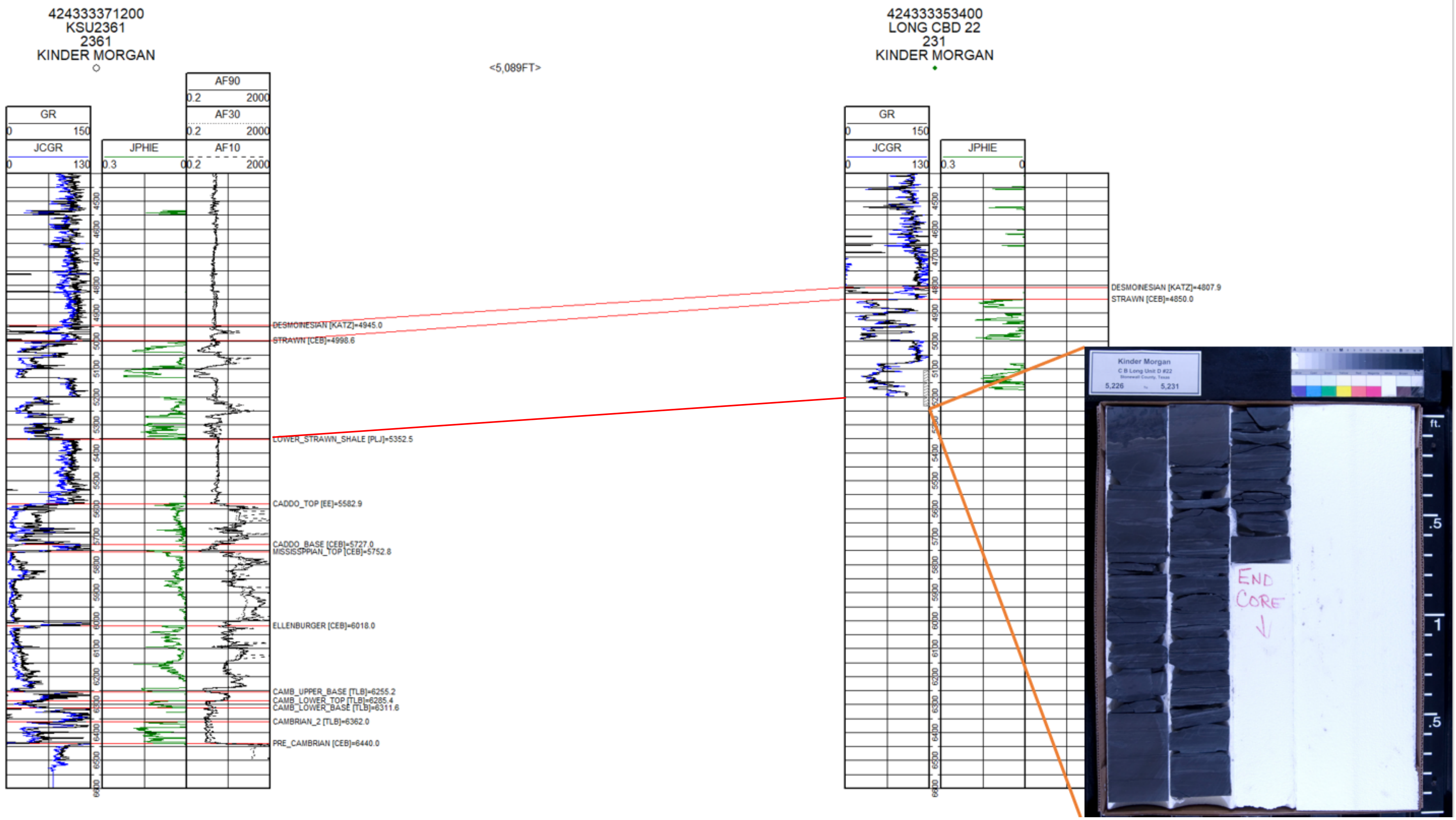


Figure 14 – Cross Section Depicting Correlative Offset Core with Lower Strawn Shale

2.2.4 Injection Interval – Ellenburger/Cambrian Sands

Ellenburger

The Ellenburger is a widespread lower Ordovician carbonate deposited over the entire north Texas area, indicating a relatively uniform depositional condition (Hendricks, 1964). North Central Texas experienced a low-energy, restricted shelf environment comprised of a homogeneous sequence of gray to dark-gray, fine to medium crystalline dolomite containing irregular mottling (probable bioturbation structures) and lesser parallel-laminated mudstone and peloid-wackestone (Kerans, 1990). Figure 15 is a map depicting the different depositional environments of the lower Ordovician, with associated lithologies. This map confirms the inferred dolomite lithology of the open hole log analysis in Figure 11 of the KSU 2361 well.

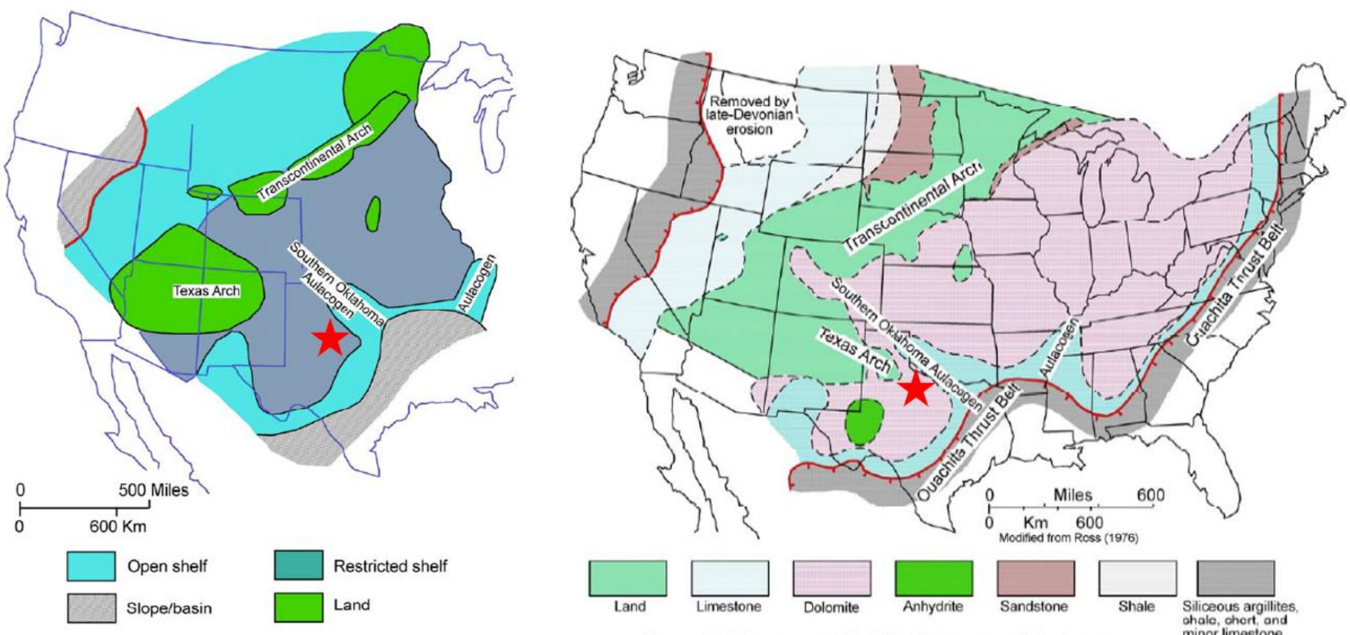


Figure 2. Paleogeographic lithofacies map of the Lower Ordovician section in the United States. From Ross (1976).

Figure 3. Interpreted regional depositional setting during Early Ordovician time. After Ross (1976) and Kerans (1990).

Figure 15 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

Ellenburger Porosity/Permeability Development

Within the low-energy, restricted shelf environment, facies are highly dolomitized and have a heavy presence of bioturbation resulting in mottling (Loucks, 2003). The dolomitization led to porosity development within the Ellenburger, along with diagenetic leaching processes and other secondary porosity features such as karsts and vugs. The tables in Figure 16 show permeability and porosity values tabulated from Ellenburger reservoirs within Texas, categorized by their diagenetic facies into three groups: Karst Modified, Ramp Carbonates, and Tectonically Fractured Dolostones. Based on the descriptions in Figure 16, the Ellenburger of the KSU 2361 would fall within the Karst Modified Reservoirs category outlined in red with average porosity and permeability values of 3% and 32 mD, respectively. This corresponds with the data collected from the KSU 2361 well. As shown in Figure

11 above, the calculated effective porosity curve in green (JPHIE) is an average of roughly 3% over the Ellenburger formation. Permeability was estimated from volumes injected plotted against pressure responses within the KSU 2361 well; these permeabilities ranged from 12-20 mD. Similarities between these two datasets validate reservoir characteristics used for model inputs.

Cambrian

The deposition of Cambrian and lower Ordovician strata on the early Paleozoic shelf was initiated by a transgressing sea which, entering the area from the south, first laid down a clastic sequence. Initial deposits were sandstone and arenaceous carbonates that grade upward into the slightly cherty carbonates of the Ellenburger group (Galley, 1958). Lithologies include glauconitic and phosphatic to clean sandstones of various textures, intergrading and alternating with chemical, clastic, and even local limestones and dolomites, together with intercalated thin shales (Conselman, 1954).

Cambrian Porosity/Permeability Development

Few reservoir characteristics have been published on the Cambrian sands. Porosity and permeability were estimated based on the KSU 2361 wells open hole log and injection data. There are three discreet sandstone intervals within the Cambrian at this location. The upper two sands identified in the CAMBRIAN package have an average effective porosity of 12.9% and 8.8%. The average effective porosity of the third sand is 8.4%. These effective porosity values are plotted as the JPHIE (effective porosity) curve in Figure 11. Due to nature of the Ellenburger and Cambrian zones being commingled during injection tests, modeling makes the assumption of 12-20mD average permeability for the interval, for history matched injection volumes and pressures.

Table 2. Geologic characteristics of the three Ellenburger reservoir groups. From Holtz and Kerans (1992).

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 16 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

Formation Fluid

Four wells were identified within approximately 20 miles of the KSU 2361 well through a review of oil-field brine compositions of the Ellenburger formation from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3. None of these four wells are salt water disposal wells. The location of these wells is shown in Figure 17. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids. Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger Formation is compatible with the proposed injection fluids.

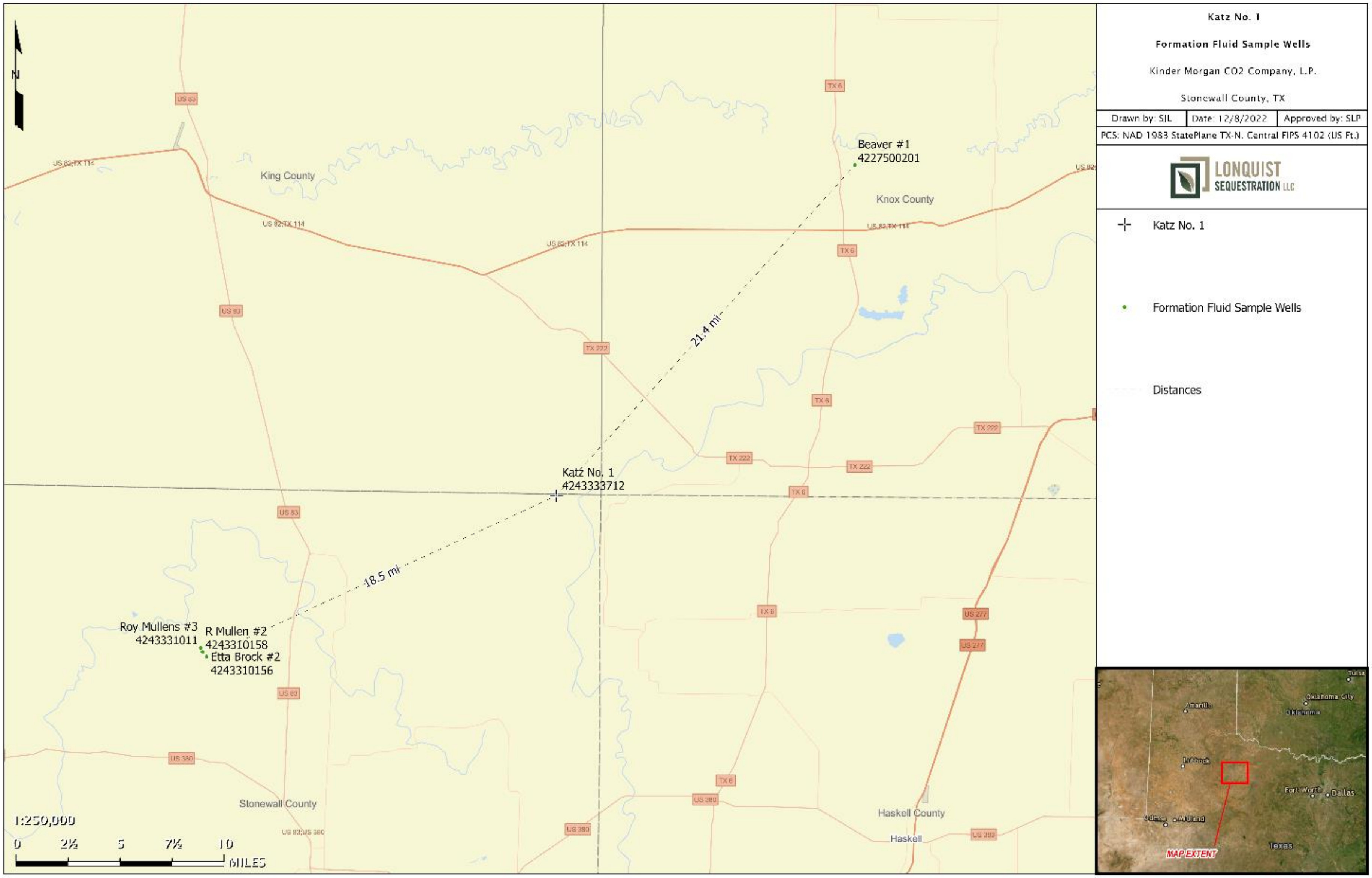


Figure 17 – Offset Wells used for Formation Fluid Characterization.

Table 3 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples

	Average	Low	High
Total Dissolved Solids (ppm)	144065	98802	210131
pH	6.15	5	7
Sodium (ppm)	43391	30833	64222
Calcium (ppm)	9275	5128	13200
Chlorides (ppm)	88355	60061	128685

2.2.5 Lower Confining Zone – Precambrian

The Precambrian outcrops to the south at the Llano uplift and the west in the Trans-Pecos regions of Texas and central New Mexico. Outcrops near the Llano Uplift in McCulloch County consist of highly weathered granite, schist, and gneiss. The granite is fine- to coarse-grained and contains numerous pegmatite veins. The schist has a high percentage of biotite, which gives it a dark-gray color, and it is often referred to as "gray shale" or "blue mud" by well drillers. The gneiss is pinkish and fine-grained (Mason, 1961). A study in 1996 was performed by Adams and Keller to better understand the Precambrian distribution in Texas indicates that Precambrian at the Katz 2361 location should contain an average metamorphic rock, as seen in Figure 18. This agrees with the open hole log response in the Precambrian formation in the open hole log section of Katz 2361. Gamma-ray log values of the Precambrian section are consistently above 90 GAPI (Gamma Units of the American Petroleum Institute), indicating a high radioactive response. A very high resistivity reading within this section indicates little to no porosity, as shown in the JPHIE, validating the characteristics described above. These traits are ideal attributes of a tight, lower confining basement.

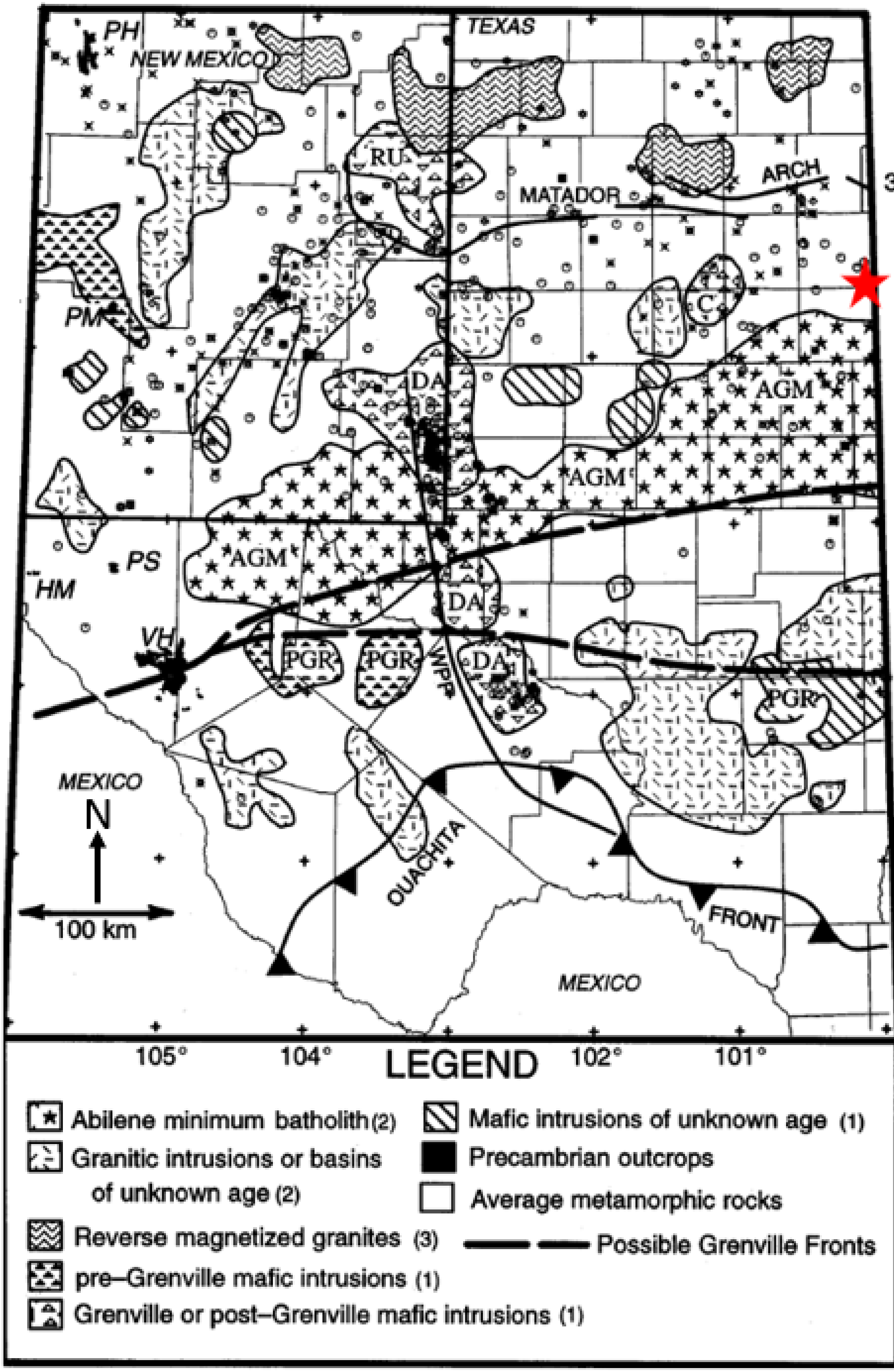


Figure 18 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Fracture Pressure Gradient

Fracture pressure gradients were estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for determining fracture gradients. Poisson's ratio (ν), overburden gradient (OBG), and pore gradient (PG) are all variables that can be changed to match the site-specific injection zone. The expected fracture gradient was determined using industry standards and a literature review. The overburden gradient was assumed to be 1.05 psi/ft. This value is considered best practice when there are no site-specific numbers available. The pore pressure gradient was calculated to be 0.43 psi/ft from the bottom hole pressure data. For limestone/dolomite rock in the injection zone, the Poisson's ratio was assumed to be 0.3 through literature review (Molina, Vilarras, Zeidouni 2016). Using these values in the equation below, a fracture gradient of 0.70 psi/ft was calculated for the injection zone.

For the upper confining interval, a similar fracture gradient was calculated. The upper confining shale has an increased chance to vertically fracture if the injection interval below is fractured (Molina, Vilarras, Zeidouni 2016). Therefore, a Poisson's ratio equal to that of the injection interval was used as a conservative estimate. The lower confining zone was assumed to be of a similar matrix to the injection interval, with the key difference being that the formation is much tighter (lower porosity/permeability). Therefore, the Poisson's ratio was assumed to be slightly higher in this rock. As seen in Table 4, the fracture gradient of .64 psi/ft is slightly higher in the lower confining zone.

Multiple approaches can be taken to manage reservoir pressure. Current engineering practices for acid gas CO_2 injection recommend applying a 10% safety factor to the fracture pressure of the geology being injected into, resulting a 0.63 psi/ft gradient. This new value represents the maximum allowable bottom-hole pressure during injection. Another approach is to maintain a maximum wellhead pressure (WHP). In the reservoir model, a WHP of 1,850 psi was used to constrain the simulated well. This translates to a value that is 84% of the frac gradient or a 16% safety factor. By using either approach, there is a reduced risk of fracture propagation in the injection zone.

A conservative maximum pressure constraint of 0.60 psi/ft was used for injection modeling, which is well below the calculated fracture gradient for each zone. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

Table 4 – Fracture Gradient Assumptions

	Injection Interval	Upper Confining	Lower Confining
Overburden Gradient (psi/ft)	1.05	1.05	1.05
Pore Gradient (psi/ft)	0.43	0.43	0.43
Poisson's Ratio	0.30	0.30	0.31
Fracture Gradient (psi/ft)	0.70	0.70	0.71
FG + 10% Safety Factor (psi/ft)	**0.63**	**0.63**	**0.64**

The following calculations were used to obtain fracture gradient estimates:

$$FG = \frac{\mathrm{n}}{1-\mathrm{n}}(OBG - PG) + PG$$

$$FG = \frac{0.3}{1-0.3}(1.05 - 0.43) + 0.43 = 0.70$$

$FG\ with\ SF = 0.70\ \times(1-0.1) = \mathbf{0.63}$ **(Injection and Upper Confining intervals)**

$FG\ with\ SF = 0.71 \times (1 - 0.1) =$ **.64 (Lower Confining interval)**

2.4 Local Structure

Regional structure in the area of the KSU 2361 well is influenced by a shallow angle ramp down dip to the southwest towards the Midland Basin, which is set up by a north-south regional fault to the east. Specifically, the KSU 2361 well is located on the western portion of a shelf-like feature that dips slightly away from the fault to the east. Figure 19 is a structure map on the top of the Ellenburger with the KSU 2361 well indicated by the black star.

Subsurface interpretations of the Ellenburger formation heavily relied on 3D seismic coverage in the area. The seismic coverage outline is represented by the purple boundary seen in Figure 19. Only two wells penetrated the Ellenburger formation within the 3D seismic data volume and are shown in the northwest to southeast seismic profile along with the cross-section in Figure 22. These two wells are active injection wells within the proposed injection interval operated by Kinder Morgan, one being the Katz 2361 well while the other is the Katz #3741 well. Both wells were used to create time-to-depth conversions for the Ellenburger horizon. Shallower formations provide additional well control to assist in creating time-to-depth conversions displayed in the seismic profiles in Figures 21 and 22.

The KSU 2361 well is located roughly 12,000' west of the mapped fault seen in Figure 19. This distance provides a buffer between the injection plume and the fault that alleviates concerns regarding the interaction between the injectate and the fault. As shown in the seismic profile, this fault does not project above the Caddo formation and is not present in the LSS. As this fault does not project into the upper confining shale layer, there is little risk of the fault acting as a conduit for the injectate to leak outside the proposed injection interval.

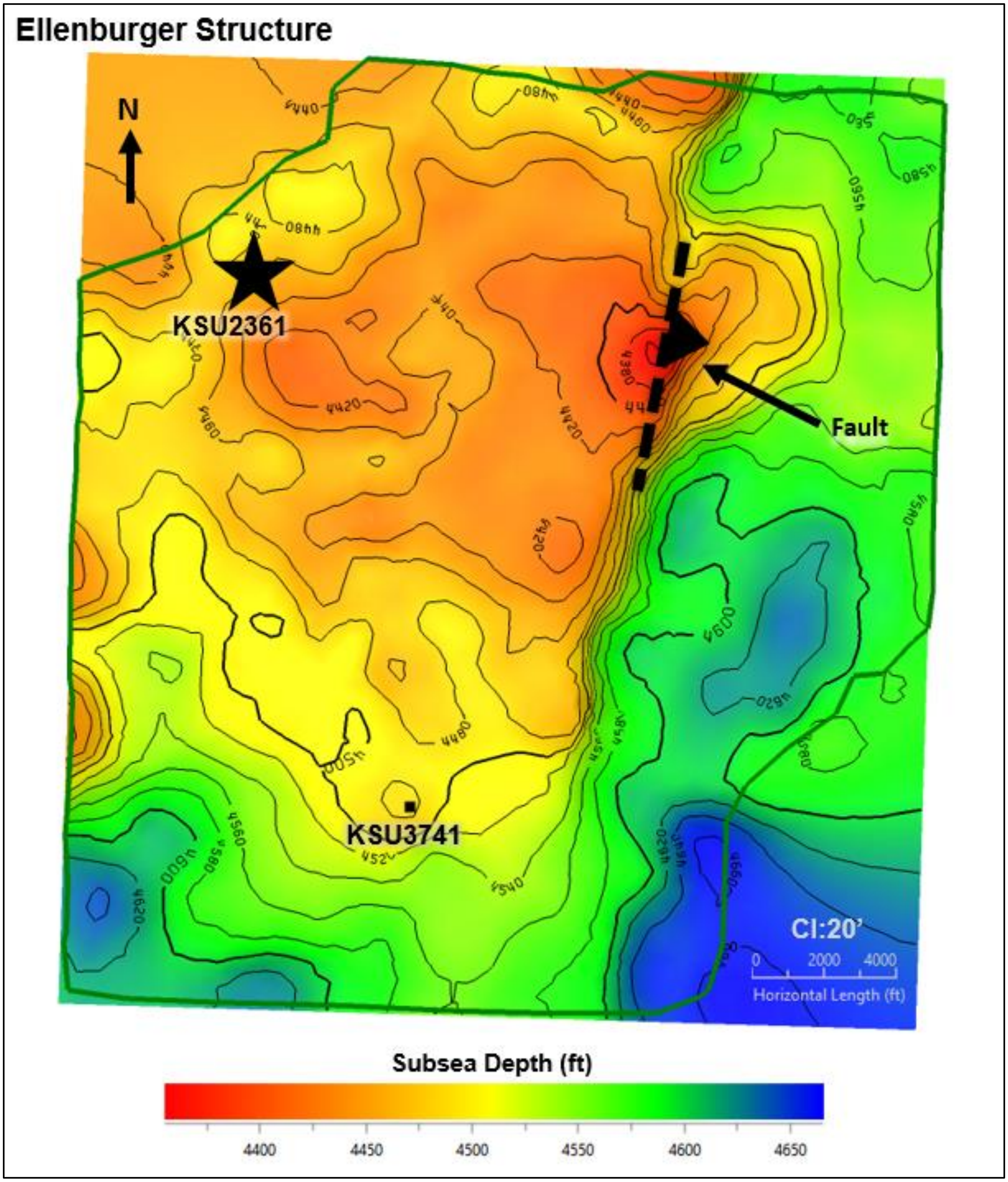


Figure 19 – Ellenburger Structure Map (Subsea Depths). Contour Interval (CI) on Ellenburger Structure map is 20'. The green outline is the boundary of the seismic data.

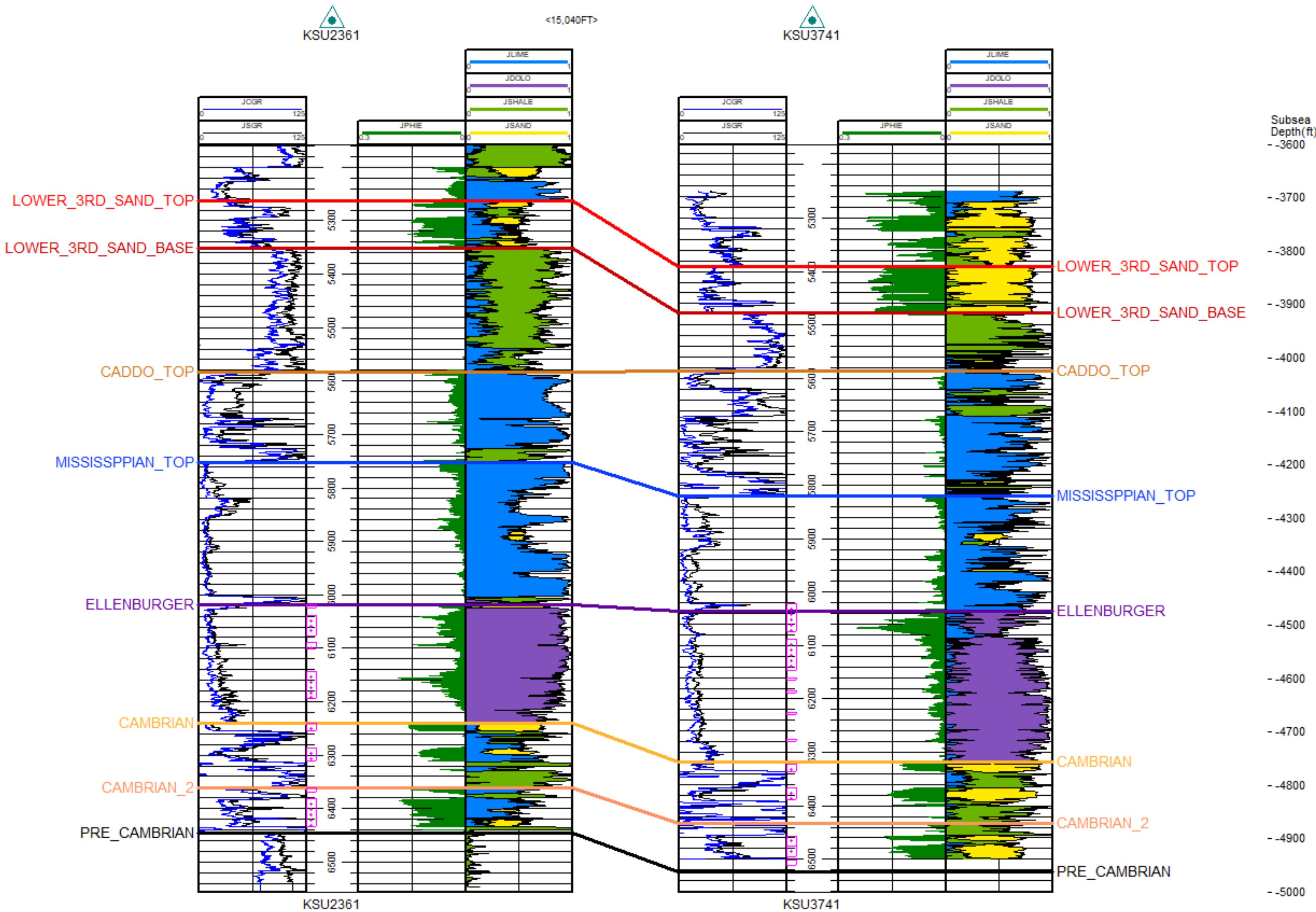


Figure 20 – Structural Northwest-Southeast Cross Section

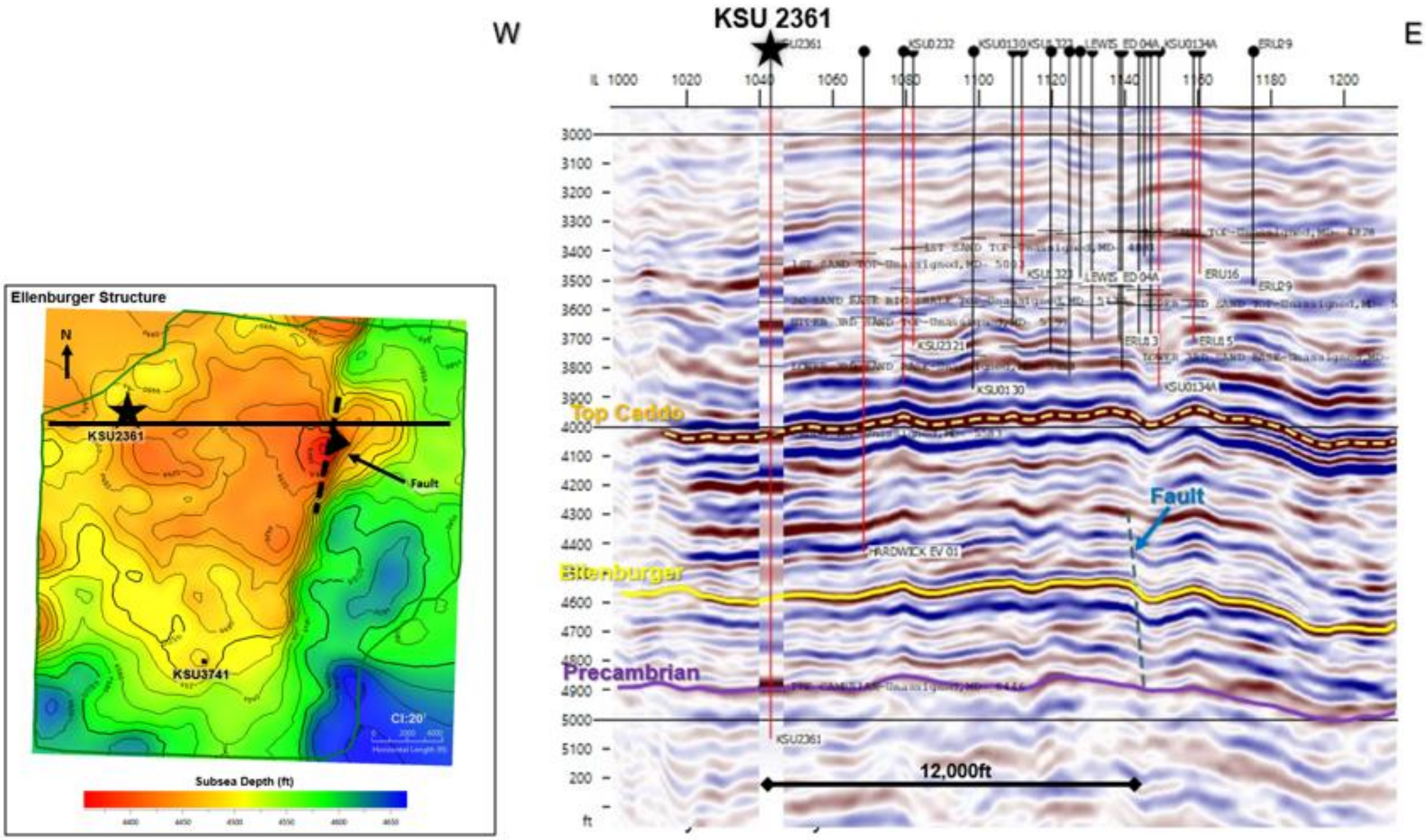


Figure 21 – Structural West to East Seismic Profile. Ellenburger structure map modified from Figure 19.

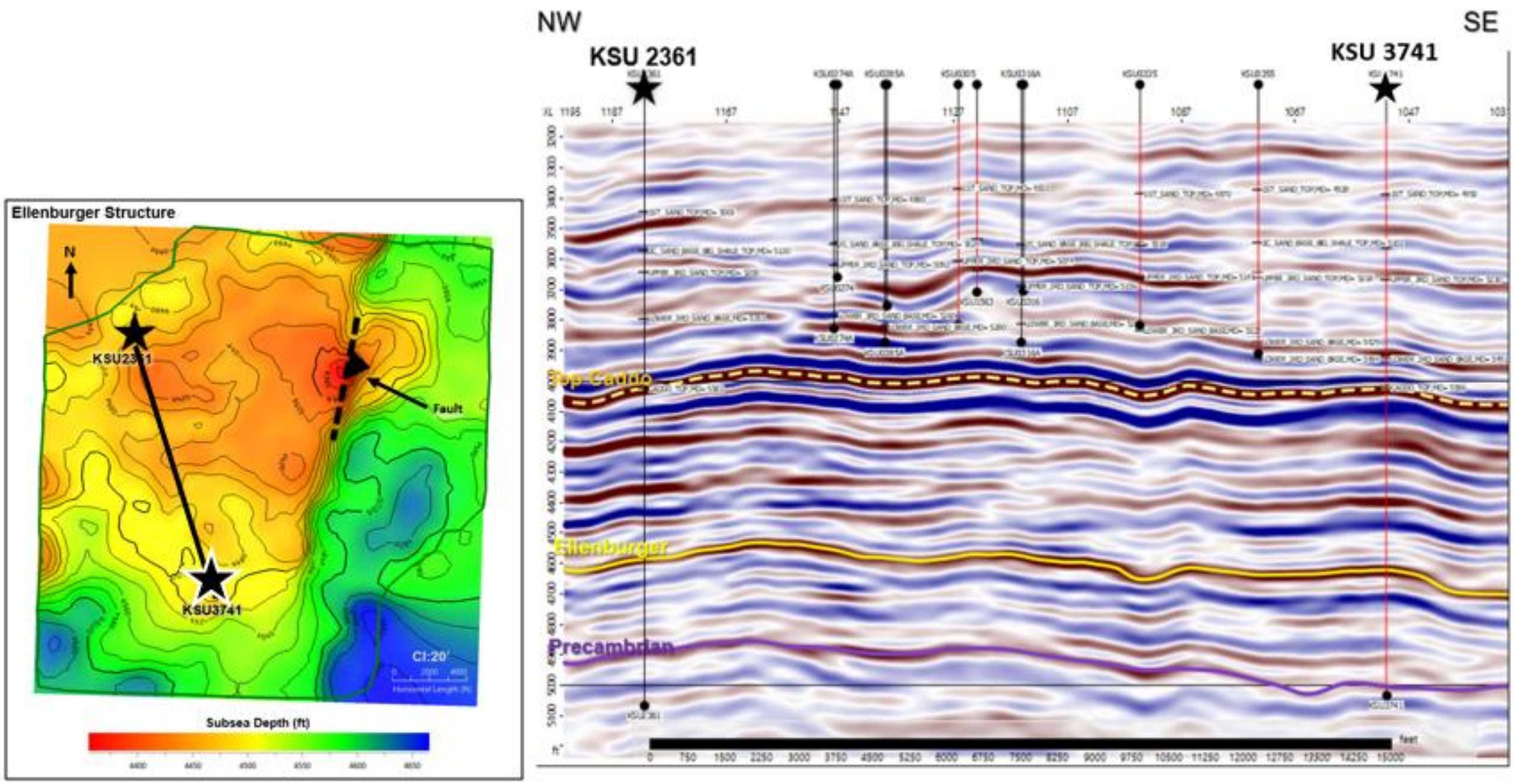


Figure 22 – Structural Northwest to Southeast Seismic Profile between the two wells that penetrate the Ellenburger within the seismic volume. Ellenburger structure map modified from Figure 19.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger and Cambrian sand formations at the KSU 2361 well location indicate that the formations have sufficient thickness, porosity, permeability, and lateral continuity to accept the proposed injection fluids. The Mississippian Lime formation at the KSU 2361 well has low permeability. It is of sufficient thickness and lateral continuity to serve as the upper confining zone, with the Lower Strawn Shale acting as a secondary confining unit. Beneath the injection interval, the low permeability, low porosity Precambrian formation is unsuitable for fluid migration and serves as the lower confining zone.

The area of review has been studied to identify potential subsurface features that may affect the ability of these injection and confinement units to retain the injectate within the requested injection interval. Faults have been identified, characterized, and determined to be low risk to the containment of injectate and do not increase the risk of migration of fluids above the injection interval.

2.6 Groundwater Hydrology

Stonewall, Haskell, Knox, and King Counties fall within the boundary of the Texas Water Development Board's (TWDB) Groundwater Management Area 6. The Seymour Aquifer is identified by the TWDB's *Aquifers of Texas* report in the vicinity of the KSU 2361 well (George et al., 2011). Table 5 references the Seymour Aquifer's position in geologic time and the associated geologic formations, which include the Seymour Formation, Lingos Formation, and Quaternary alluvium (Ewing et al., 2004). A depiction of the general stratigraphy of the Seymour Aquifer is shown in Figure 23.

Table 5 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas (Ewing et al., 2004).

System	Series	Group	Formation
Quaternary	Recent to Pleistocene		Alluvium
			Seymour
Tertiary	missing		
Cretaceous			
Jurassic			
Triassic			
Permian	Ochoa		Quartermaster
	Guadalupe	Whitehorse	
		Pease River	Dog Creek Shale
			Blaine Gypsum
			Flowerpot Shale
			San Angelo
	Leonard	Clear Fork	Choza
			Vale
			Arroyo
		Wichita (upper portion only)	Lueders
			Clyde

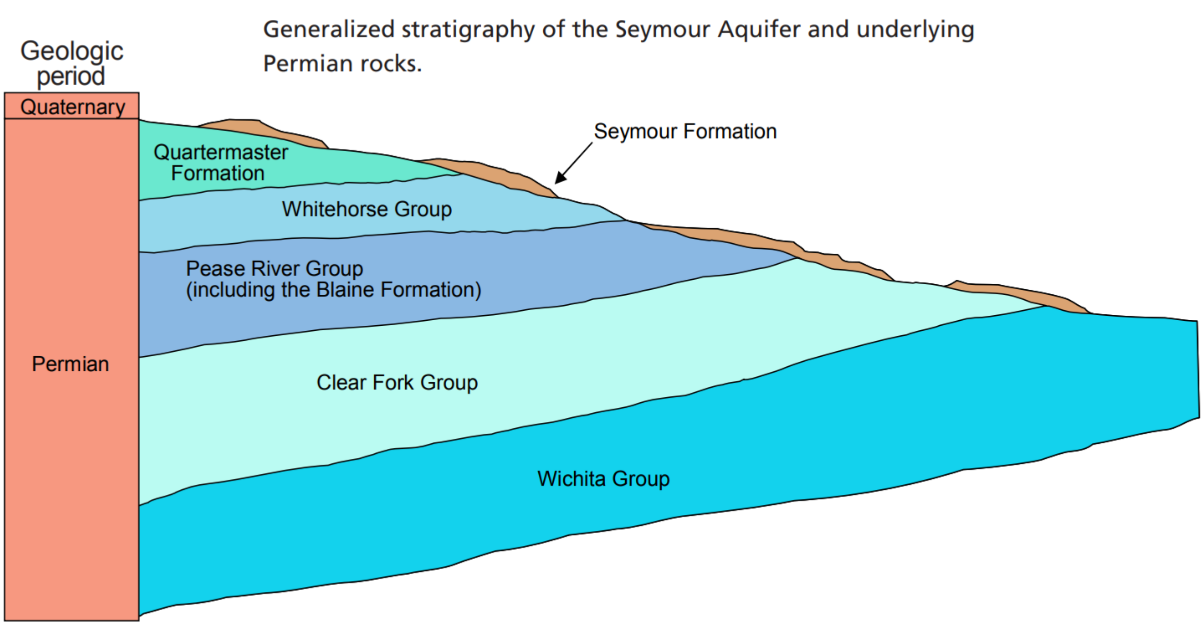


Figure 23 – Generalized Stratigraphy of the Seymour Aquifer (George et al., 2011)

The Seymour Aquifer, as defined by the TWDB, consists of isolated pods of alluvium deposits of Quaternary age, depicted in Figure 24. It extends from the southern Brazos River watershed northward to the border of Oklahoma. The Seymour Aquifer overlies Permian-age deposits that generally dip to the west. Topography, structure, and permeability variation control groundwater flow within the pods. The aquifer generally follows the topographical gradient along the major axis of the pod and discharges laterally to springs, seeps, and alluvium. Similar mechanisms can be expected within the majority of the other pods (Ewing et al., 2004).

A map showing the inferred groundwater flow pattern within a portion of one of the pods in Haskell and Knox counties is shown in Figure 25. The map approximates the natural direction of flow unaffected by pumping from wells. North of the Rule, TX, groundwater divide, the flow is toward the north, northwest, or northeast. Based on the contours of the water table and the permeabilities for the formation indicated by pumping tests, the estimated natural rate of water movement in the Seymour Aquifer, unaffected by pumping, ranges locally from approximately 200’ to 5,000’ per year. Over several miles, the estimated average rate of movement is typically between 800’ and 1,200’ per year (R.W. Harden and Associates, 1978).

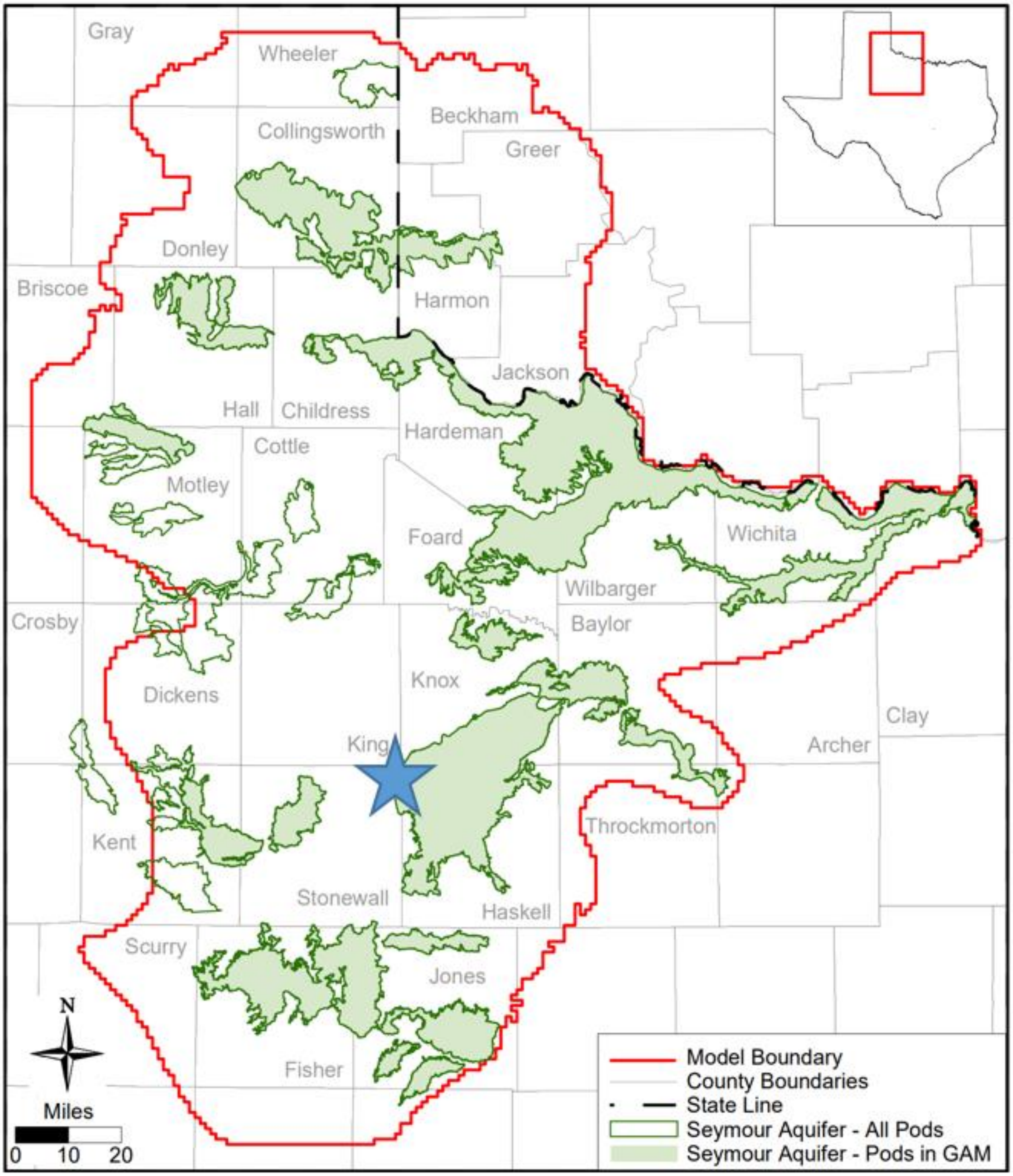


Figure 24 – Regional Extent of the Seymour Aquifer Pods (Ewing et al., 2004)

Figure 25 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer (R.W. Harden and Associates, 1978).

Total dissolved solids (TDS) are a measure of water saltiness, the sum of concentrations of all dissolved ions (such as sodium, calcium, magnesium, potassium, chloride, sulfate, and carbonates) plus silica. As shown in Figure 26, the total dissolved solids in 41% of the wells within the Seymour Aquifer exceed 1,000 milligrams per liter (mg/L), Texas' secondary maximum contaminant level (MCL). Therefore, the utility of water from the Seymour Aquifer as a drinking water supply is limited in many areas for health reasons, primarily due to elevated nitrate concentrations, and for taste reasons due to saltiness (Ewing et al., 2004).

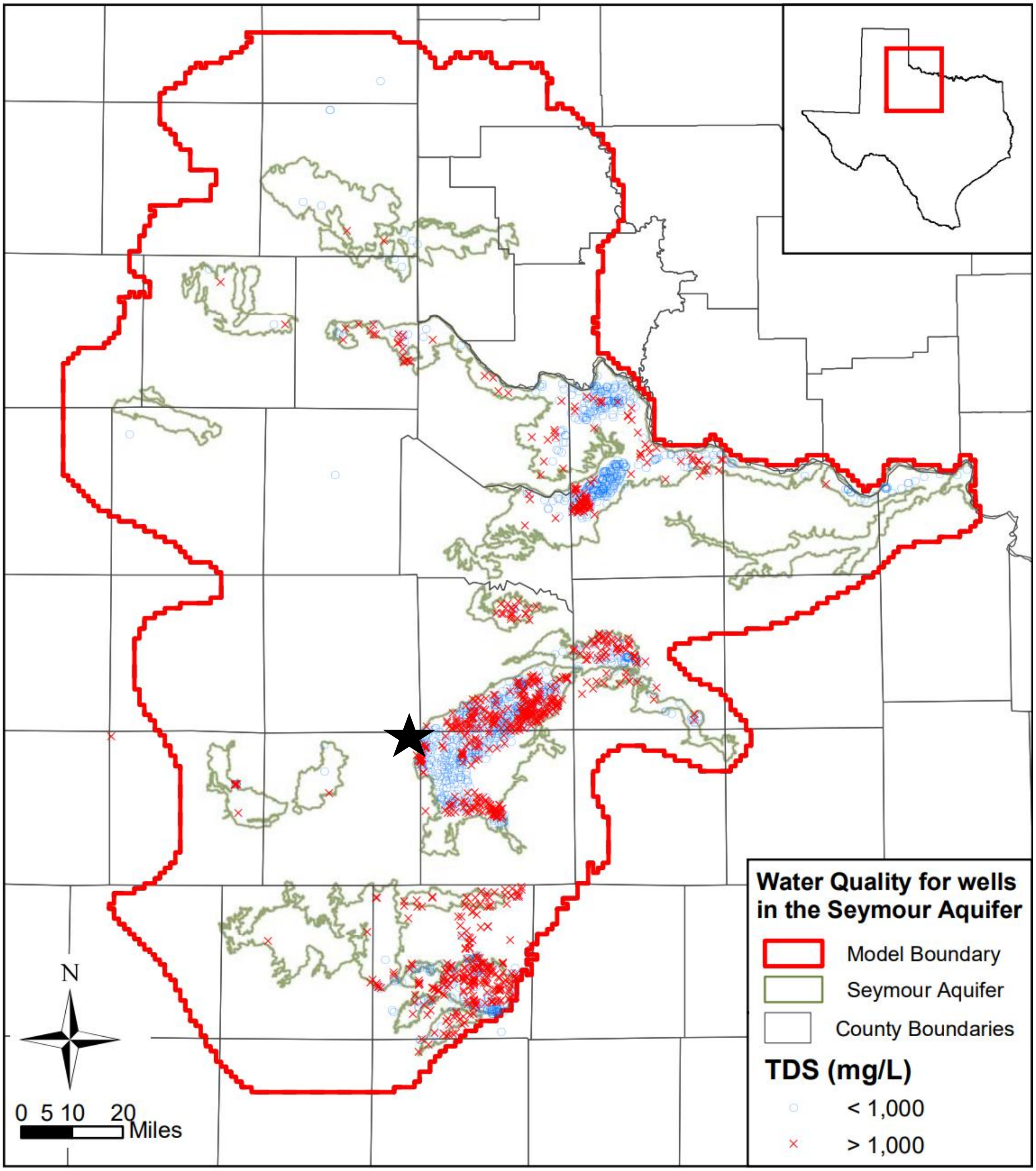


Figure 26 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer (Ewing et al., 2004)

The TRRC's Groundwater Advisory Unit (GAU) specified for the KSU 2361 well that the interval from the land surface to a depth of 100' must specifically protect usable-quality groundwater. Therefore, the base of Underground Sources of Drinking Water (USDW) can be approximated at 100' at the location of the KSU 2361 well, and there is approximately 5,920' separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued

by the TRRC as part of the Class II permitting process for the KSU 2361 well is provided in Appendix A. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Mississippian limestone, thousands of feet of tight limestone and shale beds occur between the injection interval and the lowest water-bearing aquifer.

2.6.1 Reservoir Characterization Modeling

Introduction

KSU 2361 is located in Kinder Morgan's Katz Oil Field in northeast Stonewall County. A geologic model was constructed of this area to forecast the movement of CO_2 and any pressure increases. The model is comprised of the Ellenburger and Cambrian formations, which cover 13,774 acres (~22 square miles). A single CO_2 injector was simulated for 100 years, where approximately 25 million metric tons (MMT) of CO_2 was safely stored.

Software

Paradigm's software suite was used to build the geologic and dynamic models. SKUA-GOCAD™ was utilized in building the geomodel, while Tempest™ designed the dynamic model. The EPA recognizes these software packages for an area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

SKUA-GOCAD™ is a software tool for geology that offers a range of features for structure and stratigraphy, structural analysis, fault seal, well correlation, facies interpretation, 2D/3D restoration, and basin modeling. The structure and stratigraphy module allows users to construct fully sealed structural models, while the structural analysis module provides tools for analyzing fracture probability, stress, and strain. The fault seal module enables the computation of fault displacement maps and fault SGR properties, and the well correlation module allows users to create well sections and digitize markers. The facies interpretation module offers tools for paleo-facies interpretation, and the 2D/3D restoration module provides tools for restoring 3D basin and reservoir models. Finally, the basin modeling module enables users to construct 4D basin models for transfer to basin model simulation software.

Tempest™ is another of Paradigm's industry-leading software packages for reservoir engineering. Tempest™ has history-matching capabilities, allowing for more accurate reservoir characterization modeling. In addition, this software is used to build dynamic models for CO_2 injection. Tempest™ is comprised of three modules: Tempest™ VIEW, Tempest™ ENABLE and Tempest™ MORE. Tempest™ MORE is a black oil simulator with many features and applications to simulate CO_2 injection. The Tempest™ MORE module can accept data in standard GRDECL (RMS, Petrel) file formats. It can also produce output in the ECLIPSE, Nexus/VIP, Intersect, and IMEX/GEM/STARS formats. This allows users to easily import data into the software and export it in a format compatible with other tools and systems. The standard file formats improve the interoperability and compatibility of the MORE software with other systems and tools used in the oil and gas industry

Trapping Mechanisms

To accurately simulate the CO_2 injection and predict the subsequent plume migration, Tempest™ models CO_2 trapping mechanisms in the injection zone. There are five primary trapping mechanisms: structural, hydrodynamic, residual gas (hysteresis), solubility, and geochemical. For this simulation, geochemical reactions were not considered. Each of the five mechanisms is described in further detail below.

Structural Trapping
Structural traps, a physical trapping mechanism, are underground rock formations that trap and store the injected supercritical CO_2. These traps are created by the physical properties of the cap rock, such as its porosity and permeability. For example, a structural trap may be formed by a layer of porous rock above a layer of non-porous rock, with the CO_2 being trapped in the porous rock. Some other examples of structural traps are faults or pinch-outs. Faults can limit the horizontal migration of the plume in the injected formation. The injected CO_2 is lighter than the connate brine found already in the formation. Because of this, the CO_2 floats to the top of the formation and is stored underneath the impermeable cap rock. In this model, CO_2 mass density ranges between 34.9 to 38.5 lb/ft^3 from the shallow to deep injection intervals, whereas the formation brine density is approximately 63.3 lb/ft^3.

Hydrodynamic Trapping
Hydrodynamic traps are another form of physical trapping caused by the interaction between CO_2 and the formation brine. Hydrodynamic trapping is caused by supercritical CO_2 traveling vertically upwards until it reaches the impermeable cap rock and spreads laterally through the unconfined sand layers, driven by the buoyancy and higher density of the brine in the reservoir. Once the CO_2 reaches a caprock with a capillary entry pressure greater than the buoyancy, it is effectively trapped. This type of trapping works best in laterally unconfined sedimentary basins with little to no structural traps.

Equation-of-state (EOS) calculations are performed to determine the phase of CO_2 at any given location based on pressure and temperature for structural and hydrodynamic trapping mechanisms. Several well-known EOS formulae are used within the oil and gas industry for reservoir modeling. These formulae include the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong (SRK) method. The Peng-Robinson is better suited for gas systems than the SRK method. The EOS implemented within the KSU 2361 well model was the Peng-Robinson method.

Residual Gas Trapping
Residual gas traps are also a physical form of trapping CO_2 within pore space by surface tension. This occurs when the porous rock acts as a sponge and traps the CO_2 as the displaced fluid is forced out of the pore space by the injected CO_2. As the displaced brine reenters the pore space once injection stops, small droplets of CO_2 remain in the pore space as residuals and become immobile.

Solubility Trapping
Solubility traps are a form of chemical trapping between the injected CO_2 and connate formation brine. Solubility trapping occurs when the CO_2 is dissolved in a liquid, such as the formation brine.

CO_2 is highly soluble in brine, with the resulting solution having a higher density than the connate brine. This feature affects the reservoir by causing the higher-density brine to sink within the formation, trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration. Table 6 was designed to guide the model to determine the solubility of CO_2 at various pressures and a specified salinity.

Table 6 – CO_2 Solubility Table

Pressure (psi)	CO2 Solubility (Mscf/Stb)	Salinity (ppm)
14	0.00	66,000
50	0.00	66,000
150	0.01	66,000
500	0.0198	66,000
1000	0.0297	66,000
1500	0.0388	66,000
3000	0.0660	66,000

Geochemical Trapping

Geochemical trapping is another form of chemical trapping which refers to storing CO_2 in underground rock formations by using chemical reactions to transform the CO_2 into stable, solid minerals. This process is known as mineral carbonation, and it involves the reaction of CO_2 with the minerals and rocks in underground formations to form stable carbonates. During the process of injecting CO_2 into a disposal reservoir, four (4) primary chemical compounds may be present: CO_2 in the supercritical phase, the hydrochemistry of the naturally occurring brine in the reservoir, aqueous CO_2 (an ionic bond between CO_2 gas and the brine), and the geochemistry of the formation rock. These compounds can interact, leading to the precipitation of CO_2 as a new mineral, often calcium carbonate (limestone). This process is known as mineral carbonation, a key mechanism for the long-term storage of CO_2 in underground rock formations.

Mineral trapping can also occur through the adsorption of CO_2 onto clay minerals. When modeling this process, it is important to consider both hysteresis and solubility trapping. Geochemical formulae can be included in the model using an internal geochemistry database to describe the mineral trapping reactions. These formulae can describe aqueous reactions, such as those involving CO_2 and clay minerals. For aqueous reactions, the following chemical reactions are standard formulae used in CO_2 simulation:

$$CO_2(aq) + H_2O = H^+ + HCO_3^-$$
$$CO_3^{-2} + H^+ = HCO_3^-$$
$$OH^- + H^+ = H_2O$$

The following three formulae represent three common ionic reactions that can occur between water and CO_2 within a reservoir. These reactions involve the formation of solid minerals that can be found in sandstone aquifers, and they result in the precipitation of carbon oxides. These reactions are commonly included in modeling efforts to understand and predict the behavior of CO_2 in underground storage reservoirs:

$$Anorthite\ (CaAl_2Si_2O_8) + 8H^+ = 4\ H_2O + Ca^{2+} + 2Al^{4+}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO3^-$$
$$Kaolinite\ \left(Al_2Si_2O_5(OH_4)\right) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO$$

Geochemical trapping has the potential to store CO_2 for hundreds or thousands of years, but the short-term effects of this method are relatively limited. Instead, the short-term movement and storage of CO_2 are more strongly influenced by hydrodynamic and solubility trapping mechanisms. These mechanisms involve the movement of fluids, such as water or oil, through porous rock formations and the solubilization of CO_2 in liquids, such as water or oil. As a result, these processes can be more effective in the short term at storing CO_2, although they may not have the same long-term stability as geochemical trapping.

Static Model

The geomodel was constructed to simulate the geologic structure of the Ellenburger and Cambrian formations. The grid contains 600 cells in the X-direction (East-West) and 400 cells in the Y-direction (North-South), totaling 240,000 cells per layer. Therefore, 55 layers were utilized in the model representing the gross thickness of the injection interval, totaling 13,200,000 grid blocks. The Ellenburger is comprised of 25 layers and the Cambrian is comprised of 30 layers. Each grid block is 50’ by 50’ by 10’, resulting in a model size of 5.7 miles by 3.8 miles by 550,’ as shown in Figure 27. This covers approximately 22 square miles (13,774 acres).

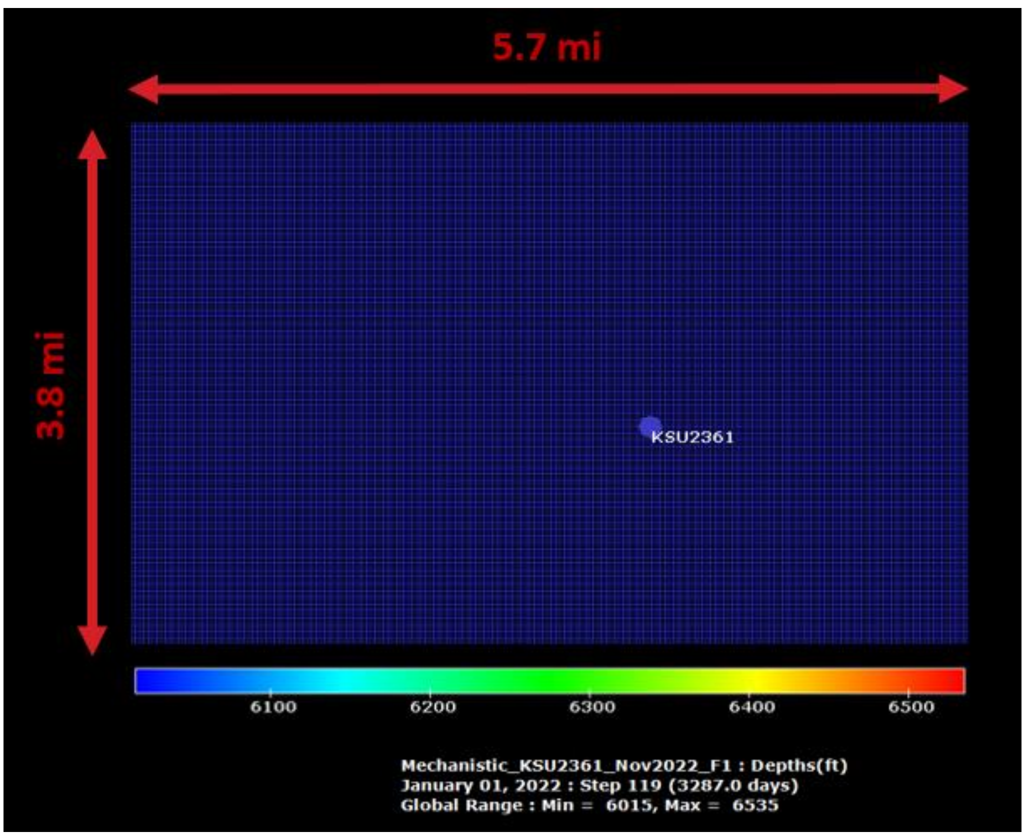


Figure 27 – Geomodel Dimensions

Well log analysis tied into seismic interpretation was used to identify any major formations tops. Four geologic units were identified and incorporated into the geomodel. Each geologic unit was used to determine the geologic structure of the injection zone. First, the Ellenburger is a carbonate formation comprised of dolomite/limestone matrix. Underlying the Ellenburger formation is the Cambrian sandstone. This sandstone was split into two geologic units, the Cambrian 1 and Cambrian 2. The Precambrian formation is at the bottom of the model. The Precambrian, comprised of granite, is the lower confining zone. Figure 28 highlights the overall structure of the target zone.

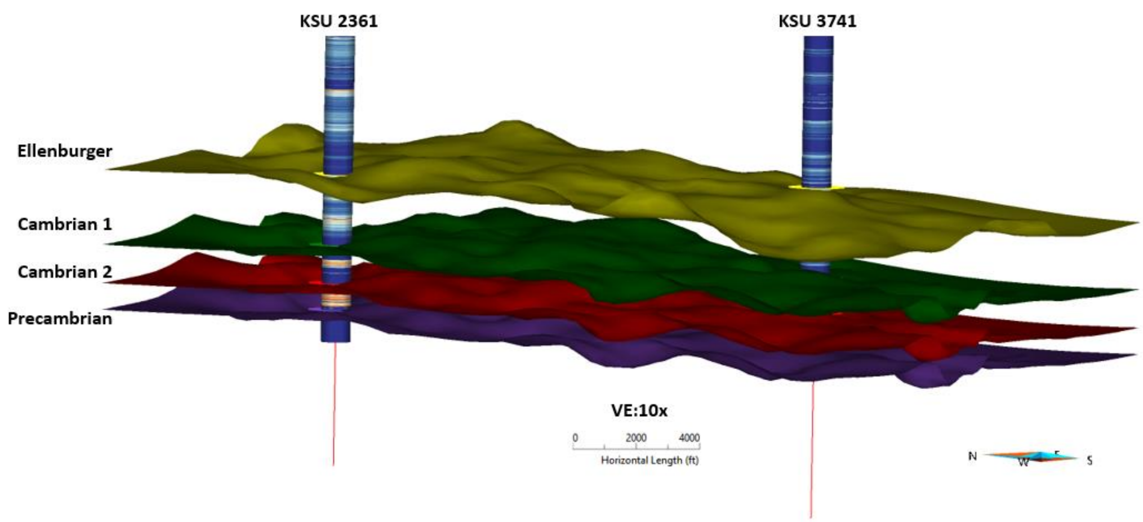


Figure 28 – Structural Horizons of the Geomodel

Permeability and porosity were distributed through the geomodel based on the formation. These rock properties were considered to be laterally homogenous in the simulation. However, vertical heterogeneity was incorporated into the model. Based on well log analysis, porosity was determined to be 10% in the Ellenburger carbonate and 12% in the Cambrian sandstone, as shown in Figure 29. Permeability was determined from history matching two wells. From this exercise, it was determined that the horizontal permeability (K_H) is 20 milliDarcy (mD) and vertical permeability (K_V) was assumed to be 10% of K_H or 2 mD. Table 7 summarizes the rock properties in the model.

Table 7 – Rock Properties

Assumptions	Values
Ellenburger Porosity (%)	10
Cambrian Porosity (%)	12
K_H (mD)	20
K_V/K_H Ratio	0.1

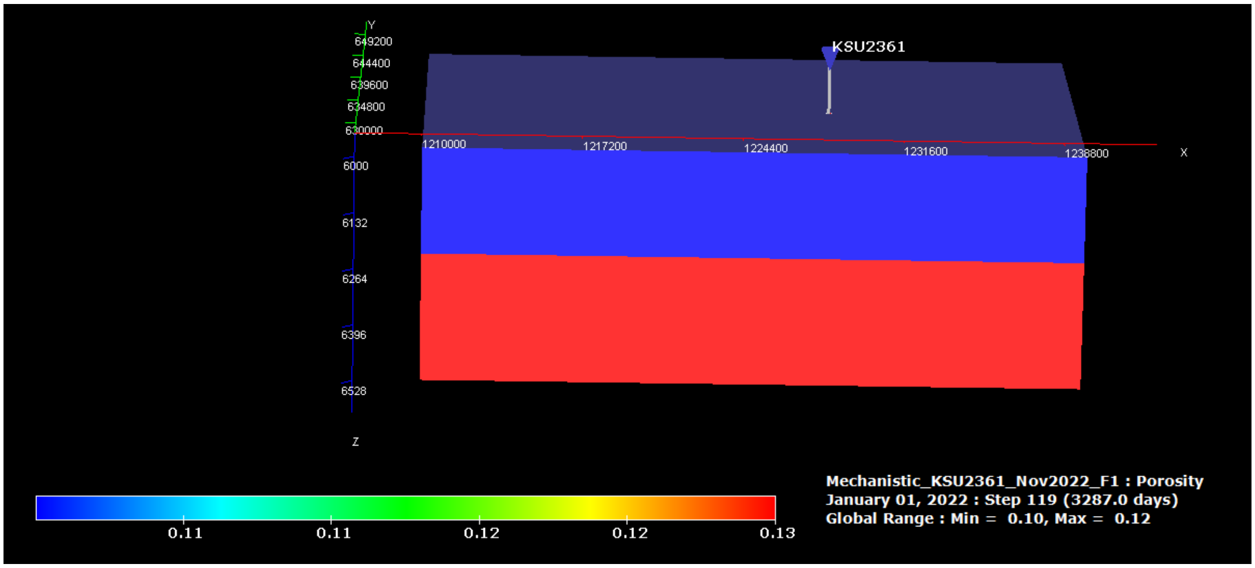


Figure 29 – Porosity Distribution in Plume Model

Dynamic Model

The primary objectives of the CO_2 plume model are as follows:

1. Determine the maximum possible injection rate without fracturing the target zone
2. Determine land acquisition strategy (i.e., maximum plume size)
3. Assess the likelihood of CO_2 leakage through potential conduits that may contaminate the Underground Source of Drinking Water (USDW)

Using the geomodel as an input, an infinite-acting model was built to simulate boundary conditions. The model assumes that the reservoir is 100% filled with brine. The formation fluid was estimated to have a salinity of 66,000 ppm. An offset step-rate test was utilized to estimate initial reservoir pressure and fracture pressure. Reservoir pressure was determined to be 2,600 psi which translates to a 0.435 psi/ft gradient. While pressure never reached high enough to propagate any fractures during the step-rate test, the fracture pressure was estimated to be approximately 4,390 psi. This translates to a fracture gradient of 0.683 psi/ft. Based off this data, a wellhead pressure of 1,850 psi was used to constrain the modelled well. An average temperature of 260 °F was also applied to the reservoir. Table 8 provides a summary of the initial conditions included in the simulation.

Table 8 – Initial Conditions Summary

Assumptions	Values
Permeability (mD)	20
Porosity (%)	10-12
Pore Gradient (psi/ft)	0.435
Frac Gradient (psi/ft)	0.683
Reservoir Temperature (°F)	260

To accurately and conservatively model the effective pore space of the rock, a net-to-gross (NTG) ratio was applied to the Ellenburger and Cambrian formations. The lateral plume extent is increased by reducing the total pore space CO_2 can flow through. Reducing the available pore space also limits

the CO_2 injection rate of the well due to higher increases in pressure. The Ellenburger had an NTG ratio of 0.5 applied, while the Cambrian formation had a 0.6 NTG ratio. This is further highlighted in Figure 30.

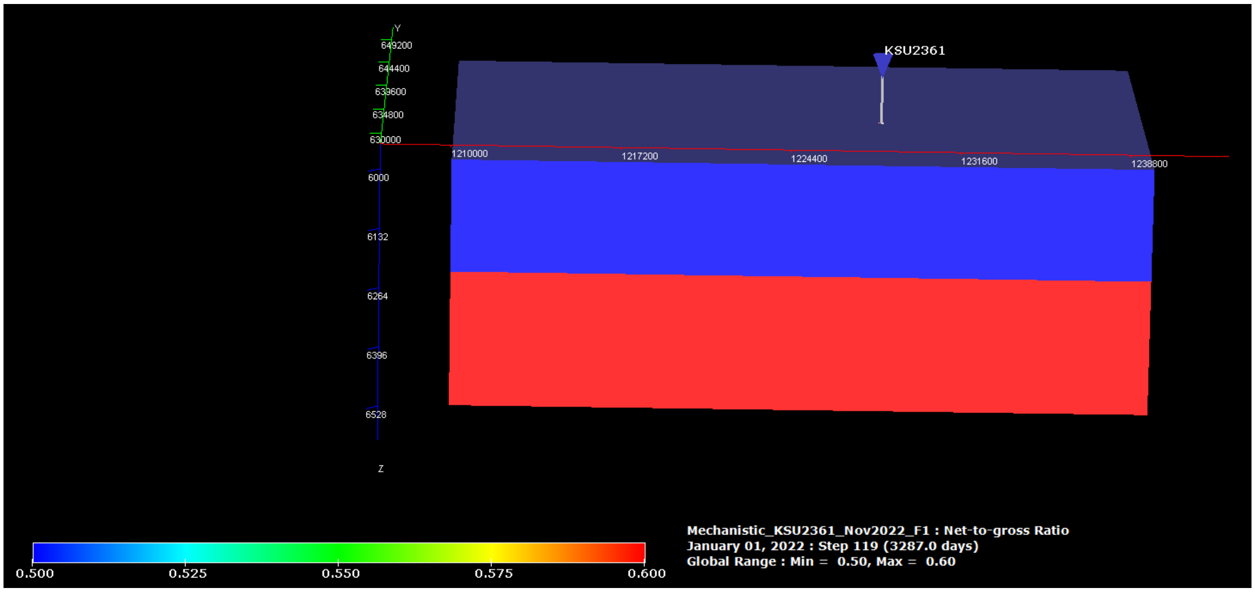


Figure 30 – NTG Ratio Applied to the Plume Model

Relative Permeability

Relative permeability curves were generated to represent a CO_2-brine system and how supercritical CO_2 will flow through a 100% brine-filled rock. Data from Kinder Morgan's McElmo Dome source models were utilized to create the relative permeability curves. The key inputs include a 9% irreducible water saturation and a 9% maximum residual gas saturation. Figure 31 shows the curves included in the simulation model.

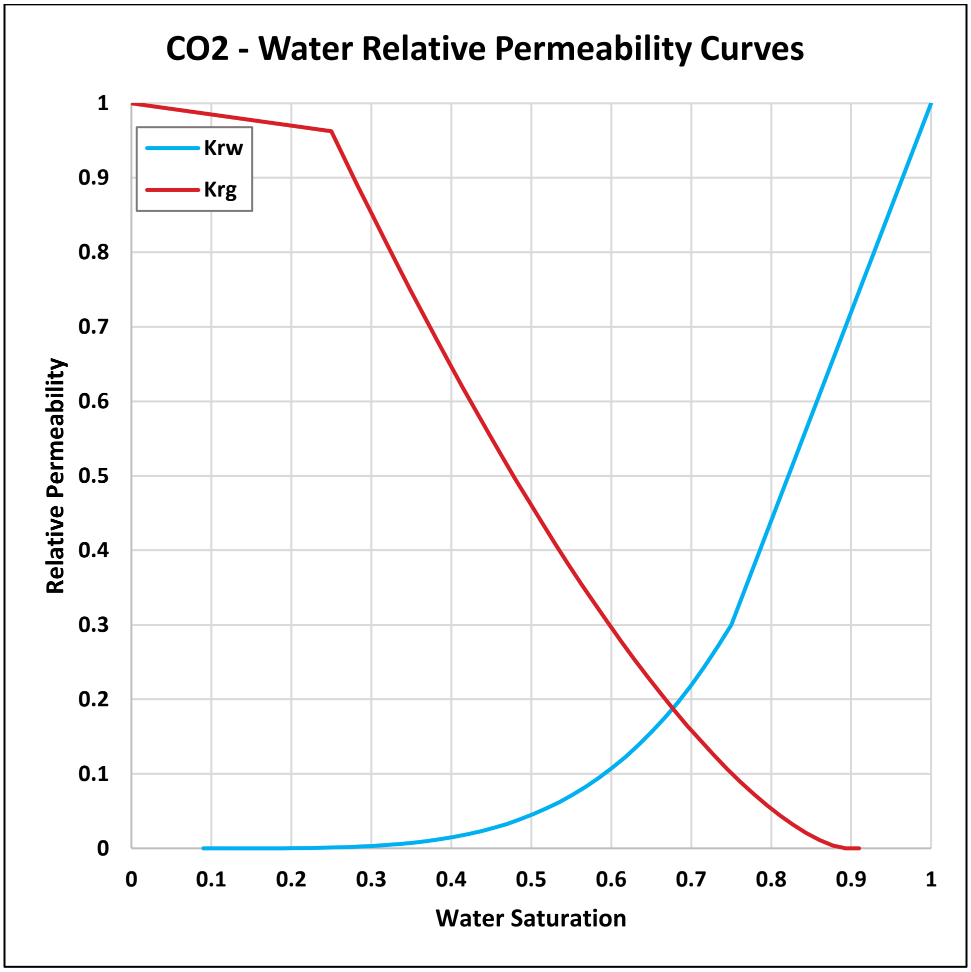


Figure 31 – CO_2-Water Relative Permeability Curves

History Matching

Two SWD wells were history-matched to determine permeability estimates. Historical injection rates were set in the model, and the simulated pressure response was compared to the recorded pressure data. This process was iterated multiple times until the simulated and real-life data matched. Monthly data points KSU 2361 (Figure 32) and KSU #3471 (Figure 33) were used to vary the injection rate in the model. These same intervals were used to compare the simulated results.

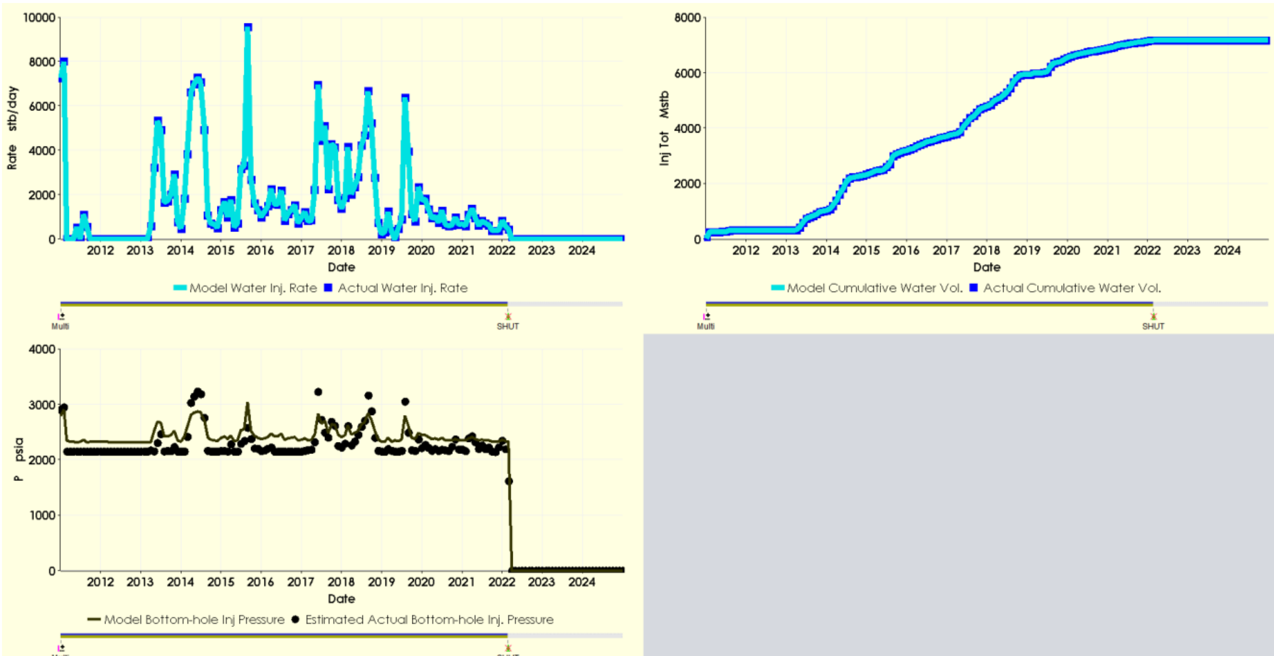


Figure 32 – History Match for KSU 2361

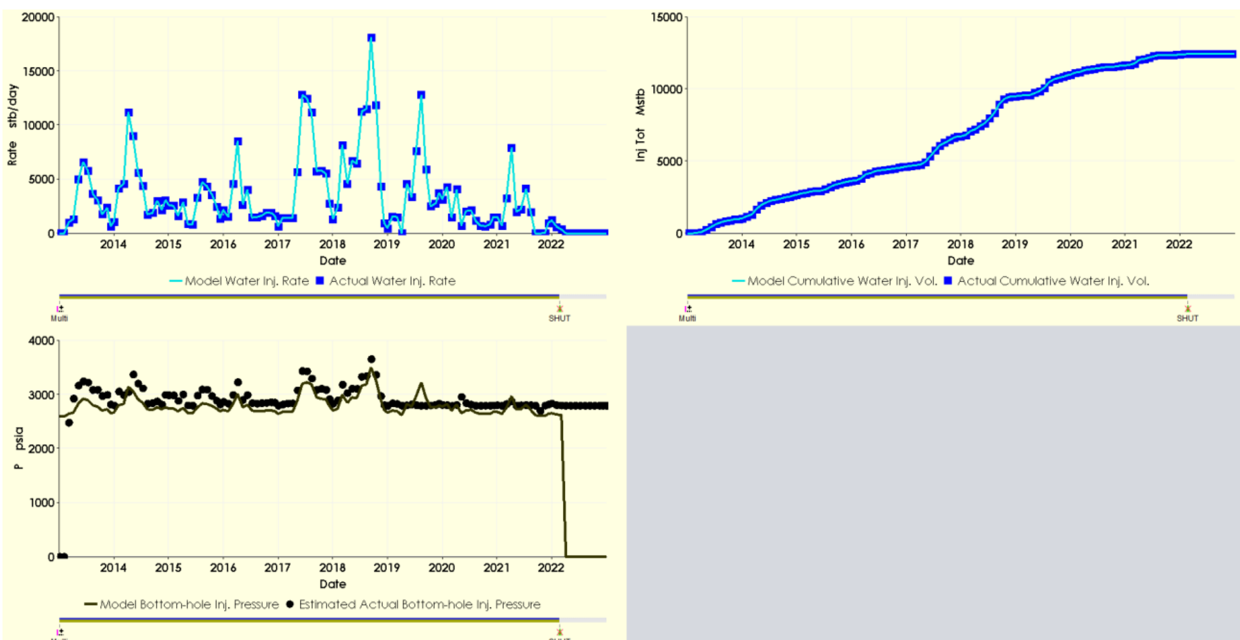


Figure 33 – History Match for KSU #3471

CO_2 Injection Operations

KSU 2361 was simulated to inject supercritical CO_2 for 21 years. A maximum wellhead pressure (WHP) was used to limit the injection rate. This value was determined from the fracture gradient estimation, and an equivalent wellhead pressure was calculated. The WHP constraint was set to 1,850 psi, equal to 84% of the fracture pressure. The injection rate was then maximized to stay

below the expected frac gradient. Figure 34 shows the simulated WHP during active injection operations.

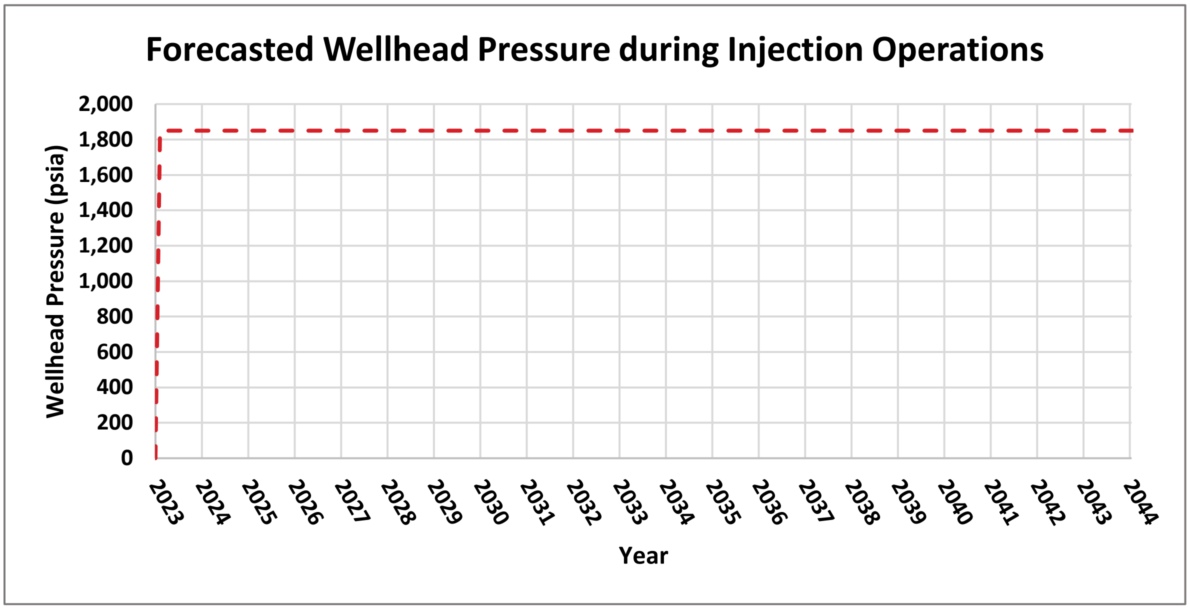


Figure 34 – Simulated Wellhead Pressure During Active Injection

During active injection, KSU 2361 achieved a maximum rate of approximately 1.22 MMT/yr. (~65 million cubic feet (MMscf)/day). During injection, the bottom hole pressure (BHP) reaches a maximum of 3,493 psi, which is safely below the fracture pressure. This is an 893-psi increase from the initial reservoir pressure. After injection ceases, the reservoir pressure decreases, reaching 65 psi buildup from the initial reservoir pressure. Figure 35 summarizes these results. The decreasing bottom-hole pressure from 2023 to 2044 is due to the relative permeability increasing over time.

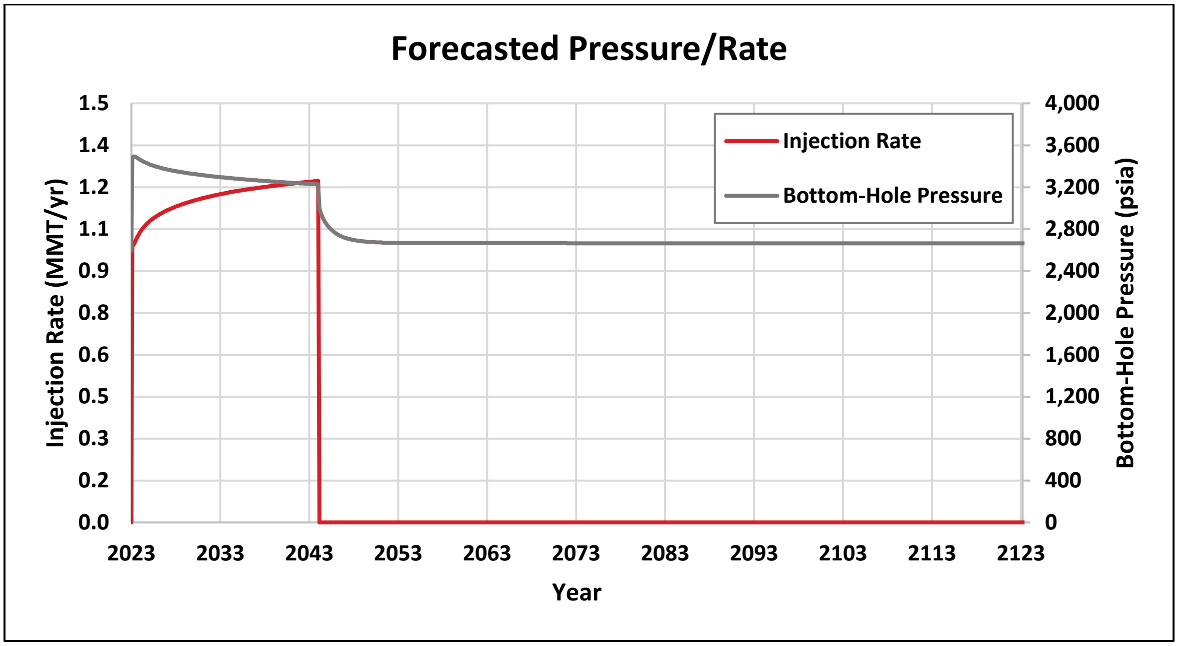


Figure 35 – Forecasted Injection Rate and BHP

Model Results

The maximum plume was determined once the plume was considered stabilized and by using a gas saturation cutoff of 3%. The plume is considered stabilized once all lateral and vertical movement of CO_2 has stopped, which also marks the end of the initial monitoring period. Aerial plume sizes were taken at 10-year intervals to determine a growth rate. As seen in Figure 36, an annualized growth rate is determined at each interval. The plume is delineated based on the maximum extent of the plume when the growth rate reaches 0%. In this model, the plume stabilizes in 2074, 30 years after the end of the injection period.

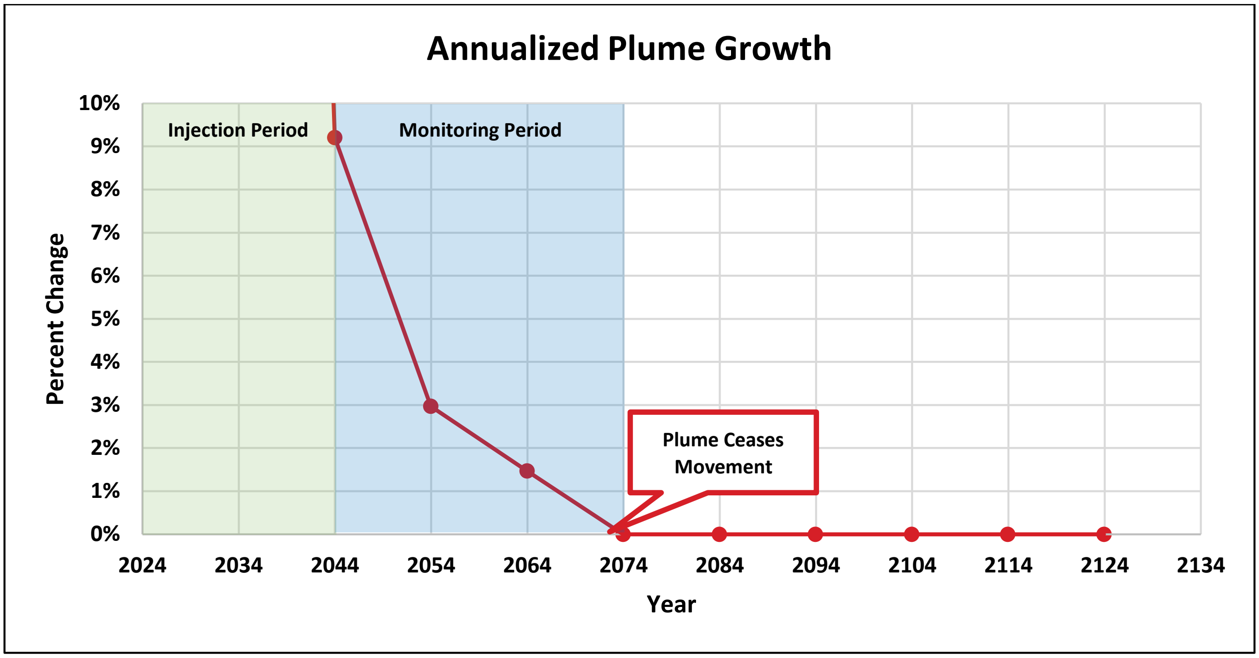


Figure 36 – Annualized Growth Rate of CO_2 Plume

The stabilized plume reaches a maximum of 3,384 ac (~5.3 sq mi). The furthest extent of this plume is to the South, as seen in Figure 37. The largest radius of the plume is 6,850' (~1.2 mi) from the wellbore. Due to the heterogeneity included in the model, the plume is not uniform from layer to layer, as seen in Figure 48. The maximum plume was chosen from the layer with the largest lateral extent of CO_2. Table 9 shows the plume radius and plume compared to time since injection starting in year zero. The results in Table 9 show that the modeled plume boundary is expected to stabilize 30 years after injection has ended. Additionally, the model was run a further 50 years to ensure the final plume boundary was stabilized, as shown in the table below.

Table 9 – Plume Model Radius and Area

Date	Year	Plume Radius (ft.)	Plume Area (Acres)
Jan-23	0	0	0
Jan-34	10	4650	1559
Jan-44	20	6400	2954
Jan-54	30	6700	3238
Jan-64	40	6800	3335
Jan-74	50	6850	3384
Jan-84	60	6850	3384
Jan-94	70	6850	3384
Jan-04	80	6850	3384
Jan-14	90	6850	3384
Jan-24	100	6850	3384

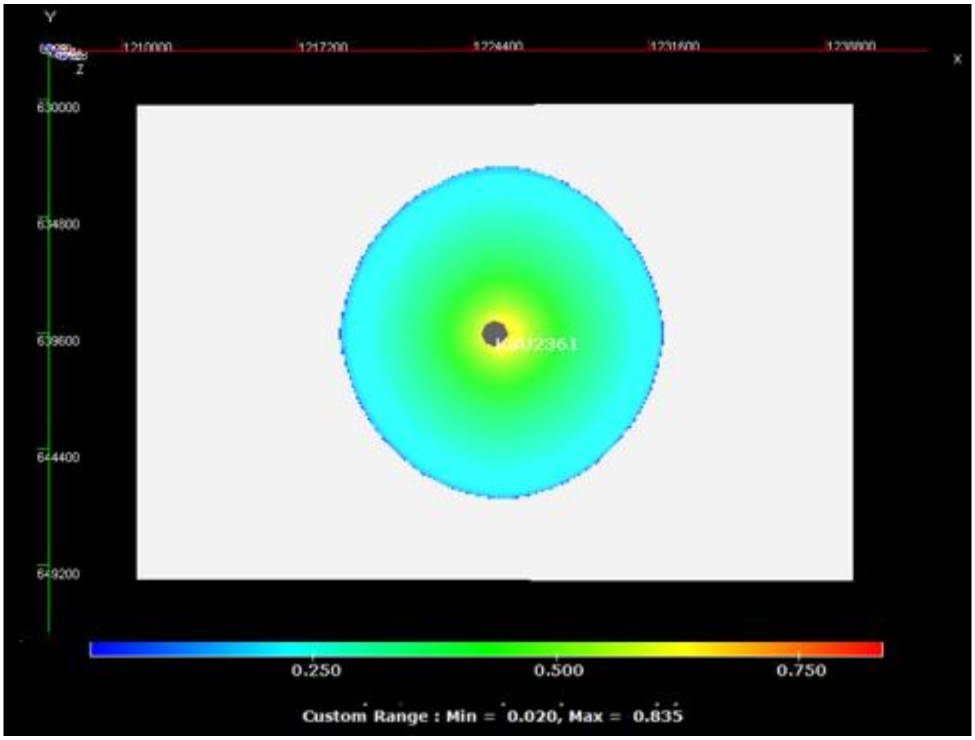


Figure 37 – Aerial View of CO_2 Plume

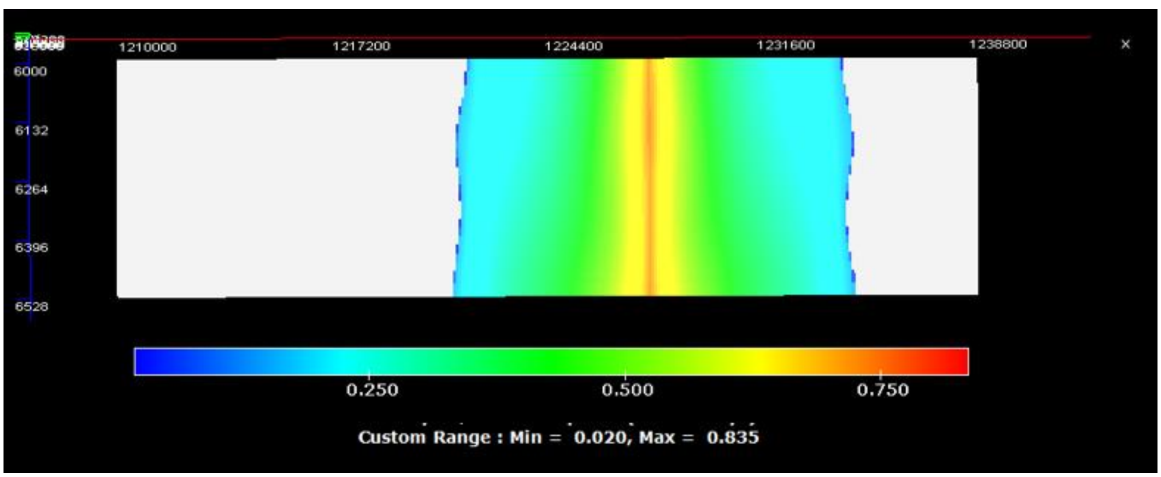


Figure 38 – Cross-Sectional View of CO_2 Plume

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA) as described in EPA 40 CFR §**98.448(a)(1**).

3.1 Maximum Monitoring Area

The EPA defines the MMA as equal to, or greater than, the area expected to contain the free-phase CO_2-occupied plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one-half mile. A numerical computer simulation was used to determine an estimate for the size and drift of the plume. Using a combination of Paradigm's SKUA-GOCAD and Aspen Technology's Tempest software packages, a geomodel, and reservoir model were used to determine the areal extent and density drift of the plume. The model accounts for the following considerations:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Kinder Morgan's pipeline gas specifications were used for the initial composition of the injectate in the model, as provided in Appendix B. The molar composition of the gas is mostly carbon dioxide, with some small amounts of nitrogen and hydrocarbons, and contained no H_2S. The molar composition was incorporated into the model as future CO_2 streams could be added for injection. As discussed in Section 2, the gas was modeled to be injected primarily into the Ellenburger and both Cambrian formations. The geomodel was created based on the rock properties seen in the Ellenburger and Cambrian rocks.

The weighted average gas saturation defined the plume boundary in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in 2044, the areal expanse of the plume will be 2,954 acres. After 30 additional years of density drift, the areal extent of the plume is 3,384 acres, with a maximum distance to the edge of the plume of approximately 6,850'. Since the stabilized plume shape is relatively circular, the maximum distance plus a one-half mile buffer from the injection well, was used to define the circular boundary of the MMA equal to 9500'.

The plume is expected to stabilize 30 years after injection ceases and does not migrate after 2050, the monitoring program of the MMA will remain active for the required amount of time.

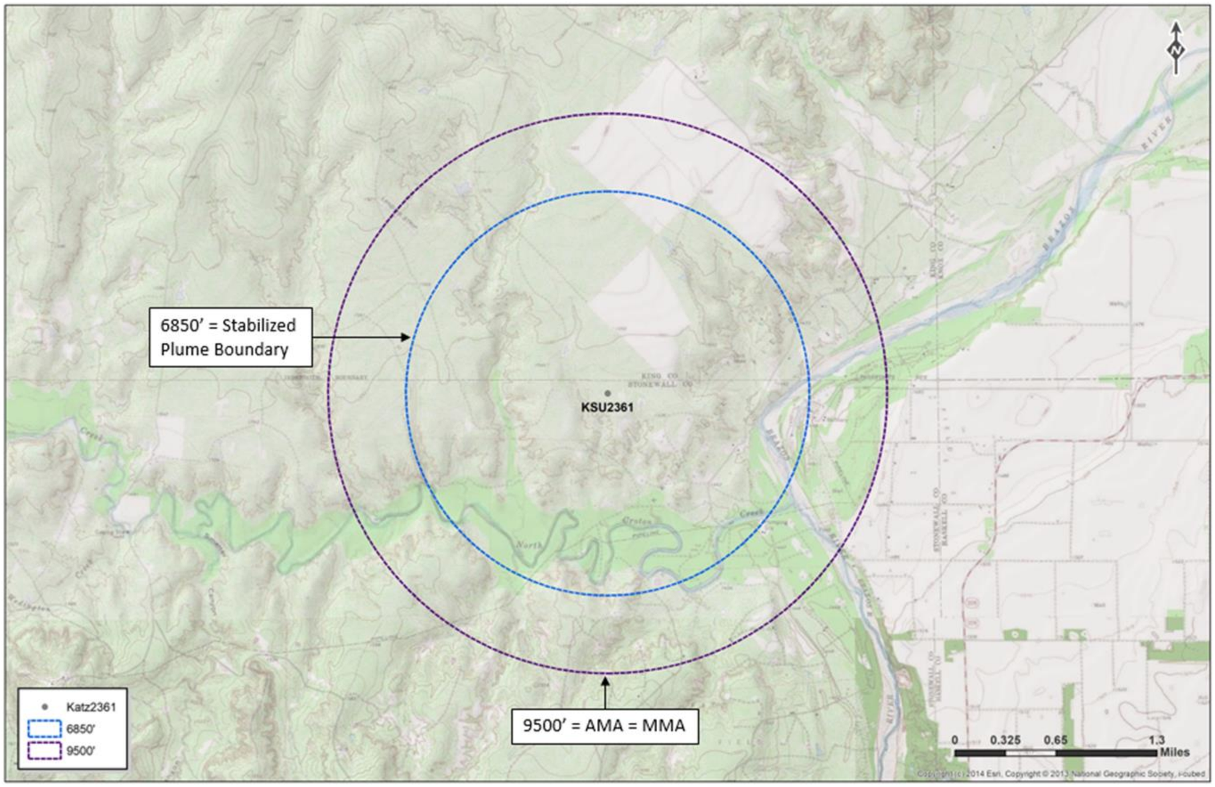


Figure 39 – Stabilized Plume Boundary, Active Monitoring Area and Maximum Monitoring Area

3.2 Active Monitoring Area

Per 40 CFR 98.449, the boundary of the AMA is established by superimposing two different boundary conditions. For the first condition, Kinder Morgan defines year t as occurring 30 years after the cessation of injection, when the modeled plume has stabilized with a maximum extent radius of 6,850'. The addition of a half-mile buffer results in a maximum extent of 9,500', satisfying the first condition. For the second condition, since Kinder Morgan defines year t as when the plume stabilizes, 30 years after the cessation of injection, the projected radius of the plume for t + 5 is also 6,850'. Superimposing the results of these two conditions results in Kinder Morgan defining the AMA with a radius of 9,500', or 3,384 acres, as shown in Figure 39.

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from Natural or Induced Seismicity

4.1 Leakage from Surface Equipment

The surface facilities at the KSU 2361 well are designed for injecting acid gas primarily consisting of CO_2. One additional pipeline will be constructed to carry the acid gas from the custody transfer meter to the KSU 2361 wellhead, as shown in Figure 40. The wellbore of the KSU 2361 is designed for acid gas, as seen in the wellbore schematic in Figure 41. The facilities have been designed to minimize leakage and failure points. The design and construction of these facilities followed industry standards and best practices. CO_2 monitors are located around the facility and the well site. These gas monitor alarms will be triggered at levels set upon completion of a baseline study of the ambient air quality, followed by a gas dispersion model. An emergency shutdown valve (ESD) is located at the wellhead and is locally controlled by pressure, with a high-pressure and low-pressure shut-off.

The facilities have been designed and constructed with other safety systems to provide for safe operations. These systems include ESD valves to isolate portions of the pipeline, pressure relief valves along the pipeline to prevent over-pressurization, and venting to allow piping and equipment to be de-pressured under safe and controlled operating conditions in the event of a leak. More information on these systems and be found in Appendix C. Should Kinder Morgan construct additional CO_2 facilities other meters will be installed as needed to comply with the 40 CFR **§98.448(a)(5**) measurement. These meters will be near the existing facilities and utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meters and tied into the facility monitoring systems. No additional wells are included within this MRV facility.

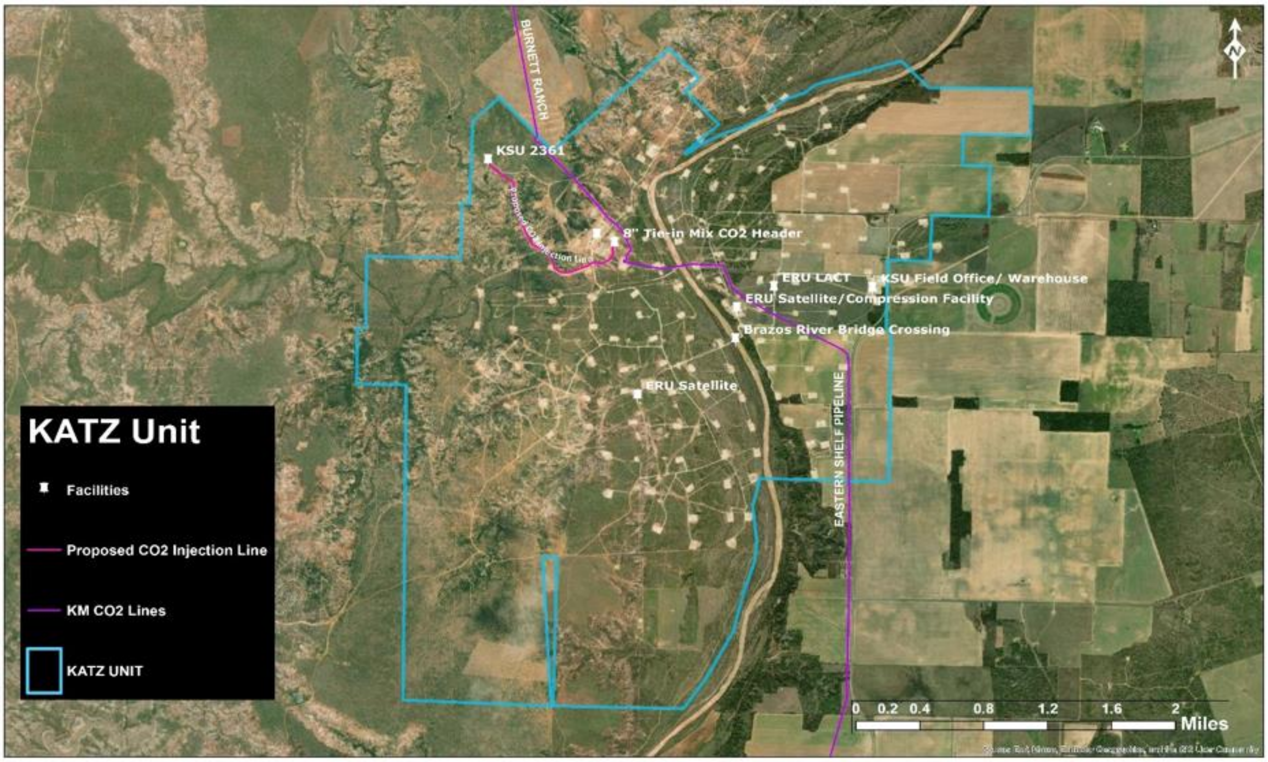


Figure 40 – Site Plan

With the level of monitoring implemented at the KSU 2361 well, a release of CO_2 would be quickly identified, and the safety systems would minimize the release volume. The CO_2 stream injected into KSU 2361 could include small amounts of methane and nitrogen, as seen in Appendix B. The CO2 injected into the Katz 2361 well is supplied by a number of different sources into the pipeline system and the composition is not expected to change over time. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR **§98.448(a)(5)**. Kinder Morgan concludes that leakage of CO_2 through the surface equipment as unlikely.

4.2 Leakage from Existing Wells within MMA

4.2.1 Oil and Gas Operations within Monitoring Area

A significant number of wells have historically been drilled within the area of the KSU 2361 well. However, production has primarily been from the shallower Strawn formation in the Katz Field. The Strawn is separated from the Ellenburger-Cambrian interval by 665' in this area. In addition to the primary Strawn production, a few wells have produced from the Mississippian. The mid-Mississippian is separated from the Ellenburger-Cambrian interval by 133'. KSU 2361 is the only well penetrating the injection interval within the projected plume area of the MMA for the KSU 2361. Therefore, it is the only well that will be monitored for surface leakage. This well is designed to handle and inject acid gas, which reduces the risk and likelihood of leakage through the existing well to near-zero.

The KSU 2361 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as depicted in the schematic denoted in Figure 41. Mechanical integrity tests (MIT), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every five years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 42. The MMA review map and a summary of all the wells in the MMA are provided in Appendix D. Figure 43 highlights that no wells penetrate the MMA's gross injection zone.

KINDER MORGAN

Schematic - Current

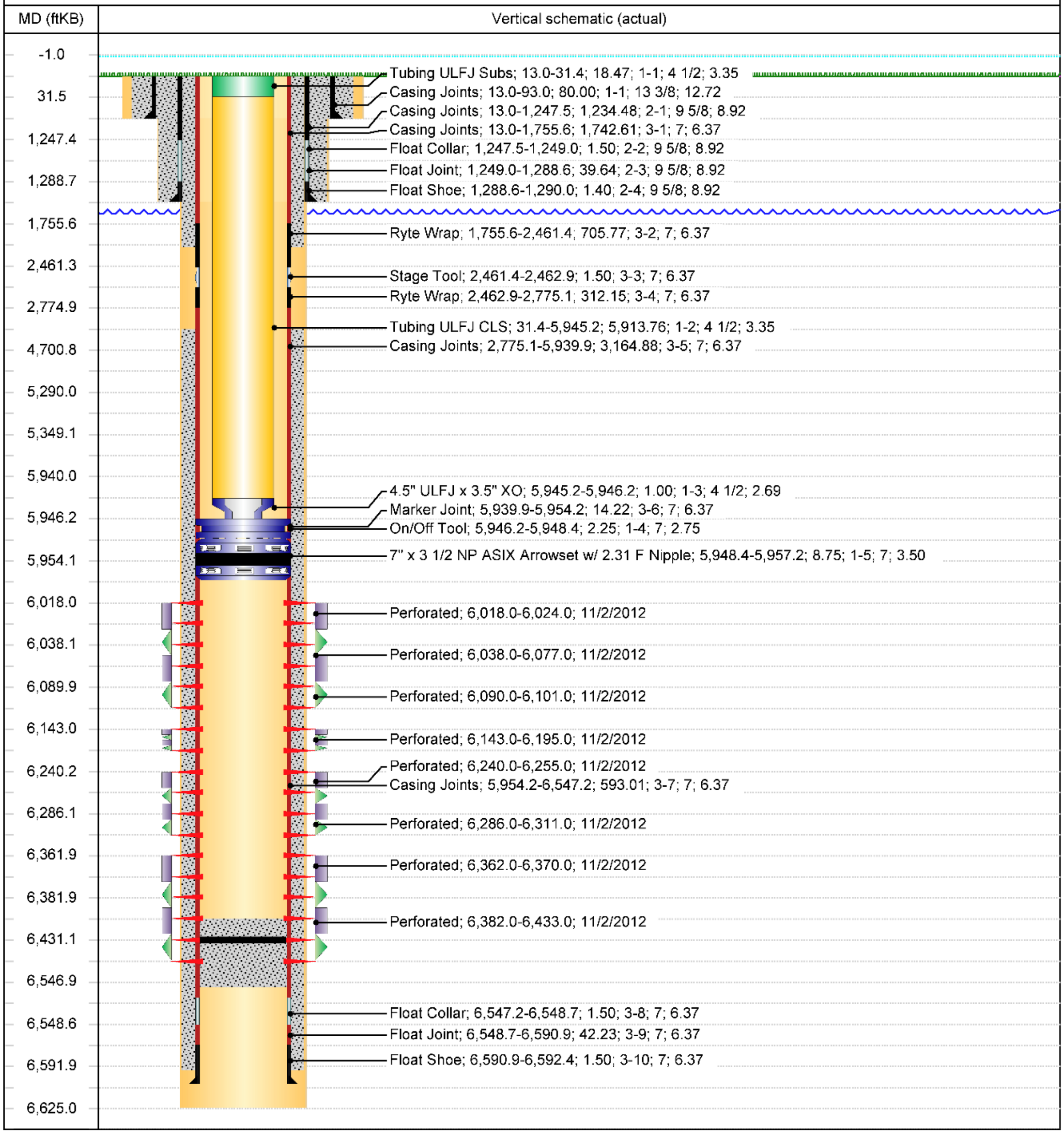
Well Name: KSU #2361

API/UWI	Surface Location	Field Name	State	Well Configuration Type	RRC/COGC...	Account Cat/Prop...
42-433-33712	SEC 2 LONG, CB	KATZ	Texas	Vertical		26039
Estimated KB Elevation (ft)	**KB-Tubing Head Distance (ft)**	**Original Well Spud Date**	**Rig Release Date**	**PBTD (All) (ftKB)**	**Total Depth All (TVD) (ftKB)**	
1,531.00	13.00	8/23/2012 18:00	9/13/2012 06:00	Original Hole - 6,431.0		

Most Recent Job

Job Category	Primary Job Type	Secondary Job Type	Start Date	End Date
Non-Rig Activity	Coil Tubing		4/2/2019	4/4/2019

TD: 6,625.0 Vertical, Original Hole, 2/21/2022 10:06:22 AM



Page 1/1 Report Printed: 2/21/2022

Figure 41 – KSU 2361 Wellbore Schematic

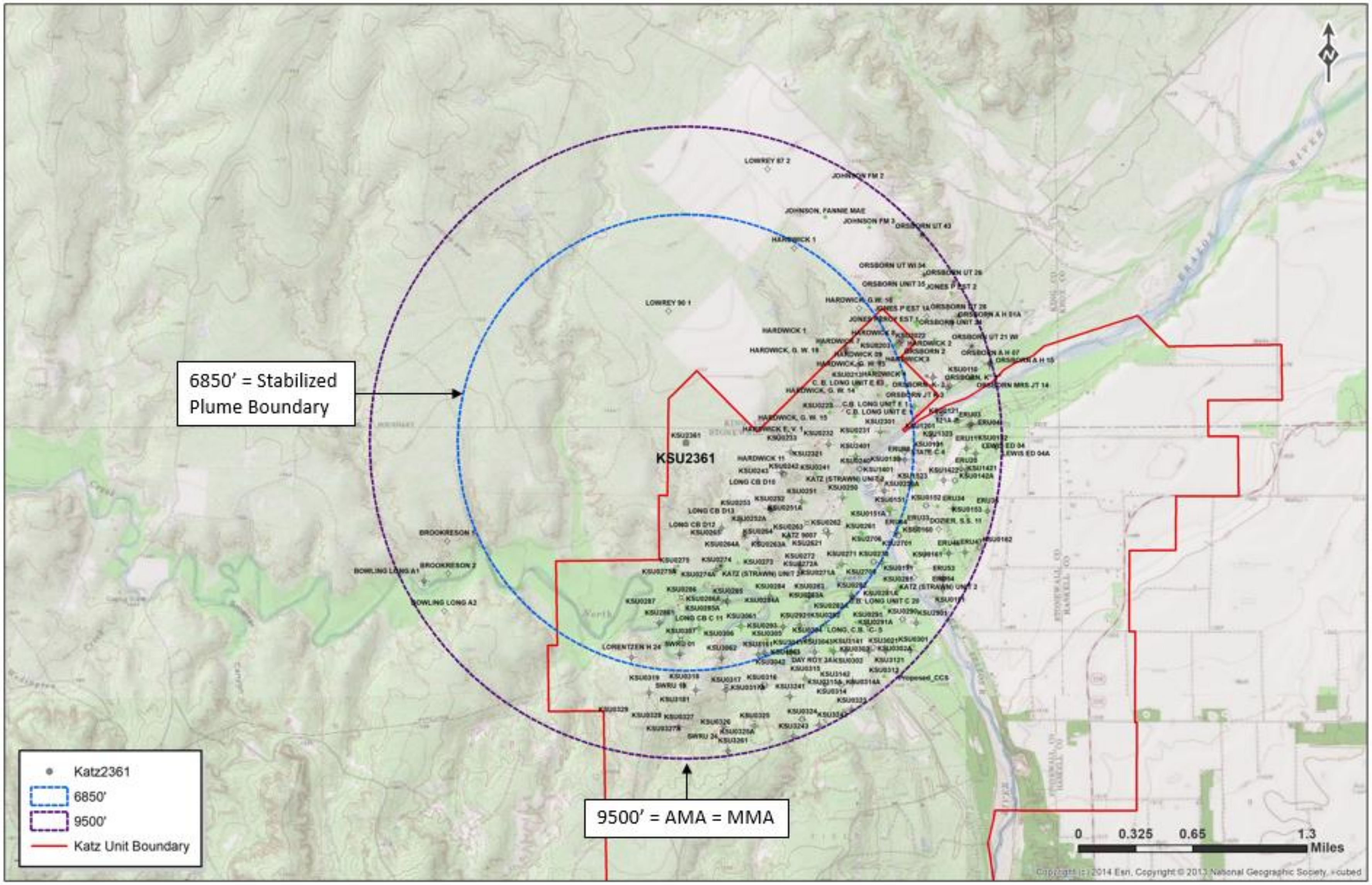


Figure 42 – All Oil and Gas Wells within the MMA

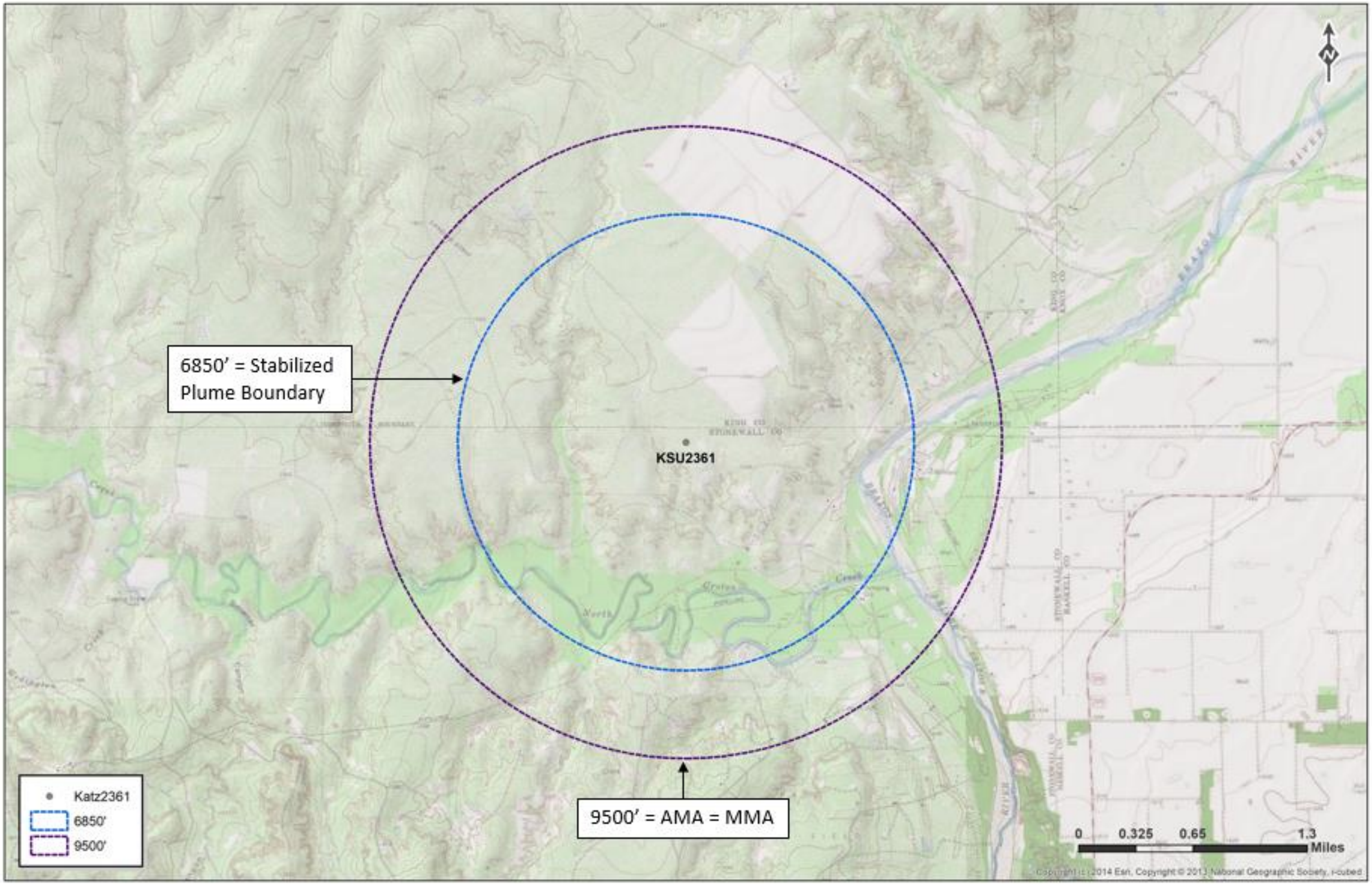


Figure 43 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA

Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Pre-Cambrian, have proven to date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC in the area of KSU 2361 include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"), 16 TAC **§3.13**. By way of example, see the KSU 2361 well drilling permit provided in Appendix A. The Ellenburger and Cambrian Sands are among the formations listed for which operators in Stonewall County and district 7B (where the KSU 2361 is located) are required to comply with TRCC Rule 13. TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. In this instance, any new well permitted and drilled to the KSU 2361 well's injection zone, and located within a one-quarter-mile radius of the KSU 2361 well, will be required under TRRC Rule 13 to set steel casing and cement above the KSU 2361 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above *all* potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued, which is also shown in the permit mentioned above in Appendix A.

4.2.2 Groundwater wells

A groundwater well search resulted in zero groundwater wells found within the MMA, as identified by the Texas Water Development Board.

The surface and intermediate casings of the KSU 2361 well, as shown in Figure 41, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See the GAU letter included in Appendix A. The wellbore casings and cements also prevent CO_2 leakage to the surface along the borehole. Kinder Morgan concludes that leakage of the sequestered CO_2 to the groundwater wells as unlikely.

4.3 Leakage Through Faults and Fractures

One fault was interpreted within the seismic coverage projecting 12,000' east of the KSU 2361 location. Initial plume models do not indicate an interaction between the injectate and the fault plane. Additionally, this fault dies within the Mississippian formation and does not penetrate the Lower Strawn Shale that acts as the upper confining unit. In the unlikely scenario in which the injection plume reaches the fault, and the fault acts as a transmissive pathway, the upper confining shale above the fault will act as an ideal sealant from injectate leaking outside of the permitted injection zone.

Should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Lower Strawn Shale, juxtaposing it against itself, preventing vertical migration.

Fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open hole logs show little to no porosity development indicating the Lower Strawn Shale or Mississippian Lime were not exposed at this location. Therefore, upward migration of injected gas through confining bed fractures is unlikely.

4.4 Leakage Through the Confining Layer

The Ellenburger and Cambrian injection zones have competent sealing rocks above and below the sand and carbonate formations. The properties of the overlying Lower Strawn Shale and its high composition of shale and mudstone make an excellent sealing rock to the underlying Ellenburger formation. Tight Mississippian Lime of roughly 266' lies between the Ellenburger and Lower Strawn Shale formations forming an impermeable upper buffer seal from the injection interval to the upper confining zone. Above this confining unit, shales found within the Homecreek Shale above the Desmoinesian formation will act as additional sealants between the injection interval and the USDW. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. Precambrian basement rock's underlying low porosity and permeability minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

4.5 Leakage from Natural or Induced Seismicity

The location of KSU 2361 is in an area of the Midland Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 44, indicates the nearest seismic event (unspecified whether natural or induced) occurred more than 40 miles away.

There is no indication of seismic activity posing a risk for loss of CO_2 to the surface within the MMA. Therefore, Kinder Morgan concludes that leakage of the sequestered CO_2 through seismicity as unlikely.

Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

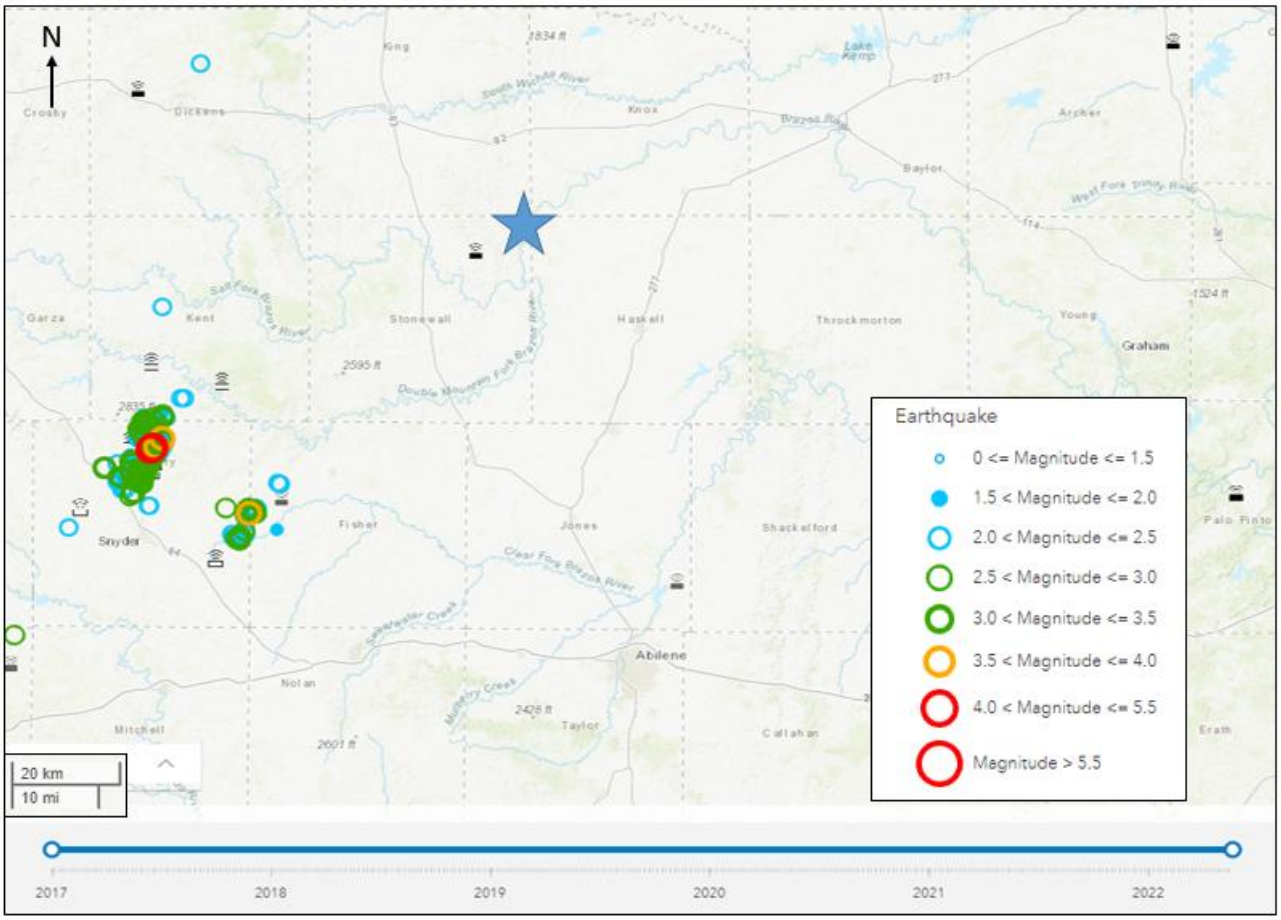


Figure 44 – Seismicity Review (TexNet – 06/01/2022)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Kinder Morgan will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 to meet the requirements of 40 CFR **§98.448(a)(3)**. Table 10 summarizes the monitoring of potential leakage pathways to the surface. Monitoring will occur during the planned 21-year injection period or cessation of injection operations, plus a proposed 5-year post-injection period.

- Leakage from surface equipment failure
- Leakage through existing and future wells within MMA
- Leakage through faults, fractures, or confining seals
- Leakage through natural or induced seismicity

Table 10 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed CO_2 monitors throughout the AGI facility
	Daily visual inspections
	Supervisory Control and Data Acquisition (SCADA)
Leakage through existing wells	Fixed CO_2 monitor at the the AGI well
	SCADA continuous monitoring at the AGI Well
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Quarterly atmospheric CO_2 measurements at well locations within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	CO_2 monitoring during offset drilling operations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage through confining layer	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage from natural or induced seismicity	Existing TexNet seismic monitoring station to be implemented

5.1 Leakage from Surface Equipment

As the facility and the KSU 2361 well are designed to handle CO_2, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used, and the connections are designed to minimize corrosion points. A baseline atmospheric CO_2 concentration will be established before injection operations begin. The facility and well site contain several CO_2 alarms with locations in close proximity.

The AGI complex is continuously monitored through automated systems. Details surrounding these systems can be found in Appendix C. In addition, field personnel conduct daily visual field inspections of gauges, monitors, and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the surface equipment associated with the sequestered CO2 and inspection of the cathodic protection system. These inspections and the automated systems allow Kinder Morgan to respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)**.

Pressures and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

5.2 Leakage From Existing and Future Wells within MMA

Kinder Morgan continuously monitors and collects injection volumes, pressures and temperatures through their SCADA systems, for the KSU 2361 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. KSU 2361 has a pressure and temperature gauge placed in the injection stream at its wellhead and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. In addition, mechanical integrity tests (MIT) performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 would ensure that new wells in the field would be constructed to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Kinder Morgan will also establish and operate an in-field monitoring program to detect CO_2 leakage within the MMA. The scope of work will include CO_2 monitoring at the AGI well site and, at minimum, quarterly atmospheric monitoring near any wells identified that penetrate the injection interval within the MMA. The collection of these measurements will be carried out by using a qualified third party. Upon approval of the MRV and through the post-injection monitoring period, Kinder Morgan will have these monitoring systems in place. No wells have been identified within the MMA that penetrate the injection interval. Additional monitoring will be added as the MMA is updated over time. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

Groundwater Quality Monitoring

Kinder Morgan will monitor the groundwater quality in fluids above the confining interval by sampling from groundwater wells in the area of the facility and analyzing the sample with a third-party laboratory on an annual basis. In the case of KSU 2361, no existing groundwater wells have been identified within the MMA. At least two groundwater monitoring wells will be drilled within 1500' of KSU 2361 at a depth of approximately 100'. The final number, locations, and depths of the wells will be determined by a study completed by a certified 3rd party firm. The approximate location and depths of these wells are shown in Figure 45. A baseline sampling from these wells will occur before injection starts. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature, and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

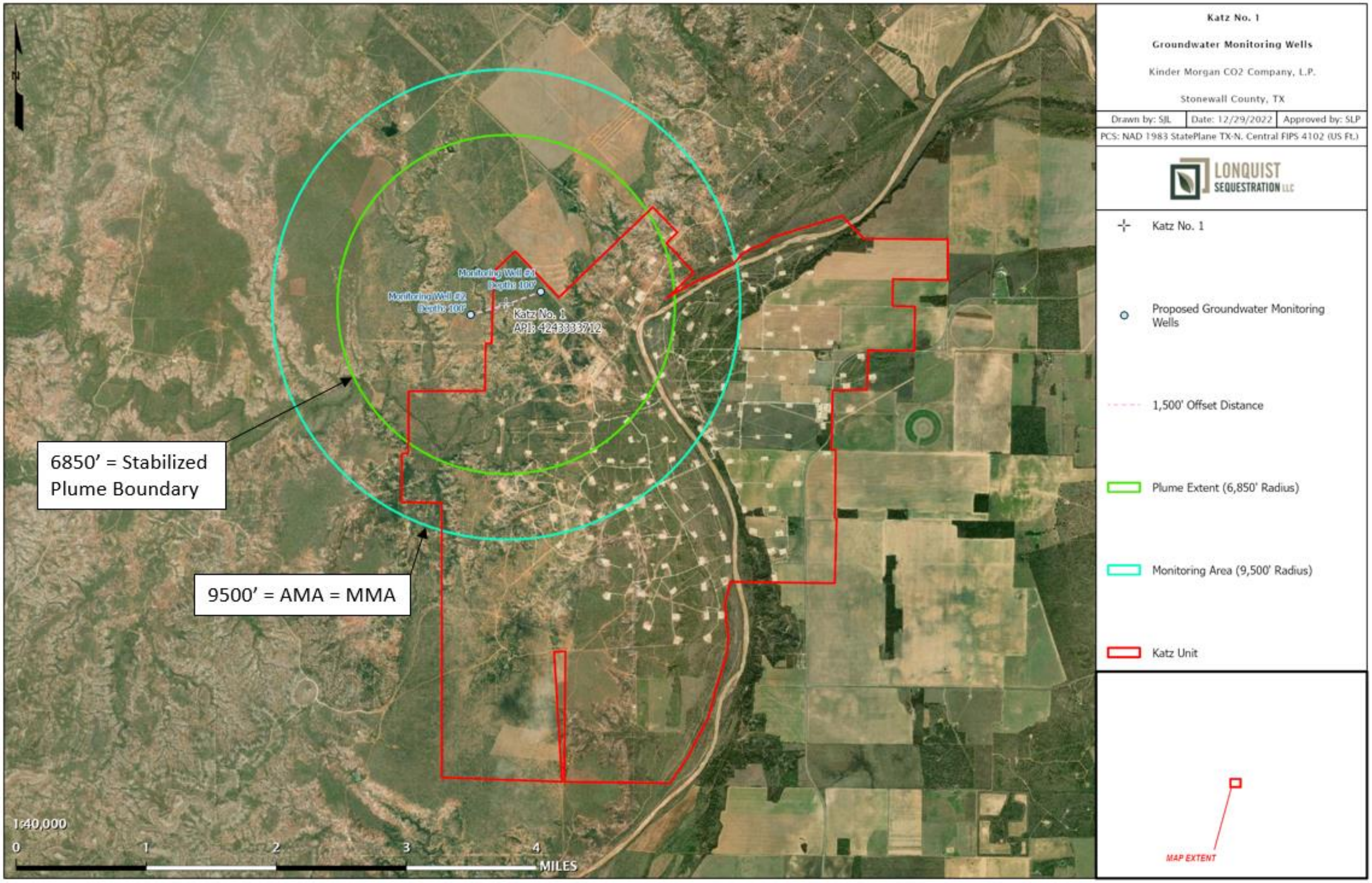


Figure 45 – Groundwater Monitoring Wells

5.3 Leakage through Faults, Fractures or Confining Seals

Kinder Morgan continuously monitors the operations of the KSU 2361 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. In addition, a field monitoring system is proposed to measure the shallow topsoil CO_2 concentrations across the MMA. These measurements will be taken quarterly by in-field gas sensors. The field CO_2 monitoring systems would alert field personnel for any release of CO_2 caused by such leakage. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

5.4 Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Kinder Morgan plans to use the nearest TexNet seismic monitoring station to monitor the area of the KSU 2361 well. This station is 7.29 miles southwest of the well location, as shown below in Figure 46. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Katz Unit. Kinder Morgan will monitor this station for any seismic activity that occurs near the well. If a seismic event of 3.0 magnitude or greater is detected, Kinder Morgan will review the injection volumes and pressures at the KSU 2361 well to determine if any significant changes occur that would indicate potential leakage. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

Figure 46 – Nearest TexNet Seismic Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Kinder Morgan will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Kinder Morgan will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Once the baseline concentrations are determined over a 12 month period prior to injection, the CO_2 monitors will be set to alarm at concentrations that are statistically significant deviation from baseline.

6.1 Visual Inspections

Daily inspections will be conducted by field personnel at the facility and the KSU 2361 well. These inspections will aid with identifying and addressing possible issues in order to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken to address such issues.

6.2 CO_2 Detection

In addition to the well site fixed monitors described previously, Kinder Morgan will establish and operate an in-field monitoring program to detect any CO_2 leakage within the MMA. The scope of baseline determination will include atmospheric CO_2 measurements at the AGI well site and near identified penetrations within the MMA. Topsoil CO_2 concentrations will also be measured, at pre-determined locations within the MMA, as baseline values before injection activities begin.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be taken. Any significant deviations over time will be analyzed for indication of leakage of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this project are well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a blowdown event, emissions will be sent to vent stacks and will be reported as required for the operation of the well.

6.5 Groundwater Monitoring

Initial samples will be taken from the groundwater monitoring wells drilled within 1,500 feet of the KSU 2361 well upon approval of Kinder Morgan's MRV and before commencing injection of CO_2. A third-party laboratory will analyze the samples to establish the baseline properties of the groundwater.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

This section identifies how Kinder Morgan will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR **§98.448(a)(5)**.

7.1 Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

Per 40 CFR **§98.444(b)**, since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters per quarter)

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (volume percent CO_2, expressed as a decimal fraction)

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The KSU 2361 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains concentrations well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Any leakage would be detected and managed as an upset event. An upset event is any unlikely event that results in the failure of any mass of CO_2 to remain permanently sequestered in the target reservoir. Continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released as a result of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Kinder Morgan believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in Section 10, below.

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12, assuming an expected injection start date of June 1, 2024, as this well will not actively produce oil or natural gas, or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to flares and reported as part of the required GHG reporting for the gas plant.

- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The KSU 2361 well currently reports GHGs under Subpart UU, but Kinder Morgan has elected to submit an MRV plan under, and otherwise comply with, Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed by March 31st of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Kinder Morgan plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 *Injected*

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated per the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP.

CO_2 *Emissions from Leaks and Vented Emissions*

- Gas monitors will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i) requirements**.**
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Kinder Morgan will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Kinder Morgan will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

Kinder Morgan will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least three years and include the following:

- Quarterly records of the CO_2 injected
    - Volumetric flow at standard conditions
    - Volumetric flow at operating conditions
    - Operating temperature and pressure
    - Concentration of the CO_2 stream
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

Adams, Donald & Keller, Randy. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective. AAPG Bulletin. 80. 410-431. 10.1306/64ED87FA-1724-11D7-8645000102C1865D.

Broadhead, Ronald E., 2005. Regional Aspects of the Wristen petroleum system, southeastern New Mexico: New Mexico Bureau of Geology and Mineral Resources Open File Report, no. 485.

Comer, John B., 1991. Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas and Southeastern New Mexico: Bureau of Economic Geology Report of Investigations, no. 201.

Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.

Ewing et al. (2004). Groundwater Availability Model for the Seymour Aquifer. *Texas Water Development Board.*

Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.

George, Peter G., Mace, Robert E., and Petrossian, Rima, 2011. Aquifers of Texas: Texas Water Development Board Report, no 380.

Gunn, R. D. (1982). Desmoinesian Depositional Systems in the Knox Baylor Trough. *North Texas Geological Society*.

Harding, R.W. and Associates. (1978). THE SEYMOUR AQUIFER: Ground-Water Quality and Availability in Haskell and Knox Counties, Texas. *Texas Department of Water Resources.*

Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.

Hoak, T., Sundberg, K., and Ortoleva, P. Overview of the Structural Geology and Tectonics of the Central Basin Platform, Delaware Basin, and Midland Basin, West Texas and New Mexico: Department of Energy Open File Report.

Holtz, M.H., and Kerans, C. (1992). Characterization and categorization of West Texas Ellenburger reservoirs. *Permian Basin Section SEPM Publication No. 92-22, p. 31-44.*

Hornhach, M. J. (2016). Ellenburger wastewater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.

Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas*.

Kane, S. C. (n.d.). THE MISSISSIPPIAN BARNETT FORMATION: A SOURCE-ROCK, SEAL, AND RESERVOIR PRODUCED BY EARLYCARBONIFEROUS FLOODING OF THE TEXAS CRATON. *BEG*.

Kerans, C. (1989). Karst-controlled reservoir heterogeneity and an example from the Ellenburger Group (Lower Ordovician) of West Texas. *Bureau of Economic Geology.*

Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.

Kupecz, J.A., and L.S. Land. (1991). Late-stage dolomitization of the Lower Ordovician Ellenburger Group, West Texas. *Journal of Sedimentary Petrology.*

Kyle, J.R. and E.F. McBride. (2014). Geology of the Voca Frac Sand District, western Llano Uplift, Texas. *Arizona Geological Survey Special Paper #9, Chapter 2, p. 1-13.*

Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.

Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

Molina, Oscar, Vilarras, Victor, and Zeidouni, Mehdi, 2016. Geologic carbon storage for shale gas recovery: 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18.

Ruppel, Stephen C. and Holtz, Mark H., 1994. Depositional and Diagenetic Facies Patterns and Reservoir Development in Silurian and Devonian Rocks of the Permian Basin: Bureau of Economic Geology Report of Investigations, no. 216.

Snee, Jens-Erik Lund and Zoback, Mark D., 2016. State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity.

Teeple, Andrew P., Ging, Patricia B., Thomas, Jonathan V., Wallace, David S., and Payne, Jason D., 2021. Hydrogeologic Framework, Geochemistry, Groundwater-Flow System, and Aquifer Hydraulic Properties Used in the Development of a Conceptual Model of the Ogallala, Edwards-Trinity (High Plains), and Dockum Aquifers In and Near Gaines, Terry, and Yoakum Counties, Texas: USGS Scientific Investigations Report 2021-5009.

SECTION 12 - APPENDICES

APPENDICES

APPENDIX A – TRRC FORMS KSU #2361

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

A-1

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 13453 AMENDMENT

KINDER MORGAN PRODUCTION CO LLC
6 DESTA DRIVE STE 6000
MIDLAND, TX 79705

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated August 27, 2018 for the permitted interval of the ELLENBURGER, and CAMBRIAN formations and subject to the following terms and special conditions:

KATZ (STRAWN) UNIT (30524) LEASE
KATZ (STRAWN) FIELD
STONEWALL COUNTY, DISTRICT 7B

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
2361	43333712	000104281	Salt Water, and Other Non-Hazardous O/G Waste	5,800	6, 435	30,000	N/A	2,900	N/A

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
2361	43333712	1. According to the cross-section submitted by the operator the Pre-Cambrian top is at 6440 feet and hence the PBTD shall be at 6435 feet (deepest perforations are at 6433 feet per RRC records). Operator agreed to this permit special condition provision in the email dated on 11-29-2018. A copy of Form W-15 Cementing Record must be filed with the Form H-5 Injection Well Pressure Test Report prior to injection documenting compliance with this Special Condition.

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON December 31, 2018.

Sean Avitt, Manager
Injection-Storage Permits Unit

Amendment Comments:

Well No.	API No.	Amendment Comments
2361	43333712	**1. Amends maximum daily injection volume for liquid from 20000 bbl/day. 2. Amends packer setting depth from 5750 feet. 3. Amends permit dated November 21, 2011.**

Note: This document will only be distributed electronically.

DEPTH OF USABLE-QUALITY GROUND WATER TO BE PROTECTED

Texas Commission on Environmental Quality
Surface Casing Program

TCEQ

Date: July 21, 2010

TCEQ File No.: SC- 5504

API Number: 43333592

Attention: ROSE BURDITT

RRC Lease No.: 000000

SC_463316_43333592_000000_5504.pdf

KINDER MORGAN PRODUCTION CO LL
500 W ILLINOIS
STE 500
MIDLAND TX 79701

P-5# 463316

--Measured--
3545 ft FNEL
72 ft FNWL
MRL:SURVEY

Digital Map Location:
X-coord/Long: 1232566
Y-coord/Lat: 638341
Datum: 27 Zone: NC

County: STONEWALL

Lease & Well No.: KATZ (STRAWN) UNIT #232&ALL

Purpose: ND

Location: SUR-EUSTIS J.,SEC-2,--[TD=5500],[RRC 7B],

To protect usable-quality ground water at this location, the Texas Commission on Environmental Quality recommends:

The interval from the land surface to a depth of 100 feet must be protected.

This recommendation is applicable to all wells drilled in this LEASE IN SECTION 2.

Note: Unless stated otherwise, this recommendation is intended to apply only to the subject well and not for area-wide use. Approval of the well completion methods for protection of this groundwater falls under the jurisdiction of the Railroad Commission of Texas. **This recommendation is intended for normal drilling, production, and plugging operations only. It does not apply to saltwater disposal operation into a nonproductive zone (RRC Form W-14).**

If you have any questions, please contact us at 512-239-0515, sc@tceq.state.tx.us, or by mail MC-151.

Sincerely,

T. Wesley McCoy

Digitally signed by Thomas Wesley McCoy
DN: c=US, st=Texas, l=Austin, ou=Surface Casing, o=Texas Commission on Environmental Quality, cn=Thomas Wesley McCoy, email=wmccoy@tceq.state.tx.us
Date: 2010.07.21 11:46:18 -05'00'

T. Wesley McCoy, P.G.

Geologist, Surface Casing Team
Waste Permits Division

GEOLOGIST SEAL

STATE OF TEXAS
T. WESLEY McCOY
GEOLOGY
117
LICENSED
PROFESSIONAL GEOSCIENTIST

The seal appearing on this document was authorized by T. Wesley McCoy on 7/21/2010
Note: Alteration of this electronic document will invalidate the digital signature.

A-3

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 718131	DATE PERMIT ISSUED OR AMENDED Jun 14, 2011	DISTRICT * 7B
API NUMBER 42-433-33712	FORM W-1 RECEIVED Jun 09, 2011	COUNTY STONEWALL
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 7194
OPERATOR 463316 KINDER MORGAN PRODUCTION CO LLC 6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (325) 677-3545
LEASE NAME KATZ (STRAWN) UNIT		WELL NUMBER 2361
LOCATION 21.9 miles NE direction from ASPERMONT		TOTAL DEPTH 7500
Section, Block and/or Survey SECTION SURVEY LONG, C B	BLOCK	ABSTRACT 1939
DISTANCE TO SURVEY LINES 3511 ft. S 539 ft. W		DISTANCE TO NEAREST LEASE LINE 539 ft.
DISTANCE TO LEASE LINES 1751 ft. NE 539 ft. W		DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
KATZ (STRAWN) KATZ (STRAWN) UNIT	7194.00 539	7,500	2361 3991	7B

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office. This is a hydrogen sulfide field. Hydrogen Sulfide Fields with perforations must be isolated and tested per State Wide Rule 36 and a Form H-9 filed with the district office. Fields with SWR 10 authority to downhole commingle must be isolated and tested individually prior to commingling production.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

Currently there are no identified formations listed for this county. It is still the operators responsibility to isolate and report any potential flow zones that are encountered in the completion of this well.

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE

A-4

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Approved
Date: 10/04/2013
Tracking No.: 62859

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator KINDER MORGAN PRODUCTION CO LLC **Operator** 463316
Operator 6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000

WELL INFORMATION

API 42-433-33712 **County:** STONEWALL
Well No.: 2361 **RRC District** 7B
Lease KATZ (STRAWN) UNIT **Field** KATZ (STRAWN)
RRC Lease 30524 **Field No.:** 48294600
Location Section: ,Block: , Survey: LONG, C B SVY, Abstract: 1939

Latitude **Longitud**
This well is **miles in a**
direction from 21.9 MILES IN A NE DIRECTION FROM ASPERMONT, TX,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC **Completion or Recompletion** 12/15/2012

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	06/14/2011	718131
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal	11/21/2011	13453
Other:		

COMPLETION INFORMATION

Spud **Date of first production after rig** 12/15/2012
Date plug back, deepening, drilling operation 08/24/2012 **Date plug back, deepening, recompletion, drilling operation** 09/13/2012
Number of producing wells on this lease this field (reservoir) including this 66 **Distance to nearest well in lease & reservoir** 3991.0
Total number of acres in 7194.00 **Elevation** 1518 GL
Total depth TVD 6625 **Total depth MD**
Plug back depth TVD 6547 **Plug back depth MD**
Was directional survey made other inclination (Form W- No **Rotation time within surface casing Is Cementing Affidavit (Form W-15)** Yes
Recompletion or No **Multiple** No
Type(s) of electric or other log(s) Induction only
Electric Log Other Description:
Location of well, relative to nearest lease **Off Lease :** No
of lease on which this well is 1751.0 **Feet from the** NE **Line and**
539.0 **Feet from the** West **Line of the**
KATZ (STRAWN) UNIT **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type

PACKET: N/A

W2: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination	Depth	Date
SWR 13 Exception	Depth	

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		Production	
Number of hours	24	Choke	
Was swab used during this	No	Oil produced prior to	

PRODUCTION DURING TEST PERIOD:

Oil		Gas	
Gas - Oil	0	Flowing Tubing	
Water			

CALCULATED 24-HOUR RATE

Oil		Gas	
Oil Gravity - API - 60.:		Casing	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1		9 5/8	12 1/4	1290			C	491	837.0	SURF ACE	
2		7	8 3/4	6592			C	750	1248.0	3256	
3		7	8 3/4	6592	2463		C	450	618.0	SURF ACE	

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	4 1/2	5945	5957 /

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	No	L 6018	6024.0
2	No	L 6038	6077.0
3	No	L 6090	6101.0
4	No	L 6143	6195.0
5	No	L 6240	6255.0
6	No	L 6286	6311.0
7	No	L 6362	6370.0
8	No	L 6382	6433.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1		PUMP 2800 GALLONS 15% HCL, FLUSH WITH 36 BARRELS TREATED WATER.	6018	6101
2		PUMP 2600 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6143	6195
3		PUMP 2440 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6240	6311
4		PUMP 2960 GALLONS 15% HCL, FLUSH WITH 76 BARRELS TREATED WATER.	6362	6433

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
BASE PALO PINTO		3215.2			
ELLENBURGER		6018.0			
CAMBRIAN		6240.0			

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

THE PURPOSE OF THIS FILING IS TO REPORT A DRILLED AND COMPLETED SALT WATER DISPOSAL WELL.

OPERATOR'S CERTIFICATION

Printed	Dorothy Horrell	**Title:**	Administrator
Telephone	(432) 688-2448	**Date**	01/14/2013

APPENDIX B – GAS COMPOSITION

CO2 Pipeline - Gas Quality Specifications

Kinder Morgan CO2 Company

Revision: 2019 11 12

Product delivered at the Origination Point shall meet the following specifications, which herein are called Quality Specifications:

(a) **CO2 Content** Product composition shall be not less than ninety five per cent (95%) CO_2 by mole fraction.

(b) **Water** Product shall contain no free water, and shall not contain more than thirty (30) pounds of water per million standard cubic feet (MMscf) in the vapor phase.

(c) **Pressure** Product shall be delivered at a pressure sufficient to get into the pipeline.

(d) **Temperature** Product shall be delivered at a temperature not greater than 120 degrees F, and not less than 65 degrees F.

(e) **H2S** Product shall not contain more than twenty (20) parts per million H_2S, by volume.

(f) **Nitrogen** Product shall not contain more than four per cent (4%) nitrogen, by mole fraction.

(g) **Sulphur** Product shall not contain more than thirty five (35) parts per million sulphur, by weight.

(h) **Oxygen** Product shall not contain more than ten (10) parts per million, oxygen, by weight.

(i) **Hydrocarbons** Product shall not contain more than five percent (5%) hydrocarbons, by mole fraction.

(j) **Glycol** Product shall not contain more than 0.3 gallon glycol, per million standard cubic feet, and at no time shall glycol be present in a liquid state at temperature and pressure conditions of the pipeline.

(k) **Carbon Monoxide** Product shall not contain more than 4,250 parts per million, carbon monoxide, by weight.

(l) **NOx** Product shall not contain more than one (1) part per million, NO_x, by weight.

(m) **SOx** Product shall not contain more than one (1) part per million, SO_x, by weight.

(n) **Particulates** Product shall not contain more than one (1) part per million, particulates, by weight.

(o) **Amines** Product shall not contain more than one (1) part per million, amines, by weight.

(p) **Hydrogen** Product shall not contain more than one per cent (1%) hydrogen, by mole fraction.

(q) **Mercury** Product shall not contain more than five (5) nano grams per liter (ng/l) mercury.

(r) **Ammonia** Product shall not contain more than fifty (50) parts per million, ammonia, by weight.

(s) **Argon** Product shall not contain more than one volume percent (1% by volume) argon.

(t) **Liquids** Product shall be free of liquids at delivery conditions and shall not produce condensed liquids in the pipeline at pipeline pressure and temperature.

(u) **Compressor Lube Oil Carry Over** Compressor lube oil carry over in the product shall not exceed fifty (50) parts per million, by weight, and shall not cause fouling of pipeline, pipeline equipment downstream systems or reservoirs.

(v) **Impurities Deleterious to Pipeline, Equipment, Downstream Systems or Reservoirs** In addition to compositional limits listed above, product shall not contain impurities deleterious to pipeline, equipment, downstream systems or reservoirs.

APPENDIX C – PIPELINE SAFETY PLAN

Kinder Morgan CO_2 pipelines are monitored 24 hours a day, 7 days a week by personnel in control centers using a SCADA computer system. This electronic surveillance system gathers pipeline pressures, volume and flow rates and the status of pumping equipment and valves. Whenever operating conditions change, an alarm warns the operator on duty and the condition is investigated. Both automated and manual valves are strategically placed along the pipeline system to enable the pipeline to be shut down immediately and sections to be isolated quickly, if necessary. Visual inspections of the pipeline right-of-way, a narrow strip of land reserved for the pipeline, are conducted by air and ground on a regular basis.

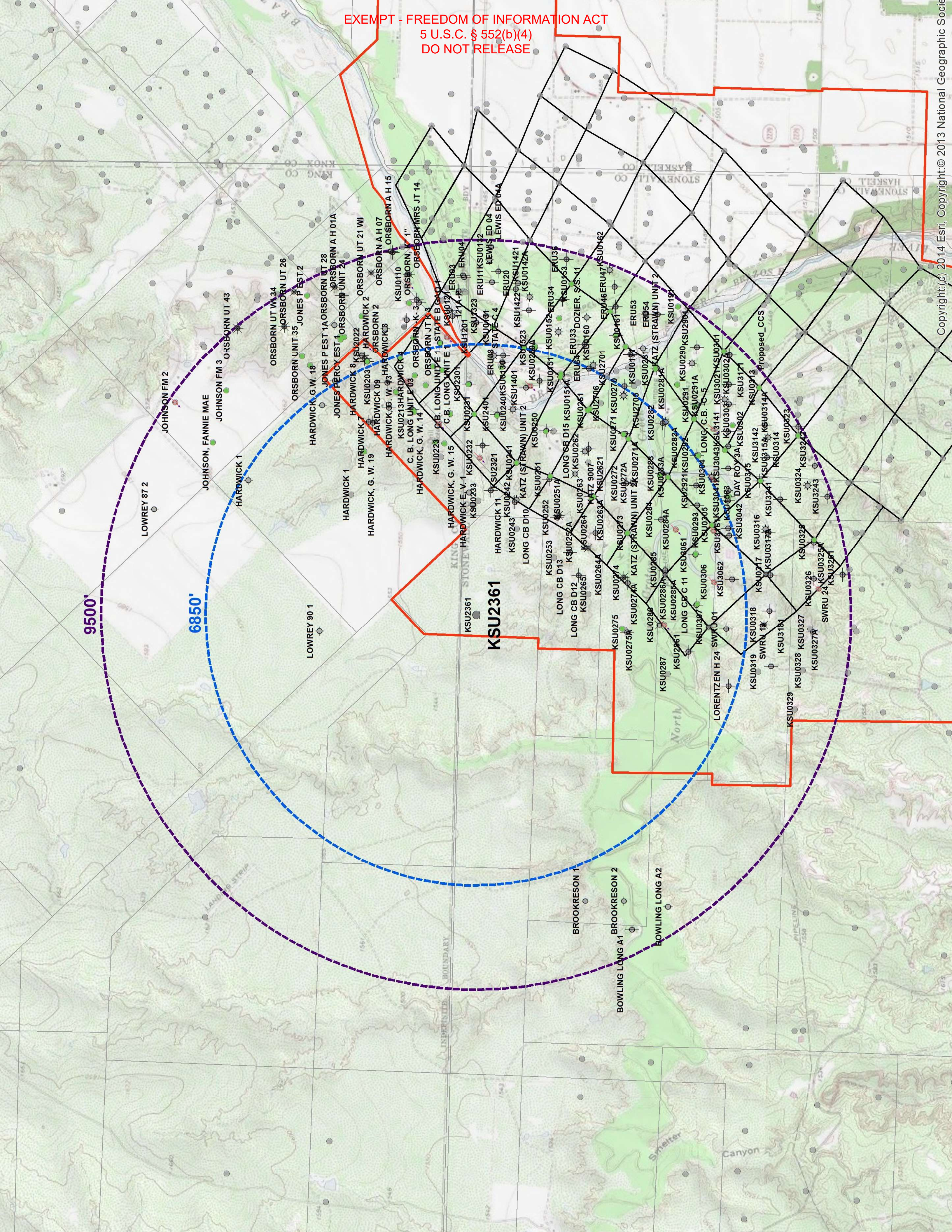
In the event of a CO_2 pipeline rupture, the Kinder Morgan CO_2 Supervisory Control and Data Acquisition (SCADA) computer system will shut down the pipeline and isolate the impacted section with automated valves. Kinder Morgan will notify the appropriate public safety answering point (i.e., 9-1-1 emergency call center) and initiate the internal Emergency Response Line to alert the operations team. An emergency response plan would be initiated with implementation of an incident command system, and Kinder Morgan will work with local emergency responders to isolate the impacted area.

APPENDIX D – MMA/AMA REVIEW MAPS

APPENDIX D-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX D-2: OIL AND GAS WELLS WITHIN THE MMA LIST

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE



Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332238	BOWLING-LONG A	2	P & A	5,815	WILDCAT	4/20/1987	5/7/1987
4243332229	BROOKRESON	1	P & A	5,730	WILDCAT	3/7/1987	5/14/1987
4243332319	BROOKRESON	2	P & A	5,745	WILDCAT	12/2/1987	12/13/1987
4226932003	C. B. LONG UNIT	E 03	P & A	5,300	KATZ	--	--
4243300422	C.B. LONG UNIT	C 11	P & A	5,127	KATZ	7/11/1989	5/15/2009
4243332388	C.B. LONG UNIT	C 16	P & A	5,200	KATZ	11/18/1989	12/8/2010
4243300585	C.B. LONG UNIT	D 10	P & A	5,197	KATZ	6/30/1989	1/13/2009
4243332465	C.B. LONG UNIT	D 13	P & A	5,201	KATZ	12/27/1989	9/23/2005
4243301965	C.B. LONG UNIT	D 4	P & A	5,188	KATZ		11/30/2010
4226900122	C.B. LONG UNIT	E 1	P & A	5,165	KATZ		9/15/2009
4226932006	C.B. LONG UNIT	E 2	P & A	5,200	KATZ	10/11/1990	2/24/2011
4243332116	DOZIER, S.S.	11	P & A	5,950	WILDCAT	6/12/1986	06/23/1986
4226900308	EAST RIVER UNIT	4	INACTIVE	4,931	KATZ		02/21/1995
4243332303	EAST RIVER UNIT	8	P & A	5,200	KATZ	11/17/1987	06/24/2009
4243332302	EAST RIVER UNIT	11	P & A	5,200	KATZ	11/26/1987	3/18/2004
4243300796	EAST RIVER UNIT	18	ACTIVE	5,300	KATZ	7/26/1951	--
4243300802	EAST RIVER UNIT	20	P & A	5,184	KATZ	8/22/1988	7/6/2009
4243300798	EAST RIVER UNIT	21	P & A	4,957	KATZ		12/5/1989
4243300787	EAST RIVER UNIT	33	P & A	5,155	KATZ		10/21/2009
4243300781	EAST RIVER UNIT	34	P & A	5,120	KATZ		10/30/2009
4243332306	EAST RIVER UNIT	36	P & A	5,200	KATZ	12/15/1987	2/28/2006
4243300849	EAST RIVER UNIT	45	P & A	5,167	KATZ		12/7/2010
4243300848	EAST RIVER UNIT	46	INACTIVE	4,875	KATZ		2/15/1990
4243332308	EAST RIVER UNIT	47	P & A	5,200	KATZ	12/5/1987	10/13/2009
4243300780	EAST RIVER UNIT	53	P & A	4,918	KATZ		2/14/1995
4243300788	EAST RIVER UNIT	54	P & A	5,211	KATZ		2/11/2009
4243332417	EAST RIVER UNIT	64	P & A	5,245	KATZ	8/8/1988	1/23/2009
4243333510	EAST RIVER UNIT	105	ACTIVE	5,325	KATZ	11/3/2009	--
4243333368	EAST RIVER UNIT	73H	P & A	4,750	KATZ	8/8/2007	9/3/2007
4243381146	EDD LEWIS		P & A	4,967	KATZ		10/14/2005
4226932269	HARDWICK	1	P & A	5,820	WILDCAT	6/19/1997	7/1/1997
4226900006	HARDWICK	2	P & A	5,147	KATZ		5/15/1975
4226900007	HARDWICK	3	P & A	5,168	KATZ		7/27/1970
4226900008	HARDWICK	4	P & A	5,146	KATZ		1/26/1984
4226900011	HARDWICK	6	P & A	5,152	KATZ		7/24/1970
4226900009	HARDWICK	7	P & A	5,150	KATZ		8/19/1967
4226900010	HARDWICK	8	P & A	5,152	KATZ		6/18/1976
4226980016	HARDWICK	9	P & A	2,171	KATZ		1/27/1984
4243301905	HARDWICK	11	P & A	5,152	KATZ		7/22/1970
4226900005	HARDWICK E. V.	1	P & A	5,960	KATZ		7/14/1951
4226931776	HARDWICK, G. W.	12	P & A	5,200	KATZ	3/10/1988	11/6/2009
4226931777	HARDWICK, G. W.	13	P & A	5,200	KATZ	3/11/1988	11/19/2009
4226931775	HARDWICK, G. W.	14	P & A	5,200	KATZ	5/29/1988	11/16/2009
4226931771	HARDWICK, G. W.	15	P & A	5,200	KATZ	3/15/1988	11/12/2009
4226931774	HARDWICK, G. W.	16	P & A	5,200	KATZ	3/8/1988	5/13/2004
4226931772	HARDWICK, G. W.	17	P & A	5,250	KATZ	3/9/1988	11/10/2009
4226932431	HARDWICK, G.W.	18	P & A	5,300	KATZ	8/13/2001	8/24/2001
4226932178	JOHNSON, FANNIE MAE	1	P & A	5,840	KATZ	4/11/1995	2/2/2016
4226932197	JOHNSON, FANNIE MAE	2	P & A	5,825	KATZ	10/5/1995	2/3/2016
4226932236	JOHNSON, FANNIE MAE	3	P & A	5,830	KATZ	11/2/1996	2/1/2016
4226900420	JONES PERCY EST	1	P & A	5,200	KATZ		1/1/1962
4226900428	JONES PERCY ESTATE	3	P & A	4,940	KATZ		7/1/1958
4226932805	KATZ (STRAWN) UNIT	110	ACTIVE	5,312	KATZ	3/13/2011	--
4226931666	KATZ (STRAWN) UNIT	121	P & A	4,879	KATZ	2/9/1987	10/24/2019
4243300797	KATZ (STRAWN) UNIT	131	ACTIVE	5,200	KATZ	9/24/1951	--
4243333513	KATZ (STRAWN) UNIT	132	ACTIVE	5,320	KATZ	12/2/2009	--
4243332296	KATZ (STRAWN) UNIT	143	P & A	5,200	KATZ	12/13/1987	7/30/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332304	KATZ (STRAWN) UNIT	151	P & A	5,200	KATZ	11/20/1987	7/20/2010
4243300779	KATZ (STRAWN) UNIT	152	ACTIVE	5,255	KATZ		--
4243300783	KATZ (STRAWN) UNIT	153	ACTIVE	5,299	KATZ	4/25/1952	--
4243333511	KATZ (STRAWN) UNIT	160	ACTIVE	5,302	KATZ	11/20/2009	--
4243333518	KATZ (STRAWN) UNIT	161	ACTIVE	5,308	KATZ	1/22/2010	--
4243333512	KATZ (STRAWN) UNIT	162	ACTIVE	5,328	KATZ	12/30/2009	--
4243333521	KATZ (STRAWN) UNIT	171	ACTIVE	5,334	KATZ	2/2/2010	--
4243333580	KATZ (STRAWN) UNIT	180	ACTIVE	5,327	KATZ	6/29/2010	--
4243333665	KATZ (STRAWN) UNIT	191	ACTIVE	5,423	KATZ	5/2/2011	--
4226932789	KATZ (STRAWN) UNIT	211	ACTIVE	5,316	KATZ	11/7/2010	--
4226932795	KATZ (STRAWN) UNIT	212	P & A	5,294	KATZ	8/21/2010	6/8/2022
4226932783	KATZ (STRAWN) UNIT	220	ACTIVE	5,308	KATZ	3/9/2010	--
4226932788	KATZ (STRAWN) UNIT	221	ACTIVE	4,863	KATZ	6/6/2010	--
4226932793	KATZ (STRAWN) UNIT	222	ACTIVE	5,308	KATZ	6/18/2010	--
4243333534	KATZ (STRAWN) UNIT	231	ACTIVE	5,315	KATZ	4/23/2010	--
4243333592	KATZ (STRAWN) UNIT	232	ACTIVE	5,340	KATZ	8/10/2010	--
4243333523	KATZ (STRAWN) UNIT	240	ACTIVE	5,309	KATZ	3/18/2010	--
4243300584	KATZ (STRAWN) UNIT	241	ACTIVE	5,250	KATZ	6/8/1957	--
4243333615	KATZ (STRAWN) UNIT	242	ACTIVE	5,297	KATZ	11/30/2010	--
4243300403	KATZ (STRAWN) UNIT	250	P & A	5,206	KATZ	10/25/1951	12/13/2019
4243300400	KATZ (STRAWN) UNIT	261	ACTIVE	5,150	KATZ		--
4243333573	KATZ (STRAWN) UNIT	262	ACTIVE	5,314	KATZ	5/25/2010	--
4243300583	KATZ (STRAWN) UNIT	264	P & A	5,242	KATZ		4/29/2011
4243333524	KATZ (STRAWN) UNIT	270	ACTIVE	5,300	KATZ	4/13/2010	--
4243300405	KATZ (STRAWN) UNIT	271	P & A	5,150	KATZ		11/4/2010
4243300421	KATZ (STRAWN) UNIT	273	ACTIVE	5,127	KATZ	7/11/1953	--
4243300424	KATZ (STRAWN) UNIT	274	P & A	5,131	KATZ	5/16/1989	12/27/2010
4243301970	KATZ (STRAWN) UNIT	275	P & A	5,185	KATZ		3/14/2011
4243300417	KATZ (STRAWN) UNIT	281	P & A	5,156	KATZ		8/16/2010
4243332387	KATZ (STRAWN) UNIT	282	P & A	5,189	KATZ	11/2/1989	9/20/2010
4243332389	KATZ (STRAWN) UNIT	284	P & A	5,210	KATZ	10/15/1989	1/10/2011
4243332390	KATZ (STRAWN) UNIT	285	P & A	5,219	KATZ		11/3/2010
4243332461	KATZ (STRAWN) UNIT	286	P & A	5,730	KATZ	12/8/1989	4/29/2013
4243333526	KATZ (STRAWN) UNIT	290	ACTIVE	5,315	KATZ	5/6/2010	--
4243333704	KATZ (STRAWN) UNIT	301	ACTIVE	5,365	KATZ	7/27/2011	--
4243301620	KATZ (STRAWN) UNIT	302	P & A	5,138	KATZ	3/28/1953	1/5/2012
4243333738	KATZ (STRAWN) UNIT	304	ACTIVE	5,300	KATZ	12/3/2011	--
4243333778	KATZ (STRAWN) UNIT	305	ACTIVE	5,330	KATZ	4/6/2012	--
4243333569	KATZ (STRAWN) UNIT	306	ACTIVE	5,328	KATZ	5/16/2010	--
4243333813	KATZ (STRAWN) UNIT	307	INACTIVE	5,365	KATZ	6/26/2012	--
4243333746	KATZ (STRAWN) UNIT	313	ACTIVE	5,380	KATZ	11/20/2011	--
4243332561	KATZ (STRAWN) UNIT	314	P & A	5,225	KATZ	12/16/1989	2/7/2012
4243333788	KATZ (STRAWN) UNIT	315	P & A	5,320	KATZ	3/17/2012	7/1/2014
4243332553	KATZ (STRAWN) UNIT	317	P & A	5,200	KATZ	12/11/1989	10/14/2013
4243333822	KATZ (STRAWN) UNIT	318	P & A	5,320	KATZ	7/5/2012	5/24/2021
4243333736	KATZ (STRAWN) UNIT	324	ACTIVE	5,380	KATZ	2/6/2012	--
4243333527	KATZ (STRAWN) UNIT	326	ACTIVE	5,503	KATZ	3/30/2010	--
4243300819	KATZ (STRAWN) UNIT	327	P & A	4,952	KATZ		12/23/2010
4243332509	KATZ (STRAWN) UNIT	1201	P & A	5,295	KATZ	7/1/1989	11/29/2010
4226931752	KATZ (STRAWN) UNIT	1221	P & A	5,200	KATZ	1/23/1988	10/11/2011
4243300800	KATZ (STRAWN) UNIT	1323	P & A	4,930	KATZ		3/23/2010
4243332298	KATZ (STRAWN) UNIT	1401	P & A	5,261	KATZ	1/24/1988	3/19/2010
4243332274	KATZ (STRAWN) UNIT	1422	P & A	5,220	KATZ	9/2/1987	11/16/2009
4243300801	KATZ (STRAWN) UNIT	1523	P & A	5,101	KATZ	5/20/1952	11/24/2009
4243332299	KATZ (STRAWN) UNIT	1801	P & A	4,879	KATZ	2/2/1988	3/31/2011
4226932806	KATZ (STRAWN) UNIT	2022	ACTIVE	5,313	KATZ	3/25/2011	--
4226932345	KATZ (STRAWN) UNIT	2121	P & A	5,800	KATZ	8/8/1999	11/12/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932002	KATZ (STRAWN) UNIT	2221	P & A	5,200	KATZ	10/25/1990	6/1/2010
4243332753	KATZ (STRAWN) UNIT	2321	P & A	5,200	KATZ	12/10/1991	3/3/2011
4243333712	KATZ (STRAWN) UNIT	2361	ACTIVE	6,625	KATZ	8/23/2012	--
4243300406	KATZ (STRAWN) UNIT	2401	P & A	5,173	KATZ	5/23/1989	12/31/2009
4243332541	KATZ (STRAWN) UNIT	2701	INACTIVE	100	KATZ	9/27/1989	--
4243332565	KATZ (STRAWN) UNIT	2702	INACTIVE	100	KATZ	12/7/1989	--
4243300401	KATZ (STRAWN) UNIT	2705	P & A	5,116	KATZ	5/12/1989	3/2/2010
4243333713	KATZ (STRAWN) UNIT	2706	COMPLETED	7,500	KATZ		--
4243300423	KATZ (STRAWN) UNIT	2861	P & A	5,161	KATZ	7/17/1989	11/21/2013
4243300399	KATZ (STRAWN) UNIT	2901	P & A	5,150	KATZ		2/17/2011
4243333160	KATZ (STRAWN) UNIT	2921	P & A	5,725	KATZ	12/10/1998	1/13/2010
4243380198	KATZ (STRAWN) UNIT	3041	P & A	5,113	KATZ	7/18/2005	6/17/2010
4243301606	KATZ (STRAWN) UNIT	3042	P & A	5,113	KATZ	11/6/1989	3/22/2012
4243300838	KATZ (STRAWN) UNIT	3062	P & A	5,240	KATZ	11/16/1989	7/1/2010
4243301610	KATZ (STRAWN) UNIT	3141	P & A	5,115	KATZ		2/16/2012
4243300837	KATZ (STRAWN) UNIT	3161	P & A	5,190	KATZ	2/13/1990	8/18/2010
4243300842	KATZ (STRAWN) UNIT	3181	P & A	4,961	KATZ		2/16/2011
4243301605	KATZ (STRAWN) UNIT	3241	P & A	5,170	KATZ		4/12/2013
4243332570	KATZ (STRAWN) UNIT	3243	P & A	5,240	KATZ	1/14/1990	2/10/2010
4243332588	KATZ (STRAWN) UNIT	3261	P & A	5,150	KATZ	2/12/1990	3/31/2010
4226932987	KATZ (STRAWN) UNIT	121A	ACTIVE	5,337	KATZ	12/3/2019	--
4243333496	KATZ (STRAWN) UNIT	142A	ACTIVE	5,305	KATZ	10/20/2009	--
4243333595	KATZ (STRAWN) UNIT	151A	ACTIVE	5,317	KATZ	9/7/2010	--
4243334217	KATZ (STRAWN) UNIT	250A	INACTIVE	5,314	KATZ	12/19/2019	--
4243333630	KATZ (STRAWN) UNIT	251A	ACTIVE	5,315	KATZ	12/10/2010	--
4243333598	KATZ (STRAWN) UNIT	252A	TA	5,300	KATZ	10/17/2010	--
4243333599	KATZ (STRAWN) UNIT	263A	ACTIVE	5,315	KATZ	9/29/2010	--
4243333639	KATZ (STRAWN) UNIT	264A	P & A	5,333	KATZ	4/5/2011	6/1/2021
4243333627	KATZ (STRAWN) UNIT	271A	ACTIVE	5,302	KATZ	12/20/2010	--
4243333632	KATZ (STRAWN) UNIT	272A	ACTIVE	5,318	KATZ	3/1/2011	--
4243333807	KATZ (STRAWN) UNIT	274A	TA	5,300	KATZ	5/24/2012	7/1/2022
4243333607	KATZ (STRAWN) UNIT	281A	ACTIVE	5,324	KATZ	10/9/2010	--
4243333617	KATZ (STRAWN) UNIT	282A	ACTIVE	5,297	KATZ	11/18/2010	--
4243333735	KATZ (STRAWN) UNIT	283A	ACTIVE	5,380	KATZ	10/7/2011	--
4243333722	KATZ (STRAWN) UNIT	284A	ACTIVE	5,345	KATZ	12/15/2011	--
4243333799	KATZ (STRAWN) UNIT	285A	INACTIVE	5,350	KATZ	4/16/2012	--
4243333927	KATZ (STRAWN) UNIT	286A	TA	5,337	KATZ	3/24/2014	--
4243333730	KATZ (STRAWN) UNIT	291A	ACTIVE	5,364	KATZ	9/24/2011	--
4243333695	KATZ (STRAWN) UNIT	302A	ACTIVE	5,390	KATZ	7/6/2011	--
4243333771	KATZ (STRAWN) UNIT	303A	ACTIVE	5,330	KATZ	2/27/2012	--
4243333753	KATZ (STRAWN) UNIT	314A	ACTIVE	5,375	KATZ	10/27/2011	--
4243334002	KATZ (STRAWN) UNIT	315A	ACTIVE	5,348	KATZ	7/11/2014	--
4243333770	KATZ (STRAWN) UNIT	316A	ACTIVE	5,400	KATZ	1/25/2012	--
4243333820	KATZ (STRAWN) UNIT	317A	INACTIVE	5,336	KATZ	12/29/2013	--
4243333776	KATZ (STRAWN) UNIT	323A	ACTIVE	5,408	KATZ	3/7/2012	--
4243333821	KATZ (STRAWN) UNIT	325A	ACTIVE	5,385	KATZ	12/10/2013	--
4226900309	LEWIS, W. D.	2	P & A	5,090	KATZ		9/29/2008
4243300412	LONG, C. B. -D-	5	P & A	5,165	KATZ		3/12/2010
4243300415	LONG, C. B. -D-	6	P & A	5,188	KATZ		11/8/2010
4243300408	LONG, C.B. -C-	4	P & A	5,214	KATZ		3/9/2011
4243300411	LONG, C.B. -C-	5	P & A	5,165	KATZ		11/30/2010
4243300420	LONG, C.B. -C-	9	INACTIVE	5,163	KATZ		5/13/2010
4243300414	LONG, C.B. -C-	6 T	P & A	5,168	KATZ		11/12/2010
4243300419	LONG, C.B. -C-	8 T	P & A	5,165	KATZ		11/15/2010
4243300418	LONG, C.B. -D-	7	P & A	5,190	KATZ	8/1/1989	8/10/2010
4243300586	LONG, C.B. -D-	11	P & A	5,183	KATZ	6/15/1989	8/30/2010
4243300587	LONG, C.B. -D-	12	P & A	4,896	KATZ		1/13/1986

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932293	LOWERY 87	2	P & A	5,835	WILDCAT	11/11/1997	11/24/1997
4226932268	LOWREY 90	1	P & A	5,800	WILDCAT	5/25/1997	6/4/1997
4226932270	MANGIS	2	P & A	5,770	KAIA	7/10/1997	7/20/1997
4226932325	ORSBORN	2	P & A	5,718	KAIA	10/22/1998	11/4/1998
4226900108	ORSBORN	7	P & A	4,940	KATZ		8/30/2006
4226932955	ORSBORN K	14	INACTIVE	5,235	KATZ	11/5/2015	--
4226900077	ORSBORN -K-	3	P & A	5,091	KATZ		7/19/1993
4226900082	ORSBORN UNIT	1	INACTIVE	5,155	KATZ	8/14/1952	--
4226900081	ORSBORN UNIT	14	P & A	5,077	KATZ		8/30/2018
4226900105	ORSBORN UNIT	15	P & A	5,211	KATZ		8/25/1994
4226910001	ORSBORN UNIT	19	P & A	5,144	KATZ	9/1/1984	9/6/1984
4226931306	ORSBORN UNIT	21	P & A	5,170	KATZ	9/25/1984	11/11/2021
4226931395	ORSBORN UNIT	24	P & A	5,200	KATZ	1/23/1985	3/25/2022
4226931398	ORSBORN UNIT	26	P & A	5,247	KATZ	2/4/1985	5/9/2019
4226931397	ORSBORN UNIT	28	P & A	5,220	KATZ	2/18/1985	3/1/2013
4226931738	ORSBORN UNIT	34	P & A	5,250	KATZ	10/9/1987	8/28/2018
4226932314	ORSBORN UNIT	43	P & A	5,350	KATZ	4/24/1998	4/29/2019
4226932956	ORSBORN UNIT	44	INACTIVE	5,230	KATZ	6/28/2016	--
4226900076	ORSBORN, "K"	1	P & A	5,099	KATZ		7/12/1993
4226900104	ORSBORN, ALMA H.	1	P & A	5,155	KATZ		5/7/1957
4243300841	SOUTHWEST RIVER UNIT	1	P & A	4,903	KATZ		7/17/1998
4243301612	SOUTHWEST RIVER UNIT	5	P & A	5,115	KATZ		2/20/2012
4243301621	SOUTHWEST RIVER UNIT	6	P & A	5,154	KATZ	4/14/1953	1/25/2012
4243301609	SOUTHWEST RIVER UNIT	9	P & A	5,150	KATZ		4/13/2011
4243301619	SOUTHWEST RIVER UNIT	10	P & A	5,104	KATZ	2/17/1953	12/14/2010
4243300844	SOUTHWEST RIVER UNIT	13	P & A	4,987	KATZ		9/18/1995
4243300836	SOUTHWEST RIVER UNIT	16	P & A	5,170	KATZ		1/5/2011
4243332587	SOUTHWEST RIVER UNIT	18	P & A	5,300	KATZ	2/1/1990	1/27/2010
4243300811	SOUTHWEST RIVER UNIT	24	P & A	4,920	KATZ		11/28/2002
4243301444	SOUTHWEST RIVER UNIT	28	P & A	4,950	KATZ	8/13/2007	4/13/2011
4243300823	SOUTHWEST RIVER UNIT	36	P & A	4,963	KATZ		--
4243300815	SOUTHWEST RIVER UNIT	37	P & A	4,972	KATZ		10/15/1991
4243300835	SOUTHWEST RIVER UNIT	71	P & A	5,171	KATZ		10/4/1991
4243300809	SOUTHWEST RIVER UNIT	25W	P & A	5,230	KATZ		10/22/2013
4243332560	SOUTHWEST RIVER UNIT	27W	P & A	5,206	KATZ	1/9/1990	3/12/2013
4226900069	STATE A GAO	1	P & A	5,085	KATZ		4/19/1985
4226900070	STATE B GAO	1	P & A	4,876	KATZ		4/17/1985
4243301761	STATE OF TEXAS -C-	1	P & A	5,296	KATZ		2/11/1983
4243301762	STATE OF TEXAS -C-	2	P & A	5,205	KATZ		12/4/1982
4243301764	STATE OF TEXAS -C-	4	P & A	5,205	KATZ		11/29/1982
4226900012			ACTIVE	5,105			--
4226900016			ACTIVE	5,175			--
4243300005			P & A	3,251			--

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Request for Additional Information: Kinder Morgan CCS Complex
June 5, 2023

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	3.1	56	Section 3.1 of the MRV plan states: "...the stabilized plume shape is relatively circular, the maximum distance plus a one-half mile buffer from the injection well, was used to define the circular boundary of the MMA equal to 9500'." Section 3.2 of the MRV plan states: "Assuming year t occurs at the point the plume stabilized (30 years after the cessation of injection), the plume extent in year t + 5 has the maximum radius of 6,850', which is the extent of the MMA." Please ensure the MRV plan is clear/consistent as to whether the MMA is defined by a boundary of 6,850' or 9,500'.	Section 3.1 – Page 56 - No changes necessary Section 3.2 – Page 57 – original verbiage, referenced here, omitted and addressed in EPA RFAI #2.

<table>
<tr><th rowspan="2">No.</th><th colspan="2">MRV Plan</th><th rowspan="2">EPA Questions</th><th rowspan="2">Responses</th></tr>
<tr><th>Section</th><th>Page</th></tr>
<tr><td>2.</td><td>3.2</td><td>57</td><td>Per 40 CFR 98.449, “Active monitoring area” is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

(1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year t + 5.

The plan states that “Assuming year t occurs at the point the plume stabilized (30 years after the cessation of injection), the plume extent in year t + 5 has the maximum radius of 6,850’, which is the extent of the MMA. Thus, Kinder Morgan will define the AMA as equal to the MMA, in this case, as show in Figure 39.”

In the MRV plan, please elaborate on whether the AMA delineation meets the definition above and/or update as necessary. Specifically, please explain whether the choice of AMA meets both criteria (1) and (2) identified by the AMA definition.

To help clarify how the AMA and MMA were delineated, we recommend adding labels to the red and blue lines in Figure 39.</td><td>Section 3.2 – Page 57 – verbiage added

“Per 40 CFR 98.449, the boundary of the AMA is established by superimposing two different boundary conditions. For the first condition, Kinder Morgan defines year t as occurring 30 years after the cessation of injection, when the modeled plume has stabilized with a maximum extent radius of 6,850’. The addition of a half-mile buffer results in a maximum extent of 9,500’, satisfying the first condition. For the second condition, since Kinder Morgan defines year t as when the plume stabilizes, 30 years after the cessation of injection, the projected radius of the plume for t + 5 is also 6,850’. Superimposing the results of these two conditions results in Kinder Morgan defining the AMA with a radius of 9,500’, or 3,384 acres.”</td></tr>
</table>

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	5.1	68	In the previous RFAI, the following was asked: **““The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and inspection of the cathodic protection system.”** **Please clarify what system is being referred to in the above excerpt.”** While clarification was given in the response to our questions, please also adjust the text within the MRV plan itself.	Section 5.1 – Page 68 – Verbiage added: “The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the **surface equipment associated with the sequestered CO2** and inspection of the cathodic protection system.”
4.	7.4	76	In the previous RFAI, the following was asked: **““Any leakage would be detected and managed as an upset event.”** **Please define what is meant by “upset event”.”** While clarification was given in the response to our questions, please also adjust the text within the MRV plan itself.	Section 7.4 – Page 76 – Verbiage added: **“An upset event is any unlikely event that results in the failure of any mass of CO2 to remain permanently sequestered in the target reservoir.”**

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Kinder Morgan Permian CCS LLC

Prepared for *Kinder Morgan Permian CCS LLC*
Houston, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 3.0
April 2023

INTRODUCTION

Kinder Morgan Production Co. LLC (Kinder Morgan) currently has a Class II disposal permit issued by the Texas Railroad Commission (TRRC) for the Katz Strawn Unit 2361 well (KSU 2361), API# 42-433-33712. The permit was originally issued in November 2011 for saltwater disposal operations, and the well has actively injected saltwater since 2013. This permit currently authorizes Kinder Morgan to inject up to 30,000 barrels saltwater per day (bbls/d), equating to 65 million standard cubic feet per day (MMscf/day) of carbon dioxide, into the Ellenburger and Cambrian formations at a depth of 5,800' to 6,800' with a maximum allowable surface pressure of 2,900 psi. The KSU 2361 well is located in a rural, sparsely populated area of Stonewall County, Texas, approximately twelve miles west of the town of Knox City, as shown in Figure 1.

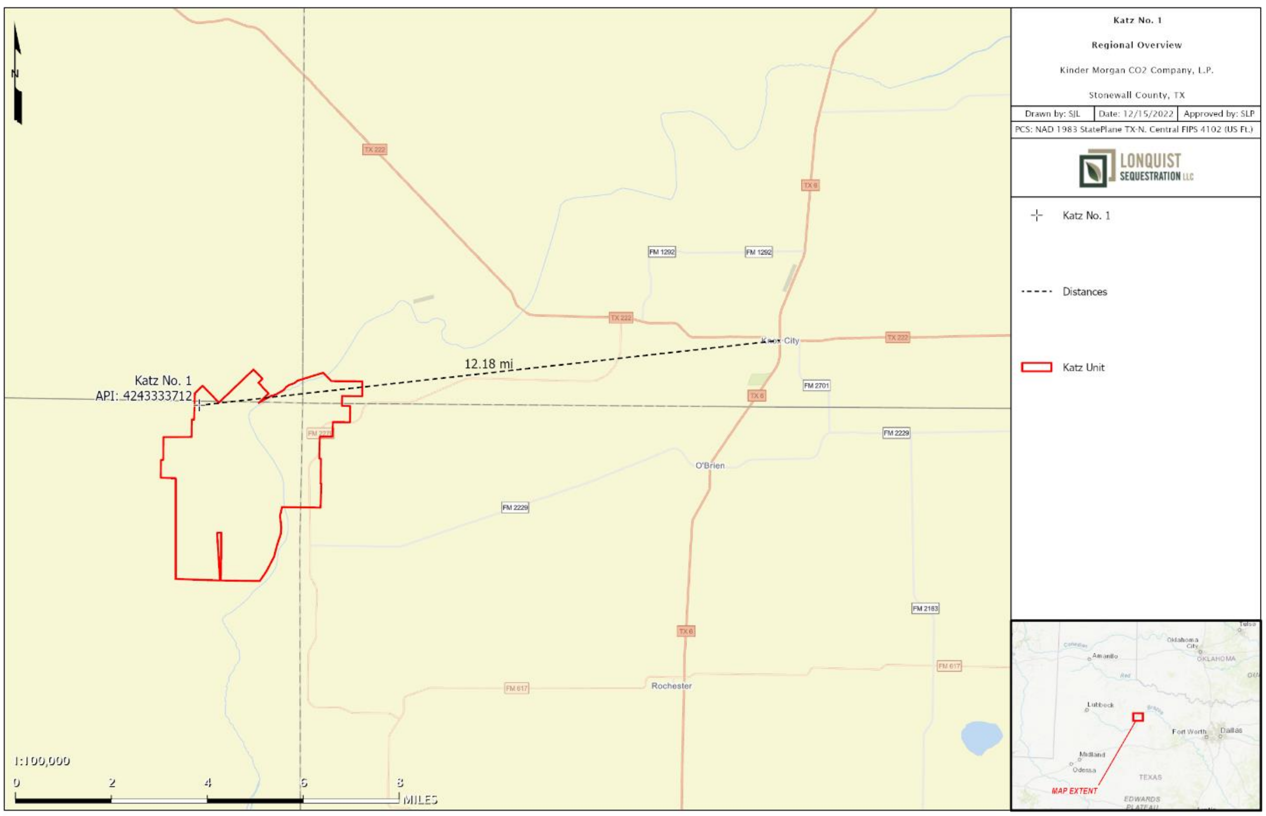


Figure 1 – Location of KSU 2361 Well

Kinder Morgan is seeking TRRC approval to amend the existing KSU 2361 Class II saltwater disposal permit to inject treated acid gas (TAG), including CO_2. In the future, Kinder Morgan may provide surplus injection capacity to dispose oil and gas waste derived TAG from similar third-party gas processing facilities. Kinder Morgan intends to inject into this well for 21 years at a capacity ranging up to 65 million standard cubic feet per day (MMSCF/d). The source of this injected CO_2 gas is from Red Cedar natural gas processing plants in southern Colorado. Table 1 below shows the expected composition of the gas stream to be injected. Table 2 shows the expected average volume of CO_2 gas commitments from similar type emission sources in the same area, along with the contract status as of March 2023.

Table 1 – Expected Gas Composition at KSU 2361

Component	Mol Percent
Carbon Dioxide	99.20%
Methane	0.25%
Ethane	0.03%
Propane	0.04%
Nitrogen	0.48%
Hydrogen Sulfide	0.00%

Table 2 – Expected Sequestered Gas Volumes for KSU 2361

Contract Status	Avg. Rate (MMcfd)
Committed	22
Proposal	8
Proposal	23
Proposal	9
Total	62

Kinder Morgan is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

ACRONYMS AND ABBREVIATIONS

'	Feet
%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2020.11
GHGs	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	MilliDarcy(ies)
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million

MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MMSCF	Million Standard Cubic Feet
MSCF/D	Thousand Cubic Feet per Day
MMSCF/d	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

INTRODUCTION 1
ACRONYMS AND ABBREVIATIONS 3
SECTION 1 – UIC INFORMATION 8
1.1 Underground Injection Control (UIC) Permit Class: Class II 8
1.2 UIC Well Identification Number: 8
SECTION 2 – PROJECT DESCRIPTION 9
2.1 Regional Geology 10
2.1.1 Regional Faulting 18
2.2 Site Characterization 19
2.2.1 Stratigraphy and Lithologic Characteristics 19
2.2.2 Upper Confining Zone – Mississippian Lime 21
2.2.3 Secondary Confining Interval – Lower Strawn Shale 22
2.2.4 Injection Interval – Ellenburger/Cambrian Sands 25
2.2.5 Lower Confining Zone – Precambrian 29
2.3 Fracture Pressure Gradient 31
2.4 Local Structure 32
2.5 Injection and Confinement Summary 37
2.6 Groundwater Hydrology 37
2.6.1 Reservoir Characterization Modeling 43
SECTION 3 – DELINEATION OF MONITORING AREA 56
3.1 Maximum Monitoring Area 56
3.2 Active Monitoring Area 57
SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE 58
4.1 Leakage from Surface Equipment 58
4.2 Leakage from Existing Wells within MMA 59
4.2.1 Oil and Gas Operations within Monitoring Area 59
4.2.2 Groundwater wells 64
4.3 Leakage Through Faults and Fractures 65
4.4 Leakage Through the Confining Layer 65
4.5 Leakage from Natural or Induced Seismicity 65
SECTION 5 – MONITORING FOR LEAKAGE 67
5.1 Leakage from Surface Equipment 68
5.2 Leakage From Existing and Future Wells within MMA 68
5.3 Leakage through Faults, Fractures or Confining Seals 71
5.4 Leakage through Natural or Induced Seismicity 71
SECTION 6 – BASELINE DETERMINATIONS 73
6.1 Visual Inspections 73
6.2 CO_2 Detection 73
6.3 Operational Data 73
6.4 Continuous Monitoring 73
6.5 Groundwater Monitoring 74
SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION 75
7.1 Mass of CO_2 Received 75
7.2 Mass of CO_2 Injected 75

7.3 Mass of CO_2 Produced 76
7.4 Mass of CO_2 Emitted by Surface Leakage 76
7.5 Mass of CO_2 Sequestered 77
SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN 78
SECTION 9 – QUALITY ASSURANCE 79
9.1 Monitoring QA/QC 79
9.2 Missing Data 79
9.3 MRV Plan Revisions 80
SECTION 10 – RECORDS RETENTION 81
SECTION 11 - REFERENCES 82
SECTION 12 - APPENDICES 84

LIST OF FIGURES

Figure 1 – Location of KSU 2361 Well 1
Figure 2 – Regional Map of the Permian Basin. 10
Figure 3 – Stratigraphic Column of the Eastern Shelf 11
Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations 12
Figure 5 – Top of Structure Map of the Ellenburger Group in West Texas 13
Figure 6 – Generalized Isopach Map of the Ellenburger Group in West Texas 14
Figure 7 – Thickness of Cambrian and Lower Ordovician Strata 15
Figure 8 – Formation Tops at KSU 2361. 16
Figure 9 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma. 18
Figure 10 – KSU 2361 Type Log 19
Figure 11 – Type Log of Zones of Interest 20
Figure 12 – Depositional Map of the Mississippian 21
Figure 13 – Core Description 23
Figure 14 – Cross Section Depicting Corelative Offset Core with Lower Strawn Shale 24
Figure 15 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003) 25
Figure 16 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003) 27
Figure 17 – Offset Wells used for Formation Fluid Characterization. 28
Figure 18 – Pre-Cambrian Distribution Map 30
Figure 19 – Ellenburger Structure Map 33
Figure 20 – Structural Northwest-Southeast Cross Section 34
Figure 21 – Structural West to East Seismic Profile 35
Figure 22 – Structural Northwest to Southeast Seismic Profile 36
Figure 23 – Generalized Stratigraphy of the Seymour Aquifer 38
Figure 24 – Regional Extent of the Seymour Aquifer Pods 40
Figure 25 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer 41
Figure 26 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer 42
Figure 27 – Geomodel Dimensions 46
Figure 28 – Structural Horizons of the Geomodel 47
Figure 29 – Porosity Distribution in Plume Model 48
Figure 30 – NTG Ratio Applied to the Plume Model 49
Figure 31 – CO_2-Water Relative Permeability Curves 50
Figure 32 – History Match for KSU 2361 51
Figure 33 – History Match for KSU #3471 51
Figure 34 – Simulated Wellhead Pressure During Active Injection 52

Figure 35 – Forecasted Injection Rate and BHP 53
Figure 36 – Annualized Growth Rate of CO_2 Plume 54
Figure 37 – Aerial View of CO_2 Plume....55
Figure 38 – Cross-Sectional View of CO_2 Plume 55
Figure 39 – Stabilized Plume Boundary, Active Monitoring Area, and Maximum Monitoring Area....57
Figure 40 – Site Plan 59
Figure 41 – KSU 2361 Wellbore Schematic 61
Figure 42 – All Oil and Gas Wells within the MMA....62
Figure 43 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA 63
Figure 44 – Seismicity Review (TexNet – 06/01/2022)....66
Figure 45 – Groundwater Monitoring Wells....70
Figure 46 – Nearest TexNet Seismic Station....72

LIST OF TABLES

Table 1 – Expected Gas Composition of Sequestered Gas Stream....2
Table 2 – Expected Gas Volumes of Sequestered Gas Stream....2
Table 3 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples 29
Table 4 – Fracture Gradient Assumptions 31
Table 5 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas 38
Table 6 – CO_2 Solubility Table 45
Table 7 – Rock Properties 47
Table 8 – Initial Conditions Summary 48
Table 9 – Plume Model Radius and Area....54
Table 10 – Summary of Leakage Monitoring Methods 67

SECTION 1 – UIC INFORMATION

This section contains key information regarding the UIC Permit.

1.1 Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. TRRC classifies the KSU 2361 well as UIC Class II. A Class II permit was issued to Kinder Morgan under TRRC Rule 9 (entitled "Disposal into Non-Productive Formations") and Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").

1.2 UIC Well Identification Number:

Katz Strawn Unit 2361, API No. 42-433-33712, UIC #000104281.

SECTION 2 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the KSU 2361 well.

The injection interval for KSU 2361 is approximately 670’ below the base of the Strawn formation, the primary producing formation in the area, and approximately 5,900’ below the base of the lowest useable-quality aquifer. Therefore, the location, facility, and the well design of the KSU 2361 well are planned to protect against the migration of CO_2 out of the injection interval, protect against contamination of subsurface resources and, most critical, to prevent surface releases.

2.1 Regional Geology

The KSU 2361 well is located on the Eastern Shelf, a broad marine shelf located in the eastern portion of the Permian Basin, shown in Figure 2. Figure 3 depicts an Eastern Shelf stratigraphic column representative of the strata found at the KSU 2361 well location. The red stars reference the injection formations, and a green star indicates the historically productive interval in the area.

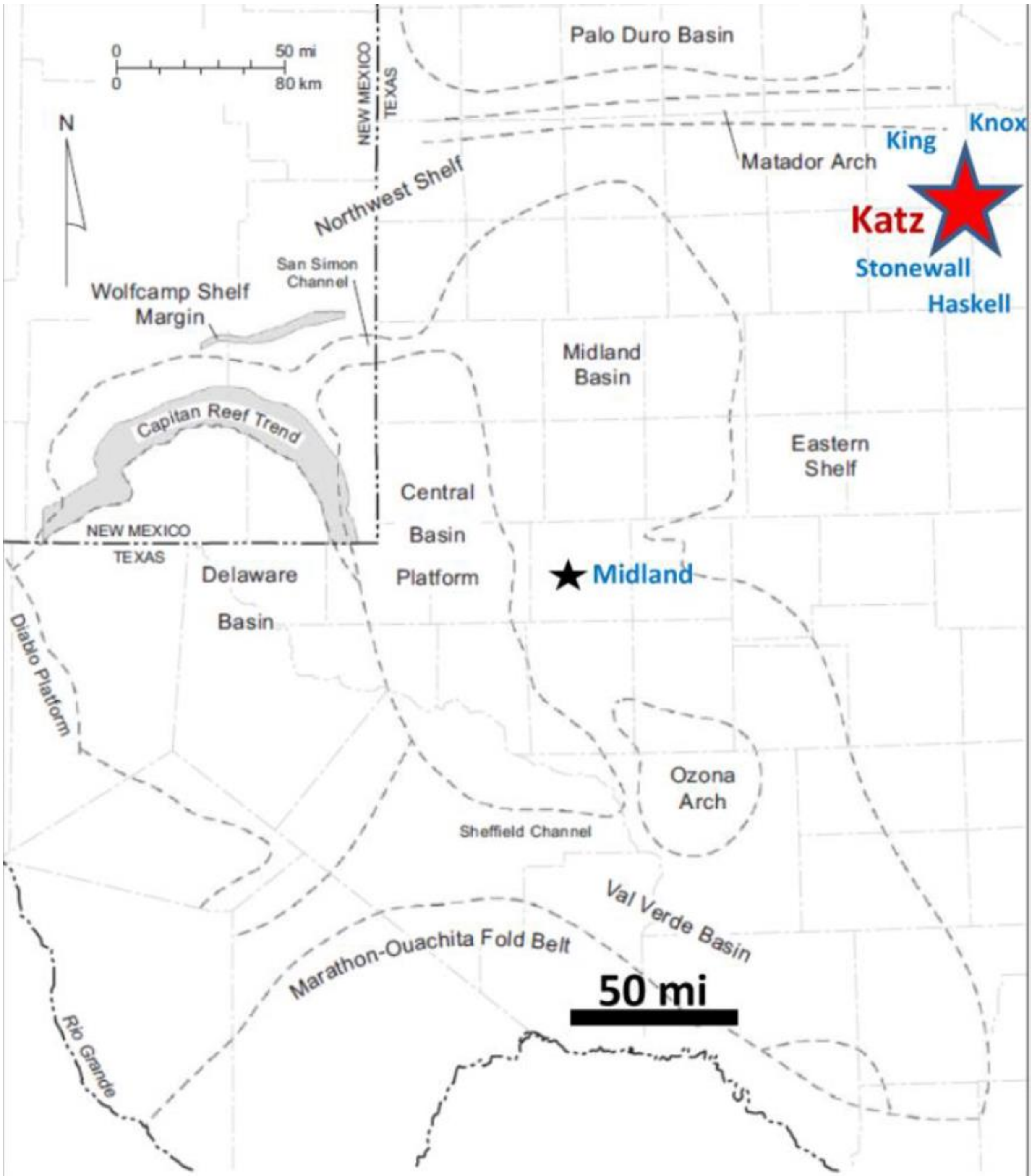


Figure 2 – Regional Map of the Permian Basin. The red star is the approximate location of KSU 2361 well.

SYSTEM	SERIES OR EPOCH FORMATION NAME	STONEWALL CO, TX LITHOLOGIES	
QUATERNARY	Holocene	Alluvium (sand, shale)	
	Pleistocene		
TERTIARY			
CRETACEOUS		*ABSENT*	
TRIASSIC			
PERMIAN	Guadalupe	gypsum, shale, dolomite	
	Wichita Gp	shale	
	Wolfcamp	shale, sandstone, limestone	
PENNSYLVANIAN	Virgil (Cisco)	shale, limestone, sandstone	
	Missouri (Canyon)	shale, limestone	
	Des Moines (Strawn)	sandstone, shale, limestone	★ Oil
	Atoka (Bend)	shale, sandstone	
	Morrow	*ABSENT*	
MISSISSIPPIAN	Chester	limestone	
	Meramec-Osage		
DEVONIAN		*ABSENT*	
SILURIAN			
ORDOVICIAN	Ellenburger	dolomite	★ Disposal Zone
CAMBRIAN	Wilberns	shale, sandstone, limestone	★ Disposal Zone
PRECAMBRIAN		granite	

Figure 3 – Stratigraphic Column of the Eastern Shelf.

The upper target injection interval is the lower Ordovician-age Ellenburger Group, which is subdivided into the Honeycut, Gorman, and Tanyard Formations, as seen in Figure 4. Upper Cambrian-age sandstone units of the Wilberns Formation, comprise the lower target injection interval.

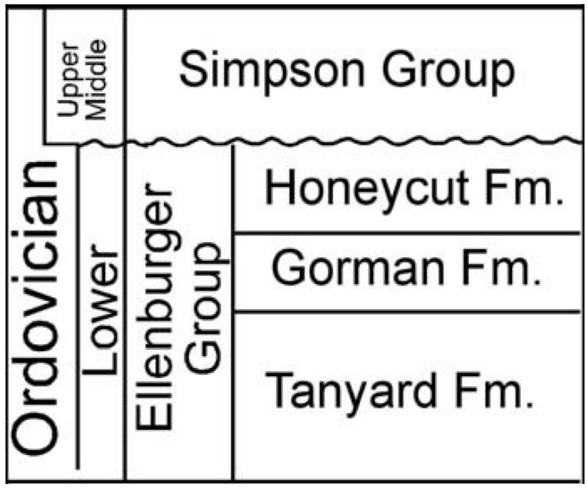


Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations (Kupecz, 1992).

The Ellenburger Group is present at varying depths in each of the provinces of the Permian Basin. In the Midland Basin area, the top of Ellenburger carbonate is as deep as 11,000' (GL) (Loucks, 2003). Due to regional structural dip of the Eastern Shelf, in northeast Stonewall County, the top of Ellenburger is found at only approximately 6,000' deep (GL). The depositional environment over the Stonewall, King, Knox, and Haskell County intersection during the Ordovician Period was a broad, shallow water carbonate platform with an interior of dolomite and an outer area of limestone. This was interpreted by Kerans (1990) as the dolomite being a restricted shelf interior and the limestone being an outer rim of more open-shelf deposits (Loucks, 2003).

Kerans (1990) performed the most complete regional analysis on Ellenburger depositional systems and facies. He recognized six general lithofacies as follows: litharenite: fan delta – marginal marine depositional system; mixed siliciclastic-carbonate packstone/grainstone: lower tidal-flat depositional system; ooid and peloid grainstone: high-energy restricted-shelf depositional system; mottled mudstone: low-energy restricted-shelf depositional system; laminated mudstone: upper tidal-flat depositional system; and gastropod-intraclast-peloid packstone/grainstone: open shallow-water-shelf depositional system.

According to Loucks, the diagenesis of the Ellenburger Group is complex, and the processes that produced the diagenesis spanned millions of years. The three major diagenetic processes of note are dolomitization, karsting, and tectonic fracturing. Dolomitization favors the preservation of fractures and pores due to its greater chemical and mechanical stability relative to limestone. Kupecz and Land (1991) delineated generations of dolomite into early-stage and late-stage. They attributed 90% of the dolomite as early-stage, wherein the source of magnesium was probably seawater. The other 10% of dolomite was attributed as late-stage, in which warm, reactive fluids were expelled from basinal shales during the Ouachita Orogeny. Karsting can affect only the surface of a carbonate terrain, forming terra rosa, or it can extensively dissolve the carbonate surface,

forming karst towers (Loucks, 2003). It can also produce extensive subsurface dissolution in the form of caves and other structures, which increases porosity and permeability. Fracturing can be tectonic or karst-related. Tectonic fractures are commonly the youngest fractures in the rock and generally crosscut karst-related fractures (Kerans, 1989). Holtz and Kerans (1992) divided Ellenburger reservoirs into three groups based on these fracture types. The Eastern Shelf of the Permian Basin falls within the ramp carbonates group, in which predominant pore types are intercrystalline and interparticle. These reservoirs are characterized by the thinnest net pay, highest porosity, moderate permeability, highest initial water saturation, and highest residual oil saturation.

Figures 5 and 6 show the regional structure contours and isopachs of the Ellenburger Group, respectively. Figure 7 shows isopachs of Cambrian and lower Ordovician strata. Stars depict the KSU 2361 well location in each of these figures. In Figure 8, formation tops from gamma-ray data indicate the net pay thickness of the Ellenburger and Cambrian is approximately 223' within this interval in the KSU 2361 well location.

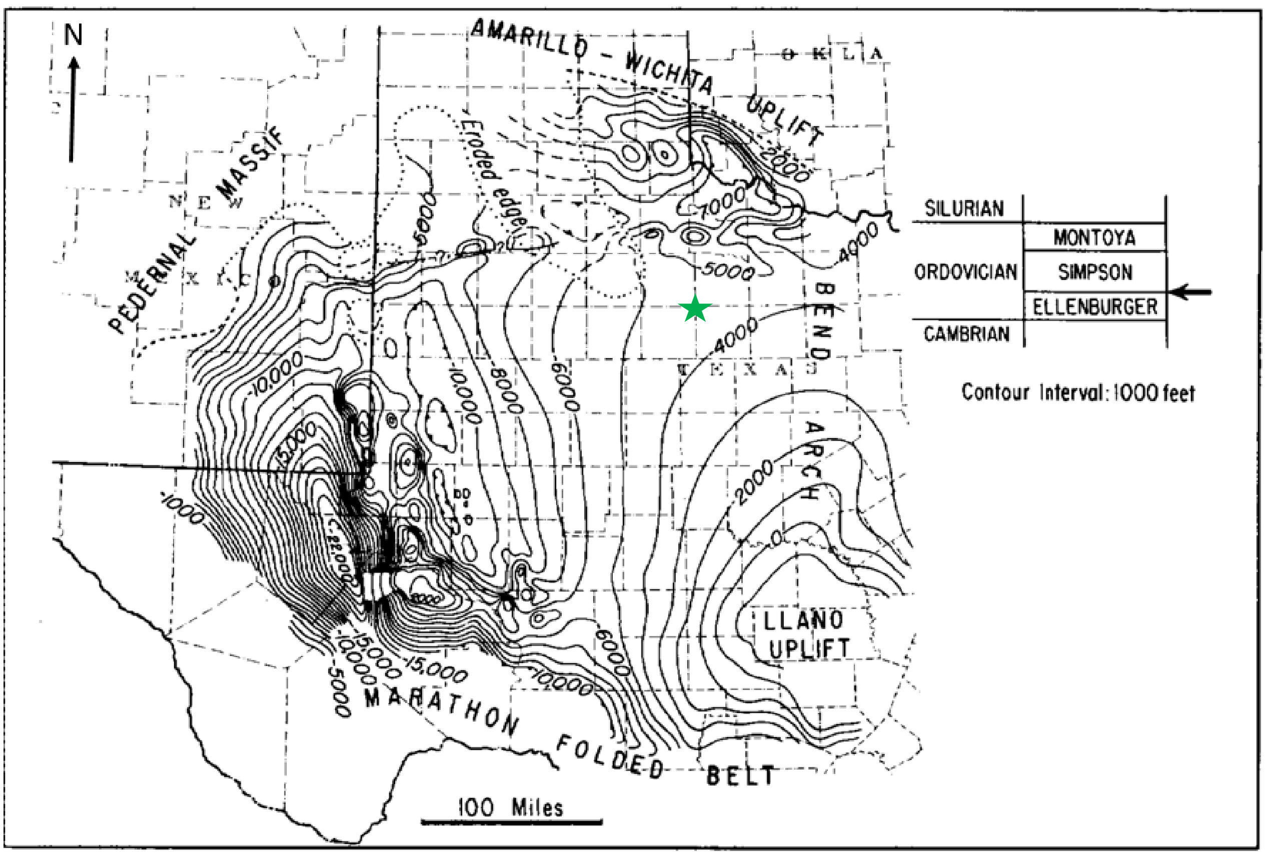


Figure 5 – Top of Structure Map of the Ellenburger Group in West Texas (Subsea Values) (Galley, 1955).

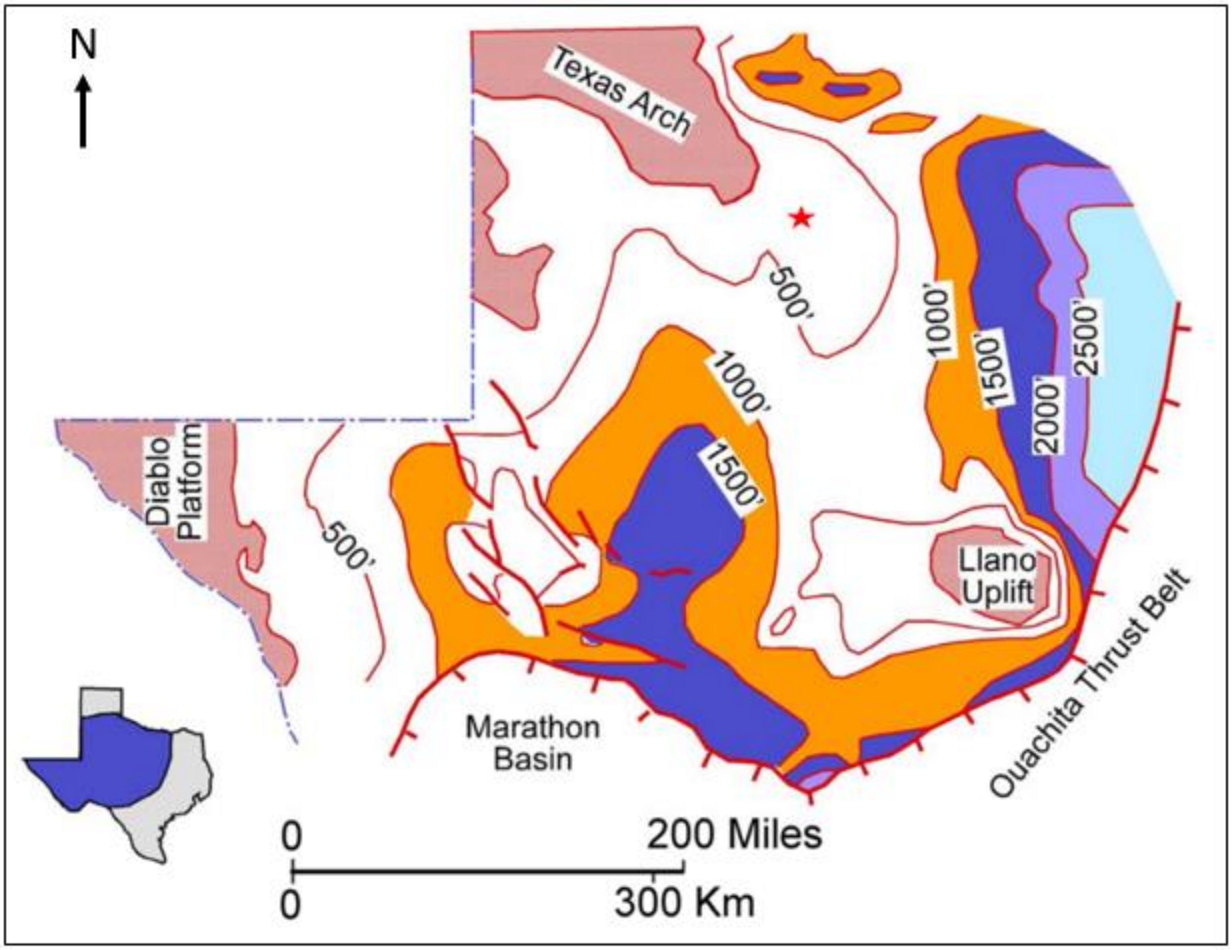


Figure 6 – Generalized Isopach Map of the Ellenburger Group in West Texas (Kerans, 1989).

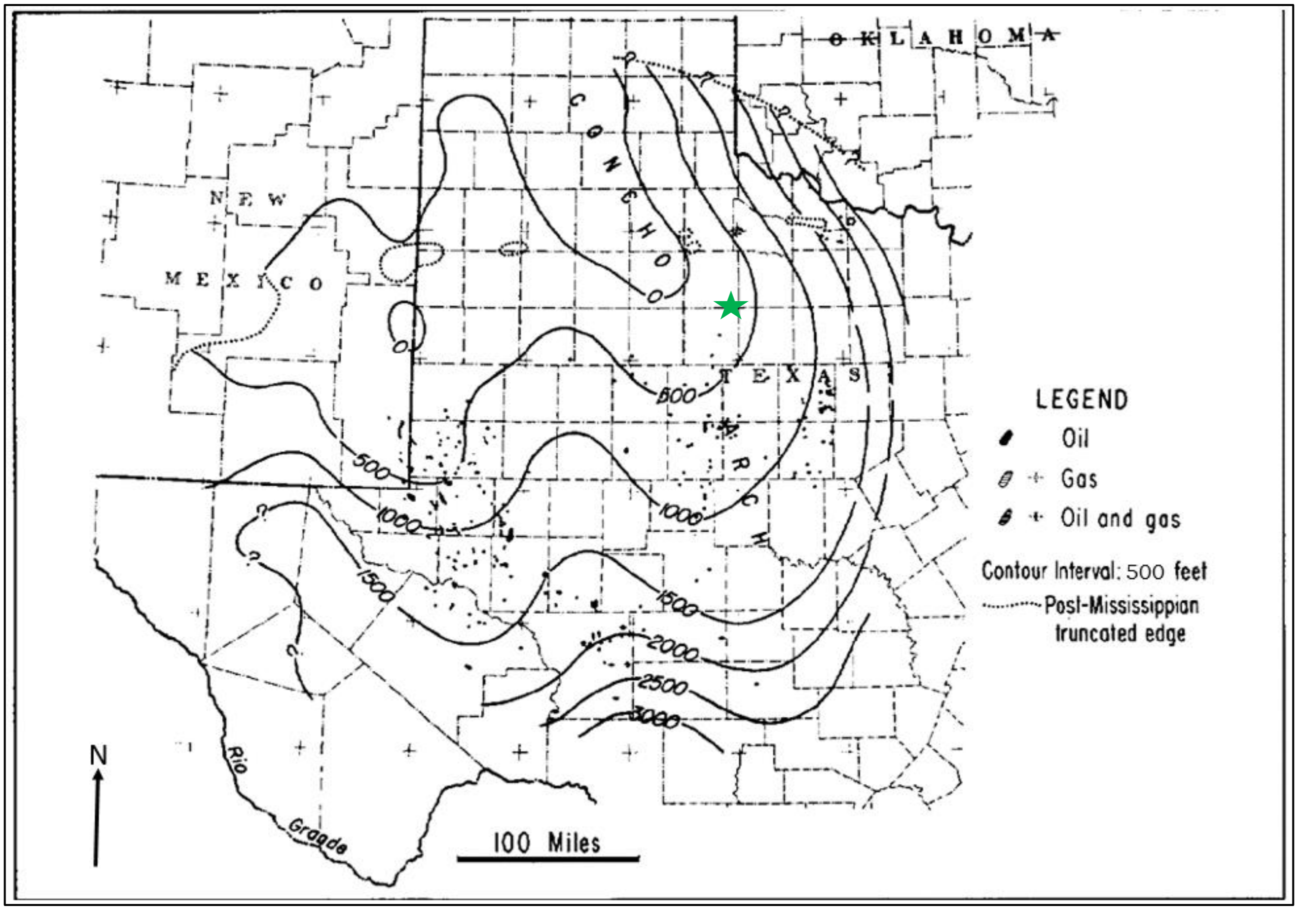


Figure 7 – Thickness of Cambrian and Lower Ordovician Strata
(Galley, 1955).

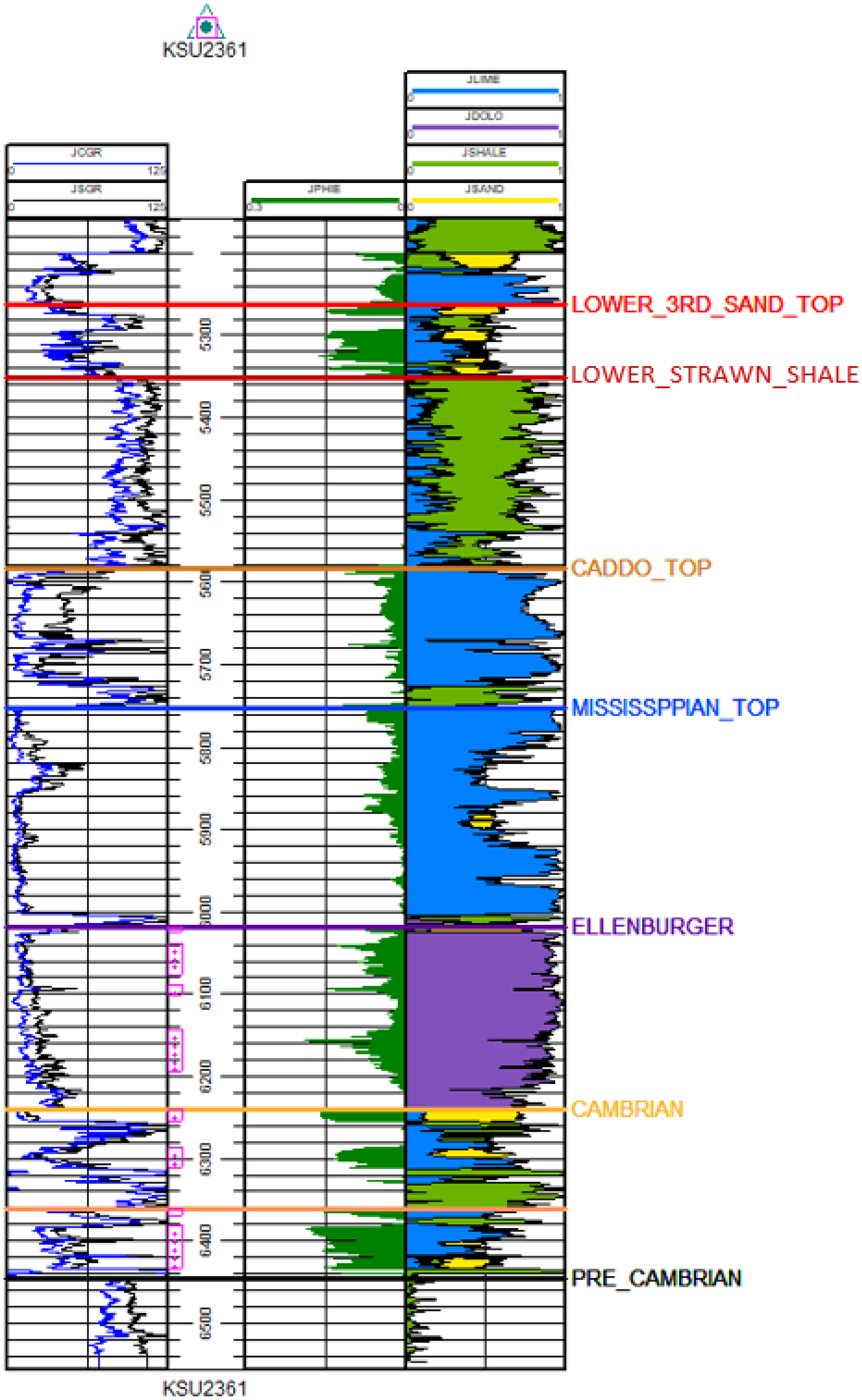


Figure 8 – Formation Tops at KSU 2361. Purple represents dolomite and the upper injection interval. Yellow represents sandstone, which is present in the pay interval. Pink boxes within depth column indicate active perforated intervals.

Cambrian-age strata consist of interbedded sandstone, limestone, and shale members. The initial deposits laid down on the eroded surface of Precambrian rocks were sandstone and arenaceous carbonates. Shale members are thickest in the southeast and nonexistent on the west side of the Permian Basin (Galley, 1955).

Overlying the Precambrian basement rock is the Riley Formation. This, in turn, is overlain by transgressive and progradational shallow-water marine sandstone, siltstone, limestone, and dolomite of the Wilberns Formation. The Riley Formation consists of sandstone packages whose thicknesses vary from place to place in response to the paleotopography of the underlying Precambrian surface (Kyle and McBride, 2014). The depositional environment in this area during the Cambrian was influenced by the sea, which advanced from the southeast (Galley, 1955). This led to the formation of a complex succession of transgressive and regressive sandstone units, both glauconitic and non-glauconitic (Kyle and McBride, 2014).

The Riley Formation is probably thickest south of the Llano region and laps out about 100 miles west and a slightly greater distance northwestward from the Llano region. It has accumulated in a northwestward-extending arm of the sea and likely extended beyond its present limits since there is a disconformity at its top. The Wilberns Formation thins appreciably northwestward from the Llano region to about 230’ in Nolan County and to 70’ in Lubbock County. West and north of the Llano region, usage suggested by Cloud and Barnes and adopted by petroleum geologists places the Tanyard-Wilberns boundary in the vicinity of the first appearance downward of glauconite (Barnes et al., 1959).

Figure 9 indicates that the Riley Formation’s northwestern extent ends in Jones and Fisher counties, which implies that Cambrian strata at KSU 2361 may be limited to the Wilberns Formation only.

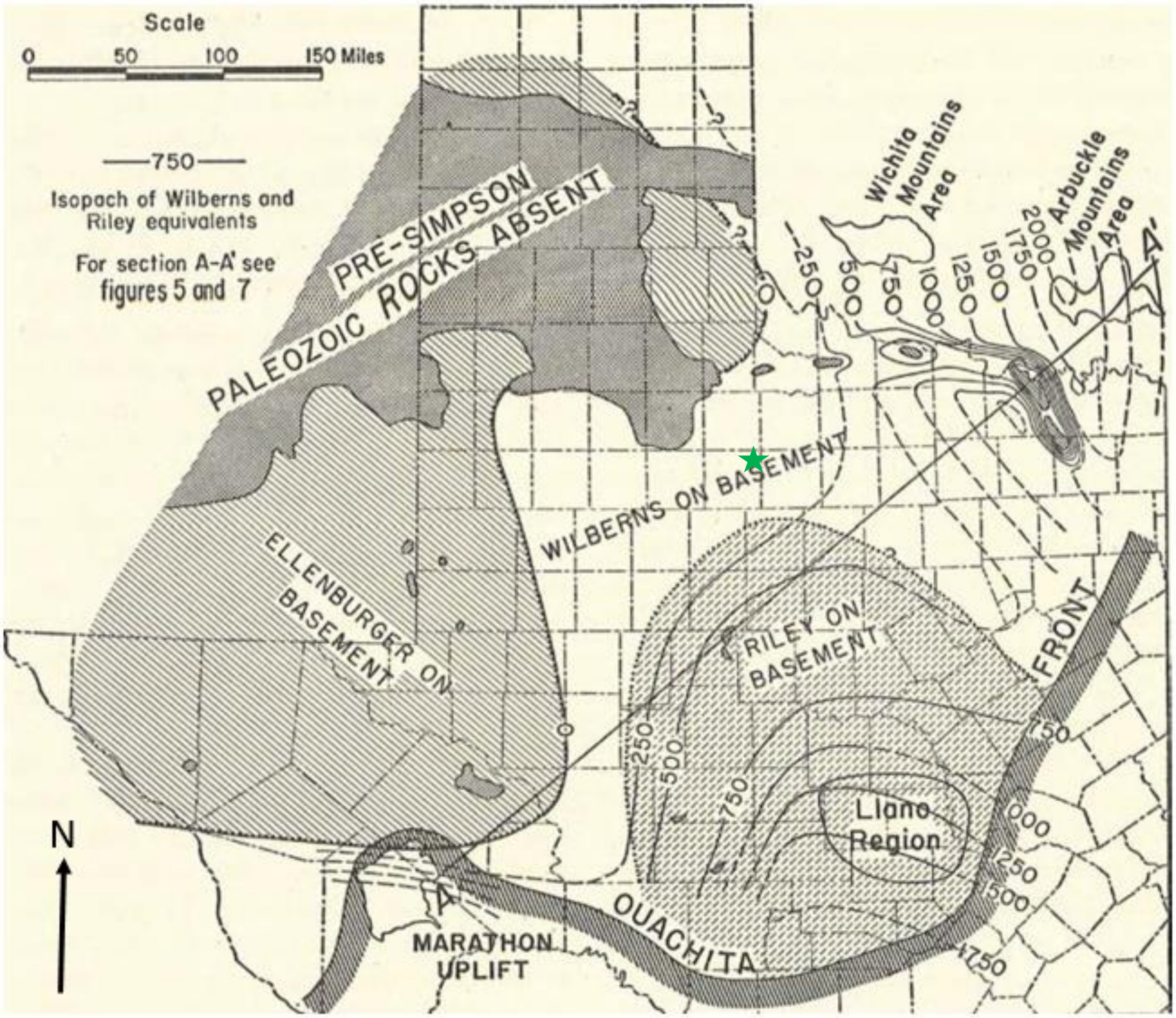


Figure 9 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma. The green star approximates the location of KSU 2361 (Barnes et al., 1959).

2.1.1 Regional Faulting

Regional faulting in the KSU 2361 area trends primarily N-S in direction. This is the result of the dip rotation from a SW-NE trend seen in the Fort Worth basin to the east that rotates N-S as you move west towards the Bend-Arch and the edge of the basin (Hornhach, 2016). This trend then carries towards the Eastern Shelf closer to the KSU 2361 location. The most common faults are high-angle basement faults that primarily die within the Pennsylvanian in the KSU 2361 well area. Faulting is discussed in more detail in the Site characterization.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the KSU 2361 well.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 depicts an annotated open hole log from the surface to the total depth of the KSU 2361 well, with regional formation tops indicating the injection and primary upper confining units. Figure 11 provides a magnified view of the zones of interest, from above the Lower Strawn to the Precambrian, with general lithologic descriptions along the right edge of the figure.

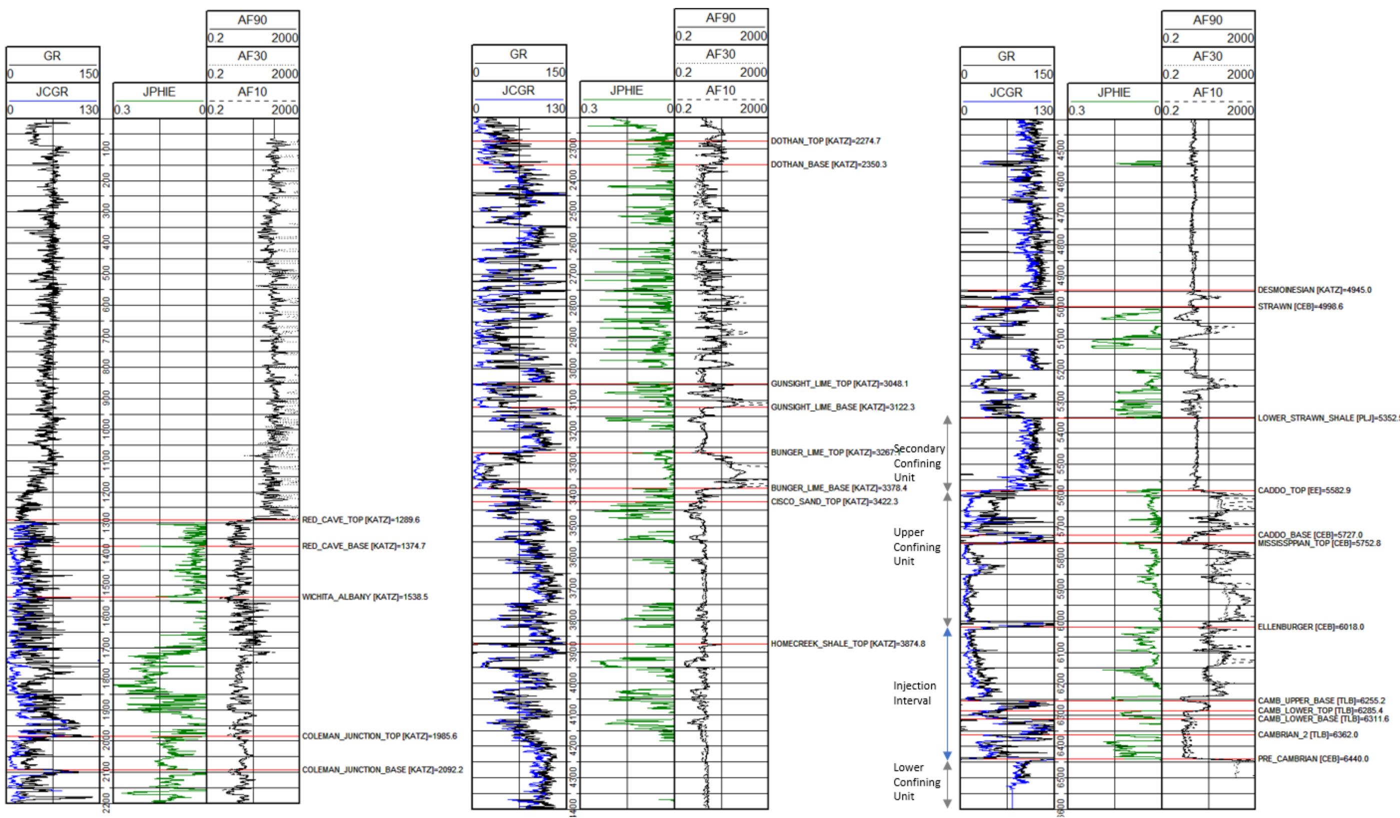


Figure 10 – KSU 2361 Type Log

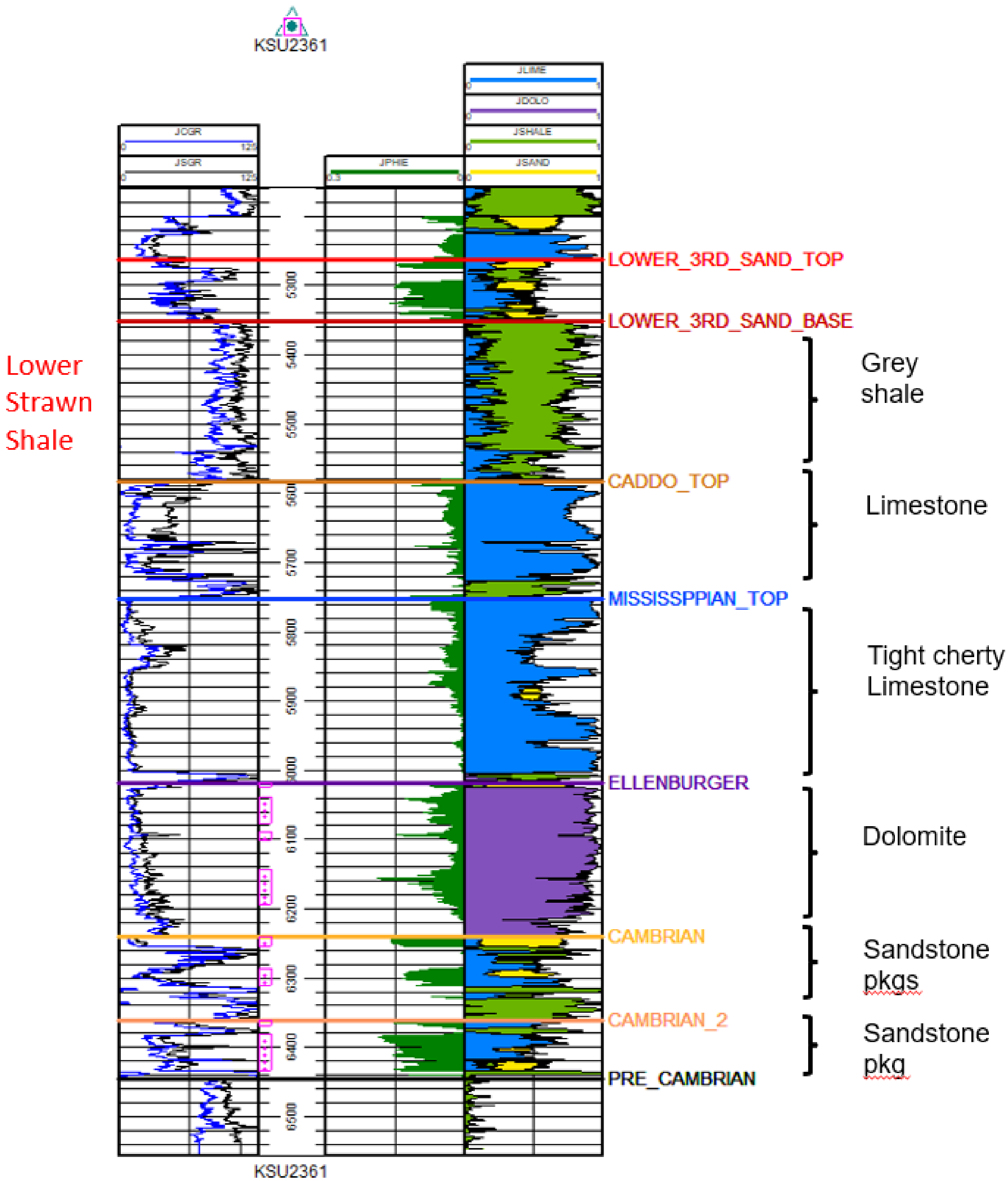


Figure 11 – Type Log of Zones of Interest

2.2.2 Upper Confining Zone – Mississippian Lime

The Mississippian Lime is the primary confining unit for the KSU 2361. This formation is the product of a large extensive shallow water carbonate platform that covered much of the southern and western Laurussia (Kane). Figure 12 shows the location of the KSU 2361 well to be found within the Chappel Shelf of the Mississippian Age. Representative cores of the Mississippian Lime formation found on the Chappel Shelf in the Llano uplift area consist of light-colored, fine- to coarse-grained, skeletal packstone (Kane). The open hole log seen in Figure 11 depicts the Mississippian Lime as predominantly cherty limestone. The basal carbonate section has little to no effective porosity development, which should translate to no permeability development. The Mississippian Platform Carbonate play is the smallest oil-producing play in the Permian Basin, which is tied to the abundance of crinoidal, grain-rich facies in platform successions. Most production from Mississippian reservoirs comes from more porous upper Mississippian ooid grainstones (Kane). This indicates that little to no reservoir characteristics are developed within the lower Mississippian Lime, creating an optimal seal.

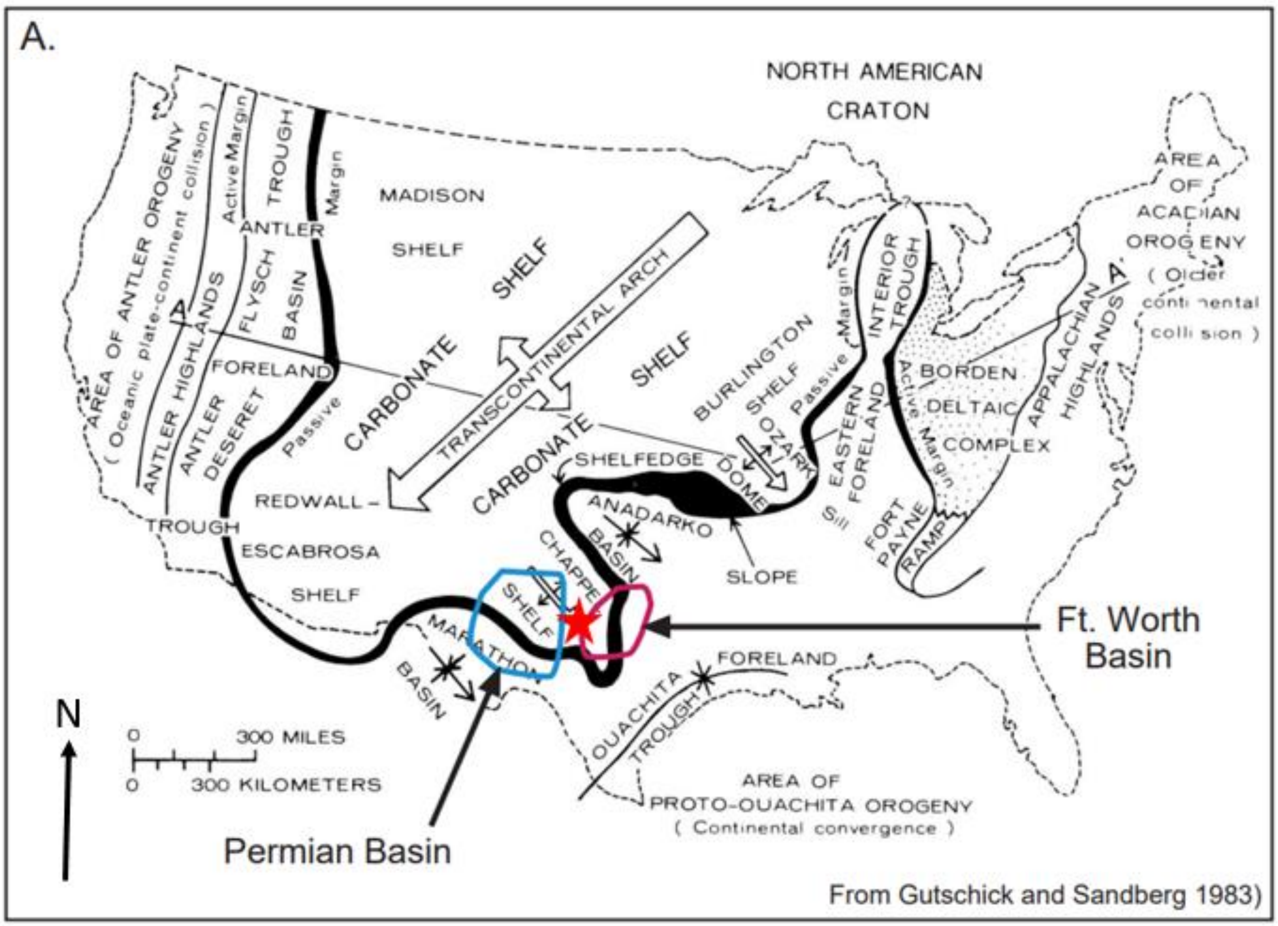


Figure 12 – Depositional Map of the Mississippian (Kane)

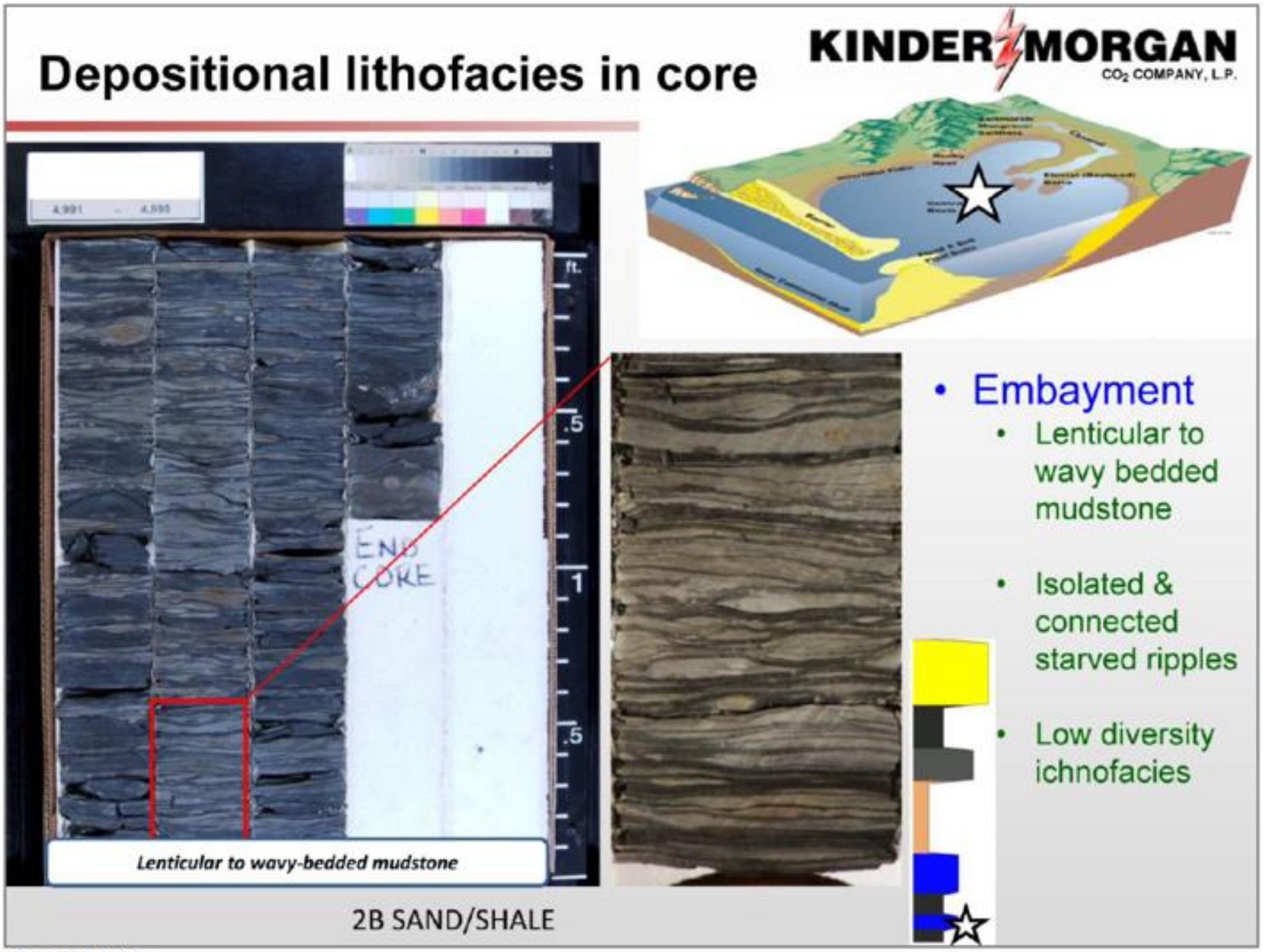
2.2.3 Secondary Confining Interval – Lower Strawn Shale

The Lower Strawn Shale (LSS) is Desmoinesian in age and was heavily influenced by the Knox Baylor Trough, which is near the KSU 2361 location and is late-Desmoinesian in age. The trough resulted from the Ouachita-Marathon overthrust movement that disrupted the Fort Worth basin depositional center, moving the Desmoinesian depocenter further to the west to form the Knox Baylor Trough. This trough allowed sediments to be transported west to the Midland Basin. These sediments were derived from the destruction of the elongated Bowie Delta System, which derived its sediments from the Muenster-Wichita Mountain system (Gunn, 1982).

Depositional facies within the Strawn unit resemble assemblages typical of a mixed siliciclastic-carbonate continental-to-shelf transitional succession found along a complex embayed coastline. Six petrophysically distinct lithofacies were identified: (1) lenticular to wavy-bedded mudstone, (2) flaser to wavy-bedded sandstone, (3) carbonate-rich sandstone, (4) ripple-to-trough cross-laminated sandstone with common convolute bedding, (5) trough cross-laminated sandstone with abundant mud rip ups and mud balls, and (6) heavily bioturbated sandstone. Combined lithofacies and ichnofacies observations suggest that paleoenvironments of the Katz Field included a bayhead delta, back-barrier estuary embayment, tidal flood delta, tidal flat, and upper to middle shoreface (Jesse G. White, 2014). The LSS is associated with the back-barrier estuary embayment depositional environment, evidenced by the abundance of mudstone.

Figure 13 provides core photos and associated descriptions of a core sample taken in the Katz field within an embayment environment. Core descriptions of this core sample observed characteristics that serve as excellent sealant properties to prohibit the migration of injection fluids above the injection zone. Conventional core data was collected in an offset well near the LSS depths in the API #42-433-33534 well, 5,089' away from the KSU 2361 well. Figure 14 is a cross-section relating the KSU 2361 well and the API #42-433-33534 well, indicating the cored interval alongside pictures of the lower portion of the core that most closely resembles the LSS. Horizontal permeabilities within the pictured core data range from 0.05 to 0.3 mD, with a vertical permeability value of less than 0.01 mD.

Along with the core reports and descriptions, Figure 14 plots calculated log curves from petrophysical analyses run on open-hole log data from the KSU 2361 well. Figure 14 indicates no effective porosity within the LSS (JPHIE green curve, 2nd track from the left) with a shale lithology reading (JHSHALE, green shading, 3rd track from the left). The petrophysical properties and lithology indicated by core and log data demonstrate that the LSS possesses characteristics of an excellent sealing formation.



__4991 TO 4998:__

4991.00 – 4997.4: Black to dark gray lenticular to wavy bedded mudstone encasing light gray lenticular siltstone to muddy very-fine sandstone. Abundant light gray calcareous horizons. Note zones of reddish color.

4997.4 – 4997.5: Burrowed transgressive bioclastic lag deposit? Abundant crinoid and bioclastic debris over burrowed laminated to contorted black shale.

4997.5 - 4997.7: Black laminated shale

4997.7 - 4998.0: Dark gray to gray black crinoid mudstone interbedded with a single tan algal mudstone-wackestone hardground exhibiting mudcracks.

Trace fossils shown in blow-ups include *Paleophycus, Planolites, Thalassinoides* and *Teichichnus*.

Sedimentology infers **brackish water deposits** (Brackish water is water that has more salinity than fresh water, but not as much as seawater. It may result from mixing of seawater with fresh water, as in estuaries.

4991 - 4998: Estuary – embayment. Brackish water deposit. Muddy.

Figure 13 – Core Description

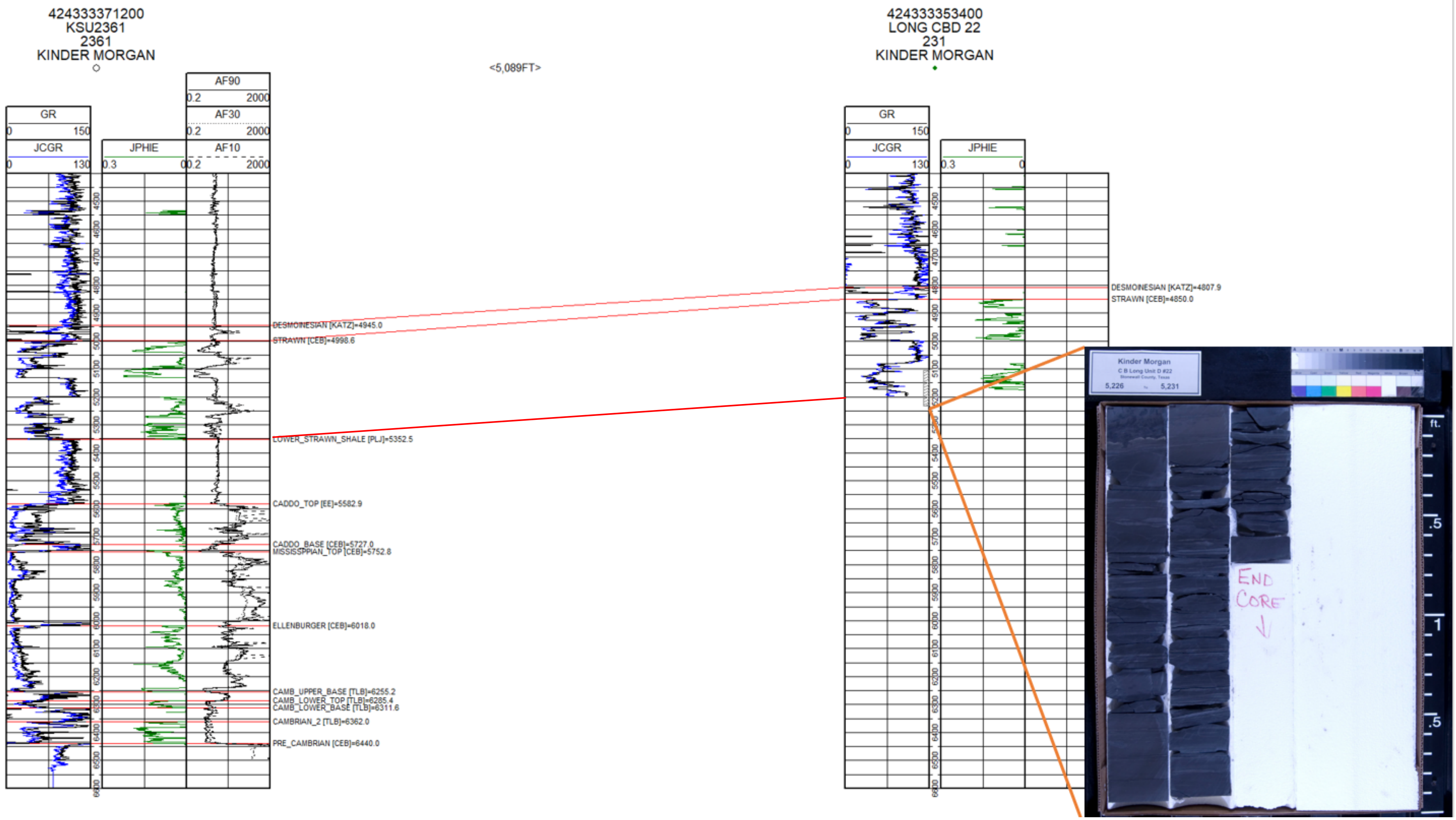


Figure 14 – Cross Section Depicting Correlative Offset Core with Lower Strawn Shale

2.2.4 Injection Interval – Ellenburger/Cambrian Sands

Ellenburger

The Ellenburger is a widespread lower Ordovician carbonate deposited over the entire north Texas area, indicating a relatively uniform depositional condition (Hendricks, 1964). North Central Texas experienced a low-energy, restricted shelf environment comprised of a homogeneous sequence of gray to dark-gray, fine to medium crystalline dolomite containing irregular mottling (probable bioturbation structures) and lesser parallel-laminated mudstone and peloid-wackestone (Kerans, 1990). Figure 15 is a map depicting the different depositional environments of the lower Ordovician, with associated lithologies. This map confirms the inferred dolomite lithology of the open hole log analysis in Figure 11 of the KSU 2361 well.

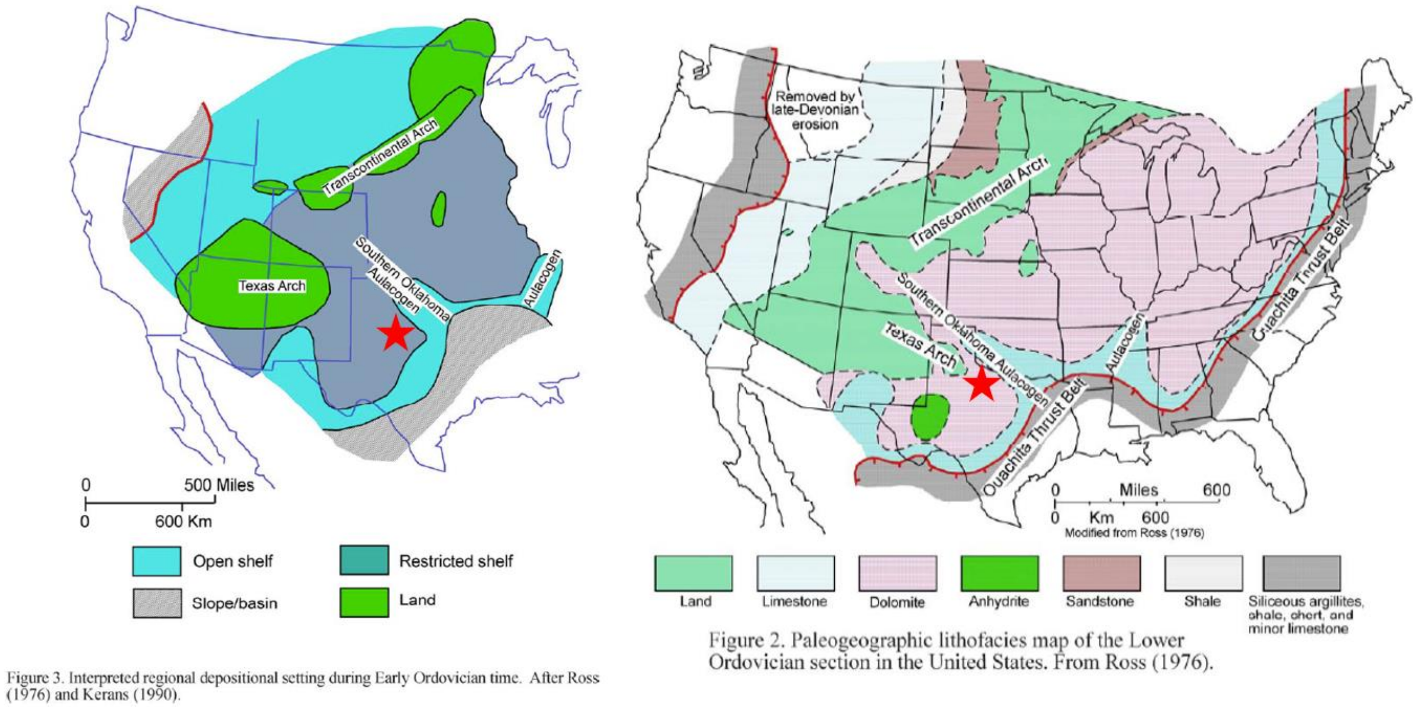


Figure 15 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

Ellenburger Porosity/Permeability Development

Within the low-energy, restricted shelf environment, facies are highly dolomitized and have a heavy presence of bioturbation resulting in mottling (Loucks, 2003). The dolomitization led to porosity development within the Ellenburger, along with diagenetic leaching processes and other secondary porosity features such as karsts and vugs. The tables in Figure 16 show permeability and porosity values tabulated from Ellenburger reservoirs within Texas, categorized by their diagenetic facies into three groups: Karst Modified, Ramp Carbonates, and Tectonically Fractured Dolostones. Based on the descriptions in Figure 16, the Ellenburger of the KSU 2361 would fall within the Karst Modified Reservoirs category outlined in red with average porosity and permeability values of 3% and 32 mD, respectively. This corresponds with the data collected from the KSU 2361 well. As shown in Figure

11 above, the calculated effective porosity curve in green (JPHIE) is an average of roughly 3% over the Ellenburger formation. Permeability was estimated from volumes injected plotted against pressure responses within the KSU 2361 well; these permeabilities ranged from 12-20 mD. Similarities between these two datasets validate reservoir characteristics used for model inputs.

Cambrian

The deposition of Cambrian and lower Ordovician strata on the early Paleozoic shelf was initiated by a transgressing sea which, entering the area from the south, first laid down a clastic sequence. Initial deposits were sandstone and arenaceous carbonates that grade upward into the slightly cherty carbonates of the Ellenburger group (Galley, 1958). Lithologies include glauconitic and phosphatic to clean sandstones of various textures, intergrading and alternating with chemical, clastic, and even local limestones and dolomites, together with intercalated thin shales (Conselman, 1954).

Cambrian Porosity/Permeability Development

Few reservoir characteristics have been published on the Cambrian sands. Porosity and permeability were estimated based on the KSU 2361 wells open hole log and injection data. There are three discreet sandstone intervals within the Cambrian at this location. The upper two sands identified in the CAMBRIAN package have an average effective porosity of 12.9% and 8.8%. The average effective porosity of the third sand is 8.4%. These effective porosity values are plotted as the JPHIE (effective porosity) curve in Figure 11. Due to nature of the Ellenburger and Cambrian zones being commingled during injection tests, modeling makes the assumption of 12-20mD average permeability for the interval, for history matched injection volumes and pressures.

Table 2. Geologic characteristics of the three Ellenburger reservoir groups. From Holtz and Kerans (1992).

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 16 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

Formation Fluid

Four wells were identified within approximately 20 miles of the KSU 2361 well through a review of oil-field brine compositions of the Ellenburger formation from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3. None of these four wells are salt water disposal wells. The location of these wells is shown in Figure 17. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids. Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger Formation is compatible with the proposed injection fluids.

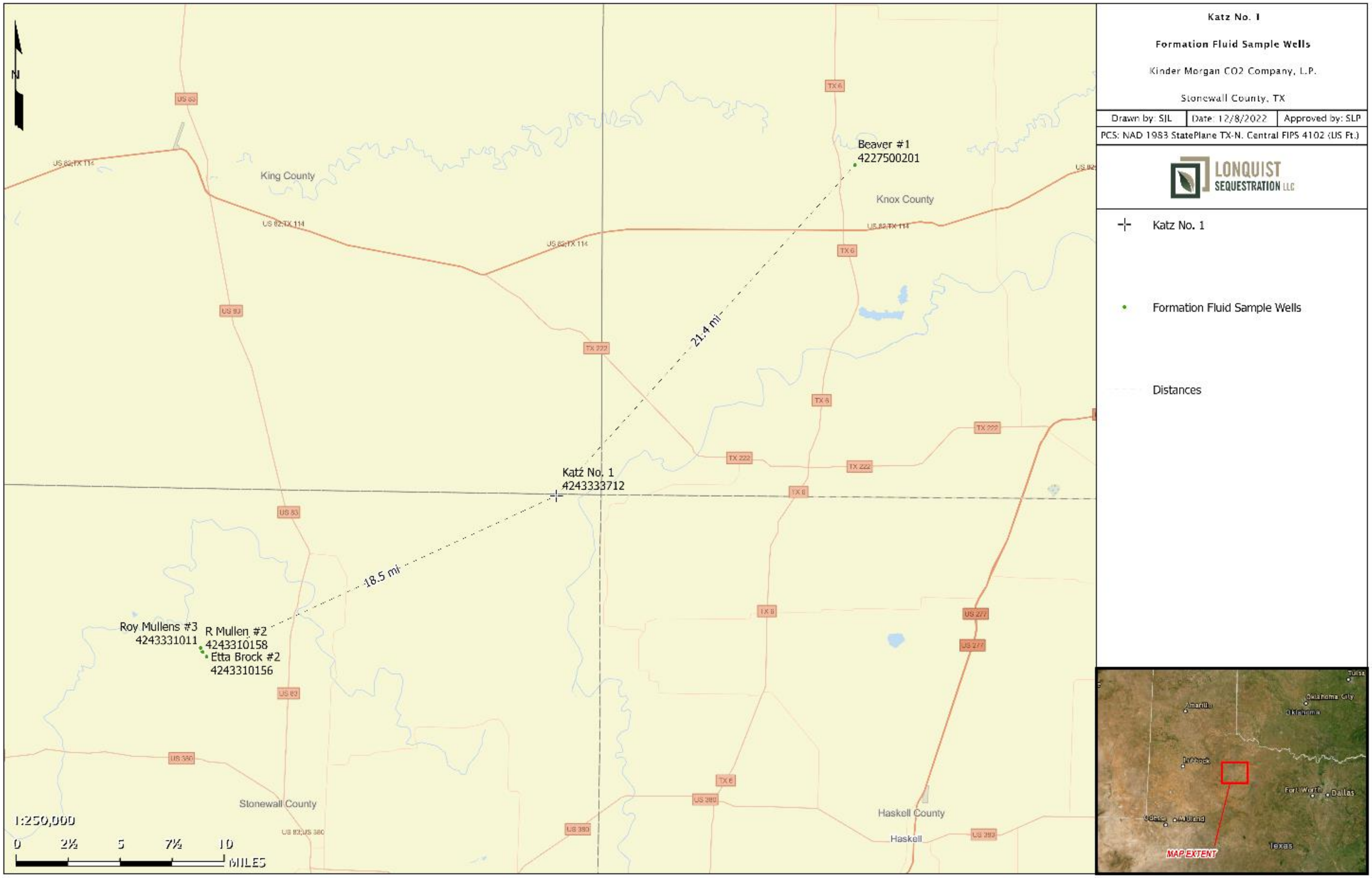


Figure 17 – Offset Wells used for Formation Fluid Characterization.

Table 3 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples

	Average	Low	High
Total Dissolved Solids (ppm)	144065	98802	210131
pH	6.15	5	7
Sodium (ppm)	43391	30833	64222
Calcium (ppm)	9275	5128	13200
Chlorides (ppm)	88355	60061	128685

2.2.5 Lower Confining Zone – Precambrian

The Precambrian outcrops to the south at the Llano uplift and the west in the Trans-Pecos regions of Texas and central New Mexico. Outcrops near the Llano Uplift in McCulloch County consist of highly weathered granite, schist, and gneiss. The granite is fine- to coarse-grained and contains numerous pegmatite veins. The schist has a high percentage of biotite, which gives it a dark-gray color, and it is often referred to as "gray shale" or "blue mud" by well drillers. The gneiss is pinkish and fine-grained (Mason, 1961). A study in 1996 was performed by Adams and Keller to better understand the Precambrian distribution in Texas indicates that Precambrian at the Katz 2361 location should contain an average metamorphic rock, as seen in Figure 18. This agrees with the open hole log response in the Precambrian formation in the open hole log section of Katz 2361. Gamma-ray log values of the Precambrian section are consistently above 90 GAPI (Gamma Units of the American Petroleum Institute), indicating a high radioactive response. A very high resistivity reading within this section indicates little to no porosity, as shown in the JPHIE, validating the characteristics described above. These traits are ideal attributes of a tight, lower confining basement.

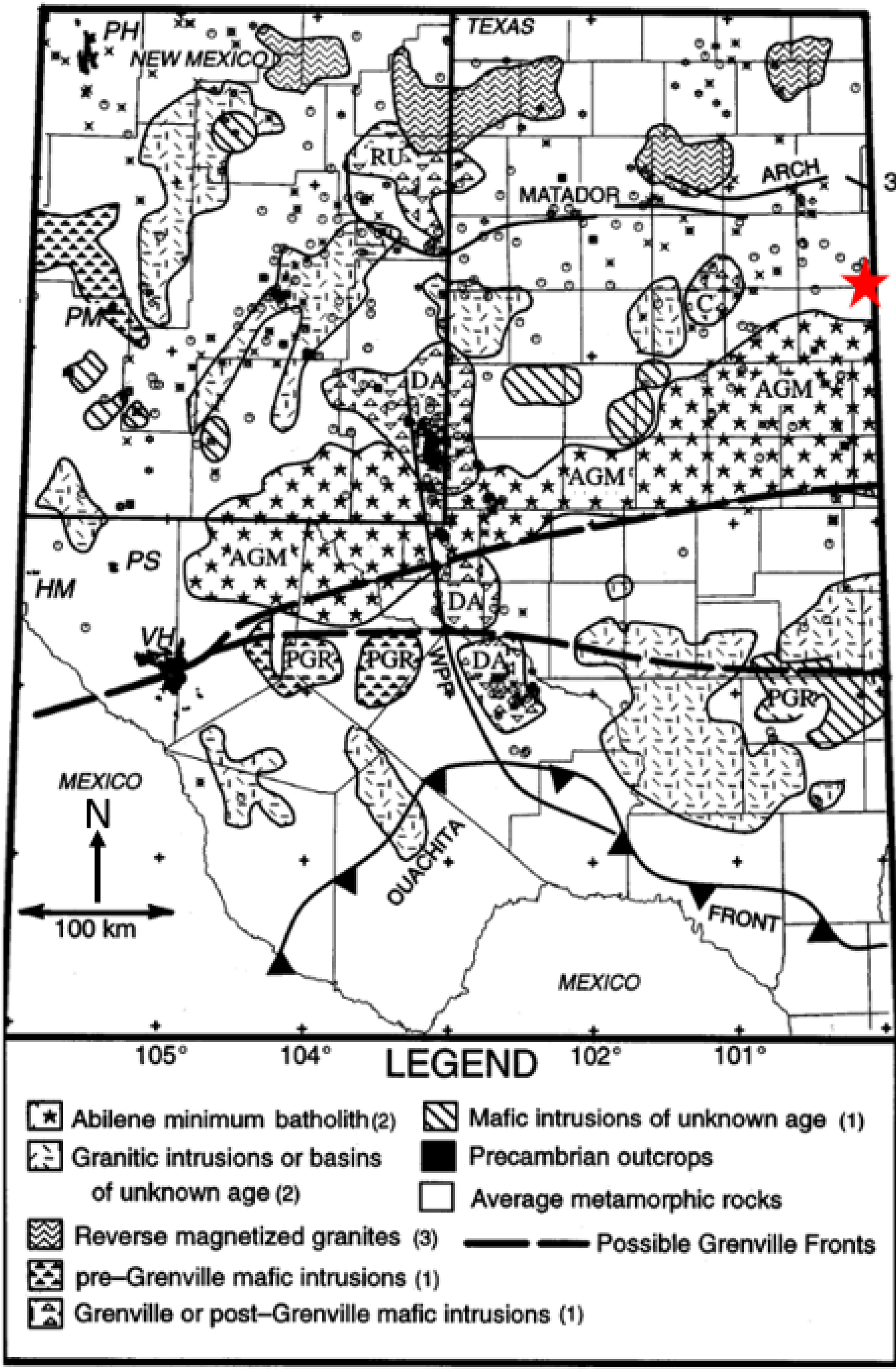


Figure 18 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Fracture Pressure Gradient

Fracture pressure gradients were estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for determining fracture gradients. Poisson's ratio (ν), overburden gradient (OBG), and pore gradient (PG) are all variables that can be changed to match the site-specific injection zone. The expected fracture gradient was determined using industry standards and a literature review. The overburden gradient was assumed to be 1.05 psi/ft. This value is considered best practice when there are no site-specific numbers available. The pore pressure gradient was calculated to be 0.43 psi/ft from the bottom hole pressure data. For limestone/dolomite rock in the injection zone, the Poisson's ratio was assumed to be 0.3 through literature review (Molina, Vilarras, Zeidouni 2016). Using these values in the equation below, a fracture gradient of 0.70 psi/ft was calculated for the injection zone.

For the upper confining interval, a similar fracture gradient was calculated. The upper confining shale has an increased chance to vertically fracture if the injection interval below is fractured (Molina, Vilarras, Zeidouni 2016). Therefore, a Poisson's ratio equal to that of the injection interval was used as a conservative estimate. The lower confining zone was assumed to be of a similar matrix to the injection interval, with the key difference being that the formation is much tighter (lower porosity/permeability). Therefore, the Poisson's ratio was assumed to be slightly higher in this rock. As seen in Table 4, the fracture gradient of .64 psi/ft is slightly higher in the lower confining zone.

Multiple approaches can be taken to manage reservoir pressure. Current engineering practices for acid gas CO_2 injection recommend applying a 10% safety factor to the fracture pressure of the geology being injected into, resulting a 0.63 psi/ft gradient. This new value represents the maximum allowable bottom-hole pressure during injection. Another approach is to maintain a maximum wellhead pressure (WHP). In the reservoir model, a WHP of 1,850 psi was used to constrain the simulated well. This translates to a value that is 84% of the frac gradient or a 16% safety factor. By using either approach, there is a reduced risk of fracture propagation in the injection zone.

A conservative maximum pressure constraint of 0.60 psi/ft was used for injection modeling, which is well below the calculated fracture gradient for each zone. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

Table 4 – Fracture Gradient Assumptions

	Injection Interval	Upper Confining	Lower Confining
Overburden Gradient (psi/ft)	1.05	1.05	1.05
Pore Gradient (psi/ft)	0.43	0.43	0.43
Poisson's Ratio	0.30	0.30	0.31
Fracture Gradient (psi/ft)	0.70	0.70	0.71
FG + 10% Safety Factor (psi/ft)	**0.63**	**0.63**	**0.64**

The following calculations were used to obtain fracture gradient estimates:

$$FG = \frac{\text{n}}{1-\text{n}}(OBG - PG) + PG$$

$$FG = \frac{0.3}{1-0.3}(1.05 - 0.43) + 0.43 = 0.70$$

$$FG\ with\ SF = 0.70\ \times (1 - 0.1) = \mathbf{0.63}$$ **(Injection and Upper Confining intervals)**

$$FG\ with\ SF = 0.71 \times (1 - 0.1) = \mathbf{.64}$$ **(Lower Confining interval)**

2.4 Local Structure

Regional structure in the area of the KSU 2361 well is influenced by a shallow angle ramp down dip to the southwest towards the Midland Basin, which is set up by a north-south regional fault to the east. Specifically, the KSU 2361 well is located on the western portion of a shelf-like feature that dips slightly away from the fault to the east. Figure 19 is a structure map on the top of the Ellenburger with the KSU 2361 well indicated by the black star.

Subsurface interpretations of the Ellenburger formation heavily relied on 3D seismic coverage in the area. The seismic coverage outline is represented by the purple boundary seen in Figure 19. Only two wells penetrated the Ellenburger formation within the 3D seismic data volume and are shown in the northwest to southeast seismic profile along with the cross-section in Figure 22. These two wells are active injection wells within the proposed injection interval operated by Kinder Morgan, one being the Katz 2361 well while the other is the Katz #3741 well. Both wells were used to create time-to-depth conversions for the Ellenburger horizon. Shallower formations provide additional well control to assist in creating time-to-depth conversions displayed in the seismic profiles in Figures 21 and 22.

The KSU 2361 well is located roughly 12,000' west of the mapped fault seen in Figure 19. This distance provides a buffer between the injection plume and the fault that alleviates concerns regarding the interaction between the injectate and the fault. As shown in the seismic profile, this fault does not project above the Caddo formation and is not present in the LSS. As this fault does not project into the upper confining shale layer, there is little risk of the fault acting as a conduit for the injectate to leak outside the proposed injection interval.

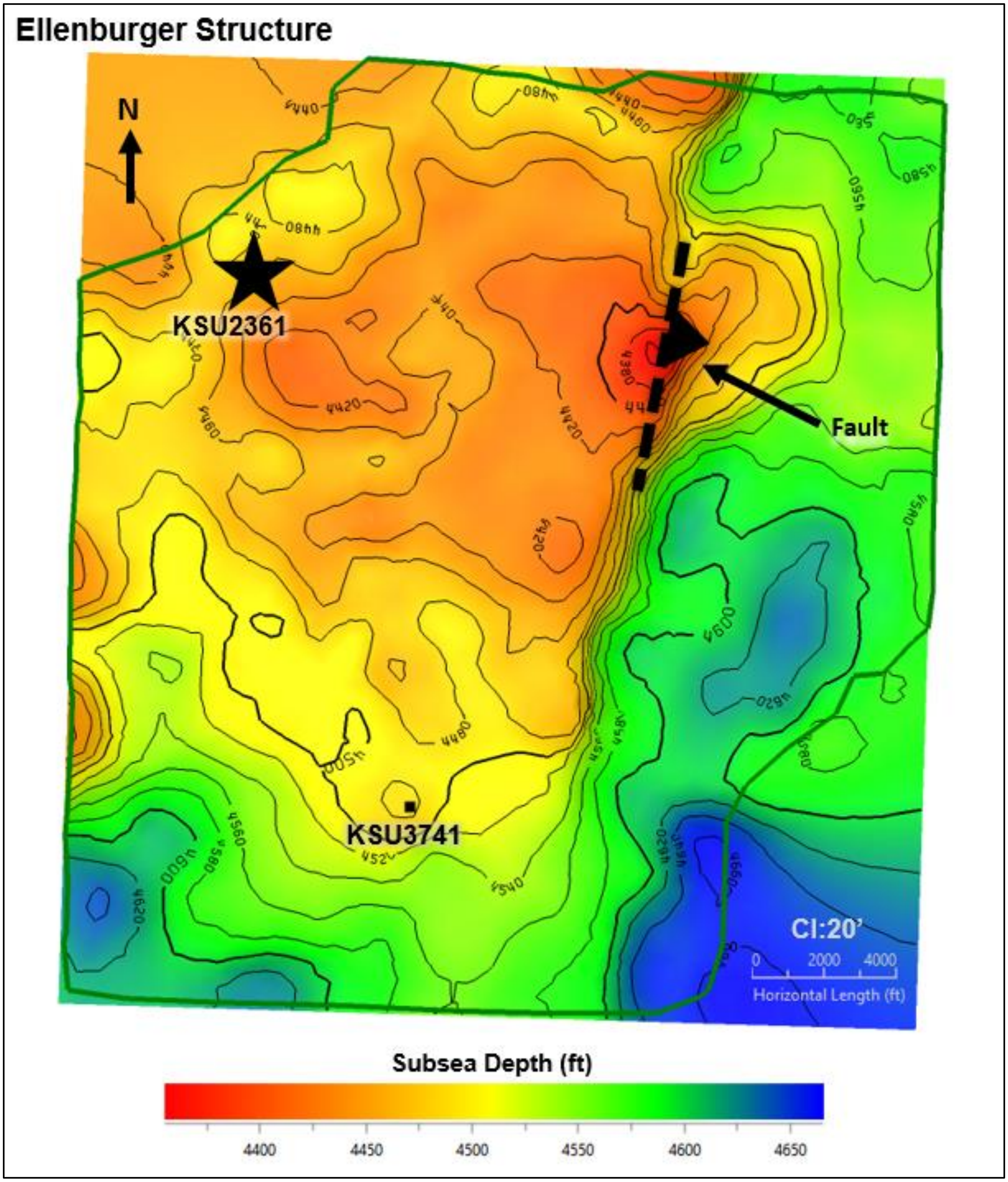


Figure 19 – Ellenburger Structure Map (Subsea Depths). Contour Interval (CI) on Ellenburger Structure map is 20'. The green outline is the boundary of the seismic data.

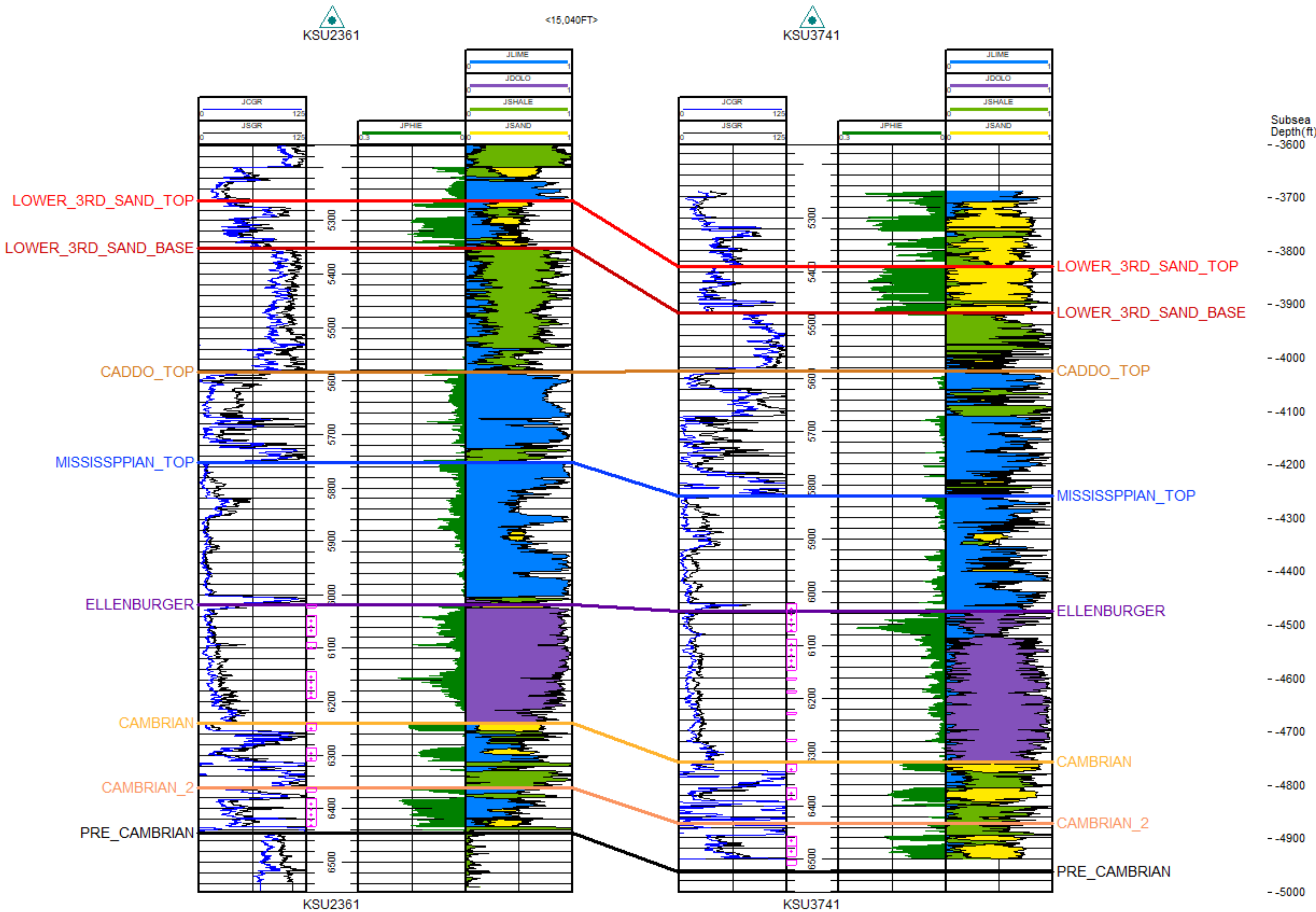


Figure 20 – Structural Northwest-Southeast Cross Section

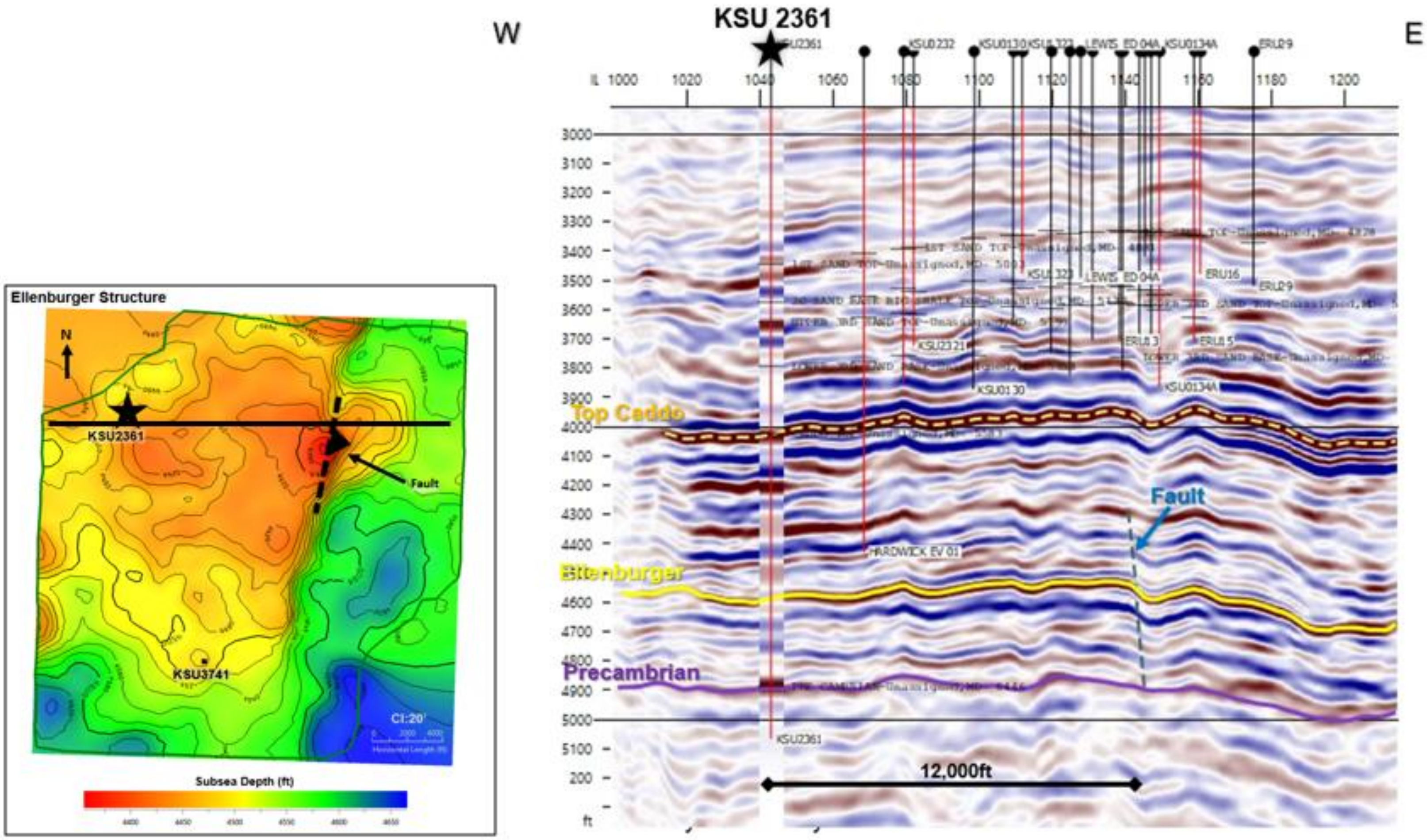


Figure 21 – Structural West to East Seismic Profile. Ellenburger structure map modified from Figure 19.

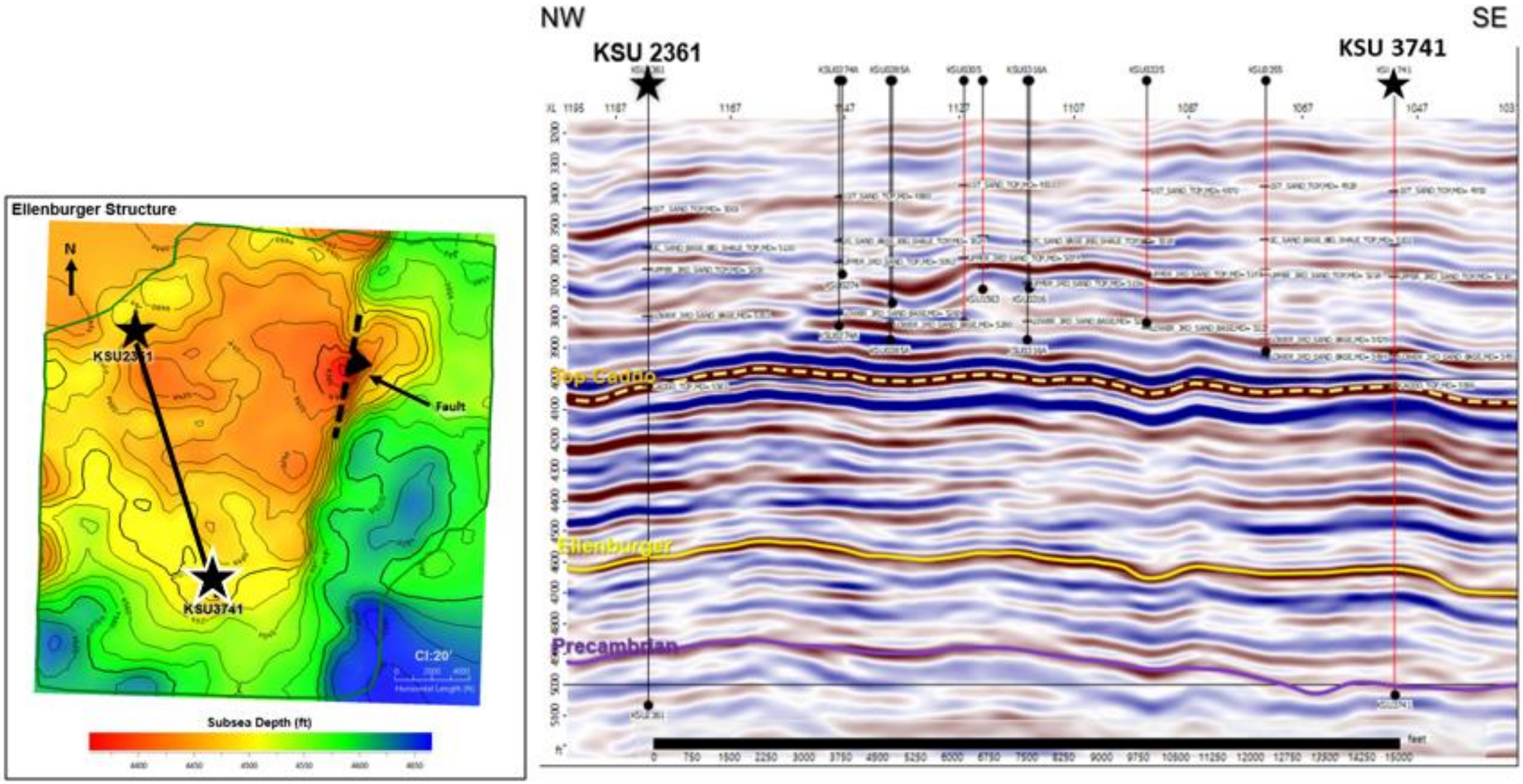


Figure 22 – Structural Northwest to Southeast Seismic Profile between the two wells that penetrate the Ellenburger within the seismic volume. Ellenburger structure map modified from Figure 19.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger and Cambrian sand formations at the KSU 2361 well location indicate that the formations have sufficient thickness, porosity, permeability, and lateral continuity to accept the proposed injection fluids. The Mississippian Lime formation at the KSU 2361 well has low permeability. It is of sufficient thickness and lateral continuity to serve as the upper confining zone, with the Lower Strawn Shale acting as a secondary confining unit. Beneath the injection interval, the low permeability, low porosity Precambrian formation is unsuitable for fluid migration and serves as the lower confining zone.

The area of review has been studied to identify potential subsurface features that may affect the ability of these injection and confinement units to retain the injectate within the requested injection interval. Faults have been identified, characterized, and determined to be low risk to the containment of injectate and do not increase the risk of migration of fluids above the injection interval.

2.6 Groundwater Hydrology

Stonewall, Haskell, Knox, and King Counties fall within the boundary of the Texas Water Development Board's (TWDB) Groundwater Management Area 6. The Seymour Aquifer is identified by the TWDB's *Aquifers of Texas* report in the vicinity of the KSU 2361 well (George et al., 2011). Table 5 references the Seymour Aquifer's position in geologic time and the associated geologic formations, which include the Seymour Formation, Lingos Formation, and Quaternary alluvium (Ewing et al., 2004). A depiction of the general stratigraphy of the Seymour Aquifer is shown in Figure 23.

Table 5 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas (Ewing et al., 2004).

System	Series	Group	Formation
Quaternary	Recent to Pleistocene		Alluvium
			Seymour
Tertiary	missing		
Cretaceous			
Jurassic			
Triassic			
Permian	Ochoa		Quartermaster
	Guadalupe	Whitehorse	
		Pease River	Dog Creek Shale
			Blaine Gypsum
			Flowerpot Shale
			San Angelo
	Leonard	Clear Fork	Choza
			Vale
			Arroyo
		Wichita (upper portion only)	Lueders
			Clyde

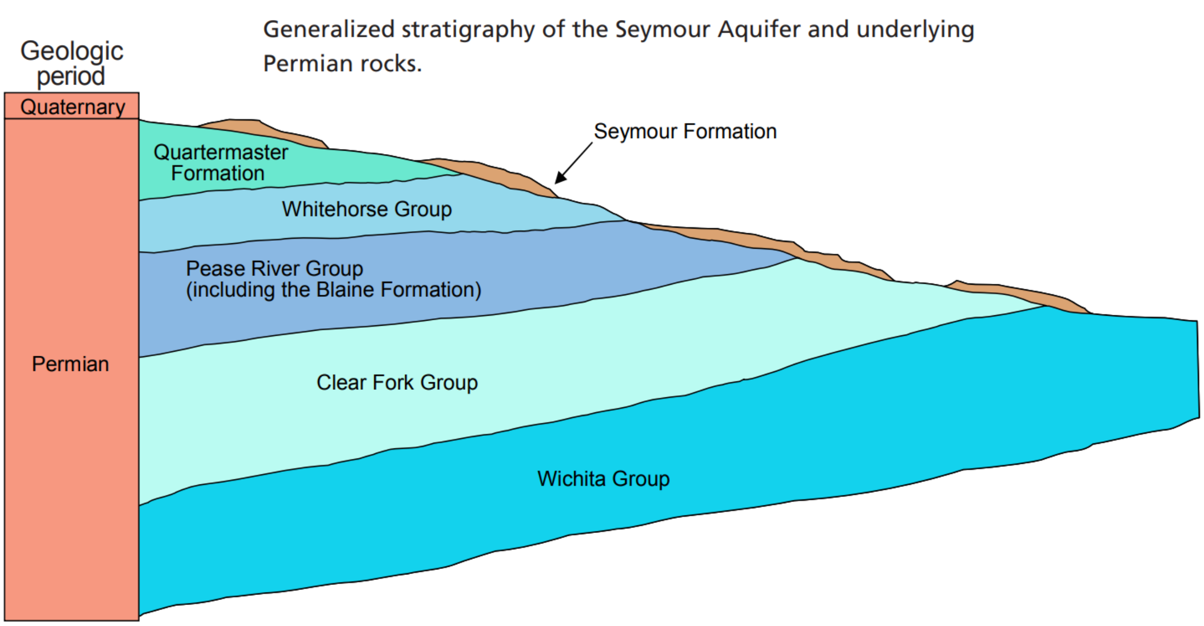


Figure 23 – Generalized Stratigraphy of the Seymour Aquifer (George et al., 2011)

The Seymour Aquifer, as defined by the TWDB, consists of isolated pods of alluvium deposits of Quaternary age, depicted in Figure 24. It extends from the southern Brazos River watershed northward to the border of Oklahoma. The Seymour Aquifer overlies Permian-age deposits that generally dip to the west. Topography, structure, and permeability variation control groundwater flow within the pods. The aquifer generally follows the topographical gradient along the major axis of the pod and discharges laterally to springs, seeps, and alluvium. Similar mechanisms can be expected within the majority of the other pods (Ewing et al., 2004).

A map showing the inferred groundwater flow pattern within a portion of one of the pods in Haskell and Knox counties is shown in Figure 25. The map approximates the natural direction of flow unaffected by pumping from wells. North of the Rule, TX, groundwater divide, the flow is toward the north, northwest, or northeast. Based on the contours of the water table and the permeabilities for the formation indicated by pumping tests, the estimated natural rate of water movement in the Seymour Aquifer, unaffected by pumping, ranges locally from approximately 200' to 5,000' per year. Over several miles, the estimated average rate of movement is typically between 800' and 1,200' per year (R.W. Harden and Associates, 1978).

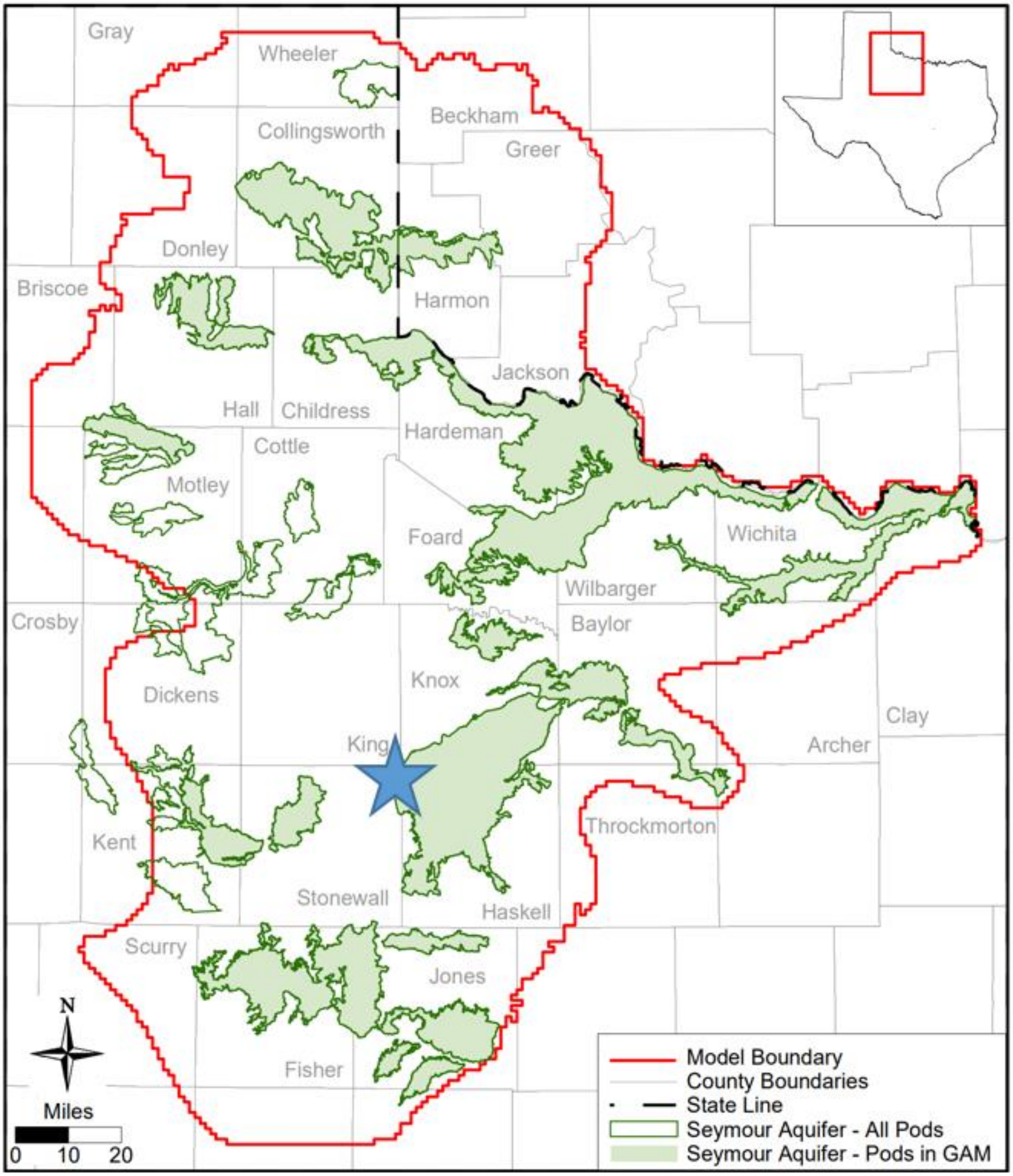


Figure 24 – Regional Extent of the Seymour Aquifer Pods (Ewing et al., 2004)

Figure 25 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer (R.W. Harden and Associates, 1978).

Total dissolved solids (TDS) are a measure of water saltiness, the sum of concentrations of all dissolved ions (such as sodium, calcium, magnesium, potassium, chloride, sulfate, and carbonates) plus silica. As shown in Figure 26, the total dissolved solids in 41% of the wells within the Seymour Aquifer exceed 1,000 milligrams per liter (mg/L), Texas' secondary maximum contaminant level (MCL). Therefore, the utility of water from the Seymour Aquifer as a drinking water supply is limited in many areas for health reasons, primarily due to elevated nitrate concentrations, and for taste reasons due to saltiness (Ewing et al., 2004).

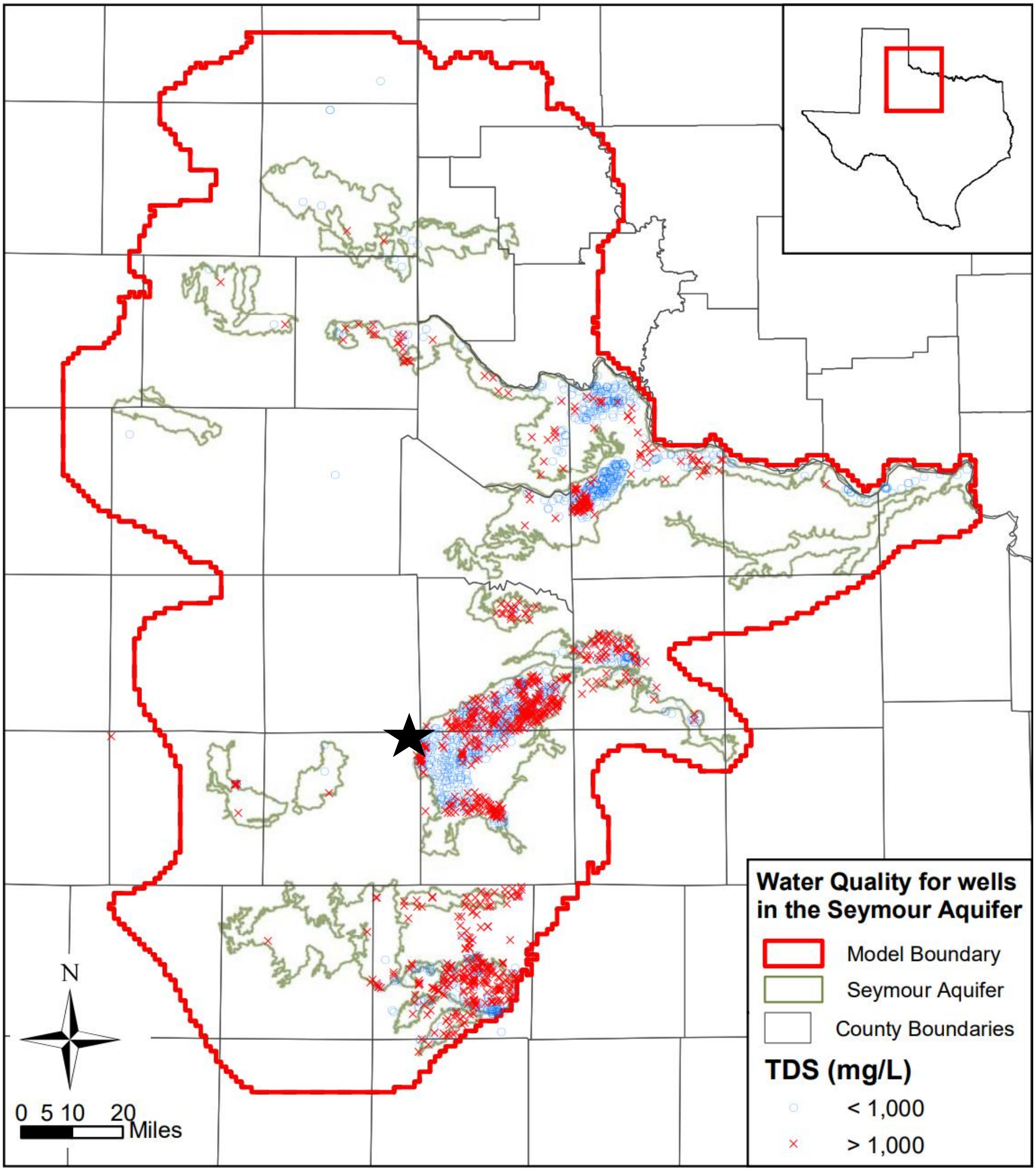


Figure 26 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer (Ewing et al., 2004)

The TRRC's Groundwater Advisory Unit (GAU) specified for the KSU 2361 well that the interval from the land surface to a depth of 100' must specifically protect usable-quality groundwater. Therefore, the base of Underground Sources of Drinking Water (USDW) can be approximated at 100' at the location of the KSU 2361 well, and there is approximately 5,920' separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued

by the TRRC as part of the Class II permitting process for the KSU 2361 well is provided in Appendix A. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Mississippian limestone, thousands of feet of tight limestone and shale beds occur between the injection interval and the lowest water-bearing aquifer.

2.6.1 Reservoir Characterization Modeling

Introduction

KSU 2361 is located in Kinder Morgan's Katz Oil Field in northeast Stonewall County. A geologic model was constructed of this area to forecast the movement of CO_2 and any pressure increases. The model is comprised of the Ellenburger and Cambrian formations, which cover 13,774 acres (~22 square miles). A single CO_2 injector was simulated for 100 years, where approximately 25 million metric tons (MMT) of CO_2 was safely stored.

Software

Paradigm's software suite was used to build the geologic and dynamic models. SKUA-GOCAD™ was utilized in building the geomodel, while Tempest™ designed the dynamic model. The EPA recognizes these software packages for an area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

SKUA-GOCAD™ is a software tool for geology that offers a range of features for structure and stratigraphy, structural analysis, fault seal, well correlation, facies interpretation, 2D/3D restoration, and basin modeling. The structure and stratigraphy module allows users to construct fully sealed structural models, while the structural analysis module provides tools for analyzing fracture probability, stress, and strain. The fault seal module enables the computation of fault displacement maps and fault SGR properties, and the well correlation module allows users to create well sections and digitize markers. The facies interpretation module offers tools for paleo-facies interpretation, and the 2D/3D restoration module provides tools for restoring 3D basin and reservoir models. Finally, the basin modeling module enables users to construct 4D basin models for transfer to basin model simulation software.

Tempest™ is another of Paradigm's industry-leading software packages for reservoir engineering. Tempest™ has history-matching capabilities, allowing for more accurate reservoir characterization modeling. In addition, this software is used to build dynamic models for CO_2 injection. Tempest™ is comprised of three modules: Tempest™ VIEW, Tempest™ ENABLE and Tempest™ MORE. Tempest™ MORE is a black oil simulator with many features and applications to simulate CO_2 injection. The Tempest™ MORE module can accept data in standard GRDECL (RMS, Petrel) file formats. It can also produce output in the ECLIPSE, Nexus/VIP, Intersect, and IMEX/GEM/STARS formats. This allows users to easily import data into the software and export it in a format compatible with other tools and systems. The standard file formats improve the interoperability and compatibility of the MORE software with other systems and tools used in the oil and gas industry

Trapping Mechanisms

To accurately simulate the CO_2 injection and predict the subsequent plume migration, Tempest™ models CO_2 trapping mechanisms in the injection zone. There are five primary trapping mechanisms: structural, hydrodynamic, residual gas (hysteresis), solubility, and geochemical. For this simulation, geochemical reactions were not considered. Each of the five mechanisms is described in further detail below.

Structural Trapping
Structural traps, a physical trapping mechanism, are underground rock formations that trap and store the injected supercritical CO_2. These traps are created by the physical properties of the cap rock, such as its porosity and permeability. For example, a structural trap may be formed by a layer of porous rock above a layer of non-porous rock, with the CO_2 being trapped in the porous rock. Some other examples of structural traps are faults or pinch-outs. Faults can limit the horizontal migration of the plume in the injected formation. The injected CO_2 is lighter than the connate brine found already in the formation. Because of this, the CO_2 floats to the top of the formation and is stored underneath the impermeable cap rock. In this model, CO_2 mass density ranges between 34.9 to 38.5 lb/ft^3 from the shallow to deep injection intervals, whereas the formation brine density is approximately 63.3 lb/ft^3.

Hydrodynamic Trapping
Hydrodynamic traps are another form of physical trapping caused by the interaction between CO_2 and the formation brine. Hydrodynamic trapping is caused by supercritical CO_2 traveling vertically upwards until it reaches the impermeable cap rock and spreads laterally through the unconfined sand layers, driven by the buoyancy and higher density of the brine in the reservoir. Once the CO_2 reaches a caprock with a capillary entry pressure greater than the buoyancy, it is effectively trapped. This type of trapping works best in laterally unconfined sedimentary basins with little to no structural traps.

Equation-of-state (EOS) calculations are performed to determine the phase of CO_2 at any given location based on pressure and temperature for structural and hydrodynamic trapping mechanisms. Several well-known EOS formulae are used within the oil and gas industry for reservoir modeling. These formulae include the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong (SRK) method. The Peng-Robinson is better suited for gas systems than the SRK method. The EOS implemented within the KSU 2361 well model was the Peng-Robinson method.

Residual Gas Trapping
Residual gas traps are also a physical form of trapping CO_2 within pore space by surface tension. This occurs when the porous rock acts as a sponge and traps the CO_2 as the displaced fluid is forced out of the pore space by the injected CO_2. As the displaced brine reenters the pore space once injection stops, small droplets of CO_2 remain in the pore space as residuals and become immobile.

Solubility Trapping
Solubility traps are a form of chemical trapping between the injected CO_2 and connate formation brine. Solubility trapping occurs when the CO_2 is dissolved in a liquid, such as the formation brine.

CO_2 is highly soluble in brine, with the resulting solution having a higher density than the connate brine. This feature affects the reservoir by causing the higher-density brine to sink within the formation, trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration. Table 6 was designed to guide the model to determine the solubility of CO_2 at various pressures and a specified salinity.

Table 6 – CO_2 Solubility Table

Pressure (psi)	CO2 Solubility (Mscf/Stb)	Salinity (ppm)
14	0.00	66,000
50	0.00	66,000
150	0.01	66,000
500	0.0198	66,000
1000	0.0297	66,000
1500	0.0388	66,000
3000	0.0660	66,000

<u>Geochemical Trapping</u>

Geochemical trapping is another form of chemical trapping which refers to storing CO_2 in underground rock formations by using chemical reactions to transform the CO_2 into stable, solid minerals. This process is known as mineral carbonation, and it involves the reaction of CO_2 with the minerals and rocks in underground formations to form stable carbonates. During the process of injecting CO_2 into a disposal reservoir, four (4) primary chemical compounds may be present: CO_2 in the supercritical phase, the hydrochemistry of the naturally occurring brine in the reservoir, aqueous CO_2 (an ionic bond between CO_2 gas and the brine), and the geochemistry of the formation rock. These compounds can interact, leading to the precipitation of CO_2 as a new mineral, often calcium carbonate (limestone). This process is known as mineral carbonation, a key mechanism for the long-term storage of CO_2 in underground rock formations.

Mineral trapping can also occur through the adsorption of CO_2 onto clay minerals. When modeling this process, it is important to consider both hysteresis and solubility trapping. Geochemical formulae can be included in the model using an internal geochemistry database to describe the mineral trapping reactions. These formulae can describe aqueous reactions, such as those involving CO_2 and clay minerals. For aqueous reactions, the following chemical reactions are standard formulae used in CO_2 simulation:

$$CO_2(aq) + H_2O = H^+ + HCO_3^-$$
$$CO_3^{-2} + H^+ = HCO_3^-$$
$$OH^- + H^+ = H_2O$$

The following three formulae represent three common ionic reactions that can occur between water and CO_2 within a reservoir. These reactions involve the formation of solid minerals that can be found in sandstone aquifers, and they result in the precipitation of carbon oxides. These reactions are commonly included in modeling efforts to understand and predict the behavior of CO_2 in underground storage reservoirs:

$$Anorthite\ (CaAl_2Si_2O_8) + 8H^+ = 4\ H_2O + Ca^{2+} + 2Al^{4+}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO3^-$$
$$Kaolinite\ \left(Al_2Si_2O_5(OH_4)\right) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO$$

Geochemical trapping has the potential to store CO_2 for hundreds or thousands of years, but the short-term effects of this method are relatively limited. Instead, the short-term movement and storage of CO_2 are more strongly influenced by hydrodynamic and solubility trapping mechanisms. These mechanisms involve the movement of fluids, such as water or oil, through porous rock formations and the solubilization of CO_2 in liquids, such as water or oil. As a result, these processes can be more effective in the short term at storing CO_2, although they may not have the same long-term stability as geochemical trapping.

Static Model

The geomodel was constructed to simulate the geologic structure of the Ellenburger and Cambrian formations. The grid contains 600 cells in the X-direction (East-West) and 400 cells in the Y-direction (North-South), totaling 240,000 cells per layer. Therefore, 55 layers were utilized in the model representing the gross thickness of the injection interval, totaling 13,200,000 grid blocks. The Ellenburger is comprised of 25 layers and the Cambrian is comprised of 30 layers. Each grid block is 50’ by 50’ by 10’, resulting in a model size of 5.7 miles by 3.8 miles by 550,’ as shown in Figure 27. This covers approximately 22 square miles (13,774 acres).

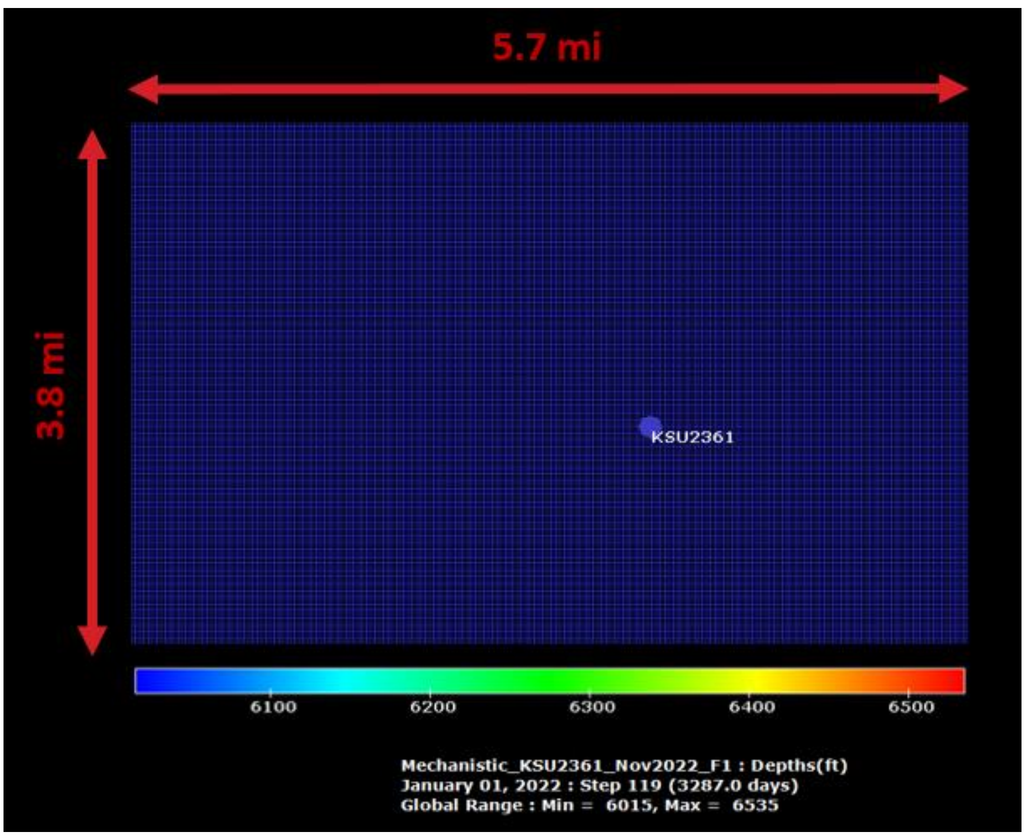


Figure 27 – Geomodel Dimensions

Well log analysis tied into seismic interpretation was used to identify any major formations tops. Four geologic units were identified and incorporated into the geomodel. Each geologic unit was used to determine the geologic structure of the injection zone. First, the Ellenburger is a carbonate formation comprised of dolomite/limestone matrix. Underlying the Ellenburger formation is the Cambrian sandstone. This sandstone was split into two geologic units, the Cambrian 1 and Cambrian 2. The Precambrian formation is at the bottom of the model. The Precambrian, comprised of granite, is the lower confining zone. Figure 28 highlights the overall structure of the target zone.

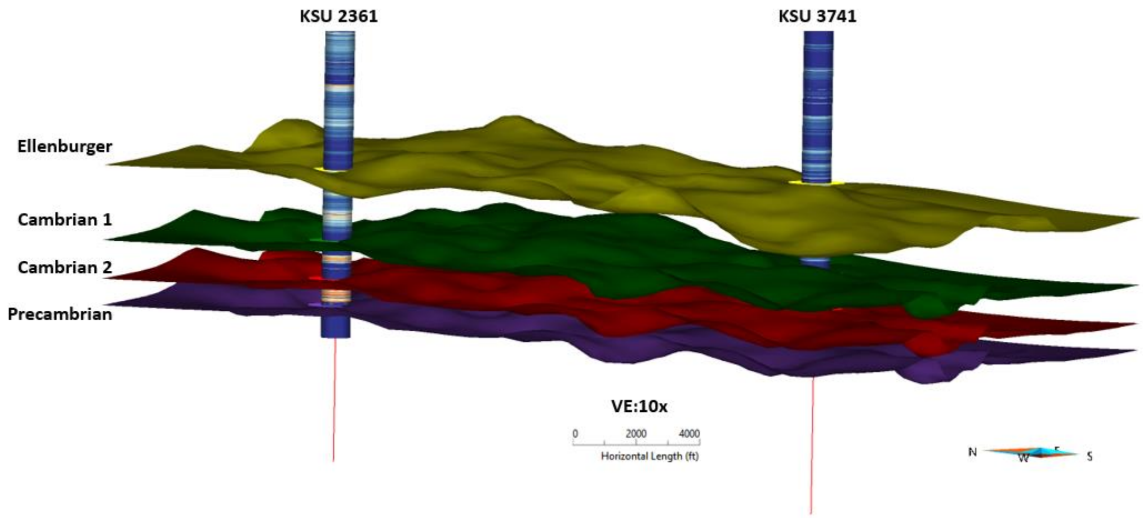


Figure 28 – Structural Horizons of the Geomodel

Permeability and porosity were distributed through the geomodel based on the formation. These rock properties were considered to be laterally homogenous in the simulation. However, vertical heterogeneity was incorporated into the model. Based on well log analysis, porosity was determined to be 10% in the Ellenburger carbonate and 12% in the Cambrian sandstone, as shown in Figure 29. Permeability was determined from history matching two wells. From this exercise, it was determined that the horizontal permeability (K_H) is 20 milliDarcy (mD) and vertical permeability (K_V) was assumed to be 10% of K_H or 2 mD. Table 7 summarizes the rock properties in the model.

Table 7 – Rock Properties

Assumptions	Values
Ellenburger Porosity (%)	10
Cambrian Porosity (%)	12
K_H (mD)	20
K_V/K_H Ratio	0.1

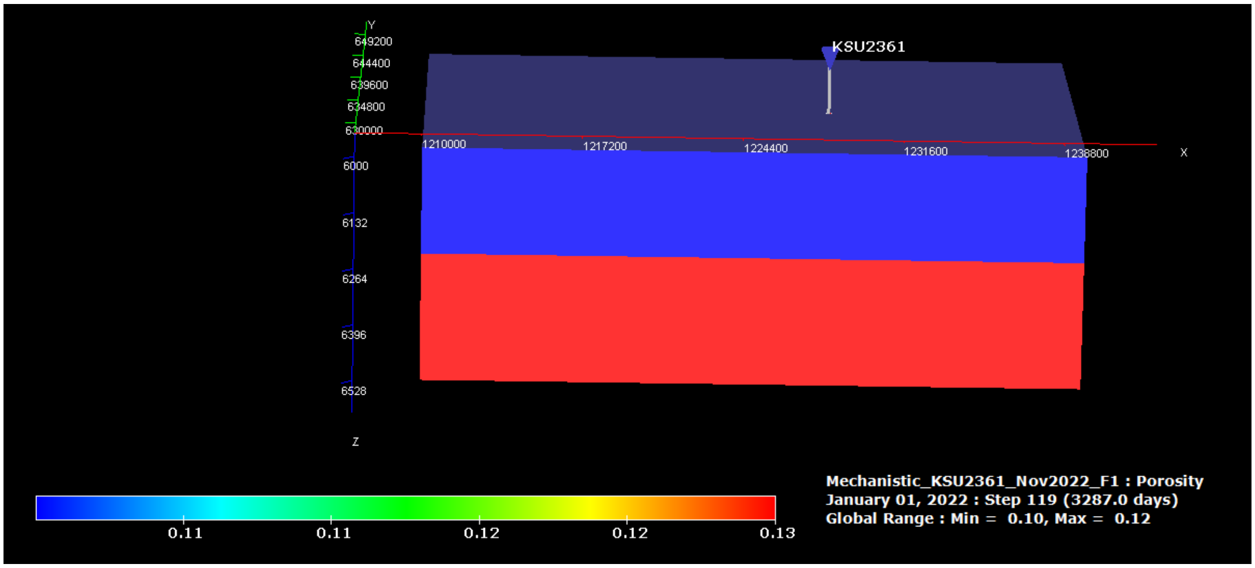


Figure 29 – Porosity Distribution in Plume Model

Dynamic Model

The primary objectives of the CO_2 plume model are as follows:

1. Determine the maximum possible injection rate without fracturing the target zone
2. Determine land acquisition strategy (i.e., maximum plume size)
3. Assess the likelihood of CO_2 leakage through potential conduits that may contaminate the Underground Source of Drinking Water (USDW)

Using the geomodel as an input, an infinite-acting model was built to simulate boundary conditions. The model assumes that the reservoir is 100% filled with brine. The formation fluid was estimated to have a salinity of 66,000 ppm. An offset step-rate test was utilized to estimate initial reservoir pressure and fracture pressure. Reservoir pressure was determined to be 2,600 psi which translates to a 0.435 psi/ft gradient. While pressure never reached high enough to propagate any fractures during the step-rate test, the fracture pressure was estimated to be approximately 4,390 psi. This translates to a fracture gradient of 0.683 psi/ft. Based off this data, a wellhead pressure of 1,850 psi was used to constrain the modelled well. An average temperature of 260 °F was also applied to the reservoir. Table 8 provides a summary of the initial conditions included in the simulation.

Table 8 – Initial Conditions Summary

Assumptions	Values
Permeability (mD)	20
Porosity (%)	10-12
Pore Gradient (psi/ft)	0.435
Frac Gradient (psi/ft)	0.683
Reservoir Temperature (°F)	260

To accurately and conservatively model the effective pore space of the rock, a net-to-gross (NTG) ratio was applied to the Ellenburger and Cambrian formations. The lateral plume extent is increased by reducing the total pore space CO_2 can flow through. Reducing the available pore space also limits

the CO_2 injection rate of the well due to higher increases in pressure. The Ellenburger had an NTG ratio of 0.5 applied, while the Cambrian formation had a 0.6 NTG ratio. This is further highlighted in Figure 30.

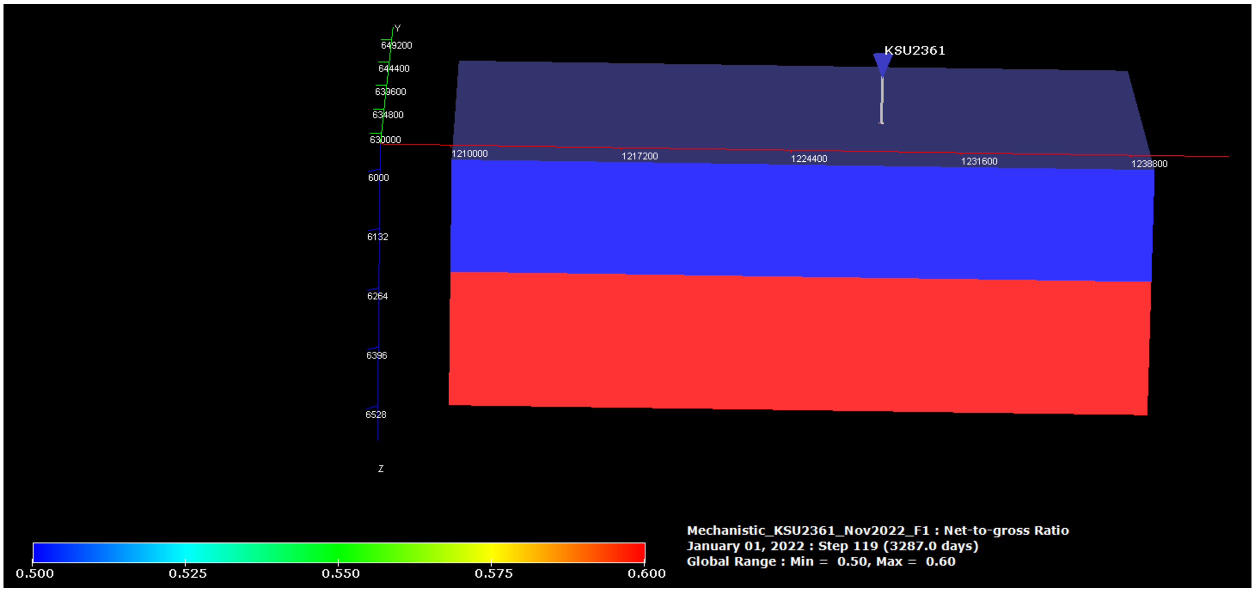


Figure 30 – NTG Ratio Applied to the Plume Model

Relative Permeability

Relative permeability curves were generated to represent a CO_2-brine system and how supercritical CO_2 will flow through a 100% brine-filled rock. Data from Kinder Morgan's McElmo Dome source models were utilized to create the relative permeability curves. The key inputs include a 9% irreducible water saturation and a 9% maximum residual gas saturation. Figure 31 shows the curves included in the simulation model.

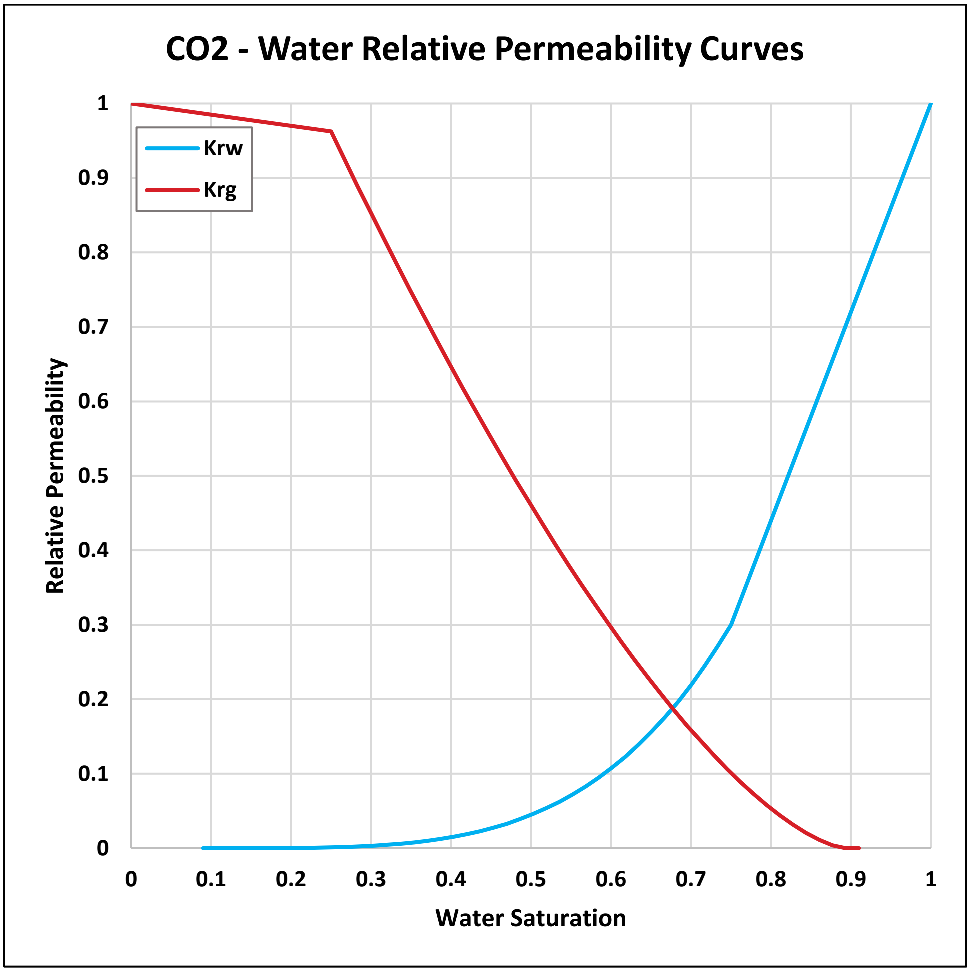


Figure 31 – CO_2-Water Relative Permeability Curves

History Matching

Two SWD wells were history-matched to determine permeability estimates. Historical injection rates were set in the model, and the simulated pressure response was compared to the recorded pressure data. This process was iterated multiple times until the simulated and real-life data matched. Monthly data points KSU 2361 (Figure 32) and KSU #3471 (Figure 33) were used to vary the injection rate in the model. These same intervals were used to compare the simulated results.

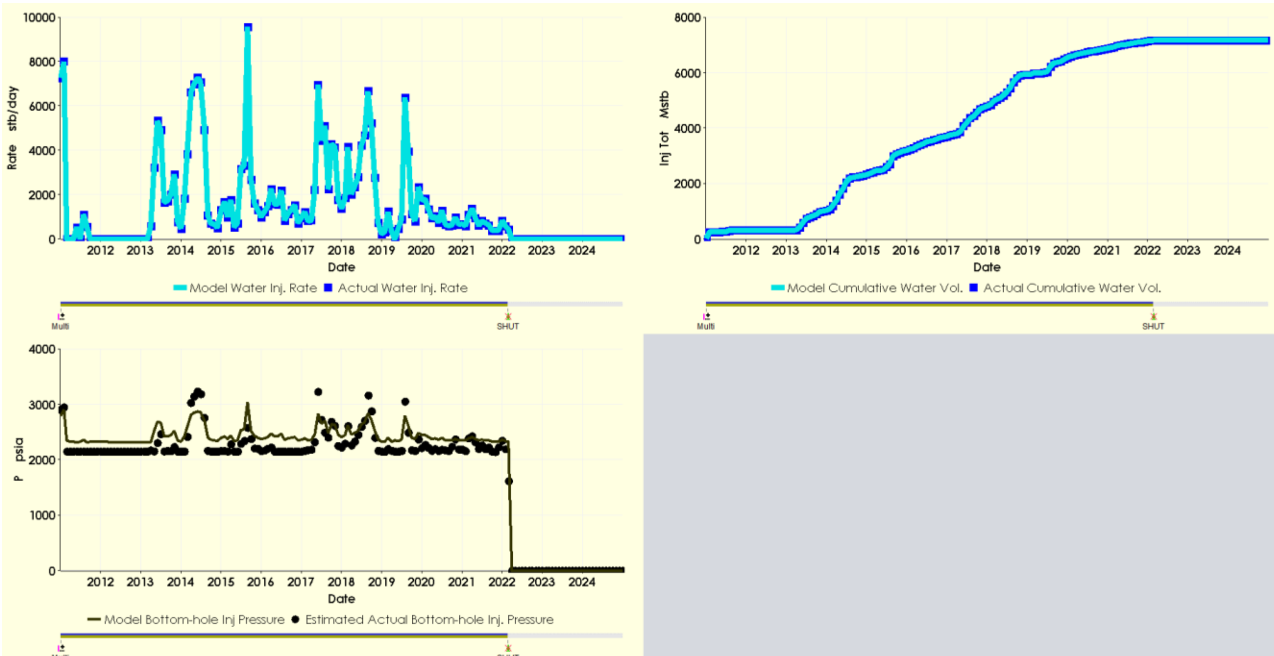


Figure 32 – History Match for KSU 2361

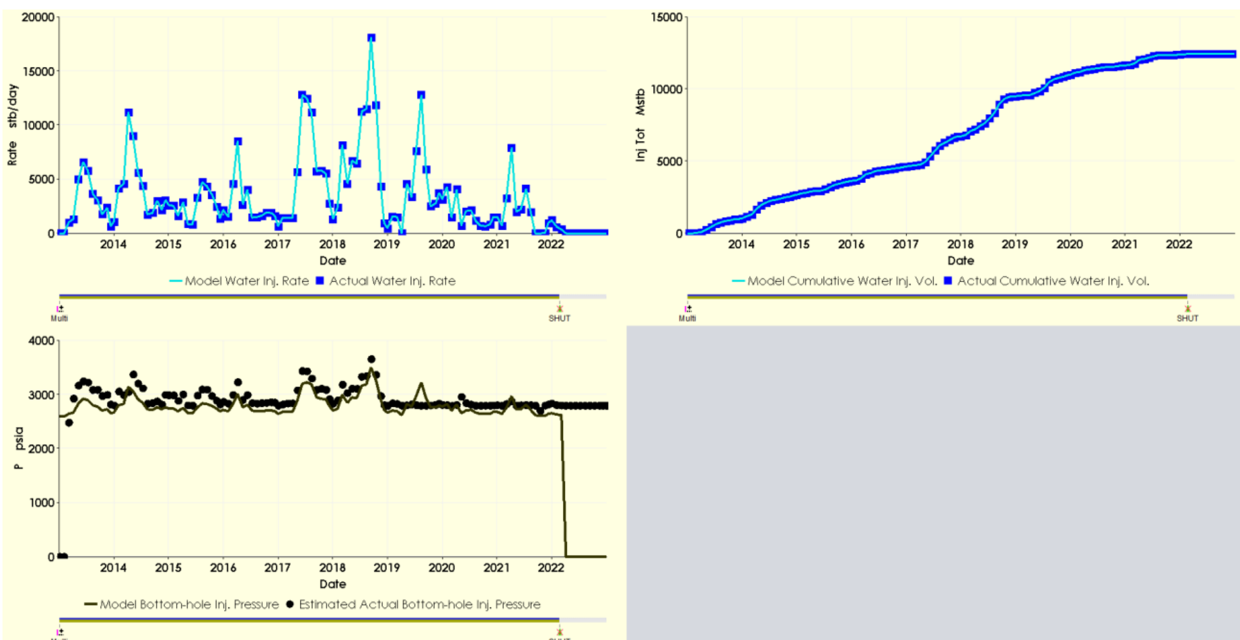


Figure 33 – History Match for KSU #3471

CO_2 Injection Operations

KSU 2361 was simulated to inject supercritical CO_2 for 21 years. A maximum wellhead pressure (WHP) was used to limit the injection rate. This value was determined from the fracture gradient estimation, and an equivalent wellhead pressure was calculated. The WHP constraint was set to 1,850 psi, equal to 84% of the fracture pressure. The injection rate was then maximized to stay

below the expected frac gradient. Figure 34 shows the simulated WHP during active injection operations.

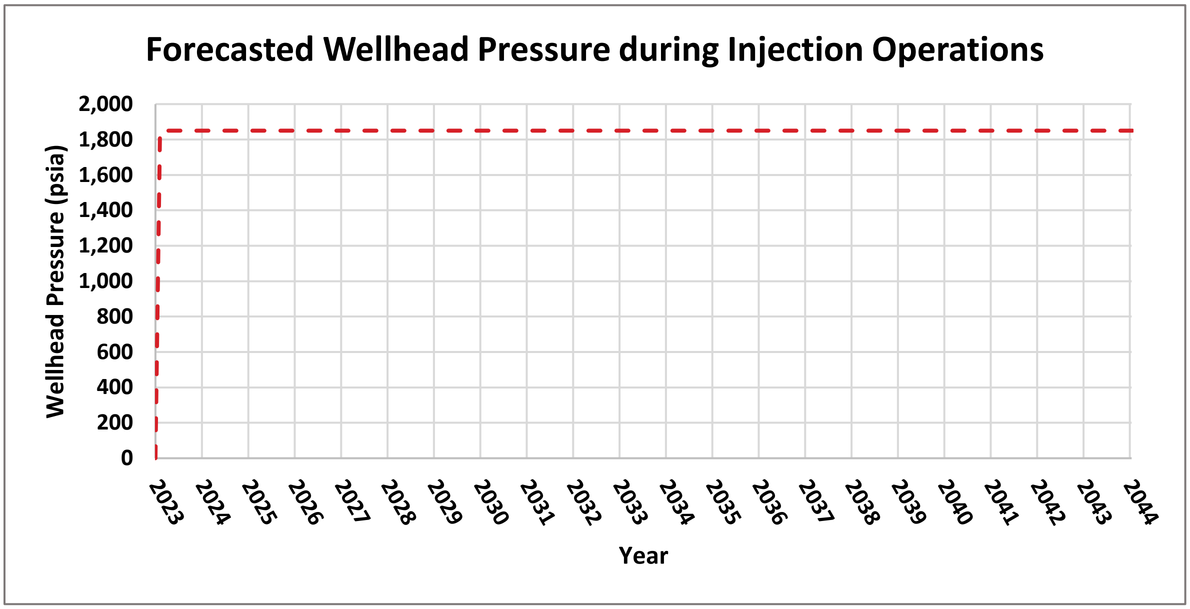


Figure 34 – Simulated Wellhead Pressure During Active Injection

During active injection, KSU 2361 achieved a maximum rate of approximately 1.22 MMT/yr. (~65 million cubic feet (MMscf)/day). During injection, the bottom hole pressure (BHP) reaches a maximum of 3,493 psi, which is safely below the fracture pressure. This is an 893-psi increase from the initial reservoir pressure. After injection ceases, the reservoir pressure decreases, reaching 65 psi buildup from the initial reservoir pressure. Figure 35 summarizes these results. The decreasing bottom-hole pressure from 2023 to 2044 is due to the relative permeability increasing over time.

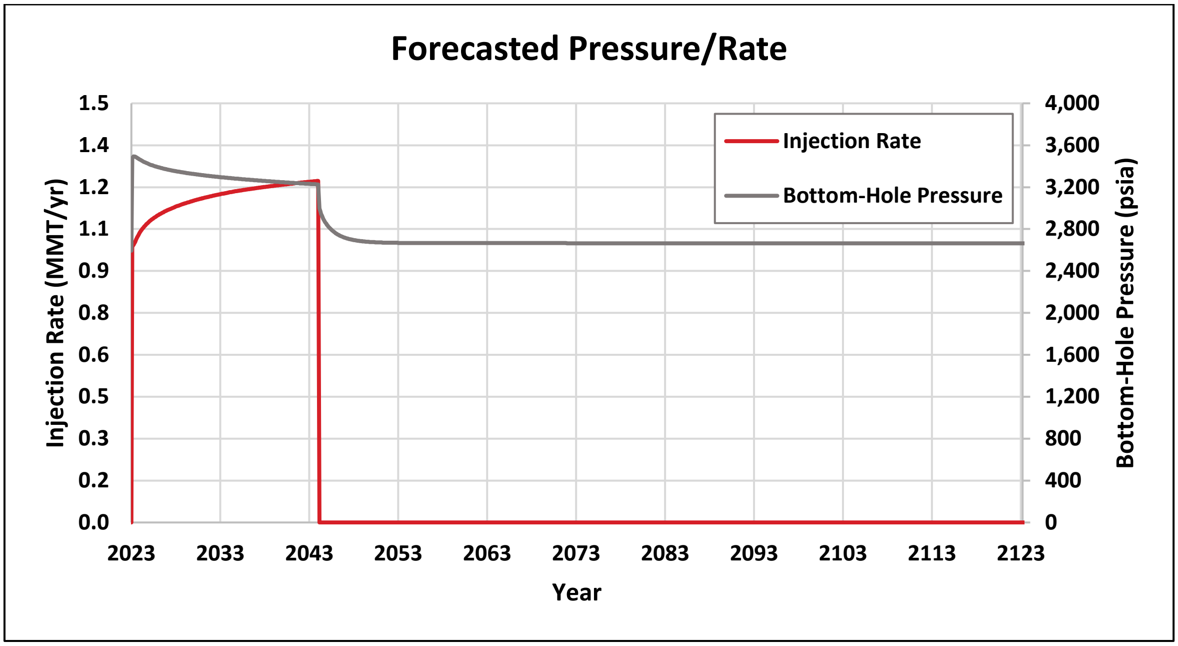


Figure 35 – Forecasted Injection Rate and BHP

Model Results

The maximum plume was determined once the plume was considered stabilized and by using a gas saturation cutoff of 3%. The plume is considered stabilized once all lateral and vertical movement of CO_2 has stopped, which also marks the end of the initial monitoring period. Aerial plume sizes were taken at 10-year intervals to determine a growth rate. As seen in Figure 36, an annualized growth rate is determined at each interval. The plume is delineated based on the maximum extent of the plume when the growth rate reaches 0%. In this model, the plume stabilizes in 2074, 30 years after the end of the injection period.

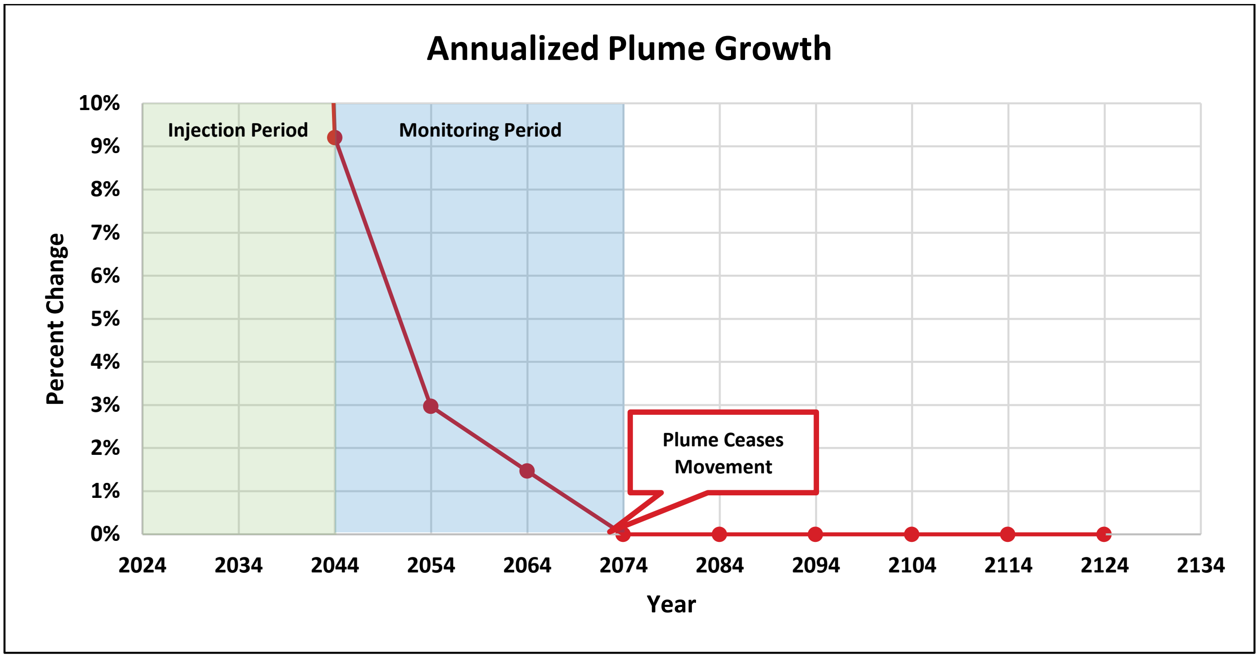


Figure 36 – Annualized Growth Rate of CO_2 Plume

The stabilized plume reaches a maximum of 3,384 ac (~5.3 sq mi). The furthest extent of this plume is to the South, as seen in Figure 37. The largest radius of the plume is 6,850' (~1.2 mi) from the wellbore. Due to the heterogeneity included in the model, the plume is not uniform from layer to layer, as seen in Figure 48. The maximum plume was chosen from the layer with the largest lateral extent of CO_2. Table 9 shows the plume radius and plume compared to time since injection starting in year zero. The results in Table 9 show that the modeled plume boundary is expected to stabilize 30 years after injection has ended. Additionally, the model was run a further 50 years to ensure the final plume boundary was stabilized, as shown in the table below.

Table 9 – Plume Model Radius and Area

Date	Year	Plume Radius (ft.)	Plume Area (Acres)
Jan-23	0	0	0
Jan-34	10	4650	1559
Jan-44	20	6400	2954
Jan-54	30	6700	3238
Jan-64	40	6800	3335
Jan-74	50	6850	3384
Jan-84	60	6850	3384
Jan-94	70	6850	3384
Jan-04	80	6850	3384
Jan-14	90	6850	3384
Jan-24	100	6850	3384

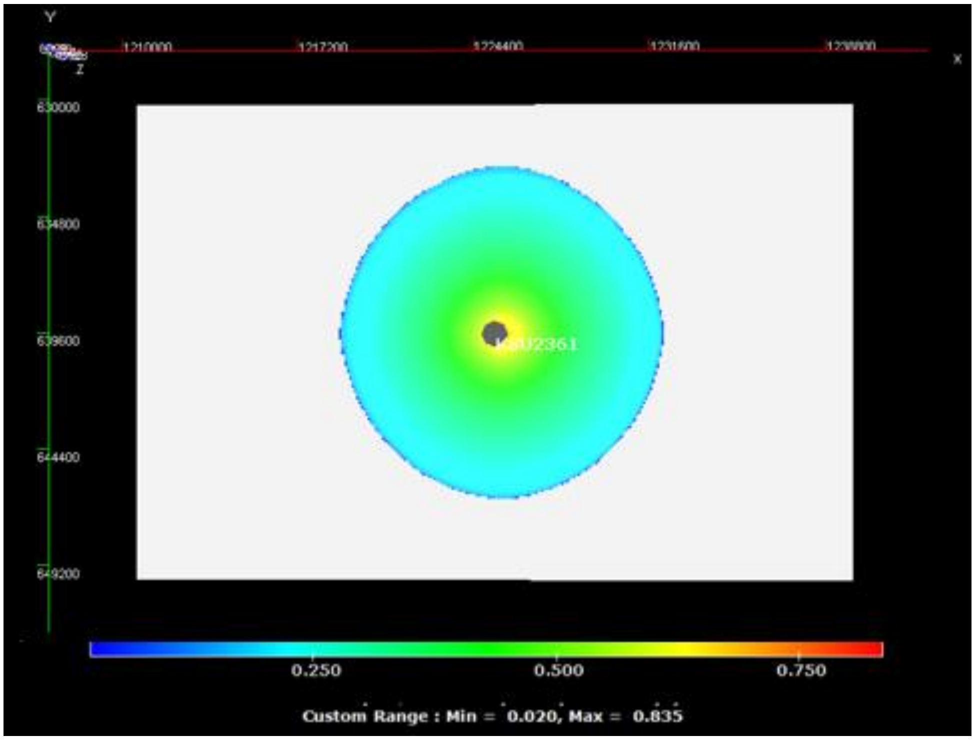


Figure 37 – Aerial View of CO_2 Plume

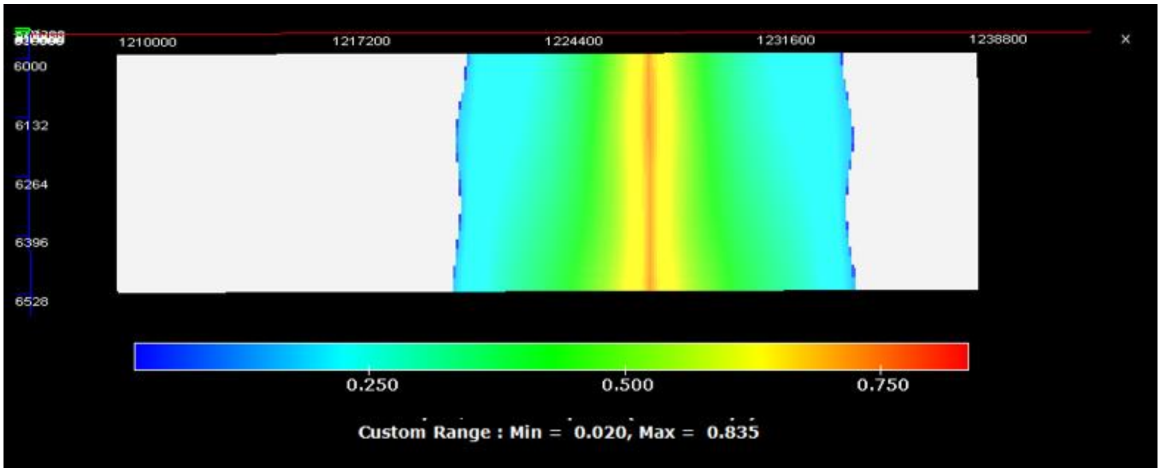


Figure 38 – Cross-Sectional View of CO_2 Plume

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA) as described in EPA 40 CFR §**98.448(a)(1**).

3.1 Maximum Monitoring Area

The EPA defines the MMA as equal to, or greater than, the area expected to contain the free-phase CO_2-occupied plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one-half mile. A numerical computer simulation was used to determine an estimate for the size and drift of the plume. Using a combination of Paradigm's SKUA-GOCAD and Aspen Technology's Tempest software packages, a geomodel, and reservoir model were used to determine the areal extent and density drift of the plume. The model accounts for the following considerations:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Kinder Morgan's pipeline gas specifications were used for the initial composition of the injectate in the model, as provided in Appendix B. The molar composition of the gas is mostly carbon dioxide, with some small amounts of nitrogen and hydrocarbons, and contained no H_2S. The molar composition was incorporated into the model as future CO_2 streams could be added for injection. As discussed in Section 2, the gas was modeled to be injected primarily into the Ellenburger and both Cambrian formations. The geomodel was created based on the rock properties seen in the Ellenburger and Cambrian rocks.

The weighted average gas saturation defined the plume boundary in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in 2044, the areal expanse of the plume will be 2,954 acres. The maximum distance between the wellbore and the edge of the plume is approximately 6,400', after injection stops in 2044. After 30 additional years of density drift, the areal extent of the plume is 3,384 acres, with a maximum distance to the edge of the plume of approximately 6,850'. Since the stabilized plume shape is relatively circular, the maximum distance plus a one-half mile buffer from the injection well, was used to define the circular boundary of the MMA equal to 9500'.

The plume is expected to stabilize 30 years after injection ceases and does not migrate after 2050, the monitoring program of the MMA will remain active for the required amount of time.

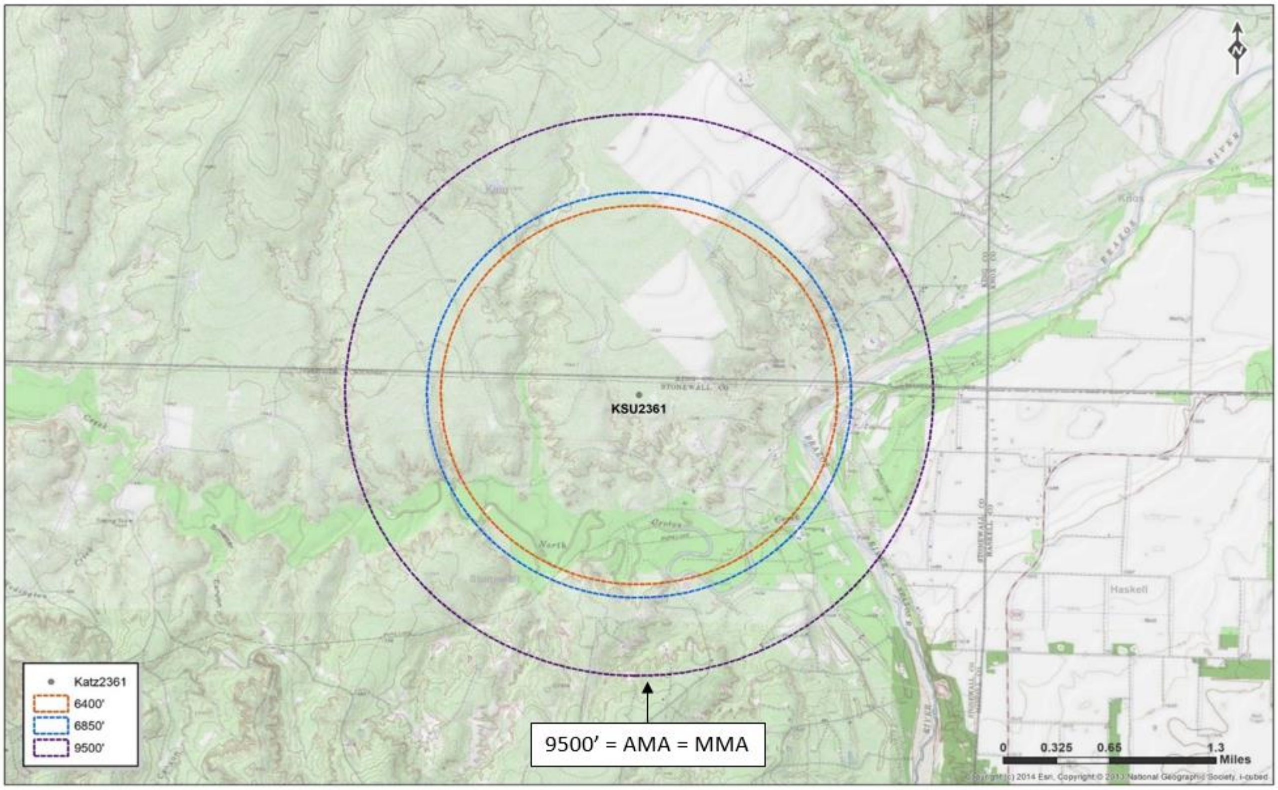


Figure 39 – Stabilized Plume Boundary, Active Monitoring Area, and Maximum Monitoring Area

3.2 Active Monitoring Area

Assuming year t occurs at the point the plume stabilized (30 years after the cessation of injection), the plume extent in year t + 5 has the maximum radius of 6,850', which is the extent of the MMA. Thus, Kinder Morgan will define the AMA as equal to the MMA, in this case, as show in Figure 39.

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from Natural or Induced Seismicity

4.1 Leakage from Surface Equipment

The surface facilities at the KSU 2361 well are designed for injecting acid gas primarily consisting of CO_2. One additional pipeline will be constructed to carry the acid gas from the custody transfer meter to the KSU 2361 wellhead, as shown in Figure 40. The wellbore of the KSU 2361 is designed for acid gas, as seen in the wellbore schematic in Figure 41. The facilities have been designed to minimize leakage and failure points. The design and construction of these facilities followed industry standards and best practices. CO_2 monitors are located around the facility and the well site. These gas monitor alarms will be triggered at levels set upon completion of a baseline study of the ambient air quality, followed by a gas dispersion model. An emergency shutdown valve (ESD) is located at the wellhead and is locally controlled by pressure, with a high-pressure and low-pressure shut-off.

The facilities have been designed and constructed with other safety systems to provide for safe operations. These systems include ESD valves to isolate portions of the pipeline, pressure relief valves along the pipeline to prevent over-pressurization, and venting to allow piping and equipment to be de-pressured under safe and controlled operating conditions in the event of a leak. More information on these systems and be found in Appendix C. Should Kinder Morgan construct additional CO_2 facilities other meters will be installed as needed to comply with the 40 CFR **§98.448(a)(5**) measurement. These meters will be near the existing facilities and utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meters and tied into the facility monitoring systems. No additional wells are included within this MRV facility.

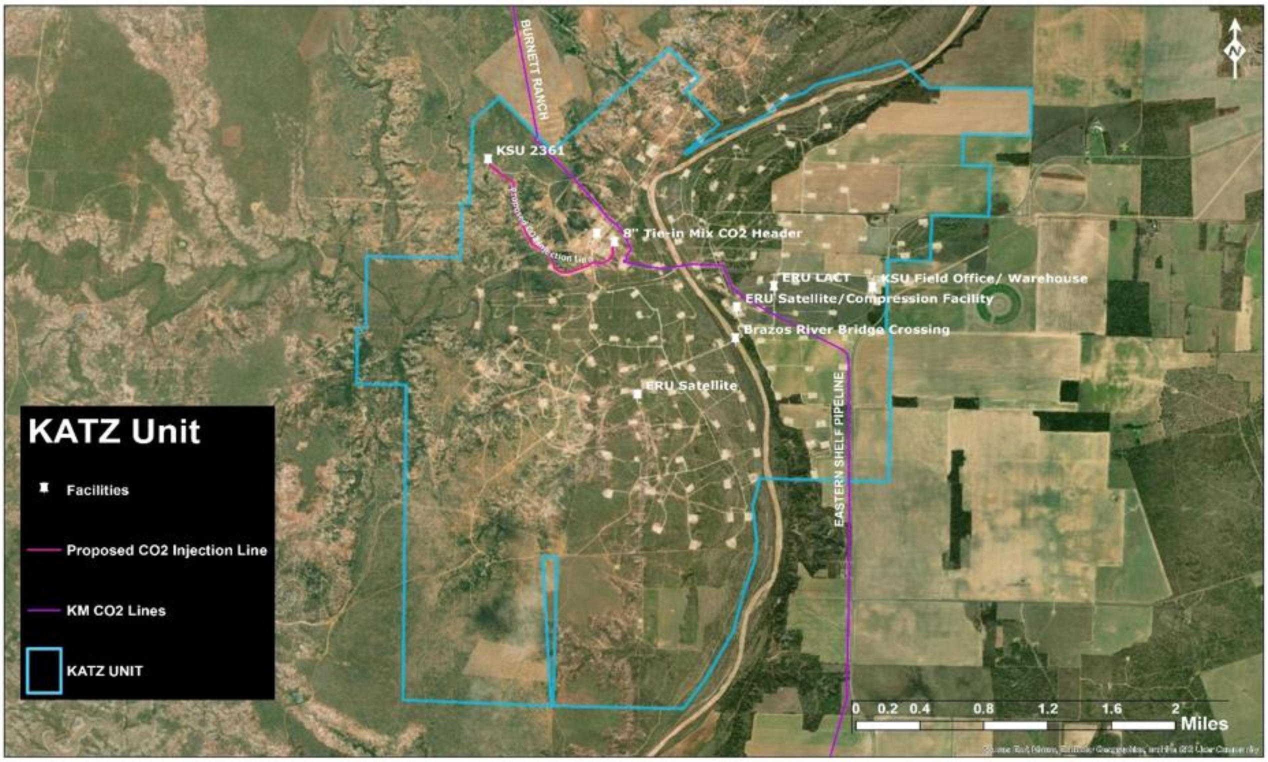


Figure 40 – Site Plan

With the level of monitoring implemented at the KSU 2361 well, a release of CO_2 would be quickly identified, and the safety systems would minimize the release volume. The CO_2 stream injected into KSU 2361 could include small amounts of methane and nitrogen, as seen in Appendix B. The CO2 injected into the Katz 2361 well is supplied by a number of different sources into the pipeline system and the composition is not expected to change over time. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR **§98.448(a)(5)**. Kinder Morgan concludes that leakage of CO_2 through the surface equipment as unlikely.

4.2 Leakage from Existing Wells within MMA

4.2.1 Oil and Gas Operations within Monitoring Area

A significant number of wells have historically been drilled within the area of the KSU 2361 well. However, production has primarily been from the shallower Strawn formation in the Katz Field. The Strawn is separated from the Ellenburger-Cambrian interval by 665’ in this area. In addition to the primary Strawn production, a few wells have produced from the Mississippian. The mid-Mississippian is separated from the Ellenburger-Cambrian interval by 133’. KSU 2361 is the only well penetrating the injection interval within the projected plume area of the MMA for the KSU 2361. Therefore, it is the only well that will be monitored for surface leakage. This well is designed to handle and inject acid gas, which reduces the risk and likelihood of leakage through the existing well to near-zero.

The KSU 2361 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as depicted in the schematic denoted in Figure 41. Mechanical integrity tests (MIT), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every five years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 42. The MMA review map and a summary of all the wells in the MMA are provided in Appendix D. Figure 43 highlights that no wells penetrate the MMA's gross injection zone.

KINDER MORGAN

Schematic - Current

Well Name: KSU #2361

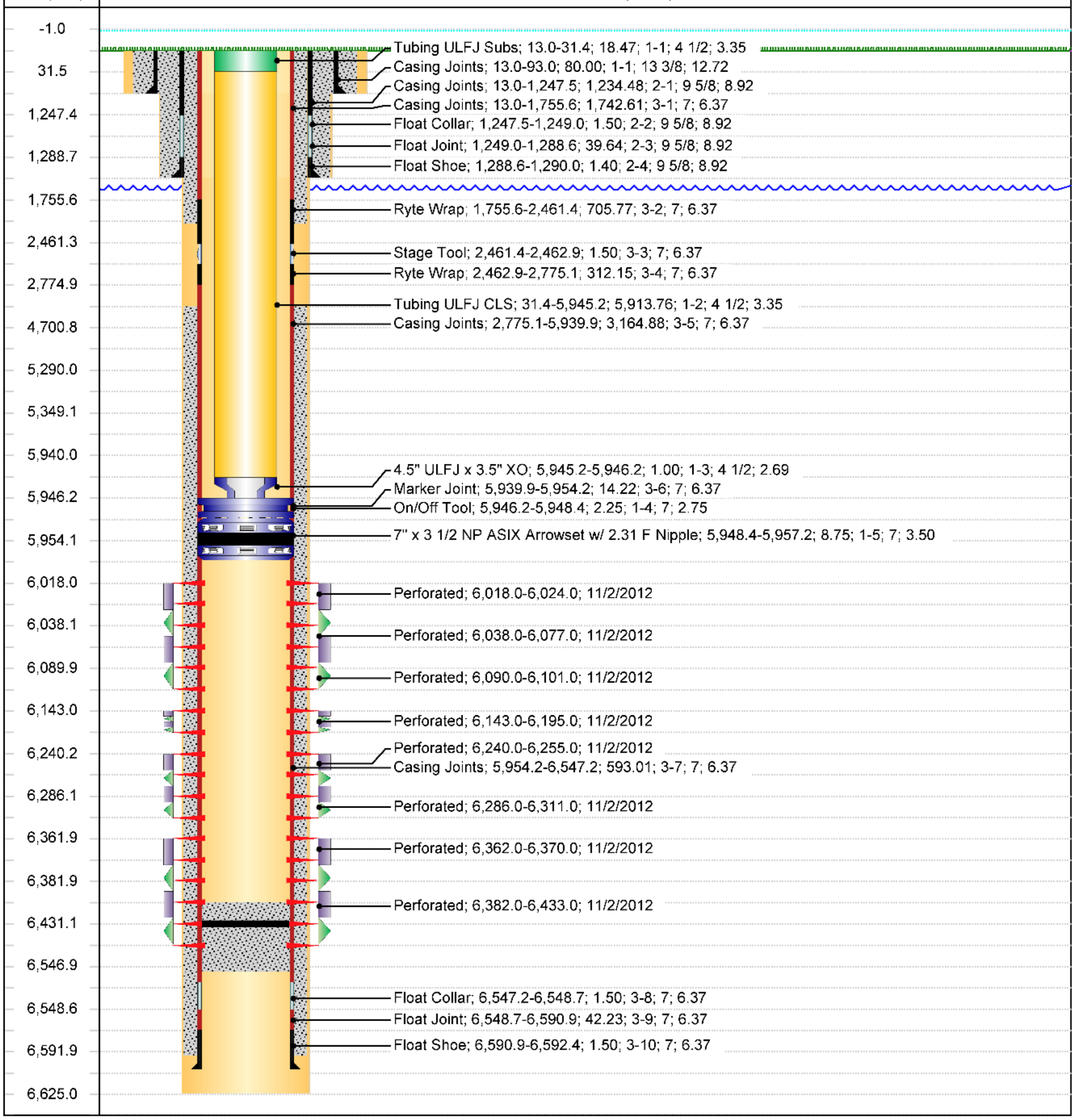
API/UWI	Surface Location	Field Name	State	Well Configuration Type	RRC/COGC...	Account Cat/Prop...
42-433-33712	SEC 2 LONG, CB	KATZ	Texas	Vertical		26039
Estimated KB Elevation (ft)	**KB-Tubing Head Distance (ft)**	**Original Well Spud Date**	**Rig Release Date**	**PBTD (All) (ftKB)**	**Total Depth All (TVD) (ftKB)**	
1,531.00	13.00	8/23/2012 18:00	9/13/2012 06:00	Original Hole - 6,431.0		

Most Recent Job

Job Category	Primary Job Type	Secondary Job Type	Start Date	End Date
Non-Rig Activity	Coil Tubing		4/2/2019	4/4/2019

TD: 6,625.0 Vertical, Original Hole, 2/21/2022 10:06:22 AM

MD (ftKB) | Vertical schematic (actual)



Page 1/1 **Report Printed: 2/21/2022**

Figure 41 – KSU 2361 Wellbore Schematic

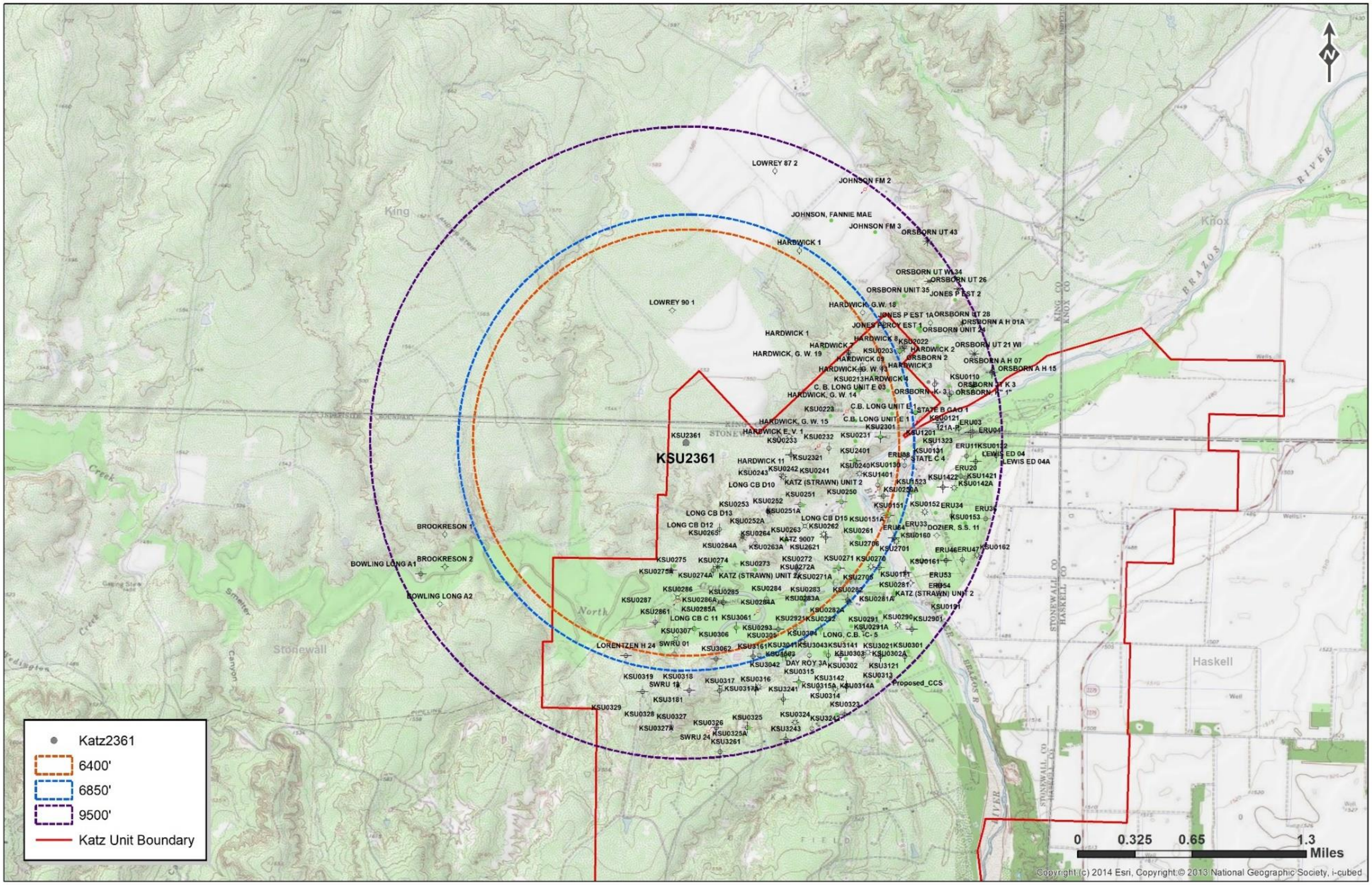


Figure 42 – All Oil and Gas Wells within the MMA

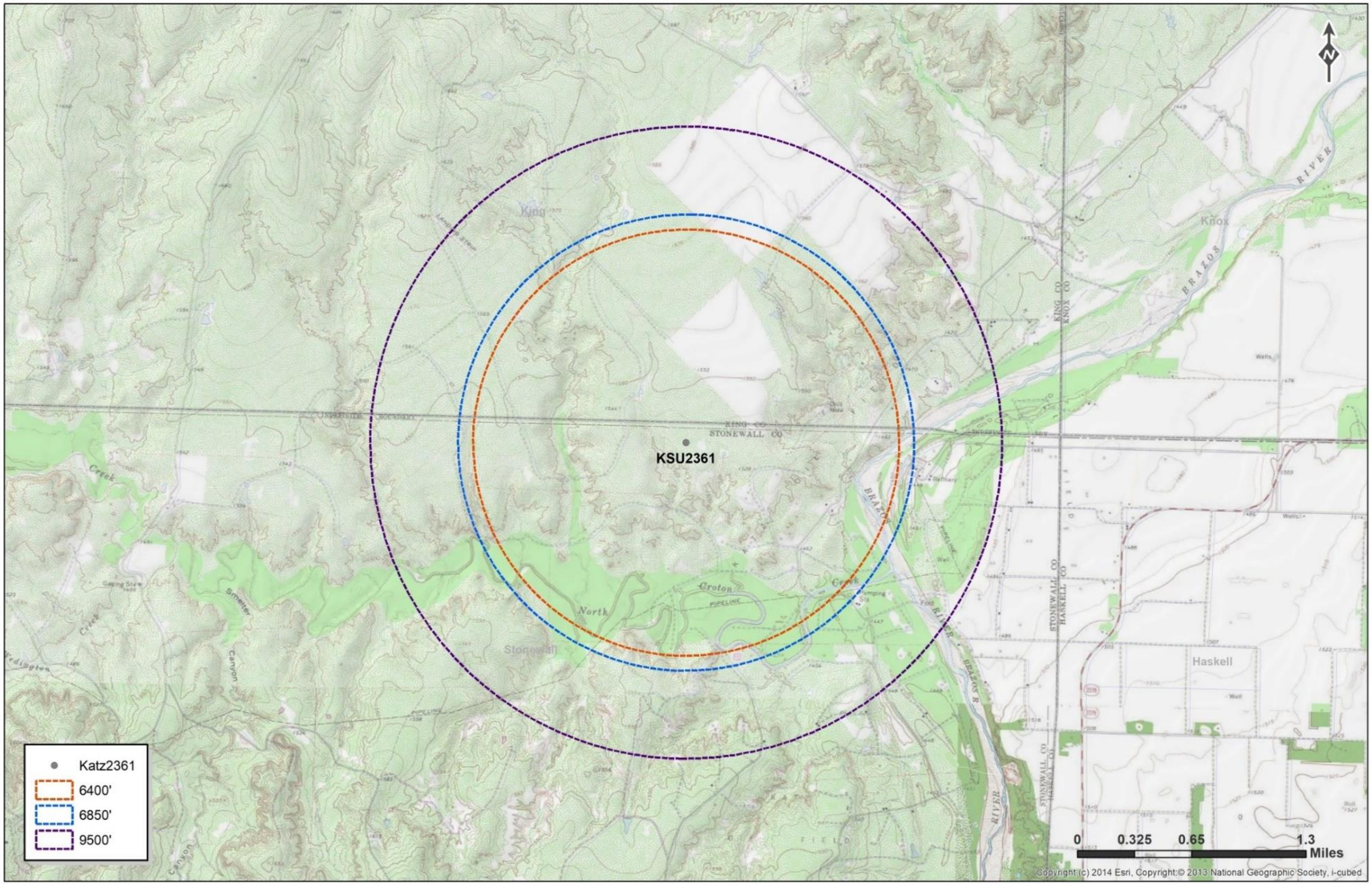


Figure 43 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA

Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Pre-Cambrian, have proven to date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC in the area of KSU 2361 include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"), 16 TAC **§3.13**. By way of example, see the KSU 2361 well drilling permit provided in Appendix A. The Ellenburger and Cambrian Sands are among the formations listed for which operators in Stonewall County and district 7B (where the KSU 2361 is located) are required to comply with TRCC Rule 13. TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. In this instance, any new well permitted and drilled to the KSU 2361 well's injection zone, and located within a one-quarter-mile radius of the KSU 2361 well, will be required under TRRC Rule 13 to set steel casing and cement above the KSU 2361 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above *all* potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued, which is also shown in the permit mentioned above in Appendix A.

4.2.2 Groundwater wells

A groundwater well search resulted in zero groundwater wells found within the MMA, as identified by the Texas Water Development Board.

The surface and intermediate casings of the KSU 2361 well, as shown in Figure 41, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See the GAU letter included in Appendix A. The wellbore casings and cements also prevent CO_2 leakage to the surface along the borehole. Kinder Morgan concludes that leakage of the sequestered CO_2 to the groundwater wells as unlikely.

4.3 Leakage Through Faults and Fractures

One fault was interpreted within the seismic coverage projecting 12,000' east of the KSU 2361 location. Initial plume models do not indicate an interaction between the injectate and the fault plane. Additionally, this fault dies within the Mississippian formation and does not penetrate the Lower Strawn Shale that acts as the upper confining unit. In the unlikely scenario in which the injection plume reaches the fault, and the fault acts as a transmissive pathway, the upper confining shale above the fault will act as an ideal sealant from injectate leaking outside of the permitted injection zone.

Should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Lower Strawn Shale, juxtaposing it against itself, preventing vertical migration.

Fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open hole logs show little to no porosity development indicating the Lower Strawn Shale or Mississippian Lime were not exposed at this location. Therefore, upward migration of injected gas through confining bed fractures is unlikely.

4.4 Leakage Through the Confining Layer

The Ellenburger and Cambrian injection zones have competent sealing rocks above and below the sand and carbonate formations. The properties of the overlying Lower Strawn Shale and its high composition of shale and mudstone make an excellent sealing rock to the underlying Ellenburger formation. Tight Mississippian Lime of roughly 266' lies between the Ellenburger and Lower Strawn Shale formations forming an impermeable upper buffer seal from the injection interval to the upper confining zone. Above this confining unit, shales found within the Homecreek Shale above the Desmoinesian formation will act as additional sealants between the injection interval and the USDW. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. Precambrian basement rock's underlying low porosity and permeability minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

4.5 Leakage from Natural or Induced Seismicity

The location of KSU 2361 is in an area of the Midland Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 44, indicates the nearest seismic event (unspecified whether natural or induced) occurred more than 40 miles away.

There is no indication of seismic activity posing a risk for loss of CO_2 to the surface within the MMA. Therefore, Kinder Morgan concludes that leakage of the sequestered CO_2 through seismicity as unlikely.

Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

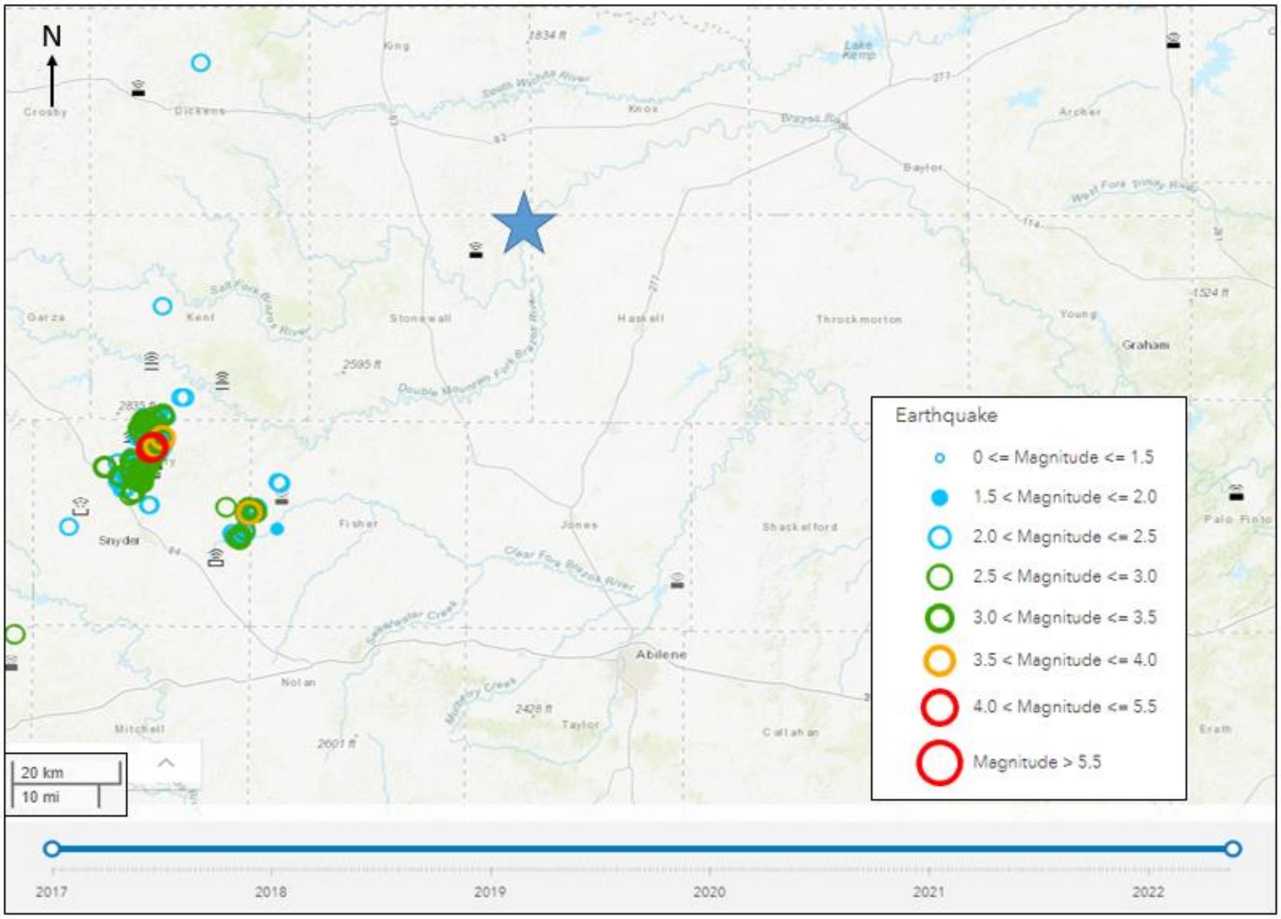


Figure 44 – Seismicity Review (TexNet – 06/01/2022)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Kinder Morgan will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 to meet the requirements of 40 CFR **§98.448(a)(3)**. Table 10 summarizes the monitoring of potential leakage pathways to the surface. Monitoring will occur during the planned 21-year injection period or cessation of injection operations, plus a proposed 5-year post-injection period.

- Leakage from surface equipment failure
- Leakage through existing and future wells within MMA
- Leakage through faults, fractures, or confining seals
- Leakage through natural or induced seismicity

Table 10 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed CO_2 monitors throughout the AGI facility
	Daily visual inspections
	Supervisory Control and Data Acquisition (SCADA)
Leakage through existing wells	Fixed CO_2 monitor at the the AGI well
	SCADA continuous monitoring at the AGI Well
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Quarterly atmospheric CO_2 measurements at well locations within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	CO_2 monitoring during offset drilling operations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage through confining layer	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage from natural or induced seismicity	Existing TexNet seismic monitoring station to be implemented

5.1 Leakage from Surface Equipment

As the facility and the KSU 2361 well are designed to handle CO_2, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used, and the connections are designed to minimize corrosion points. A baseline atmospheric CO_2 concentration will be established before injection operations begin. The facility and well site contain several CO_2 alarms with locations in close proximity.

The AGI complex is continuously monitored through automated systems. Details surrounding these systems can be found in Appendix C. In addition, field personnel conduct daily visual field inspections of gauges, monitors, and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and inspection of the cathodic protection system. These inspections and the automated systems allow Kinder Morgan to respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)**.

Pressures and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

5.2 Leakage From Existing and Future Wells within MMA

Kinder Morgan continuously monitors and collects injection volumes, pressures and temperatures through their SCADA systems, for the KSU 2361 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. KSU 2361 has a pressure and temperature gauge placed in the injection stream at its wellhead and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. In addition, mechanical integrity tests (MIT) performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 would ensure that new wells in the field would be constructed to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Kinder Morgan will also establish and operate an in-field monitoring program to detect CO_2 leakage within the MMA. The scope of work will include CO_2 monitoring at the AGI well site and, at minimum, quarterly atmospheric monitoring near any wells identified that penetrate the injection interval within the MMA. The collection of these measurements will be carried out by using a qualified third party. Upon approval of the MRV and through the post-injection monitoring period, Kinder Morgan will have these monitoring systems in place. No wells have been identified within the MMA that penetrate the injection interval.

Additional monitoring will be added as the MMA is updated over time. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

Groundwater Quality Monitoring

Kinder Morgan will monitor the groundwater quality in fluids above the confining interval by sampling from groundwater wells in the area of the facility and analyzing the sample with a third-party laboratory on an annual basis. In the case of KSU 2361, no existing groundwater wells have been identified within the MMA. At least two groundwater monitoring wells will be drilled within 1500’ of KSU 2361 at a depth of approximately 100’. The final number, locations, and depths of the wells will be determined by a study completed by a certified 3rd party firm. The approximate location and depths of these wells are shown in Figure 45. A baseline sampling from these wells will occur before injection starts. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature, and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

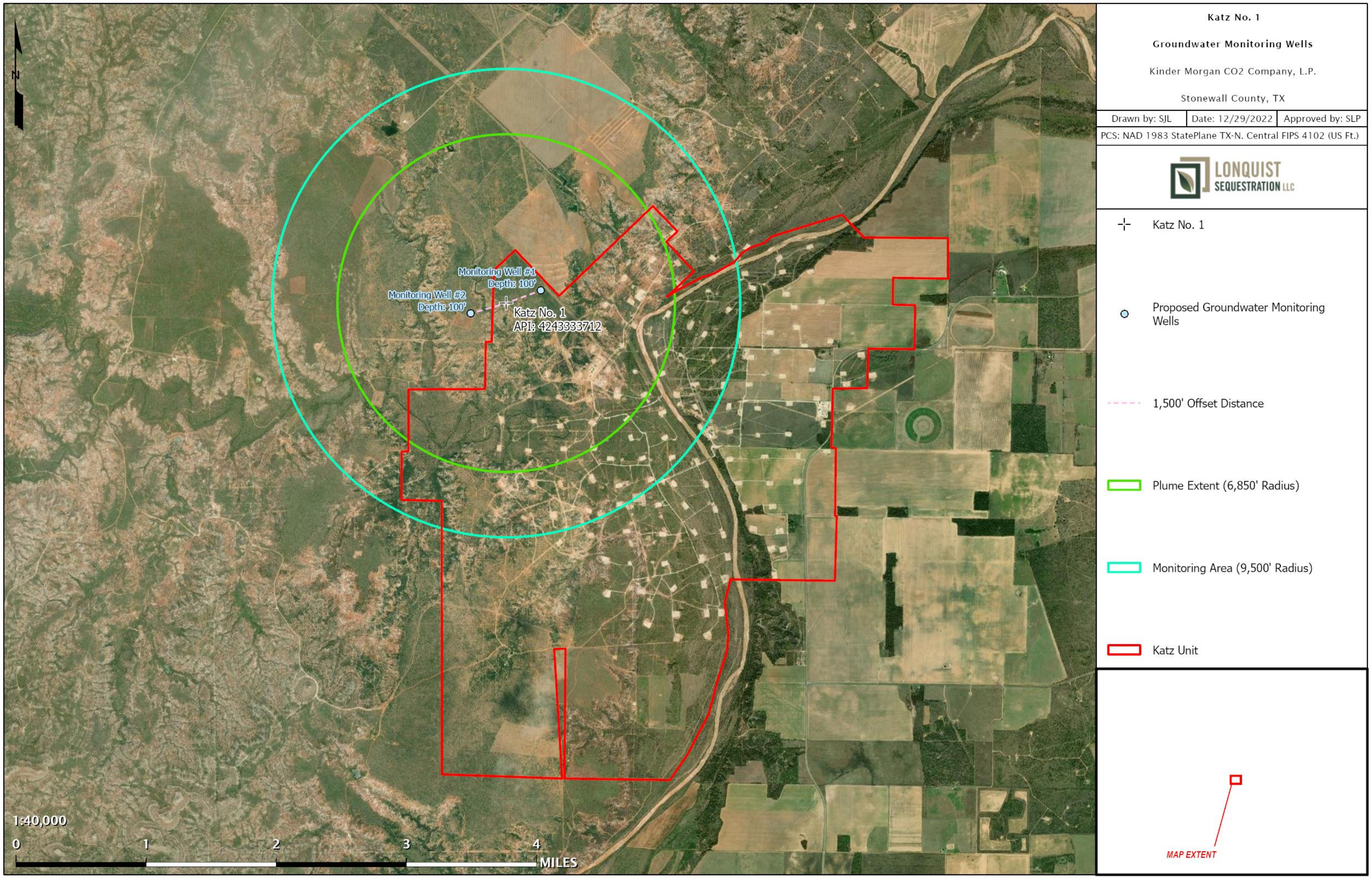


Figure 45 – Groundwater Monitoring Wells

5.3 Leakage through Faults, Fractures or Confining Seals

Kinder Morgan continuously monitors the operations of the KSU 2361 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. In addition, a field monitoring system is proposed to measure the shallow topsoil CO_2 concentrations across the MMA. These measurements will be taken quarterly by in-field gas sensors. The field CO_2 monitoring systems would alert field personnel for any release of CO_2 caused by such leakage. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

5.4 Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Kinder Morgan plans to use the nearest TexNet seismic monitoring station to monitor the area of the KSU 2361 well. This station is 7.29 miles southwest of the well location, as shown below in Figure 46. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Katz Unit. Kinder Morgan will monitor this station for any seismic activity that occurs near the well. If a seismic event of 3.0 magnitude or greater is detected, Kinder Morgan will review the injection volumes and pressures at the KSU 2361 well to determine if any significant changes occur that would indicate potential leakage. In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.

Figure 46 – Nearest TexNet Seismic Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Kinder Morgan will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Kinder Morgan will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Once the baseline concentrations are determined over a 12 month period prior to injection, the CO_2 monitors will be set to alarm at concentrations that are statistically significant deviation from baseline.

6.1 Visual Inspections

Daily inspections will be conducted by field personnel at the facility and the KSU 2361 well. These inspections will aid with identifying and addressing possible issues in order to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken to address such issues.

6.2 CO_2 Detection

In addition to the well site fixed monitors described previously, Kinder Morgan will establish and operate an in-field monitoring program to detect any CO_2 leakage within the MMA. The scope of baseline determination will include atmospheric CO_2 measurements at the AGI well site and near identified penetrations within the MMA. Topsoil CO_2 concentrations will also be measured, at pre-determined locations within the MMA, as baseline values before injection activities begin.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be taken. Any significant deviations over time will be analyzed for indication of leakage of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this project are well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a blowdown event, emissions will be sent to vent stacks and will be reported as required for the operation of the well.

6.5 Groundwater Monitoring

Initial samples will be taken from the groundwater monitoring wells drilled within 1,500 feet of the KSU 2361 well upon approval of Kinder Morgan's MRV and before commencing injection of CO_2. A third-party laboratory will analyze the samples to establish the baseline properties of the groundwater.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

This section identifies how Kinder Morgan will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR **§98.448(a)(5)**.

7.1 Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

Per 40 CFR **§98.444(b)**, since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters per quarter)

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (volume percent CO_2, expressed as a decimal fraction)

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The KSU 2361 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains concentrations well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released as a result of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Kinder Morgan believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in Section 10, below.

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12, assuming an expected injection start date of June 1, 2024, as this well will not actively produce oil or natural gas, or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to flares and reported as part of the required GHG reporting for the gas plant.

- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The KSU 2361 well currently reports GHGs under Subpart UU, but Kinder Morgan has elected to submit an MRV plan under, and otherwise comply with, Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed by March 31st of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Kinder Morgan plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 *Injected*

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated per the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP.

CO_2 *Emissions from Leaks and Vented Emissions*

- Gas monitors will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i) requirements**.**
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Kinder Morgan will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Kinder Morgan will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

Kinder Morgan will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least three years and include the following:

- Quarterly records of the CO_2 injected
    - Volumetric flow at standard conditions
    - Volumetric flow at operating conditions
    - Operating temperature and pressure
    - Concentration of the CO_2 stream
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

Adams, Donald & Keller, Randy. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective. AAPG Bulletin. 80. 410-431. 10.1306/64ED87FA-1724-11D7-8645000102C1865D.

Broadhead, Ronald E., 2005. Regional Aspects of the Wristen petroleum system, southeastern New Mexico: New Mexico Bureau of Geology and Mineral Resources Open File Report, no. 485.

Comer, John B., 1991. Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas and Southeastern New Mexico: Bureau of Economic Geology Report of Investigations, no. 201.

Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.

Ewing et al. (2004). Groundwater Availability Model for the Seymour Aquifer. *Texas Water Development Board.*

Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.

George, Peter G., Mace, Robert E., and Petrossian, Rima, 2011. Aquifers of Texas: Texas Water Development Board Report, no 380.

Gunn, R. D. (1982). Desmoinesian Depositional Systems in the Knox Baylor Trough. *North Texas Geological Society*.

Harding, R.W. and Associates. (1978). THE SEYMOUR AQUIFER: Ground-Water Quality and Availability in Haskell and Knox Counties, Texas. *Texas Department of Water Resources.*

Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.

Hoak, T., Sundberg, K., and Ortoleva, P. Overview of the Structural Geology and Tectonics of the Central Basin Platform, Delaware Basin, and Midland Basin, West Texas and New Mexico: Department of Energy Open File Report.

Holtz, M.H., and Kerans, C. (1992). Characterization and categorization of West Texas Ellenburger reservoirs. *Permian Basin Section SEPM Publication No. 92-22, p. 31-44.*

Hornhach, M. J. (2016). Ellenburger wastewater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.

Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas*.

Kane, S. C. (n.d.). THE MISSISSIPPIAN BARNETT FORMATION: A SOURCE-ROCK, SEAL, AND RESERVOIR PRODUCED BY EARLYCARBONIFEROUS FLOODING OF THE TEXAS CRATON. *BEG*.

Kerans, C. (1989). Karst-controlled reservoir heterogeneity and an example from the Ellenburger Group (Lower Ordovician) of West Texas. *Bureau of Economic Geology.*

Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.

Kupecz, J.A., and L.S. Land. (1991). Late-stage dolomitization of the Lower Ordovician Ellenburger Group, West Texas. *Journal of Sedimentary Petrology.*

Kyle, J.R. and E.F. McBride. (2014). Geology of the Voca Frac Sand District, western Llano Uplift, Texas. *Arizona Geological Survey Special Paper #9, Chapter 2, p. 1-13.*

Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.

Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

Molina, Oscar, Vilarras, Victor, and Zeidouni, Mehdi, 2016. Geologic carbon storage for shale gas recovery: 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18.

Ruppel, Stephen C. and Holtz, Mark H., 1994. Depositional and Diagenetic Facies Patterns and Reservoir Development in Silurian and Devonian Rocks of the Permian Basin: Bureau of Economic Geology Report of Investigations, no. 216.

Snee, Jens-Erik Lund and Zoback, Mark D., 2016. State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity.

Teeple, Andrew P., Ging, Patricia B., Thomas, Jonathan V., Wallace, David S., and Payne, Jason D., 2021. Hydrogeologic Framework, Geochemistry, Groundwater-Flow System, and Aquifer Hydraulic Properties Used in the Development of a Conceptual Model of the Ogallala, Edwards-Trinity (High Plains), and Dockum Aquifers In and Near Gaines, Terry, and Yoakum Counties, Texas: USGS Scientific Investigations Report 2021-5009.

SECTION 12 - APPENDICES

APPENDICES

APPENDIX A – TRRC FORMS KSU #2361

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

A-1

CHRISTI CRADDICK, CHAIRMAN
RYAN SITTON, COMMISSIONER
WAYNE CHRISTIAN, COMMISSIONER

DANNY SORRELLS
ASSISTANT EXECUTIVE DIRECTOR
DIRECTOR, OIL AND GAS DIVISION
PAUL DUBOIS
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 13453 AMENDMENT

KINDER MORGAN PRODUCTION CO LLC
6 DESTA DRIVE STE 6000
MIDLAND, TX 79705

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated August 27, 2018 for the permitted interval of the ELLENBURGER, and CAMBRIAN formations and subject to the following terms and special conditions:

KATZ (STRAWN) UNIT (30524) LEASE
KATZ (STRAWN) FIELD
STONEWALL COUNTY, DISTRICT 7B

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
2361	43333712	000104281	Salt Water, and Other Non-Hazardous O/G Waste	5,800	6, 435	30,000	N/A	2,900	N/A

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
2361	43333712	**1. According to the cross-section submitted by the operator the Pre-Cambrian top is at 6440 feet and hence the PBTD shall be at 6435 feet (deepest perforations are at 6433 feet per RRC records). Operator agreed to this permit special condition provision in the email dated on 11-29-2018. A copy of Form W-15 Cementing Record must be filed with the Form H-5 Injection Well Pressure Test Report prior to injection documenting compliance with this Special Condition.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON December 31, 2018.

Sean Avitt, Manager
Injection-Storage Permits Unit

Amendment Comments:

Well No.	API No.	Amendment Comments
2361	43333712	1. Amends maximum daily injection volume for liquid from 20000 bbl/day. 2. Amends packer setting depth from 5750 feet. 3. Amends permit dated November 21, 2011.

Note: This document will only be distributed electronically.

DEPTH OF USABLE-QUALITY GROUND WATER TO BE PROTECTED

Texas Commission on Environmental Quality
Surface Casing Program
TCEQ

Date: July 21, 2010

TCEQ File No.: SC- 5504

API Number: 43333592

Attention: ROSE BURDITT

RRC Lease No. 000000

SC_463316_43333592_000000_5504.pdf

KINDER MORGAN PRODUCTION CO LL
500 W ILLINOIS
STE 500
MIDLAND TX 79701

P-5# 463316

--Measured--
3545 ft FNEL
72 ft FNWL
MRL: SURVEY

Digital Map Location:
X-coord/Long: 1232566
Y-coord/Lat: 638341
Datum: 27 Zone: NC

County: STONEWALL

Lease & Well No.: KATZ (STRAWN) UNIT #232&ALL

Purpose: ND

Location: SUR-EUSTIS J.,SEC-2,--[TD=5500],[RRC 7B],

To protect usable-quality ground water at this location, the Texas Commission on Environmental Quality recommends:

The interval from the land surface to a depth of 100 feet must be protected.

This recommendation is applicable to all wells drilled in this LEASE IN SECTION 2.

Note: Unless stated otherwise, this recommendation is intended to apply only to the subject well and not for area-wide use. Approval of the well completion methods for protection of this groundwater falls under the jurisdiction of the Railroad Commission of Texas. **This recommendation is intended for normal drilling, production, and plugging operations only. It does not apply to saltwater disposal operation into a nonproductive zone (RRC Form W-14).**

If you have any questions, please contact us at 512-239-0515, sc@tceq.state.tx.us, or by mail MC-151.

Sincerely,

T. Wesley McCoy

Digitally signed by Thomas Wesley McCoy
DN: c=US, st=Texas, l=Austin, ou=Surface Casing, o=Texas Commission on Environmental Quality, cn=Thomas Wesley McCoy, email=wmccoy@tceq.state.tx.us
Date: 2010.07.21 11:46:18 -05'00'

T. Wesley McCoy, P.G.

Geologist, Surface Casing Team
Waste Permits Division

GEOLOGIST SEAL

STATE OF TEXAS
T. WESLEY McCOY
GEOLOGY
117
LICENSED
PROFESSIONAL GEOSCIENTIST

The seal appearing on this document was authorized by T. Wesley McCoy on 7/21/2010
Note: Alteration of this electronic document will invalidate the digital signature.

A-3

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 718131	DATE PERMIT ISSUED OR AMENDED Jun 14, 2011	DISTRICT * 7B
API NUMBER 42-433-33712	FORM W-1 RECEIVED Jun 09, 2011	COUNTY STONEWALL
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 7194
OPERATOR 463316 KINDER MORGAN PRODUCTION CO LLC 6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (325) 677-3545
LEASE NAME KATZ (STRAWN) UNIT		WELL NUMBER 2361
LOCATION 21.9 miles NE direction from ASPERMONT		TOTAL DEPTH 7500

Section, Block and/or Survey
SECTION
BLOCK
ABSTRACT 1939
SURVEY LONG, C B

DISTANCE TO SURVEY LINES 3511 ft. S 539 ft. W	DISTANCE TO NEAREST LEASE LINE 539 ft.
DISTANCE TO LEASE LINES 1751 ft. NE 539 ft. W	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
KATZ (STRAWN) KATZ (STRAWN) UNIT	7194.00 539	7,500	2361 3991	7B

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office. This is a hydrogen sulfide field. Hydrogen Sulfide Fields with perforations must be isolated and tested per State Wide Rule 36 and a Form H-9 filed with the district office. Fields with SWR 10 authority to downhole commingle must be isolated and tested individually prior to commingling production.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

Currently there are no identified formations listed for this county. It is still the operators responsibility to isolate and report any potential flow zones that are encountered in the completion of this well.

A-4

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Approved
Date: 10/04/2013
Tracking No.: 62859

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator KINDER MORGAN PRODUCTION CO LLC **Operator** 463316
Operator 6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000

WELL INFORMATION

API 42-433-33712 **County:** STONEWALL
Well No.: 2361 **RRC District** 7B
Lease KATZ (STRAWN) UNIT **Field** KATZ (STRAWN)
RRC Lease 30524 **Field No.:** 48294600
Location Section: ,Block: , Survey: LONG, C B SVY, Abstract: 1939

Latitude **Longitud**
This well is **miles in a**
direction from 21.9 MILES IN A NE DIRECTION FROM ASPERMONT, TX,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC **Completion or Recompletion** 12/15/2012

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	06/14/2011	718131
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal	11/21/2011	13453
Other:		

COMPLETION INFORMATION

Spud **Date of first production after rig** 12/15/2012
Date plug back, deepening, drilling operation 08/24/2012 **Date plug back, deepening, recompletion, drilling operation** 09/13/2012
Number of producing wells on this lease this field (reservoir) including this 66 **Distance to nearest well in lease & reservoir** 3991.0
Total number of acres in 7194.00 **Elevation** 1518 GL
Total depth TVD 6625 **Total depth MD**
Plug back depth TVD 6547 **Plug back depth MD**
Was directional survey made other inclination (Form W- No **Rotation time within surface casing Is Cementing Affidavit (Form W-15)** Yes
Recompletion or No **Multiple** No
Type(s) of electric or other log(s) Induction only
Electric Log Other Description:
Location of well, relative to nearest lease **Off Lease :** No
of lease on which this well is 1751.0 **Feet from the** NE **Line and**
539.0 **Feet from the** West **Line of the**
KATZ (STRAWN) UNIT **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type

PACKET: N/A

W2: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination	Depth	Date
SWR 13 Exception	Depth	

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		Production	
Number of hours	24	Choke	
Was swab used during this	No	Oil produced prior to	

PRODUCTION DURING TEST PERIOD:

Oil		Gas	
Gas - Oil	0	Flowing Tubing	
Water			

CALCULATED 24-HOUR RATE

Oil		Gas	
Oil Gravity - API - 60.:		Casing	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1		9 5/8	12 1/4	1290			C	491	837.0	SURFACE	
2		7	8 3/4	6592			C	750	1248.0	3256	
3		7	8 3/4	6592	2463		C	450	618.0	SURFACE	

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	4 1/2	5945	5957 /

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	No	L 6018	6024.0
2	No	L 6038	6077.0
3	No	L 6090	6101.0
4	No	L 6143	6195.0
5	No	L 6240	6255.0
6	No	L 6286	6311.0
7	No	L 6362	6370.0
8	No	L 6382	6433.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1		PUMP 2800 GALLONS 15% HCL, FLUSH WITH 36 BARRELS TREATED WATER.	6018	6101
2		PUMP 2600 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6143	6195
3		PUMP 2440 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6240	6311
4		PUMP 2960 GALLONS 15% HCL, FLUSH WITH 76 BARRELS TREATED WATER.	6362	6433

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
BASE PALO PINTO		3215.2			
ELLENBURGER		6018.0			
CAMBRIAN		6240.0			

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

THE PURPOSE OF THIS FILING IS TO REPORT A DRILLED AND COMPLETED SALT WATER DISPOSAL WELL.

OPERATOR'S CERTIFICATION

Printed	Dorothy Horrell	**Title:**	Administrator
Telephone	(432) 688-2448	**Date**	01/14/2013

APPENDIX B – GAS COMPOSITION

CO2 Pipeline - Gas Quality Specifications

Kinder Morgan CO2 Company

Revision: 2019 11 12

Product delivered at the Origination Point shall meet the following specifications, which herein are called Quality Specifications:

(a) **CO2 Content** Product composition shall be not less than ninety five per cent (95%) CO_2 by mole fraction.

(b) **Water** Product shall contain no free water, and shall not contain more than thirty (30) pounds of water per million standard cubic feet (MMscf) in the vapor phase.

(c) **Pressure** Product shall be delivered at a pressure sufficient to get into the pipeline.

(d) **Temperature** Product shall be delivered at a temperature not greater than 120 degrees F, and not less than 65 degrees F.

(e) **H2S** Product shall not contain more than twenty (20) parts per million H_2S, by volume.

(f) **Nitrogen** Product shall not contain more than four per cent (4%) nitrogen, by mole fraction.

(g) **Sulphur** Product shall not contain more than thirty five (35) parts per million sulphur, by weight.

(h) **Oxygen** Product shall not contain more than ten (10) parts per million, oxygen, by weight.

(i) **Hydrocarbons** Product shall not contain more than five percent (5%) hydrocarbons, by mole fraction.

(j) **Glycol** Product shall not contain more than 0.3 gallon glycol, per million standard cubic feet, and at no time shall glycol be present in a liquid state at temperature and pressure conditions of the pipeline.

(k) **Carbon Monoxide** Product shall not contain more than 4,250 parts per million, carbon monoxide, by weight.

(l) **NOx** Product shall not contain more than one (1) part per million, NO_x, by weight.

(m) **SOx** Product shall not contain more than one (1) part per million, SO_x, by weight.

(n) **Particulates** Product shall not contain more than one (1) part per million, particulates, by weight.

(o) **Amines** Product shall not contain more than one (1) part per million, amines, by weight.

(p) **Hydrogen** Product shall not contain more than one per cent (1%) hydrogen, by mole fraction.

(q) **Mercury** Product shall not contain more than five (5) nano grams per liter (ng/l) mercury.

(r) **Ammonia** Product shall not contain more than fifty (50) parts per million, ammonia, by weight.

(s) **Argon** Product shall not contain more than one volume percent (1% by volume) argon.

(t) **Liquids** Product shall be free of liquids at delivery conditions and shall not produce condensed liquids in the pipeline at pipeline pressure and temperature.

(u) **Compressor Lube Oil Carry Over** Compressor lube oil carry over in the product shall not exceed fifty (50) parts per million, by weight, and shall not cause fouling of pipeline, pipeline equipment downstream systems or reservoirs.

(v) **Impurities Deleterious to Pipeline, Equipment, Downstream Systems or Reservoirs** In addition to compositional limits listed above, product shall not contain impurities deleterious to pipeline, equipment, downstream systems or reservoirs.

APPENDIX C – PIPELINE SAFETY PLAN

Kinder Morgan CO_2 pipelines are monitored 24 hours a day, 7 days a week by personnel in control centers using a SCADA computer system. This electronic surveillance system gathers pipeline pressures, volume and flow rates and the status of pumping equipment and valves. Whenever operating conditions change, an alarm warns the operator on duty and the condition is investigated. Both automated and manual valves are strategically placed along the pipeline system to enable the pipeline to be shut down immediately and sections to be isolated quickly, if necessary. Visual inspections of the pipeline right-of-way, a narrow strip of land reserved for the pipeline, are conducted by air and ground on a regular basis.

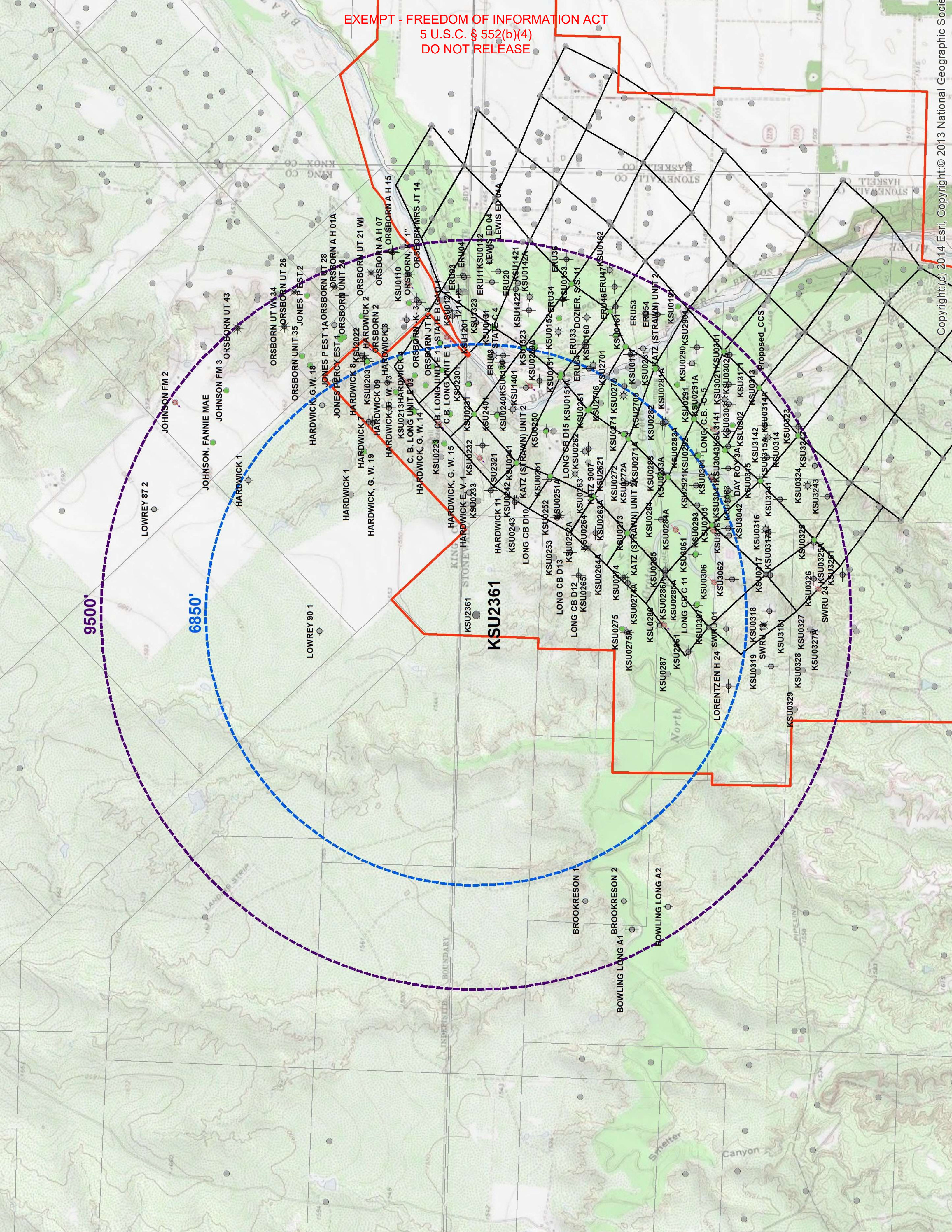
In the event of a CO_2 pipeline rupture, the Kinder Morgan CO_2 Supervisory Control and Data Acquisition (SCADA) computer system will shut down the pipeline and isolate the impacted section with automated valves. Kinder Morgan will notify the appropriate public safety answering point (i.e., 9-1-1 emergency call center) and initiate the internal Emergency Response Line to alert the operations team. An emergency response plan would be initiated with implementation of an incident command system, and Kinder Morgan will work with local emergency responders to isolate the impacted area.

APPENDIX D – MMA/AMA REVIEW MAPS

APPENDIX D-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX D-2: OIL AND GAS WELLS WITHIN THE MMA LIST

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE



Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332238	BOWLING-LONG A	2	P & A	5,815	WILDCAT	4/20/1987	5/7/1987
4243332229	BROOKRESON	1	P & A	5,730	WILDCAT	3/7/1987	5/14/1987
4243332319	BROOKRESON	2	P & A	5,745	WILDCAT	12/2/1987	12/13/1987
4226932003	C. B. LONG UNIT	E 03	P & A	5,300	KATZ	--	--
4243300422	C.B. LONG UNIT	C 11	P & A	5,127	KATZ	7/11/1989	5/15/2009
4243332388	C.B. LONG UNIT	C 16	P & A	5,200	KATZ	11/18/1989	12/8/2010
4243300585	C.B. LONG UNIT	D 10	P & A	5,197	KATZ	6/30/1989	1/13/2009
4243332465	C.B. LONG UNIT	D 13	P & A	5,201	KATZ	12/27/1989	9/23/2005
4243301965	C.B. LONG UNIT	D 4	P & A	5,188	KATZ		11/30/2010
4226900122	C.B. LONG UNIT	E 1	P & A	5,165	KATZ		9/15/2009
4226932006	C.B. LONG UNIT	E 2	P & A	5,200	KATZ	10/11/1990	2/24/2011
4243332116	DOZIER, S.S.	11	P & A	5,950	WILDCAT	6/12/1986	06/23/1986
4226900308	EAST RIVER UNIT	4	INACTIVE	4,931	KATZ		02/21/1995
4243332303	EAST RIVER UNIT	8	P & A	5,200	KATZ	11/17/1987	06/24/2009
4243332302	EAST RIVER UNIT	11	P & A	5,200	KATZ	11/26/1987	3/18/2004
4243300796	EAST RIVER UNIT	18	ACTIVE	5,300	KATZ	7/26/1951	--
4243300802	EAST RIVER UNIT	20	P & A	5,184	KATZ	8/22/1988	7/6/2009
4243300798	EAST RIVER UNIT	21	P & A	4,957	KATZ		12/5/1989
4243300787	EAST RIVER UNIT	33	P & A	5,155	KATZ		10/21/2009
4243300781	EAST RIVER UNIT	34	P & A	5,120	KATZ		10/30/2009
4243332306	EAST RIVER UNIT	36	P & A	5,200	KATZ	12/15/1987	2/28/2006
4243300849	EAST RIVER UNIT	45	P & A	5,167	KATZ		12/7/2010
4243300848	EAST RIVER UNIT	46	INACTIVE	4,875	KATZ		2/15/1990
4243332308	EAST RIVER UNIT	47	P & A	5,200	KATZ	12/5/1987	10/13/2009
4243300780	EAST RIVER UNIT	53	P & A	4,918	KATZ		2/14/1995
4243300788	EAST RIVER UNIT	54	P & A	5,211	KATZ		2/11/2009
4243332417	EAST RIVER UNIT	64	P & A	5,245	KATZ	8/8/1988	1/23/2009
4243333510	EAST RIVER UNIT	105	ACTIVE	5,325	KATZ	11/3/2009	--
4243333368	EAST RIVER UNIT	73H	P & A	4,750	KATZ	8/8/2007	9/3/2007
4243381146	EDD LEWIS		P & A	4,967	KATZ		10/14/2005
4226932269	HARDWICK	1	P & A	5,820	WILDCAT	6/19/1997	7/1/1997
4226900006	HARDWICK	2	P & A	5,147	KATZ		5/15/1975
4226900007	HARDWICK	3	P & A	5,168	KATZ		7/27/1970
4226900008	HARDWICK	4	P & A	5,146	KATZ		1/26/1984
4226900011	HARDWICK	6	P & A	5,152	KATZ		7/24/1970
4226900009	HARDWICK	7	P & A	5,150	KATZ		8/19/1967
4226900010	HARDWICK	8	P & A	5,152	KATZ		6/18/1976
4226980016	HARDWICK	9	P & A	2,171	KATZ		1/27/1984
4243301905	HARDWICK	11	P & A	5,152	KATZ		7/22/1970
4226900005	HARDWICK E. V.	1	P & A	5,960	KATZ		7/14/1951
4226931776	HARDWICK, G. W.	12	P & A	5,200	KATZ	3/10/1988	11/6/2009
4226931777	HARDWICK, G. W.	13	P & A	5,200	KATZ	3/11/1988	11/19/2009
4226931775	HARDWICK, G. W.	14	P & A	5,200	KATZ	5/29/1988	11/16/2009
4226931771	HARDWICK, G. W.	15	P & A	5,200	KATZ	3/15/1988	11/12/2009
4226931774	HARDWICK, G. W.	16	P & A	5,200	KATZ	3/8/1988	5/13/2004
4226931772	HARDWICK, G. W.	17	P & A	5,250	KATZ	3/9/1988	11/10/2009
4226932431	HARDWICK, G.W.	18	P & A	5,300	KATZ	8/13/2001	8/24/2001
4226932178	JOHNSON, FANNIE MAE	1	P & A	5,840	KATZ	4/11/1995	2/2/2016
4226932197	JOHNSON, FANNIE MAE	2	P & A	5,825	KATZ	10/5/1995	2/3/2016
4226932236	JOHNSON, FANNIE MAE	3	P & A	5,830	KATZ	11/2/1996	2/1/2016
4226900420	JONES PERCY EST	1	P & A	5,200	KATZ		1/1/1962
4226900428	JONES PERCY ESTATE	3	P & A	4,940	KATZ		7/1/1958
4226932805	KATZ (STRAWN) UNIT	110	ACTIVE	5,312	KATZ	3/13/2011	--
4226931666	KATZ (STRAWN) UNIT	121	P & A	4,879	KATZ	2/9/1987	10/24/2019
4243300797	KATZ (STRAWN) UNIT	131	ACTIVE	5,200	KATZ	9/24/1951	--
4243333513	KATZ (STRAWN) UNIT	132	ACTIVE	5,320	KATZ	12/2/2009	--
4243332296	KATZ (STRAWN) UNIT	143	P & A	5,200	KATZ	12/13/1987	7/30/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332304	KATZ (STRAWN) UNIT	151	P & A	5,200	KATZ	11/20/1987	7/20/2010
4243300779	KATZ (STRAWN) UNIT	152	ACTIVE	5,255	KATZ		--
4243300783	KATZ (STRAWN) UNIT	153	ACTIVE	5,299	KATZ	4/25/1952	--
4243333511	KATZ (STRAWN) UNIT	160	ACTIVE	5,302	KATZ	11/20/2009	--
4243333518	KATZ (STRAWN) UNIT	161	ACTIVE	5,308	KATZ	1/22/2010	--
4243333512	KATZ (STRAWN) UNIT	162	ACTIVE	5,328	KATZ	12/30/2009	--
4243333521	KATZ (STRAWN) UNIT	171	ACTIVE	5,334	KATZ	2/2/2010	--
4243333580	KATZ (STRAWN) UNIT	180	ACTIVE	5,327	KATZ	6/29/2010	--
4243333665	KATZ (STRAWN) UNIT	191	ACTIVE	5,423	KATZ	5/2/2011	--
4226932789	KATZ (STRAWN) UNIT	211	ACTIVE	5,316	KATZ	11/7/2010	--
4226932795	KATZ (STRAWN) UNIT	212	P & A	5,294	KATZ	8/21/2010	6/8/2022
4226932783	KATZ (STRAWN) UNIT	220	ACTIVE	5,308	KATZ	3/9/2010	--
4226932788	KATZ (STRAWN) UNIT	221	ACTIVE	4,863	KATZ	6/6/2010	--
4226932793	KATZ (STRAWN) UNIT	222	ACTIVE	5,308	KATZ	6/18/2010	--
4243333534	KATZ (STRAWN) UNIT	231	ACTIVE	5,315	KATZ	4/23/2010	--
4243333592	KATZ (STRAWN) UNIT	232	ACTIVE	5,340	KATZ	8/10/2010	--
4243333523	KATZ (STRAWN) UNIT	240	ACTIVE	5,309	KATZ	3/18/2010	--
4243300584	KATZ (STRAWN) UNIT	241	ACTIVE	5,250	KATZ	6/8/1957	--
4243333615	KATZ (STRAWN) UNIT	242	ACTIVE	5,297	KATZ	11/30/2010	--
4243300403	KATZ (STRAWN) UNIT	250	P & A	5,206	KATZ	10/25/1951	12/13/2019
4243300400	KATZ (STRAWN) UNIT	261	ACTIVE	5,150	KATZ		--
4243333573	KATZ (STRAWN) UNIT	262	ACTIVE	5,314	KATZ	5/25/2010	--
4243300583	KATZ (STRAWN) UNIT	264	P & A	5,242	KATZ		4/29/2011
4243333524	KATZ (STRAWN) UNIT	270	ACTIVE	5,300	KATZ	4/13/2010	--
4243300405	KATZ (STRAWN) UNIT	271	P & A	5,150	KATZ		11/4/2010
4243300421	KATZ (STRAWN) UNIT	273	ACTIVE	5,127	KATZ	7/11/1953	--
4243300424	KATZ (STRAWN) UNIT	274	P & A	5,131	KATZ	5/16/1989	12/27/2010
4243301970	KATZ (STRAWN) UNIT	275	P & A	5,185	KATZ		3/14/2011
4243300417	KATZ (STRAWN) UNIT	281	P & A	5,156	KATZ		8/16/2010
4243332387	KATZ (STRAWN) UNIT	282	P & A	5,189	KATZ	11/2/1989	9/20/2010
4243332389	KATZ (STRAWN) UNIT	284	P & A	5,210	KATZ	10/15/1989	1/10/2011
4243332390	KATZ (STRAWN) UNIT	285	P & A	5,219	KATZ		11/3/2010
4243332461	KATZ (STRAWN) UNIT	286	P & A	5,730	KATZ	12/8/1989	4/29/2013
4243333526	KATZ (STRAWN) UNIT	290	ACTIVE	5,315	KATZ	5/6/2010	--
4243333704	KATZ (STRAWN) UNIT	301	ACTIVE	5,365	KATZ	7/27/2011	--
4243301620	KATZ (STRAWN) UNIT	302	P & A	5,138	KATZ	3/28/1953	1/5/2012
4243333738	KATZ (STRAWN) UNIT	304	ACTIVE	5,300	KATZ	12/3/2011	--
4243333778	KATZ (STRAWN) UNIT	305	ACTIVE	5,330	KATZ	4/6/2012	--
4243333569	KATZ (STRAWN) UNIT	306	ACTIVE	5,328	KATZ	5/16/2010	--
4243333813	KATZ (STRAWN) UNIT	307	INACTIVE	5,365	KATZ	6/26/2012	--
4243333746	KATZ (STRAWN) UNIT	313	ACTIVE	5,380	KATZ	11/20/2011	--
4243332561	KATZ (STRAWN) UNIT	314	P & A	5,225	KATZ	12/16/1989	2/7/2012
4243333788	KATZ (STRAWN) UNIT	315	P & A	5,320	KATZ	3/17/2012	7/1/2014
4243332553	KATZ (STRAWN) UNIT	317	P & A	5,200	KATZ	12/11/1989	10/14/2013
4243333822	KATZ (STRAWN) UNIT	318	P & A	5,320	KATZ	7/5/2012	5/24/2021
4243333736	KATZ (STRAWN) UNIT	324	ACTIVE	5,380	KATZ	2/6/2012	--
4243333527	KATZ (STRAWN) UNIT	326	ACTIVE	5,503	KATZ	3/30/2010	--
4243300819	KATZ (STRAWN) UNIT	327	P & A	4,952	KATZ		12/23/2010
4243332509	KATZ (STRAWN) UNIT	1201	P & A	5,295	KATZ	7/1/1989	11/29/2010
4226931752	KATZ (STRAWN) UNIT	1221	P & A	5,200	KATZ	1/23/1988	10/11/2011
4243300800	KATZ (STRAWN) UNIT	1323	P & A	4,930	KATZ		3/23/2010
4243332298	KATZ (STRAWN) UNIT	1401	P & A	5,261	KATZ	1/24/1988	3/19/2010
4243332274	KATZ (STRAWN) UNIT	1422	P & A	5,220	KATZ	9/2/1987	11/16/2009
4243300801	KATZ (STRAWN) UNIT	1523	P & A	5,101	KATZ	5/20/1952	11/24/2009
4243332299	KATZ (STRAWN) UNIT	1801	P & A	4,879	KATZ	2/2/1988	3/31/2011
4226932806	KATZ (STRAWN) UNIT	2022	ACTIVE	5,313	KATZ	3/25/2011	--
4226932345	KATZ (STRAWN) UNIT	2121	P & A	5,800	KATZ	8/8/1999	11/12/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932002	KATZ (STRAWN) UNIT	2221	P & A	5,200	KATZ	10/25/1990	6/1/2010
4243332753	KATZ (STRAWN) UNIT	2321	P & A	5,200	KATZ	12/10/1991	3/3/2011
4243333712	KATZ (STRAWN) UNIT	2361	ACTIVE	6,625	KATZ	8/23/2012	--
4243300406	KATZ (STRAWN) UNIT	2401	P & A	5,173	KATZ	5/23/1989	12/31/2009
4243332541	KATZ (STRAWN) UNIT	2701	INACTIVE	100	KATZ	9/27/1989	--
4243332565	KATZ (STRAWN) UNIT	2702	INACTIVE	100	KATZ	12/7/1989	--
4243300401	KATZ (STRAWN) UNIT	2705	P & A	5,116	KATZ	5/12/1989	3/2/2010
4243333713	KATZ (STRAWN) UNIT	2706	COMPLETED	7,500	KATZ		--
4243300423	KATZ (STRAWN) UNIT	2861	P & A	5,161	KATZ	7/17/1989	11/21/2013
4243300399	KATZ (STRAWN) UNIT	2901	P & A	5,150	KATZ		2/17/2011
4243333160	KATZ (STRAWN) UNIT	2921	P & A	5,725	KATZ	12/10/1998	1/13/2010
4243380198	KATZ (STRAWN) UNIT	3041	P & A	5,113	KATZ	7/18/2005	6/17/2010
4243301606	KATZ (STRAWN) UNIT	3042	P & A	5,113	KATZ	11/6/1989	3/22/2012
4243300838	KATZ (STRAWN) UNIT	3062	P & A	5,240	KATZ	11/16/1989	7/1/2010
4243301610	KATZ (STRAWN) UNIT	3141	P & A	5,115	KATZ		2/16/2012
4243300837	KATZ (STRAWN) UNIT	3161	P & A	5,190	KATZ	2/13/1990	8/18/2010
4243300842	KATZ (STRAWN) UNIT	3181	P & A	4,961	KATZ		2/16/2011
4243301605	KATZ (STRAWN) UNIT	3241	P & A	5,170	KATZ		4/12/2013
4243332570	KATZ (STRAWN) UNIT	3243	P & A	5,240	KATZ	1/14/1990	2/10/2010
4243332588	KATZ (STRAWN) UNIT	3261	P & A	5,150	KATZ	2/12/1990	3/31/2010
4226932987	KATZ (STRAWN) UNIT	121A	ACTIVE	5,337	KATZ	12/3/2019	--
4243333496	KATZ (STRAWN) UNIT	142A	ACTIVE	5,305	KATZ	10/20/2009	--
4243333595	KATZ (STRAWN) UNIT	151A	ACTIVE	5,317	KATZ	9/7/2010	--
4243334217	KATZ (STRAWN) UNIT	250A	INACTIVE	5,314	KATZ	12/19/2019	--
4243333630	KATZ (STRAWN) UNIT	251A	ACTIVE	5,315	KATZ	12/10/2010	--
4243333598	KATZ (STRAWN) UNIT	252A	TA	5,300	KATZ	10/17/2010	--
4243333599	KATZ (STRAWN) UNIT	263A	ACTIVE	5,315	KATZ	9/29/2010	--
4243333639	KATZ (STRAWN) UNIT	264A	P & A	5,333	KATZ	4/5/2011	6/1/2021
4243333627	KATZ (STRAWN) UNIT	271A	ACTIVE	5,302	KATZ	12/20/2010	--
4243333632	KATZ (STRAWN) UNIT	272A	ACTIVE	5,318	KATZ	3/1/2011	--
4243333807	KATZ (STRAWN) UNIT	274A	TA	5,300	KATZ	5/24/2012	7/1/2022
4243333607	KATZ (STRAWN) UNIT	281A	ACTIVE	5,324	KATZ	10/9/2010	--
4243333617	KATZ (STRAWN) UNIT	282A	ACTIVE	5,297	KATZ	11/18/2010	--
4243333735	KATZ (STRAWN) UNIT	283A	ACTIVE	5,380	KATZ	10/7/2011	--
4243333722	KATZ (STRAWN) UNIT	284A	ACTIVE	5,345	KATZ	12/15/2011	--
4243333799	KATZ (STRAWN) UNIT	285A	INACTIVE	5,350	KATZ	4/16/2012	--
4243333927	KATZ (STRAWN) UNIT	286A	TA	5,337	KATZ	3/24/2014	--
4243333730	KATZ (STRAWN) UNIT	291A	ACTIVE	5,364	KATZ	9/24/2011	--
4243333695	KATZ (STRAWN) UNIT	302A	ACTIVE	5,390	KATZ	7/6/2011	--
4243333771	KATZ (STRAWN) UNIT	303A	ACTIVE	5,330	KATZ	2/27/2012	--
4243333753	KATZ (STRAWN) UNIT	314A	ACTIVE	5,375	KATZ	10/27/2011	--
4243334002	KATZ (STRAWN) UNIT	315A	ACTIVE	5,348	KATZ	7/11/2014	--
4243333770	KATZ (STRAWN) UNIT	316A	ACTIVE	5,400	KATZ	1/25/2012	--
4243333820	KATZ (STRAWN) UNIT	317A	INACTIVE	5,336	KATZ	12/29/2013	--
4243333776	KATZ (STRAWN) UNIT	323A	ACTIVE	5,408	KATZ	3/7/2012	--
4243333821	KATZ (STRAWN) UNIT	325A	ACTIVE	5,385	KATZ	12/10/2013	--
4226900309	LEWIS, W. D.	2	P & A	5,090	KATZ		9/29/2008
4243300412	LONG, C. B. -D-	5	P & A	5,165	KATZ		3/12/2010
4243300415	LONG, C. B. -D-	6	P & A	5,188	KATZ		11/8/2010
4243300408	LONG, C.B. -C-	4	P & A	5,214	KATZ		3/9/2011
4243300411	LONG, C.B. -C-	5	P & A	5,165	KATZ		11/30/2010
4243300420	LONG, C.B. -C-	9	INACTIVE	5,163	KATZ		5/13/2010
4243300414	LONG, C.B. -C-	6 T	P & A	5,168	KATZ		11/12/2010
4243300419	LONG, C.B. -C-	8 T	P & A	5,165	KATZ		11/15/2010
4243300418	LONG, C.B. -D-	7	P & A	5,190	KATZ	8/1/1989	8/10/2010
4243300586	LONG, C.B. -D-	11	P & A	5,183	KATZ	6/15/1989	8/30/2010
4243300587	LONG, C.B. -D-	12	P & A	4,896	KATZ		1/13/1986

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932293	LOWERY 87	2	P & A	5,835	WILDCAT	11/11/1997	11/24/1997
4226932268	LOWREY 90	1	P & A	5,800	WILDCAT	5/25/1997	6/4/1997
4226932270	MANGIS	2	P & A	5,770	KAIA	7/10/1997	7/20/1997
4226932325	ORSBORN	2	P & A	5,718	KAIA	10/22/1998	11/4/1998
4226900108	ORSBORN	7	P & A	4,940	KATZ		8/30/2006
4226932955	ORSBORN K	14	INACTIVE	5,235	KATZ	11/5/2015	--
4226900077	ORSBORN -K-	3	P & A	5,091	KATZ		7/19/1993
4226900082	ORSBORN UNIT	1	INACTIVE	5,155	KATZ	8/14/1952	--
4226900081	ORSBORN UNIT	14	P & A	5,077	KATZ		8/30/2018
4226900105	ORSBORN UNIT	15	P & A	5,211	KATZ		8/25/1994
4226910001	ORSBORN UNIT	19	P & A	5,144	KATZ	9/1/1984	9/6/1984
4226931306	ORSBORN UNIT	21	P & A	5,170	KATZ	9/25/1984	11/11/2021
4226931395	ORSBORN UNIT	24	P & A	5,200	KATZ	1/23/1985	3/25/2022
4226931398	ORSBORN UNIT	26	P & A	5,247	KATZ	2/4/1985	5/9/2019
4226931397	ORSBORN UNIT	28	P & A	5,220	KATZ	2/18/1985	3/1/2013
4226931738	ORSBORN UNIT	34	P & A	5,250	KATZ	10/9/1987	8/28/2018
4226932314	ORSBORN UNIT	43	P & A	5,350	KATZ	4/24/1998	4/29/2019
4226932956	ORSBORN UNIT	44	INACTIVE	5,230	KATZ	6/28/2016	--
4226900076	ORSBORN, "K"	1	P & A	5,099	KATZ		7/12/1993
4226900104	ORSBORN, ALMA H.	1	P & A	5,155	KATZ		5/7/1957
4243300841	SOUTHWEST RIVER UNI	1	P & A	4,903	KATZ		7/17/1998
4243301612	SOUTHWEST RIVER UNI	5	P & A	5,115	KATZ		2/20/2012
4243301621	SOUTHWEST RIVER UNI	6	P & A	5,154	KATZ	4/14/1953	1/25/2012
4243301609	SOUTHWEST RIVER UNI	9	P & A	5,150	KATZ		4/13/2011
4243301619	SOUTHWEST RIVER UNI	10	P & A	5,104	KATZ	2/17/1953	12/14/2010
4243300844	SOUTHWEST RIVER UNI	13	P & A	4,987	KATZ		9/18/1995
4243300836	SOUTHWEST RIVER UNI	16	P & A	5,170	KATZ		1/5/2011
4243332587	SOUTHWEST RIVER UNI	18	P & A	5,300	KATZ	2/1/1990	1/27/2010
4243300811	SOUTHWEST RIVER UNI	24	P & A	4,920	KATZ		11/28/2002
4243301444	SOUTHWEST RIVER UNI	28	P & A	4,950	KATZ	8/13/2007	4/13/2011
4243300823	SOUTHWEST RIVER UNI	36	P & A	4,963	KATZ		--
4243300815	SOUTHWEST RIVER UNI	37	P & A	4,972	KATZ		10/15/1991
4243300835	SOUTHWEST RIVER UNI	71	P & A	5,171	KATZ		10/4/1991
4243300809	SOUTHWEST RIVER UNI	25W	P & A	5,230	KATZ		10/22/2013
4243332560	SOUTHWEST RIVER UNI	27W	P & A	5,206	KATZ	1/9/1990	3/12/2013
4226900069	STATE A GAO	1	P & A	5,085	KATZ		4/19/1985
4226900070	STATE B GAO	1	P & A	4,876	KATZ		4/17/1985
4243301761	STATE OF TEXAS -C-	1	P & A	5,296	KATZ		2/11/1983
4243301762	STATE OF TEXAS -C-	2	P & A	5,205	KATZ		12/4/1982
4243301764	STATE OF TEXAS -C-	4	P & A	5,205	KATZ		11/29/1982
4226900012			ACTIVE	5,105			--
4226900016			ACTIVE	5,175			--
4243300005			P & A	3,251			--

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Request for Additional Information: Kinder Morgan CCS Complex
April 14, 2023

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	NA	NA	There are some figure and page numbers that still need corrected. For example: • According to the TOC, Section 2.2.5 is on page 2929. • Page 36 has a figure labeled “Figure 228”. Please ensure that all page numbers and figure numbers are in correct throughout the MRV plan.	Completed.
2.	Introduction	1	“This permit currently authorizes Kinder Morgan to inject up to 30,000 barrels saltwater per day…” As the rest of the plan appears to use units of SCF, we recommend providing an equivalent quantity in SCF here.	Completed – Page 1: This permit currently authorizes Kinder Morgan to inject up to 30,000 barrels saltwater per day (bbls/d), **equating to 65 million standard cubic feet per day (MMscf/day) of carbon dioxide**, into the Ellenburger and Cambrian formations at a depth of 5,800’ to 6,800’ with a maximum allowable surface pressure of 2,900 psi.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	NA	NA	Please ensure that all maps/figures are legible, have appropriate legends, scale bars, and an indication of cardinal direction. Please also ensure that the project site location is consistently displayed where applicable. For example: • Figure 19 does not have a legend. • Figure 24 and Figure 25 do not have the project site labeled. • Figure 3 has low resolution and is difficult to read.	Completed: Figure 19 (Page 33) has been updated and redrawn and a legend has been added to more effectively reflect color variation with subsea depth. Verbiage added to Figure 19 caption: **"Contour Interval (CI) on Ellenburger Structure map is 20'. The green outline is the boundary of the seismic data."** Figure 21 (page 35) – Inset map of Ellenburger Structure updated and modified from Figure 19 update. Verbiage added to Figure 21 caption: "**Ellenburger structure map modified from Figure 19."** Figure 22 (page 36) - Inset map of Ellenburger Structure updated and modified from Figure 19 update. Verbiage added to Figure 22 caption: "**Ellenburger structure map modified from Figure 19."** Figure 3 (Page 11) has been redone for further clarity. Figure 24 (Page 40) and Figure 25 (Page 41) have been updated with a blue star at the location of the project site.
4.	2	57	The MRV plan lists the duration of the injection period as 20 years (page 57) and 21 years (page 67). Please clarify.	Completed. Section 3.2 – Page 57 – Corrected injection duration "The AMA will cover the initial 21-year monitoring period, equating to the expected total injection time."

No.	MRV Plan Section	MRV Plan Page	EPA Questions	Responses
5.	3	56-57	Per 40 CFR 98.449, "Active monitoring area" is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by **superimposing two areas**: (1) **The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone of one-half mile** or greater if known leakage pathways extend laterally more than one-half mile. (2) **The area projected to contain the free phase CO_2 plume at the end of year t + 5.** The plan states that "The maximum distance between the wellbore and the edge of the plume is approximately 6,400', after injection stops, resulting in the AMA." In the MRV plan, please explain whether this delineation meets the definition above and/or update the AMA as necessary. To help clarify the how the AMA was delineated, we also recommend clearly labeling each of the lines in Figure 39. Is the plume boundary at the end of injection represented in this figure, if it was used to delineate the AMA?	Completed. Section 3.1 – Page 56 – verbiage added and changed to clarify definition of AMA and MMA. "The maximum distance between the wellbore and the edge of the plume is approximately 6,400', after injection stops in 2044. After 30 additional years of density drift, the areal extent of the plume is 3,384 acres, with a maximum distance to the edge of the plume of approximately 6,850'. Since the stabilized plume shape is relatively circular, the maximum distance plus a one-half mile buffer from the injection well, was used to define the circular boundary of the MMA equal to 9500'." Section 3.2 – Page 57 – verbiage added and changed to clarify definition of AMA. **"Assuming year t occurs at the point the plume stabilized (30 years after the cessation of injection), the plume extent in year t + 5 has the maximum radius of 6,850', which is the extent of the MMA. Thus, Kinder Morgan will define the AMA as equal to the MMA, in this case, as show in Figure 39."** Figure 39 – Page 57 – Updated with requested labeling for further clarification.
6.	3	56	"The plume is expected to stabilize 30 years after injection ceases and does not migrate after 2050…" According to Table 9, the plume boundary is expected to stabilize after 50 years. Please clarify in the MRV plan.	Completed – verbiage added Section 3 – Page 54 "**The results in Table 9 show that the modeled plume boundary is expected to stabilize 30 years after injection has ended. Additionally, the model was run a further 50 years to ensure the final plume boundary was stabilized, as shown in the table below.**"

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.	4.1	58	Per 40 CFR 98.448, facilities are required to provide discussion on "the likelihood, magnitude, and timing, of surface leakage of CO2 through these pathways." Please ensure that each potential leakage pathway has a characterization of the likelihood, magnitude and timing of leakage. For example, the discussion of leakage through surface equipment explains that CO2 releases would be "quickly identified", but it does not state what the expected likelihood, timing, or magnitude of these releases are. Additionally, we recommend reviewing the leakage characterizations for groundwater wells and seismicity.	Completed – verbiage added for further clarity Section 4.1 – Page 59 "If any leakage were to be detected, the volume of CO2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR §98.448(a)(5). **Kinder Morgan concludes that leakage of CO2 through the surface equipment as unlikely."** Section 4.2.2 – Page 64 "**Kinder Morgan concludes that leakage of the sequestered CO2 to the groundwater wells as unlikely.** Section 4.5 – Page 65 "**Therefore, Kinder Morgan concludes that leakage of the sequestered CO2 through seismicity as unlikely."** Section 7.4 – Page 76 **"As discussed previously, the potential for pathways for all previously mentioned forms of leakage are unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Kinder Morgan believes the most appropriate method to quantify the mass of CO2 released will be determined on a case-by-case basis. Any mass of CO2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, history-matching of the sequestering reservoir performance, among others. In the unlikely event that a leak occurs, it will be addressed, quantified and documented within the appropriate timeline. Any records of leakage events will be kept and stored as stated in Section 10, below."**

<table>
<tr><th rowspan="2">No.</th><th colspan="2">MRV Plan</th><th rowspan="2">EPA Questions</th><th rowspan="2">Responses</th></tr>
<tr><th>Section</th><th>Page</th></tr>
<tr><td>8.</td><td>5</td><td>67</td><td>Per 40 CFR 98.448(a)(3), facilities are required to provide, “a strategy for detecting and quantifying any surface leakage of CO_2”.

Please expand on your quantification strategies for the possible surface leakage pathways described in Section 5 of the MRV plan. Note that surface leaks (CO_{2E}, described in equation R-10) are separate from equipment leaks and vented emissions.

For example, while the plan describes strategies for detecting leaks from wells, faults/the confining seal, and seismicity, what strategies would the facility take to quantify leaks from such pathways?</td><td>Completed – verbiage added

Table 10 on page 67 provides a summary of facilities and strategies for detecting any leakage of CO2 to the surface, Per 40 CFR 98.448(a)(3).

Section 5.1 – Page 68
“In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.”

Section 5.2 – Page 69
“In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.”

Section 5.3 – Page 71
“In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.”

Section 5.4 – Page 71
“In the unlikely event a leak occurs, Kinder Morgan will quantify the leak per the strategies discussed in Section 7, below.”</td></tr>
<tr><td>9.</td><td>5</td><td>68</td><td>“The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and inspection of the cathodic protection system.”

Please clarify what system is being referred to in the above excerpt.</td><td>Completed – answered question below:

The “system” in this specific excerpt refers to all of the surface equipment that the sequestered CO2 will flow through.</td></tr>
<tr><td>10.</td><td>7</td><td>76</td><td>“Any leakage would be detected and managed as an upset event.”

Please define what is meant by “upset event”.</td><td>Completed – answered question below:

An "upset event" is any unlikely event that results in the failure of any mass of CO2, from the emission source, to remain permanently sequestered in the target reservoir.</td></tr>
</table>

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Kinder Morgan Permian CCS LLC

Prepared for *Kinder Morgan Permian CCS LLC*
Houston, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 2.0
March 2023

INTRODUCTION

Kinder Morgan Production Co. LLC (Kinder Morgan) currently has a Class II disposal permit issued by the Texas Railroad Commission (TRRC) for the Katz Strawn Unit 2361 well (KSU 2361), API# 42-433-33712. The permit was originally issued in November 2011 for saltwater disposal operations, and the well has actively injected saltwater since 2013. This permit currently authorizes Kinder Morgan to inject up to 30,000 barrels saltwater per day (bbls/d) into the Ellenburger and Cambrian formations at a depth of 5,800’ to 6,800’ with a maximum allowable surface pressure of 2,900 psi. The KSU 2361 well is located in a rural, sparsely populated area of Stonewall County, Texas, approximately twelve miles west of the town of Knox City, as shown in Figure 1.

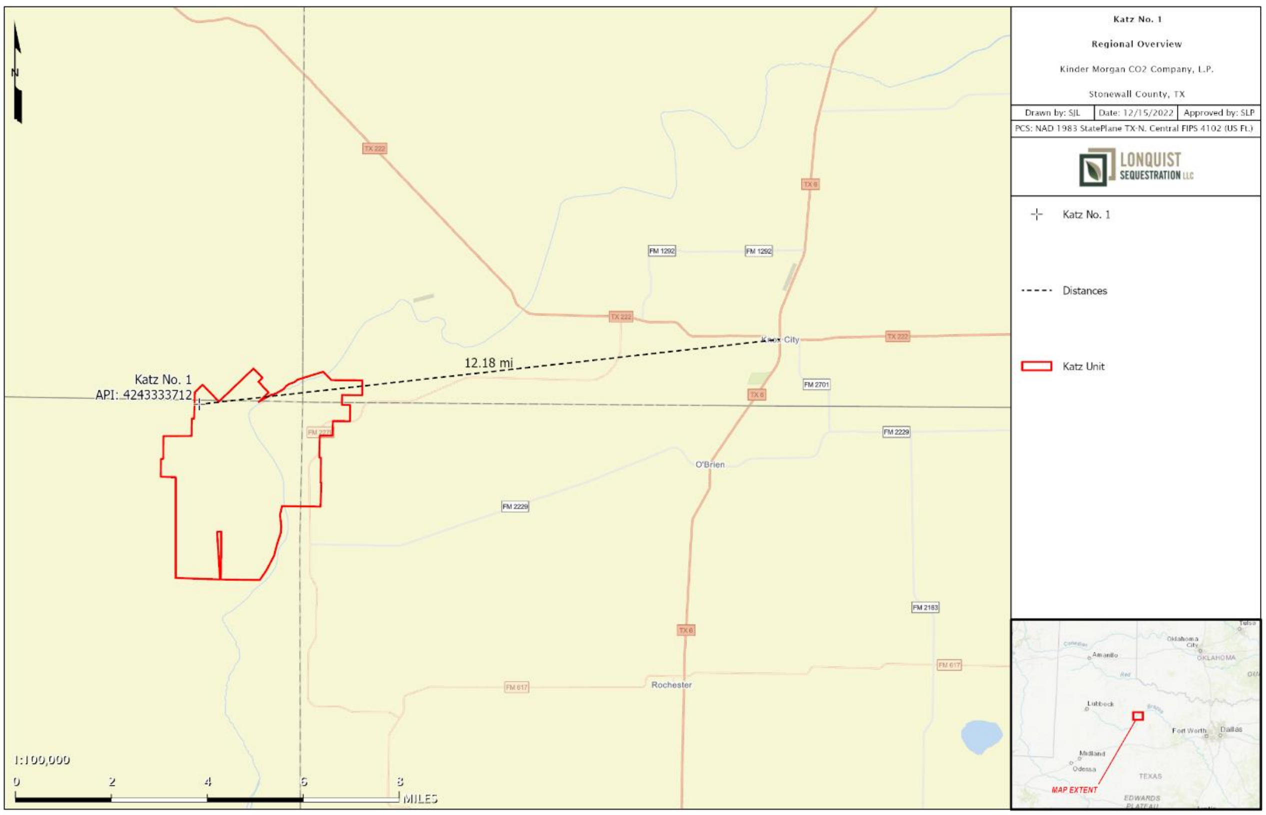


Figure 1 – Location of KSU 2361 Well

Kinder Morgan is seeking TRRC approval to amend the existing KSU 2361 Class II saltwater disposal permit to inject treated acid gas (TAG), including CO_2. In the future, Kinder Morgan may provide surplus injection capacity to dispose oil and gas waste derived TAG from similar third-party gas processing facilities. Kinder Morgan intends to inject into this well for 21 years at a capacity ranging up to 65 million standard cubic feet per day (MMSCF/d). The source of this injected CO_2 gas is from Red Cedar natural gas processing plants in southern Colorado. Table 1 below shows the expected composition of the gas stream to be injected. Table 2 shows the expected average volume of CO_2 gas commitments from similar type emission sources in the same area, along with the contract status as of March 2023.

Table 1 – Expected Gas Composition at KSU 2361

Component	Mol Percent
Carbon Dioxide	99.20%
Methane	0.25%
Ethane	0.03%
Propane	0.04%
Nitrogen	0.48%
Hydrogen Sulfide	0.00%

Table 2 – Expected Sequestered Gas Volumes for KSU 2361

Contract Status	Avg. Rate (MMcfd)
Committed	22
Proposal	8
Proposal	23
Proposal	9
Total	62

Kinder Morgan is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

ACRONYMS AND ABBREVIATIONS

‘	Feet
%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group’s GEM 2020.11
GHGs	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	MilliDarcy(ies)
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million

MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet
MMSCF	Million Standard Cubic Feet
MSCF/D	Thousand Cubic Feet per Day
MMSCF/d	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

INTRODUCTION 1
ACRONYMS AND ABBREVIATIONS..3
SECTION 1 – UIC INFORMATION..8
1.1 Underground Injection Control (UIC) Permit Class: Class II..8
1.2 UIC Well Identification Number: 8
SECTION 2 – PROJECT DESCRIPTION 9
2.1 Regional Geology..10
2.1.1 Regional Faulting 18
2.2 Site Characterization 19
2.2.1 Stratigraphy and Lithologic Characteristics..19
2.2.2 Upper Confining Zone – Mississippian Lime..21
2.2.3 Secondary Confining Interval – Lower Strawn Shale..22
2.2.4 Injection Interval – Ellenburger/Cambrian Sands..25
2.2.5 Lower Confining Zone – Precambrian 2929
2.3 Fracture Pressure Gradient 311
2.4 Local Structure..322
2.5 Injection and Confinement Summary..377
2.6 Groundwater Hydrology..377
2.6.1 Reservoir Characterization Modeling..433
SECTION 3 – DELINEATION OF MONITORING AREA..56
3.1 Maximum Monitoring Area 56
3.2 Active Monitoring Area 57
SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE..58
4.1 Leakage from Surface Equipment..58
4.2 Leakage from Existing Wells within MMA..59
4.2.1 Oil and Gas Operations within Monitoring Area..59
4.2.2 Groundwater wells 64
4.3 Leakage Through Faults and Fractures..65
4.4 Leakage Through the Confining Layer 65
4.5 Leakage from Natural or Induced Seismicity..65
SECTION 5 – MONITORING FOR LEAKAGE..67
5.1 Leakage from Surface Equipment..68
5.2 Leakage From Existing and Future Wells within MMA..68
5.3 Leakage through Faults, Fractures or Confining Seals..71
5.4 Leakage through Natural or Induced Seismicity..71
SECTION 6 – BASELINE DETERMINATIONS 73
6.1 Visual Inspections 73
6.2 CO_2 Detection 73
6.3 Operational Data 73
6.4 Continuous Monitoring 73
6.5 Groundwater Monitoring 74
SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION 75
7.1 Mass of CO_2 Received..75
7.2 Mass of CO_2 Injected 75

7.3 Mass of CO_2 Produced 766
7.4 Mass of CO_2 Emitted by Surface Leakage 76
7.5 Mass of CO_2 Sequestered 76
SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN 78
SECTION 9 – QUALITY ASSURANCE 79
9.1 Monitoring QA/QC 79
9.2 Missing Data 79
9.3 MRV Plan Revisions 79
SECTION 10 – RECORDS RETENTION 81
SECTION 11 - REFERENCES.... **Error! Bookmark not defined.**
SECTION 12 - APPENDICES 84

LIST OF FIGURES

Figure 1 – Location of KSU 2361 Well 1
Figure 2 – Regional Map of the Permian Basin. 10
Figure 3 – Stratigraphic Column of the Eastern Shelf 11
Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations 12
Figure 5 – Top of Structure Map of the Ellenburger Group in West Texas 13
Figure 6 – Generalized Isopach Map of the Ellenburger Group in West Texas 14
Figure 7 – Thickness of Cambrian and Lower Ordovician Strata 15
Figure 8 – Formation Tops at KSU 2361. 16
Figure 9 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma. 18
Figure 10 – KSU 2361 Type Log 19
Figure 11 – Type Log of Zones of Interest 20
Figure 12 – Depositional Map of the Mississippian 21
Figure 13 – Core Description 23
Figure 14 – Cross Section Depicting Corelative Offset Core with Lower Strawn Shale 24
Figure 15 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)25
Figure 16 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003) 27
Figure 17 – Offset Wells used for Formation Fluid Characterization. 288
Figure 18 – Pre-Cambrian Distribution Map 300
Figure 19 – Ellenburger Structure Map 333
Figure 20 – Structural Northwest-Southeast Cross Section 344
Figure 21 – Structural West to East Seismic Profile 355
Figure 22 – Structural Northwest to Southeast Seismic Profile 366
Figure 23 – Generalized Stratigraphy of the Seymour Aquifer 388
Figure 24 – Regional Extent of the Seymour Aquifer Pods 400
Figure 25 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer 411
Figure 26 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer 422
Figure 27 – Geomodel Dimensions 466
Figure 28 – Structural Horizons of the Geomodel 477
Figure 29 – Porosity Distribution in Plume Model 488
Figure 30 – NTG Ratio Applied to the Plume Model 49
Figure 31 – CO_2-Water Relative Permeability Curves 500
Figure 32 – History Match for KSU 2361 511
Figure 33 – History Match for KSU #3471 511
Figure 34 – Simulated Wellhead Pressure During Active Injection 522

Figure 35 – Forecasted Injection Rate and BHP 53
Figure 36 – Annualized Growth Rate of CO_2 Plume 54
Figure 37 – Aerial View of CO_2 Plume....................55
Figure 38 – Cross-Sectional View of CO_2 Plume 55
Figure 39 – Stabilized Plume Boundary, Active Monitoring Area, and Maximum Monitoring Area....................57
Figure 40 – Site Plan 59
Figure 41 – KSU 2361 Wellbore Schematic 61
Figure 42 – All Oil and Gas Wells within the MMA....................62
Figure 43 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA 63
Figure 44 – Seismicity Review (TexNet – 06/01/2022)....................66
Figure 45 – Groundwater Monitoring Wells....................70
Figure 46 – Nearest TexNet Seismic Station....................72

LIST OF TABLES

Table 1 – Expected Gas Composition of Sequestered Gas Stream....................2
Table 2 – Expected Gas Volumes of Sequestered Gas Stream....................2
Table 3 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples 29
Table 4 – Fracture Gradient Assumptions 311
Table 5 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas 388
Table 6 – CO_2 Solubility Table 475
Table 7 – Rock Properties 477
Table 8 – Initial Conditions Summary 488
Table 9 – Plume Model Radius and Area....................4854
Table 10 – Summary of Leakage Monitoring Methods 67

SECTION 1 – UIC INFORMATION

This section contains key information regarding the UIC Permit.

1.1 Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. TRRC classifies the KSU 2361 well as UIC Class II. A Class II permit was issued to Kinder Morgan under TRRC Rule 9 (entitled "Disposal into Non-Productive Formations") and Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").

1.2 UIC Well Identification Number:

Katz Strawn Unit 2361, API No. 42-433-33712, UIC #000104281.

SECTION 2 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the KSU 2361 well.

The injection interval for KSU 2361 is approximately 670’ below the base of the Strawn formation, the primary producing formation in the area, and approximately 5,900’ below the base of the lowest useable-quality aquifer. Therefore, the location, facility, and the well design of the KSU 2361 well are planned to protect against the migration of CO_2 out of the injection interval, protect against contamination of subsurface resources and, most critical, to prevent surface releases.

2.1 Regional Geology

The KSU 2361 well is located on the Eastern Shelf, a broad marine shelf located in the eastern portion of the Permian Basin, shown in Figure 2. Figure 3 depicts an Eastern Shelf stratigraphic column representative of the strata found at the KSU 2361 well location. The red stars reference the injection formations, and a green star indicates the historically productive interval in the area.

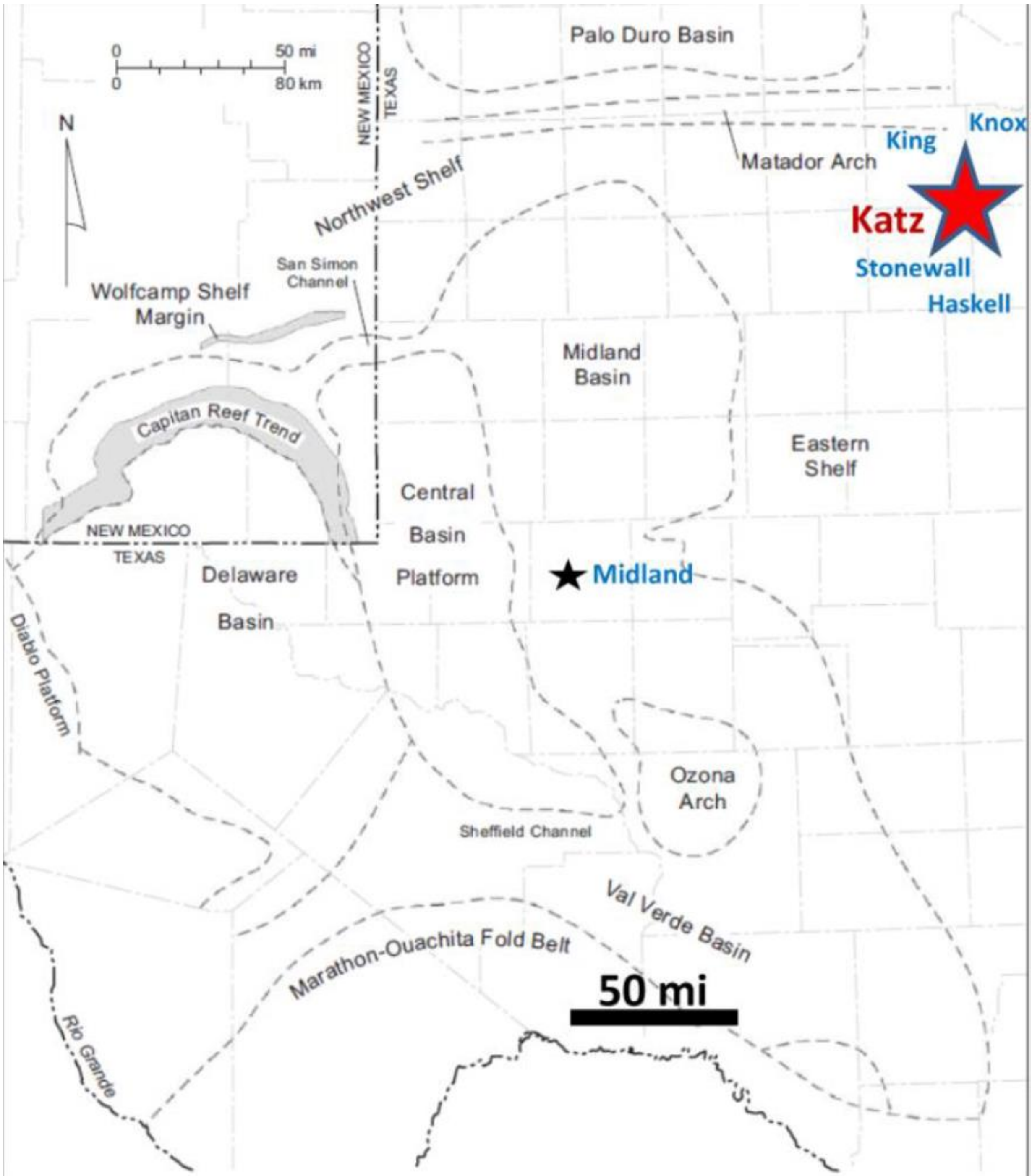


Figure 2 – Regional Map of the Permian Basin. The red star is the approximate location of KSU 2361 well.

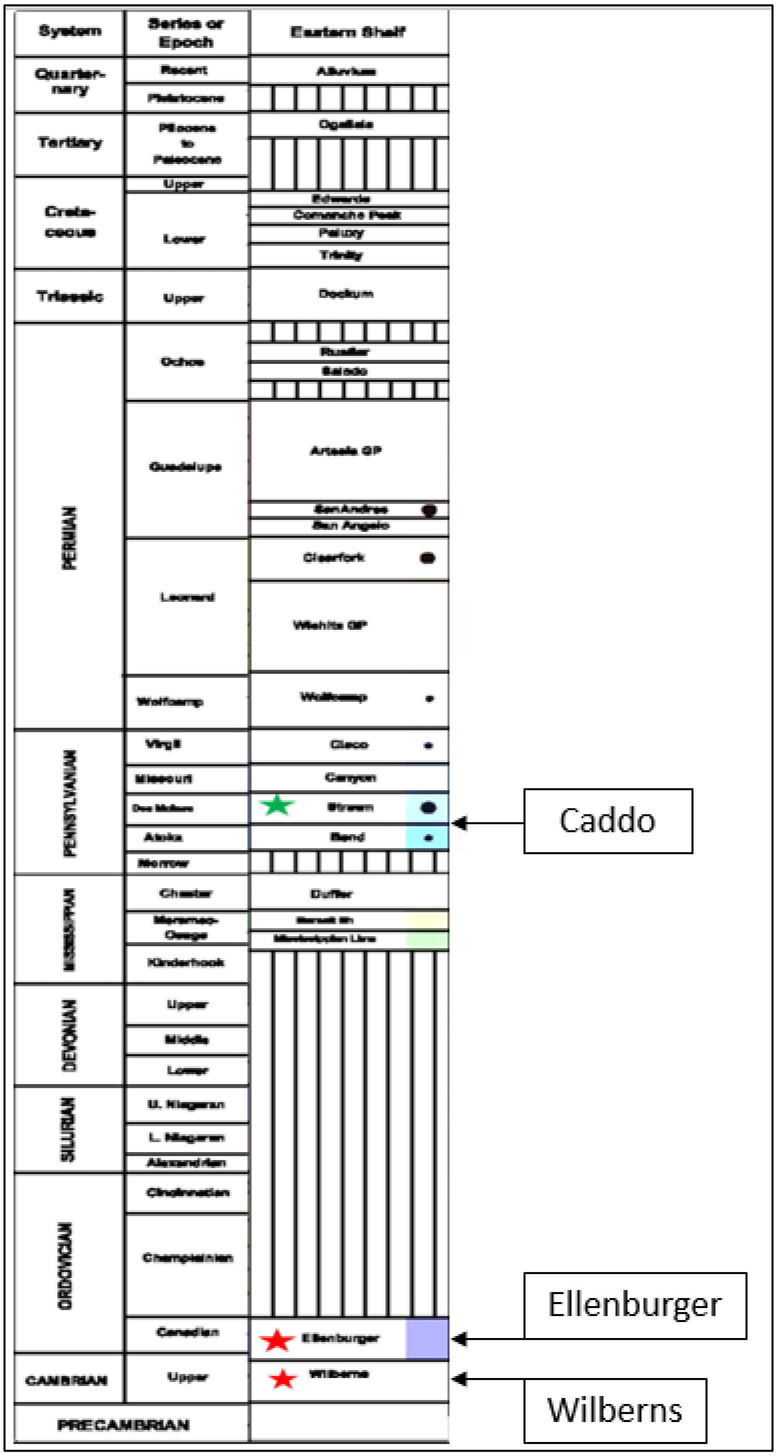


Figure 3 – Stratigraphic Column of the Eastern Shelf.

The upper target injection interval is the lower Ordovician-age Ellenburger Group, which is subdivided into the Honeycut, Gorman, and Tanyard Formations, as seen in Figure 4. Upper Cambrian-age sandstone units of the Wilberns Formation, comprise the lower target injection interval.

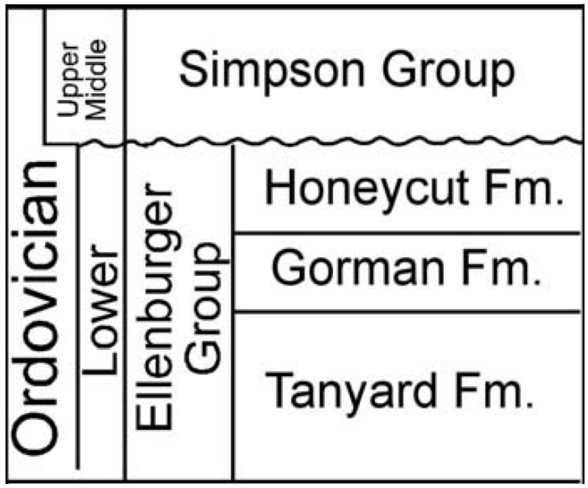


Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations (Kupecz, 1992).

The Ellenburger Group is present at varying depths in each of the provinces of the Permian Basin. In the Midland Basin area, the top of Ellenburger carbonate is as deep as 11,000' (GL) (Loucks, 2003). Due to regional structural dip of the Eastern Shelf, in northeast Stonewall County, the top of Ellenburger is found at only approximately 6,000' deep (GL). The depositional environment over the Stonewall, King, Knox, and Haskell County intersection during the Ordovician Period was a broad, shallow water carbonate platform with an interior of dolomite and an outer area of limestone. This was interpreted by Kerans (1990) as the dolomite being a restricted shelf interior and the limestone being an outer rim of more open-shelf deposits (Loucks, 2003).

Kerans (1990) performed the most complete regional analysis on Ellenburger depositional systems and facies. He recognized six general lithofacies as follows: litharenite: fan delta – marginal marine depositional system; mixed siliciclastic-carbonate packstone/grainstone: lower tidal-flat depositional system; ooid and peloid grainstone: high-energy restricted-shelf depositional system; mottled mudstone: low-energy restricted-shelf depositional system; laminated mudstone: upper tidal-flat depositional system; and gastropod-intraclast-peloid packstone/grainstone: open shallow-water-shelf depositional system.

According to Loucks, the diagenesis of the Ellenburger Group is complex, and the processes that produced the diagenesis spanned millions of years. The three major diagenetic processes of note are dolomitization, karsting, and tectonic fracturing. Dolomitization favors the preservation of fractures and pores due to its greater chemical and mechanical stability relative to limestone. Kupecz and Land (1991) delineated generations of dolomite into early-stage and late-stage. They attributed 90% of the dolomite as early-stage, wherein the source of magnesium was probably seawater. The other 10% of dolomite was attributed as late-stage, in which warm, reactive fluids were expelled from basinal shales during the Ouachita Orogeny. Karsting can affect only the surface of a carbonate terrain, forming terra rosa, or it can extensively dissolve the carbonate surface, forming karst towers (Loucks, 2003). It can also produce extensive subsurface dissolution in the form of caves and other structures, which increases porosity and permeability. Fracturing can be tectonic or karst-related. Tectonic fractures are commonly the youngest fractures in the rock and generally crosscut karst-related fractures (Kerans, 1989). Holtz and Kerans (1992) divided Ellenburger reservoirs into three groups based on these fracture types. The Eastern Shelf of the Permian Basin falls within the ramp carbonates group, in which predominant pore types are intercrystalline and interparticle. These reservoirs are characterized by the thinnest net pay, highest porosity, moderate permeability, highest initial water saturation, and highest residual oil saturation.

Figures 5 and 6 show the regional structure contours and isopachs of the Ellenburger Group, respectively. Figure 7 shows isopachs of Cambrian and lower Ordovician strata. Stars depict the KSU 2361 well location in each of these figures. In Figure 8, formation tops from gamma-ray data indicate the net pay thickness of the Ellenburger and Cambrian is approximately 223' within this interval in the KSU 2361 well location.

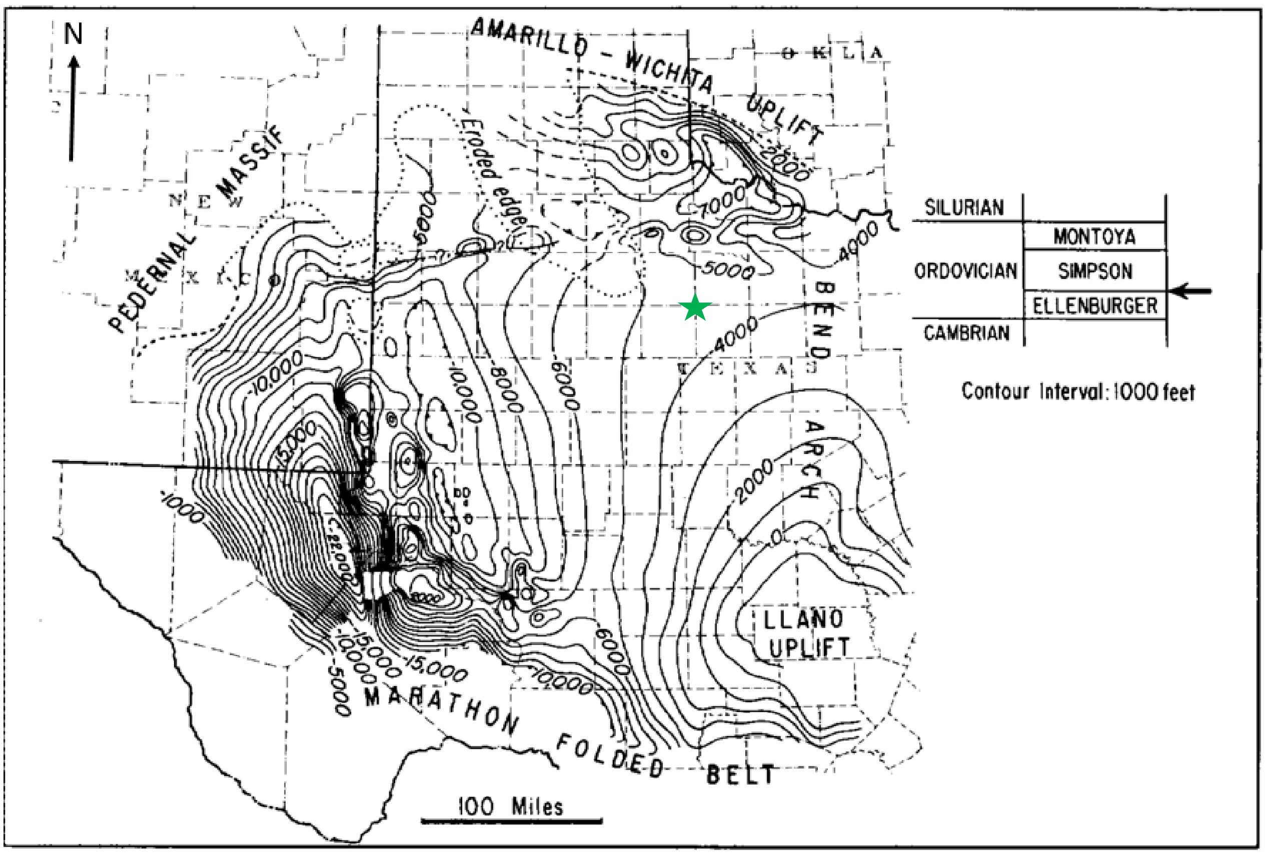


Figure 5 – Top of Structure Map of the Ellenburger Group in West Texas (Subsea Values) (Galley, 1955).

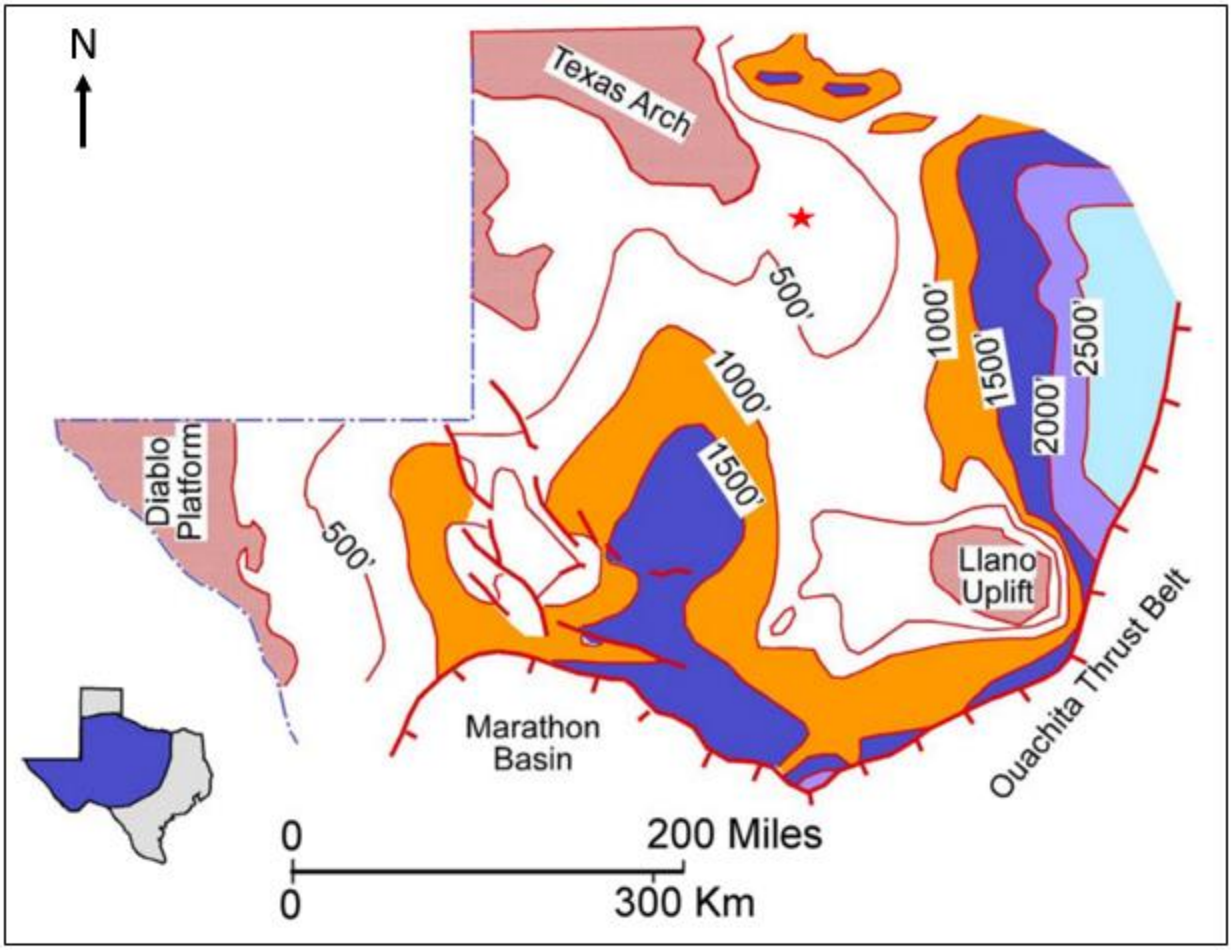


Figure 6 – Generalized Isopach Map of the Ellenburger Group in West Texas (Kerans, 1989).

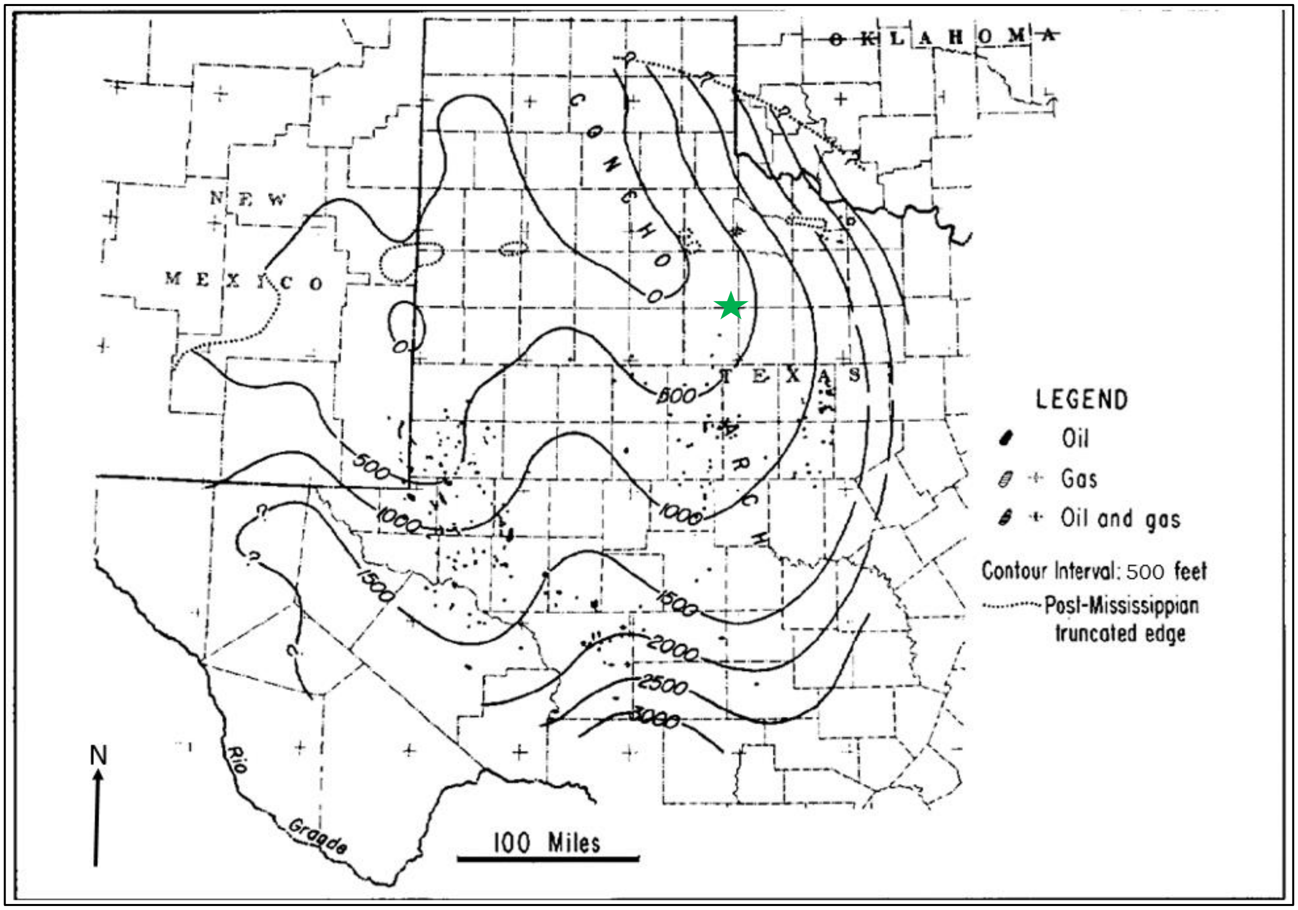


Figure 7 – Thickness of Cambrian and Lower Ordovician Strata
(Galley, 1955).

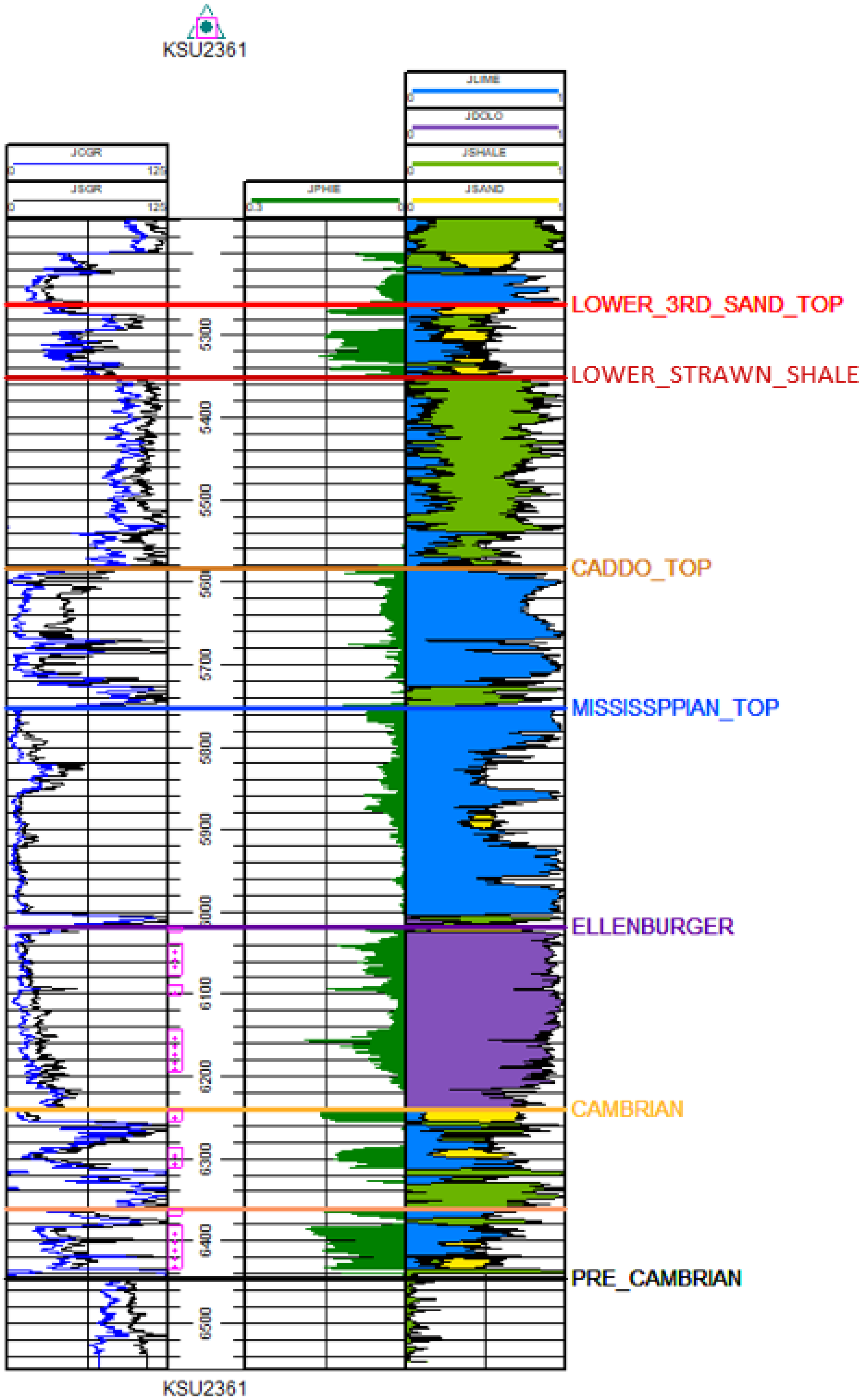


Figure 8 – Formation Tops at KSU 2361. Purple represents dolomite and the upper injection interval. Yellow represents sandstone, which is present in the pay interval. Pink boxes within depth column indicate active perforated intervals.

Cambrian-age strata consist of interbedded sandstone, limestone, and shale members. The initial deposits laid down on the eroded surface of Precambrian rocks were sandstone and arenaceous carbonates. Shale members are thickest in the southeast and nonexistent on the west side of the Permian Basin (Galley, 1955).

Overlying the Precambrian basement rock is the Riley Formation. This, in turn, is overlain by transgressive and progradational shallow-water marine sandstone, siltstone, limestone, and dolomite of the Wilberns Formation. The Riley Formation consists of sandstone packages whose thicknesses vary from place to place in response to the paleotopography of the underlying Precambrian surface (Kyle and McBride, 2014). The depositional environment in this area during the Cambrian was influenced by the sea, which advanced from the southeast (Galley, 1955). This led to the formation of a complex succession of transgressive and regressive sandstone units, both glauconitic and non-glauconitic (Kyle and McBride, 2014).

The Riley Formation is probably thickest south of the Llano region and laps out about 100 miles west and a slightly greater distance northwestward from the Llano region. It has accumulated in a northwestward-extending arm of the sea and likely extended beyond its present limits since there is a disconformity at its top. The Wilberns Formation thins appreciably northwestward from the Llano region to about 230' in Nolan County and to 70' in Lubbock County. West and north of the Llano region, usage suggested by Cloud and Barnes and adopted by petroleum geologists places the Tanyard-Wilberns boundary in the vicinity of the first appearance downward of glauconite (Barnes et al., 1959).

Figure 9 indicates that the Riley Formation's northwestern extent ends in Jones and Fisher counties, which implies that Cambrian strata at KSU 2361 may be limited to the Wilberns Formation only.

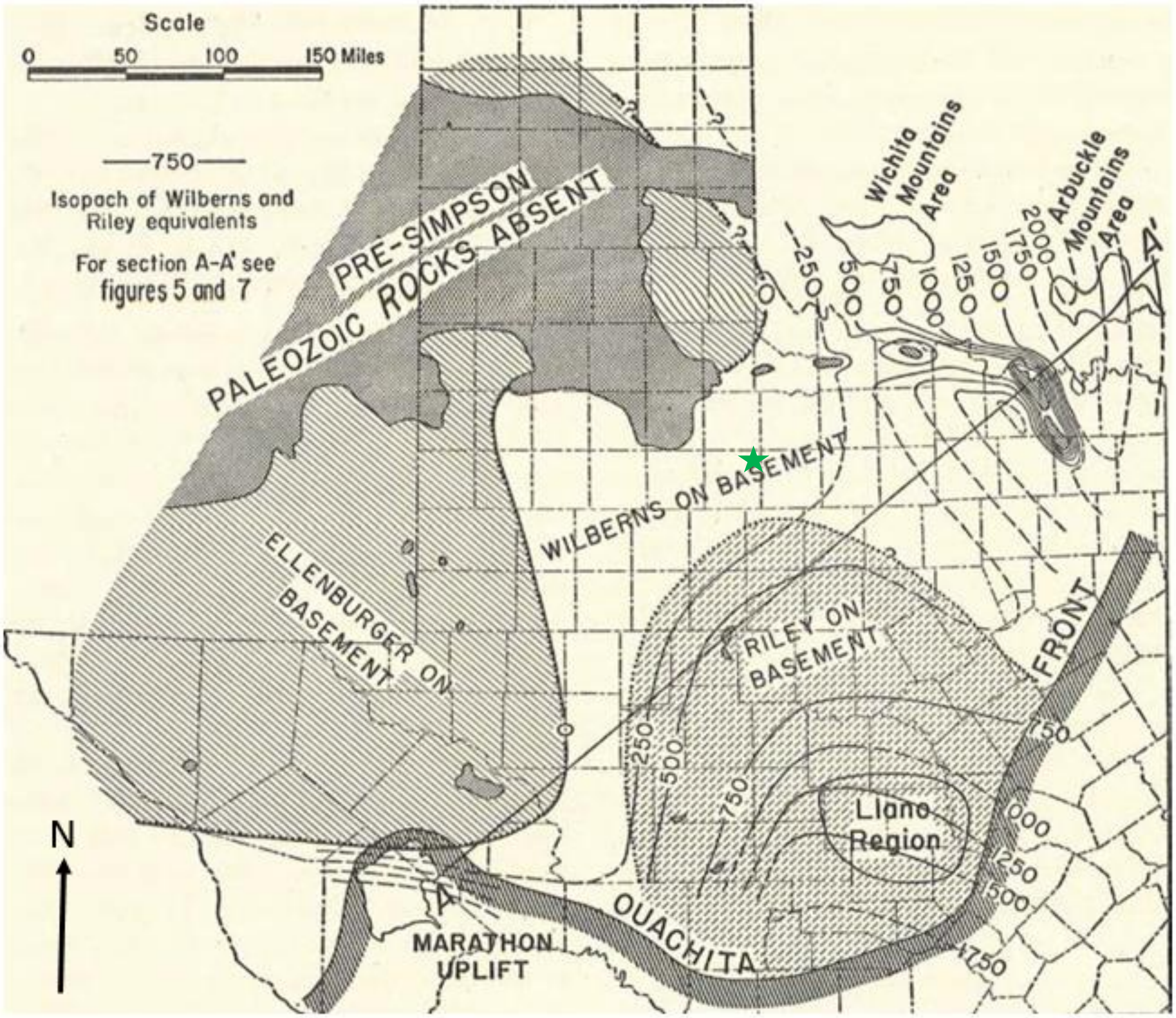


Figure 95 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma.
The green star approximates the location of KSU 2361 (Barnes et al., 1959).

2.1.1 Regional Faulting

Regional faulting in the KSU 2361 area trends primarily N-S in direction. This is the result of the dip rotation from a SW-NE trend seen in the Fort Worth basin to the east that rotates N-S as you move west towards the Bend-Arch and the edge of the basin (Hornhach, 2016). This trend then carries towards the Eastern Shelf closer to the KSU 2361 location. The most common faults are high-angle basement faults that primarily die within the Pennsylvanian in the KSU 2361 well area. Faulting is discussed in more detail in the Site characterization.

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the KSU 2361 well.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 depicts an annotated open hole log from the surface to the total depth of the KSU 2361 well, with regional formation tops indicating the injection and primary upper confining units. Figure 11 provides a magnified view of the zones of interest, from above the Lower Strawn to the Precambrian, with general lithologic descriptions along the right edge of the figure.

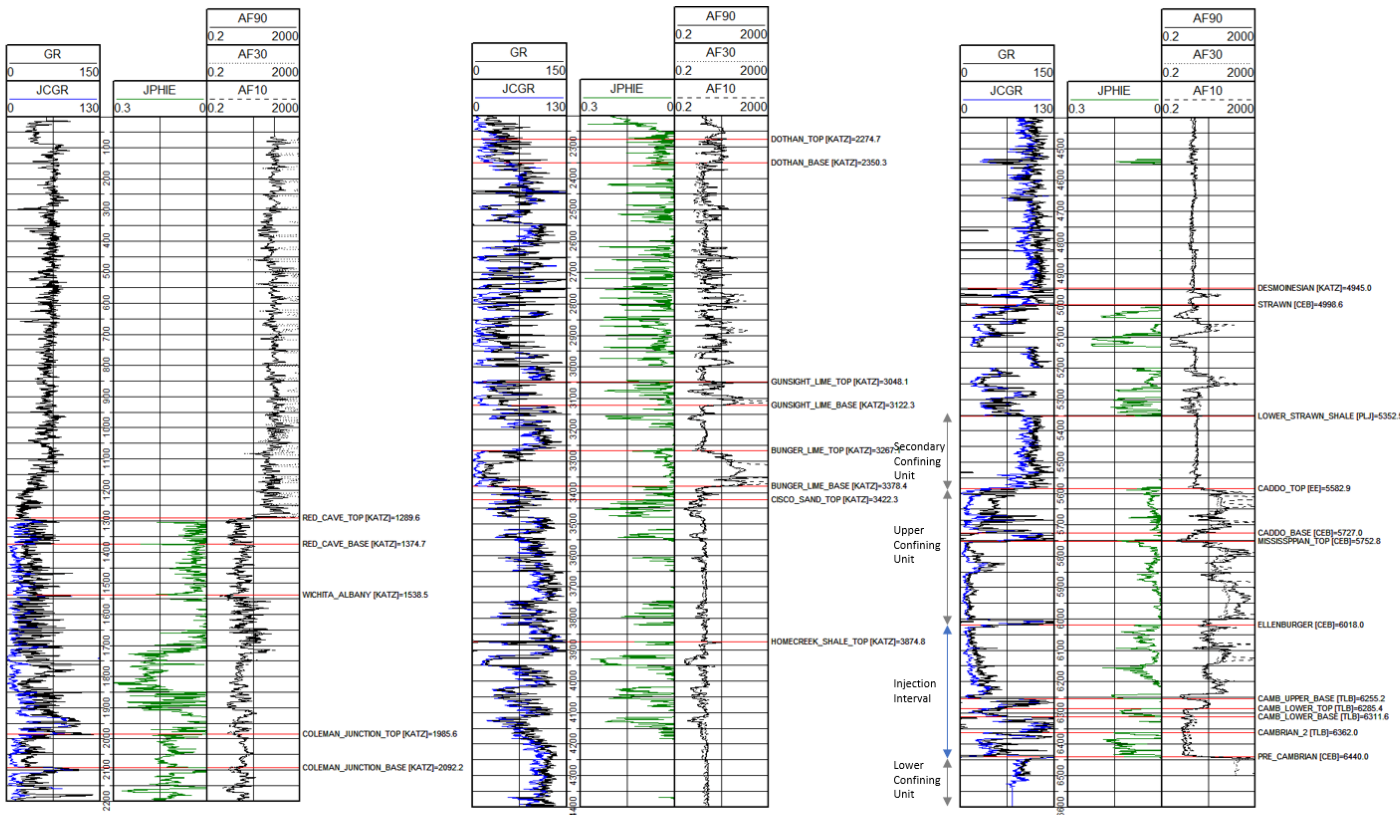


Figure 10 – KSU 2361 Type Log

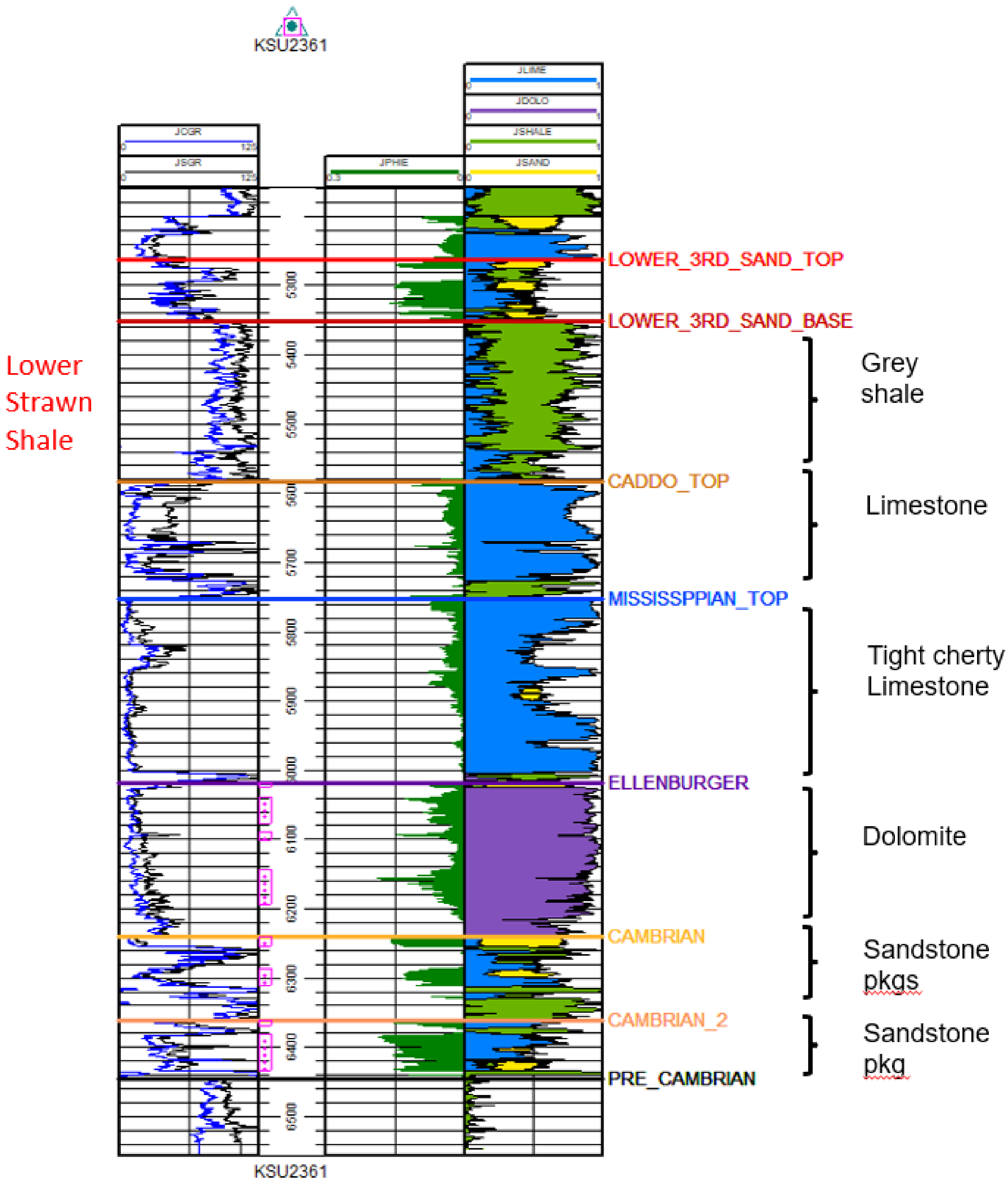


Figure 61 – Type Log of Zones of Interest

2.2.2 Upper Confining Zone – Mississippian Lime

The Mississippian Lime is the primary confining unit for the KSU 2361. This formation is the product of a large extensive shallow water carbonate platform that covered much of the southern and western Laurussia (Kane). Figure 12 shows the location of the KSU 2361 well to be found within the Chappel Shelf of the Mississippian Age. Representative cores of the Mississippian Lime formation found on the Chappel Shelf in the Llano uplift area consist of light-colored, fine- to coarse-grained, skeletal packstone (Kane). The open hole log seen in Figure 11 depicts the Mississippian Lime as predominantly cherty limestone. The basal carbonate section has little to no effective porosity development, which should translate to no permeability development. The Mississippian Platform Carbonate play is the smallest oil-producing play in the Permian Basin, which is tied to the abundance of crinoidal, grain-rich facies in platform successions. Most production from Mississippian reservoirs comes from more porous upper Mississippian ooid grainstones (Kane). This indicates that little to no reservoir characteristics are developed within the lower Mississippian Lime, creating an optimal seal.

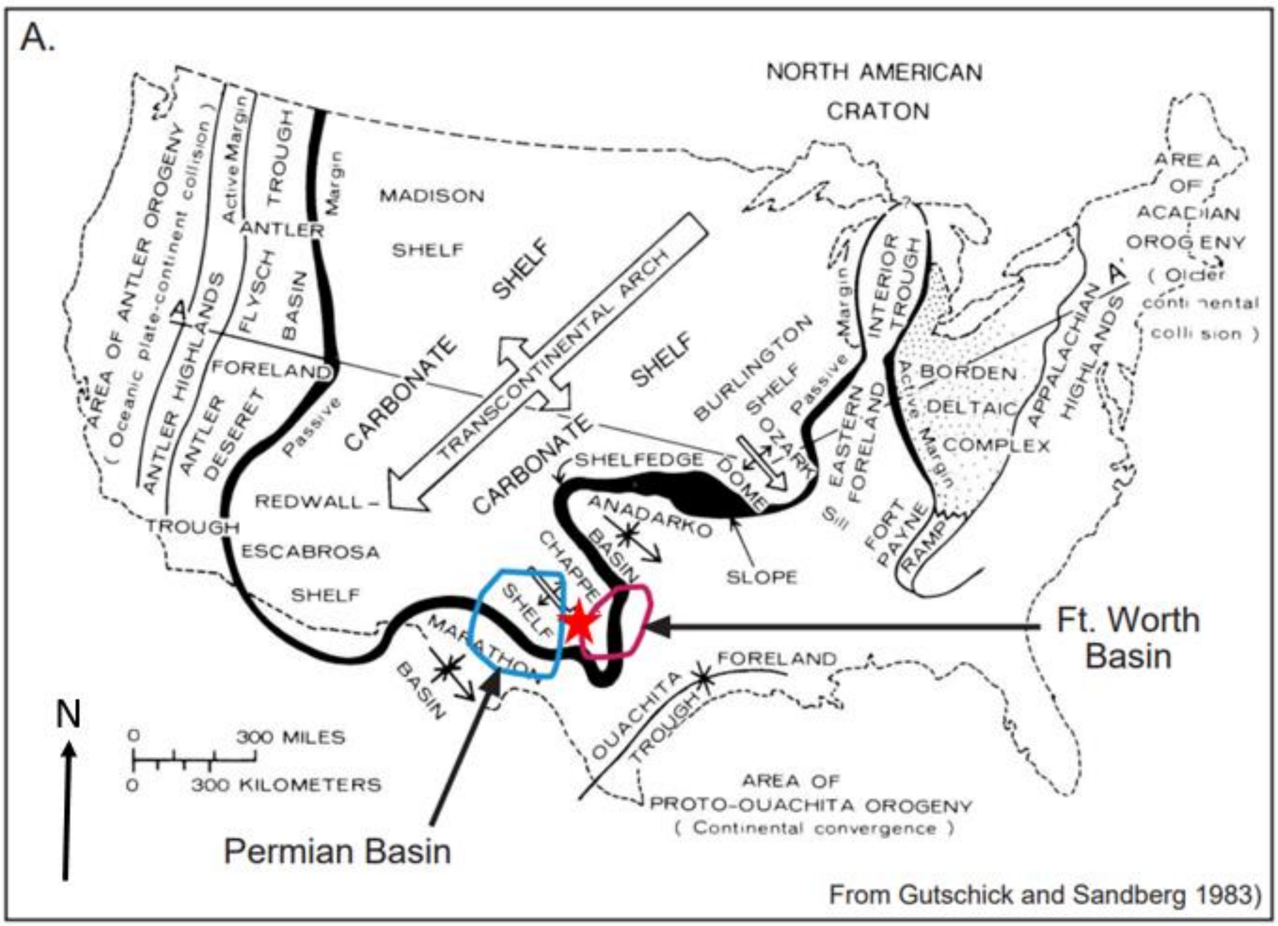


Figure 12 – Depositional Map of the Mississippian (Kane)

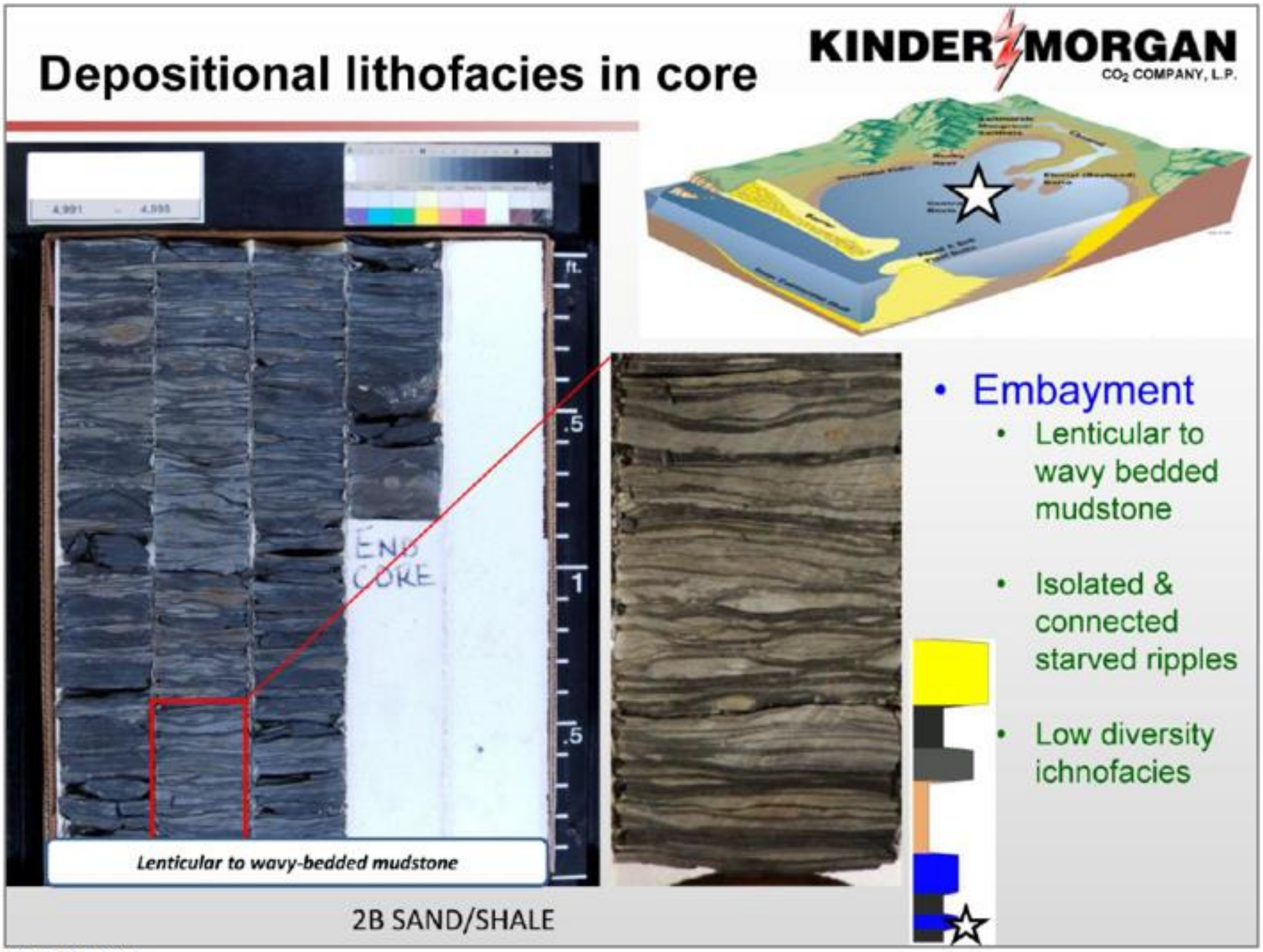
2.2.3 Secondary Confining Interval – Lower Strawn Shale

The Lower Strawn Shale (LSS) is Desmoinesian in age and was heavily influenced by the Knox Baylor Trough, which is near the KSU 2361 location and is late-Desmoinesian in age. The trough resulted from the Ouachita-Marathon overthrust movement that disrupted the Fort Worth basin depositional center, moving the Desmoinesian depocenter further to the west to form the Knox Baylor Trough. This trough allowed sediments to be transported west to the Midland Basin. These sediments were derived from the destruction of the elongated Bowie Delta System, which derived its sediments from the Muenster-Wichita Mountain system (Gunn, 1982).

Depositional facies within the Strawn unit resemble assemblages typical of a mixed siliciclastic-carbonate continental-to-shelf transitional succession found along a complex embayed coastline. Six petrophysically distinct lithofacies were identified: (1) lenticular to wavy-bedded mudstone, (2) flaser to wavy-bedded sandstone, (3) carbonate-rich sandstone, (4) ripple-to-trough cross-laminated sandstone with common convolute bedding, (5) trough cross-laminated sandstone with abundant mud rip ups and mud balls, and (6) heavily bioturbated sandstone. Combined lithofacies and ichnofacies observations suggest that paleoenvironments of the Katz Field included a bayhead delta, back-barrier estuary embayment, tidal flood delta, tidal flat, and upper to middle shoreface (Jesse G. White, 2014). The LSS is associated with the back-barrier estuary embayment depositional environment, evidenced by the abundance of mudstone.

Figure 13 provides core photos and associated descriptions of a core sample taken in the Katz field within an embayment environment. Core descriptions of this core sample observed characteristics that serve as excellent sealant properties to prohibit the migration of injection fluids above the injection zone. Conventional core data was collected in an offset well near the LSS depths in the API #42-433-33534 well, 5,089' away from the KSU 2361 well. Figure 14 is a cross-section relating the KSU 2361 well and the API #42-433-33534 well, indicating the cored interval alongside pictures of the lower portion of the core that most closely resembles the LSS. Horizontal permeabilities within the pictured core data range from 0.05 to 0.3 mD, with a vertical permeability value of less than 0.01 mD.

Along with the core reports and descriptions, Figure 14 plots calculated log curves from petrophysical analyses run on open-hole log data from the KSU 2361 well. Figure 14 indicates no effective porosity within the LSS (JPHIE green curve, 2nd track from the left) with a shale lithology reading (JHSHALE, green shading, 3rd track from the left). The petrophysical properties and lithology indicated by core and log data demonstrate that the LSS possesses characteristics of an excellent sealing formation.



4991 TO 4998:

4991.00 – 4997.4: Black to dark gray lenticular to wavy bedded mudstone encasing light gray lenticular siltstone to muddy very-fine sandstone. Abundant light gray calcareous horizons. Note zones of reddish color.

4997.4 – 4997.5: Burrowed transgressive bioclastic lag deposit? Abundant crinoid and bioclastic debris over burrowed laminated to contorted black shale.

4997.5 - 4997.7: Black laminated shale

4997.7 - 4998.0: Dark gray to gray black crinoid mudstone interbedded with a single tan algal mudstone-wackestone hardground exhibiting mudcracks.

Trace fossils shown in blow-ups include *Paleophycus, Planolites, Thalassinoides* and *Teichichnus*.

Sedimentology infers **brackish water deposits** (Brackish water is water that has more salinity than fresh water, but not as much as seawater. It may result from mixing of seawater with fresh water, as in estuaries.

4991 - 4998: Estuary – embayment. Brackish water deposit. Muddy.

Figure 137 – Core Description

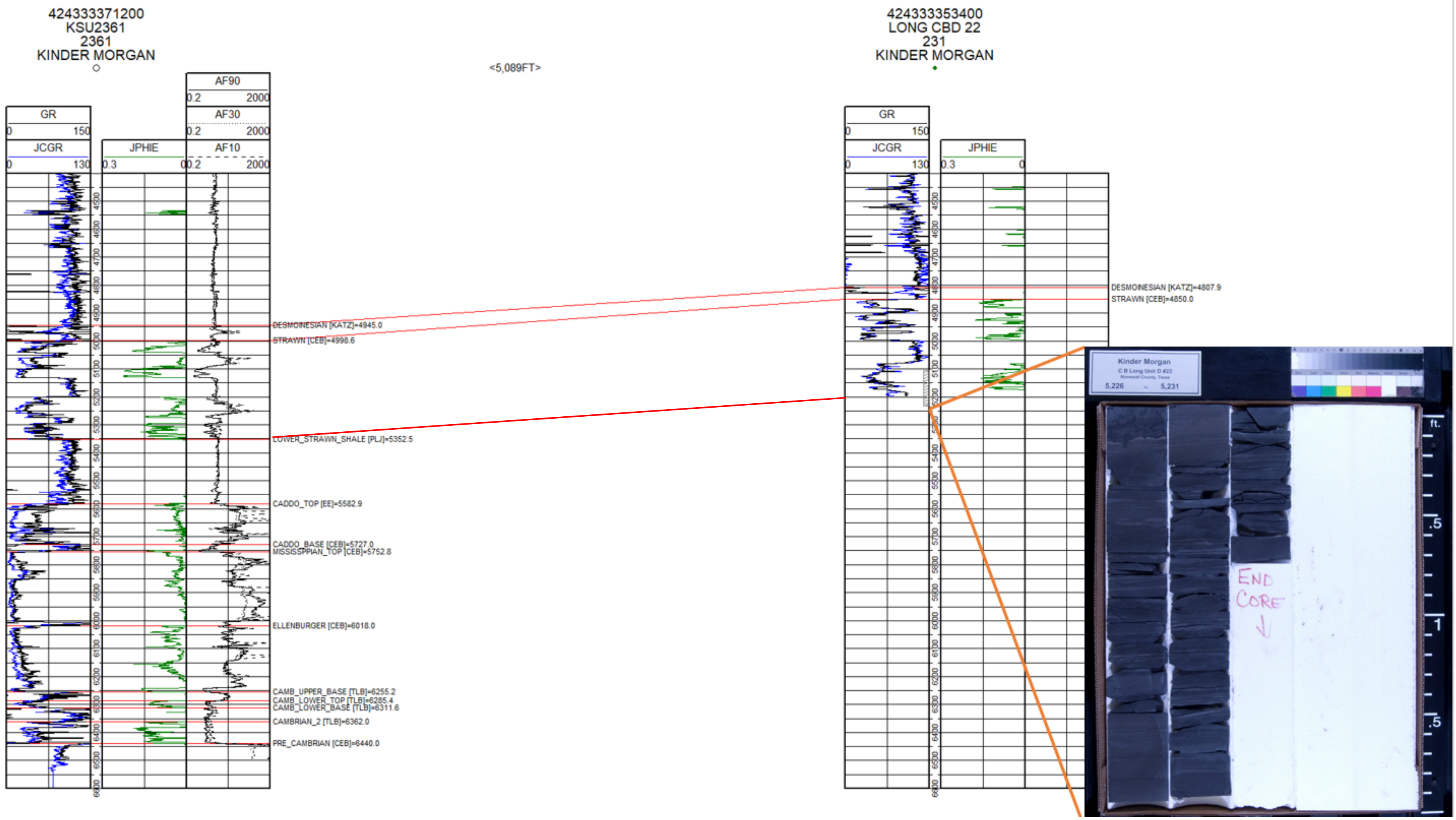


Figure 14 – Cross Section Depicting Correlative Offset Core with Lower Strawn Shale

2.2.4 Injection Interval – Ellenburger/Cambrian Sands

Ellenburger

The Ellenburger is a widespread lower Ordovician carbonate deposited over the entire north Texas area, indicating a relatively uniform depositional condition (Hendricks, 1964). North Central Texas experienced a low-energy, restricted shelf environment comprised of a homogeneous sequence of gray to dark-gray, fine to medium crystalline dolomite containing irregular mottling (probable bioturbation structures) and lesser parallel-laminated mudstone and peloid-wackestone (Kerans, 1990). Figure 15 is a map depicting the different depositional environments of the lower Ordovician, with associated lithologies. This map confirms the inferred dolomite lithology of the open hole log analysis in Figure 11 of the KSU 2361 well.

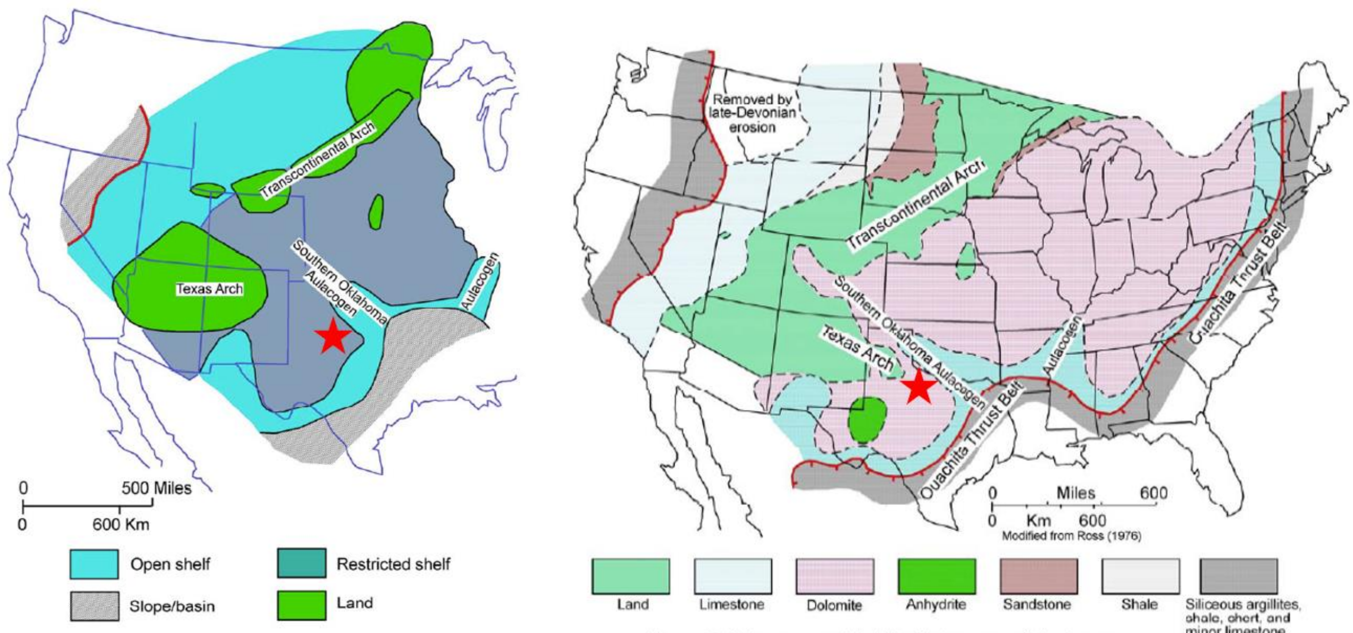


Figure 2. Paleogeographic lithofacies map of the Lower Ordovician section in the United States. From Ross (1976).

Figure 3. Interpreted regional depositional setting during Early Ordovician time. After Ross (1976) and Kerans (1990).

Figure 15 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

Ellenburger Porosity/Permeability Development

Within the low-energy, restricted shelf environment, facies are highly dolomitized and have a heavy presence of bioturbation resulting in mottling (Loucks, 2003). The dolomitization led to porosity development within the Ellenburger, along with diagenetic leaching processes and other secondary porosity features such as karsts and vugs. The tables in Figure 16 show permeability and porosity values tabulated from Ellenburger reservoirs within Texas, categorized by their diagenetic facies into three groups: Karst Modified, Ramp Carbonates, and Tectonically Fractured Dolostones. Based on the descriptions in Figure 16, the Ellenburger of the KSU 2361 would fall within the Karst Modified Reservoirs category outlined in red with average porosity and permeability values of 3% and 32 mD, respectively. This corresponds with the data collected from the KSU 2361 well. As shown in Figure

11 above, the calculated effective porosity curve in green (JPHIE) is an average of roughly 3% over the Ellenburger formation. Permeability was estimated from volumes injected plotted against pressure responses within the KSU 2361 well; these permeabilities ranged from 12-20 mD. Similarities between these two datasets validate reservoir characteristics used for model inputs.

Cambrian

The deposition of Cambrian and lower Ordovician strata on the early Paleozoic shelf was initiated by a transgressing sea which, entering the area from the south, first laid down a clastic sequence. Initial deposits were sandstone and arenaceous carbonates that grade upward into the slightly cherty carbonates of the Ellenburger group (Galley, 1958). Lithologies include glauconitic and phosphatic to clean sandstones of various textures, intergrading and alternating with chemical, clastic, and even local limestones and dolomites, together with intercalated thin shales (Conselman, 1954).

Cambrian Porosity/Permeability Development

Few reservoir characteristics have been published on the Cambrian sands. Porosity and permeability were estimated based on the KSU 2361 wells open hole log and injection data. There are three discreet sandstone intervals within the Cambrian at this location. The upper two sands identified in the CAMBRIAN package have an average effective porosity of 12.9% and 8.8%. The average effective porosity of the third sand is 8.4%. These effective porosity values are plotted as the JPHIE (effective porosity) curve in Figure 11. Due to nature of the Ellenburger and Cambrian zones being commingled during injection tests, modeling makes the assumption of 12-20mD average permeability for the interval, for history matched injection volumes and pressures.

Table 2. Geologic characteristics of the three Ellenburger reservoir groups. From Holtz and Kerans (1992).

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 16 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

Formation Fluid

Four wells were identified within approximately 20 miles of the KSU 2361 well through a review of oil-field brine compositions of the Ellenburger formation from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3. None of these four wells are salt water disposal wells. The location of these wells is shown in Figure 17. Results from the synthesis of this data are provided in Table 3. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids. Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger Formation is compatible with the proposed injection fluids.

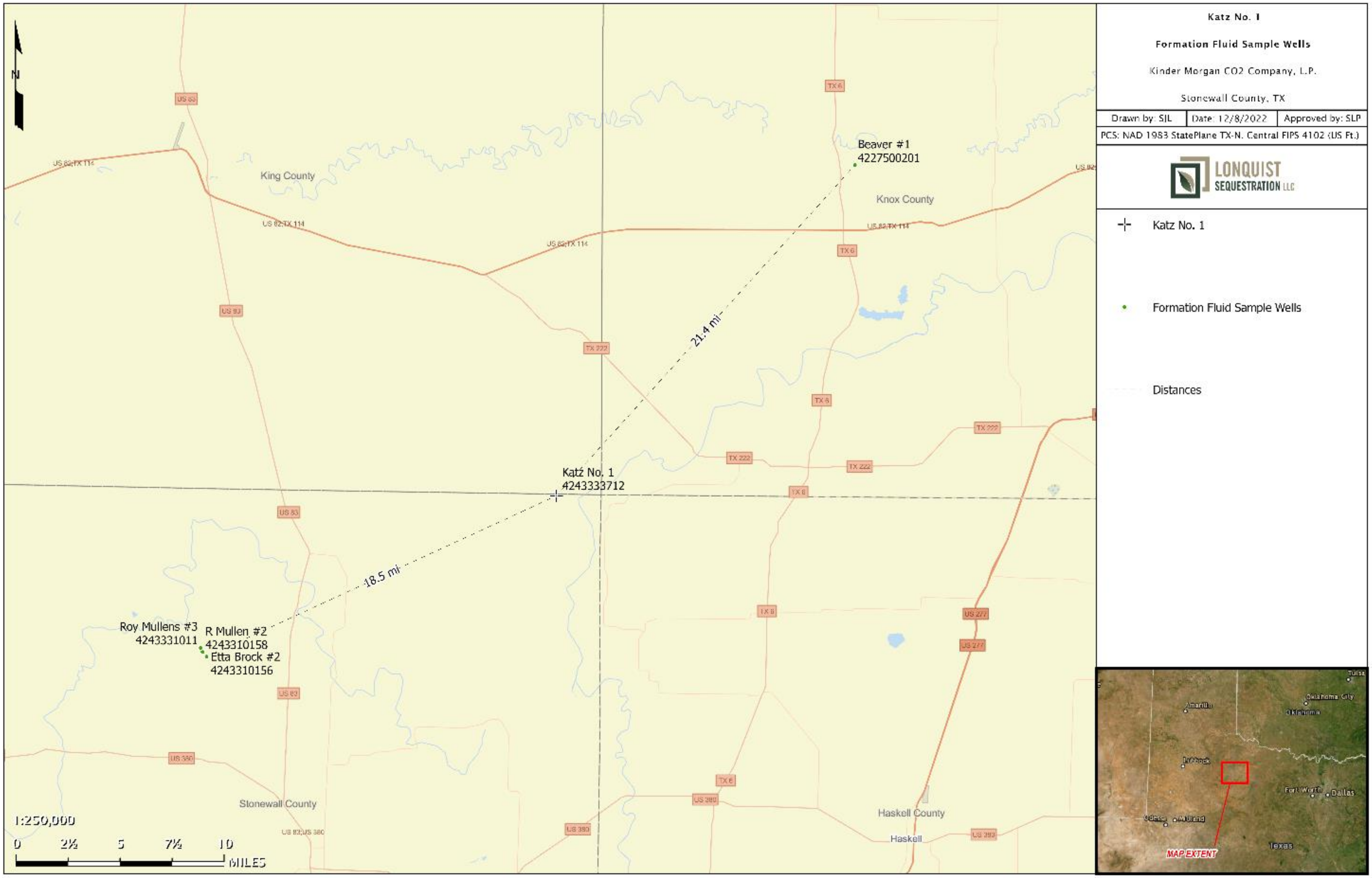


Figure 17 – Offset Wells used for Formation Fluid Characterization.

Table 3 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples

	Average	Low	High
Total Dissolved Solids (ppm)	144065	98802	210131
pH	6.15	5	7
Sodium (ppm)	43391	30833	64222
Calcium (ppm)	9275	5128	13200
Chlorides (ppm)	88355	60061	128685

2.2.5 Lower Confining Zone – Precambrian

The Precambrian outcrops to the south at the Llano uplift and the west in the Trans-Pecos regions of Texas and central New Mexico. Outcrops near the Llano Uplift in McCulloch County consist of highly weathered granite, schist, and gneiss. The granite is fine- to coarse-grained and contains numerous pegmatite veins. The schist has a high percentage of biotite, which gives it a dark-gray color, and it is often referred to as "gray shale" or "blue mud" by well drillers. The gneiss is pinkish and fine-grained (Mason, 1961). A study in 1996 was performed by Adams and Keller to better understand the Precambrian distribution in Texas indicates that Precambrian at the Katz 2361 location should contain an average metamorphic rock, as seen in Figure 18. This agrees with the open hole log response in the Precambrian formation in the open hole log section of Katz 2361. Gamma-ray log values of the Precambrian section are consistently above 90 GAPI (Gamma Units of the American Petroleum Institute), indicating a high radioactive response. A very high resistivity reading within this section indicates little to no porosity, as shown in the JPHIE, validating the characteristics described above. These traits are ideal attributes of a tight, lower confining basement.

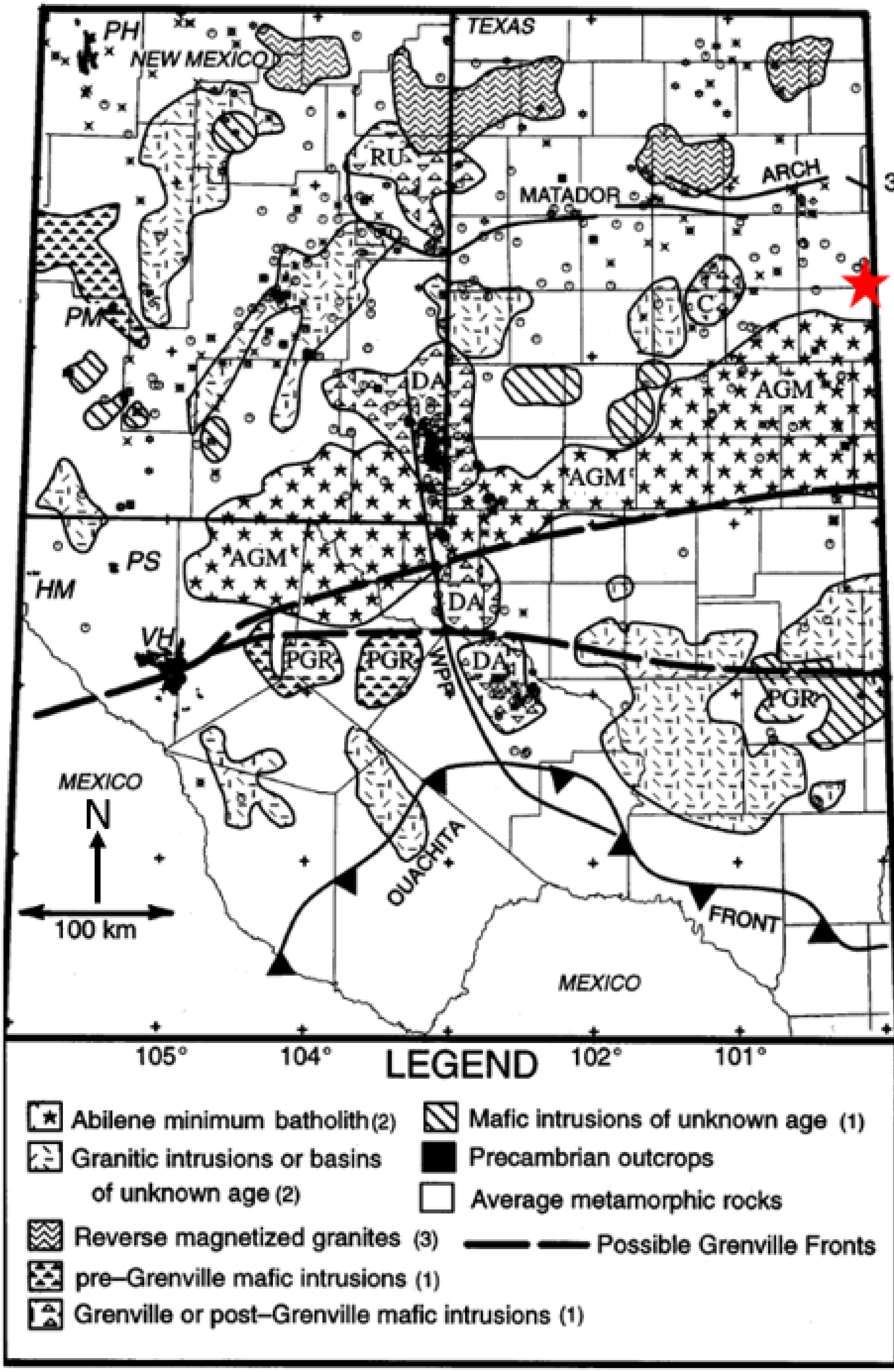


Figure 18 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

2.3 Fracture Pressure Gradient

Fracture pressure gradients were estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for determining fracture gradients. Poisson's ratio (ν), overburden gradient (OBG), and pore gradient (PG) are all variables that can be changed to match the site-specific injection zone. The expected fracture gradient was determined using industry standards and a literature review. The overburden gradient was assumed to be 1.05 psi/ft. This value is considered best practice when there are no site-specific numbers available. The pore pressure gradient was calculated to be 0.43 psi/ft from the bottom hole pressure data. For limestone/dolomite rock in the injection zone, the Poisson's ratio was assumed to be 0.3 through literature review (Molina, Vilarras, Zeidouni 2016). Using these values in the equation below, a fracture gradient of 0.70 psi/ft was calculated for the injection zone.

For the upper confining interval, a similar fracture gradient was calculated. The upper confining shale has an increased chance to vertically fracture if the injection interval below is fractured (Molina, Vilarras, Zeidouni 2016). Therefore, a Poisson's ratio equal to that of the injection interval was used as a conservative estimate. The lower confining zone was assumed to be of a similar matrix to the injection interval, with the key difference being that the formation is much tighter (lower porosity/permeability). Therefore, the Poisson's ratio was assumed to be slightly higher in this rock. As seen in Table 4, the fracture gradient of .64 psi/ft is slightly higher in the lower confining zone.

Multiple approaches can be taken to manage reservoir pressure. Current engineering practices for acid gas CO_2 injection recommend applying a 10% safety factor to the fracture pressure of the geology being injected into, resulting a 0.63 psi/ft gradient. This new value represents the maximum allowable bottom-hole pressure during injection. Another approach is to maintain a maximum wellhead pressure (WHP). In the reservoir model, a WHP of 1,850 psi was used to constrain the simulated well. This translates to a value that is 84% of the frac gradient or a 16% safety factor. By using either approach, there is a reduced risk of fracture propagation in the injection zone.

A conservative maximum pressure constraint of 0.60 psi/ft was used for injection modeling, which is well below the calculated fracture gradient for each zone. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

Table 4 – Fracture Gradient Assumptions

	Injection Interval	Upper Confining	Lower Confining
Overburden Gradient (psi/ft)	1.05	1.05	1.05
Pore Gradient (psi/ft)	0.43	0.43	0.43
Poisson's Ratio	0.30	0.30	0.31
Fracture Gradient (psi/ft)	0.70	0.70	0.71
FG + 10% Safety Factor (psi/ft)	**0.63**	**0.63**	**0.64**

The following calculations were used to obtain fracture gradient estimates:

$$FG = \frac{\mathrm{n}}{1-\mathrm{n}}(OBG - PG) + PG$$

$$FG = \frac{0.3}{1-0.3}(1.05 - 0.43) + 0.43 = 0.70$$

$FG\ with\ SF = 0.70\ \times (1 - 0.1) = \mathbf{0.63}$ **(Injection and Upper Confining intervals)**

$FG\ with\ SF = 0.71 \times (1 - 0.1) =$ **.64 (Lower Confining interval)**

2.4 Local Structure

Regional structure in the area of the KSU 2361 well is influenced by a shallow angle ramp down dip to the southwest towards the Midland Basin, which is set up by a north-south regional fault to the east. Specifically, the KSU 2361 well is located on the western portion of a shelf-like feature that dips slightly away from the fault to the east. Figure 19 is a structure map on the top of the Ellenburger with the KSU 2361 well indicated by the black star.

Subsurface interpretations of the Ellenburger formation heavily relied on 3D seismic coverage in the area. The seismic coverage outline is represented by the purple boundary seen in Figure 19. Only two wells penetrated the Ellenburger formation within the 3D seismic data volume and are shown in the northwest to southeast seismic profile along with the cross-section in Figure 22. These two wells are active injection wells within the proposed injection interval operated by Kinder Morgan, one being the Katz 2361 well while the other is the Katz #3741 well. Both wells were used to create time-to-depth conversions for the Ellenburger horizon. Shallower formations provide additional well control to assist in creating time-to-depth conversions displayed in the seismic profiles in Figures 21 and 22.

The KSU 2361 well is located roughly 12,000’ west of the mapped fault seen in Figure 19. This distance provides a buffer between the injection plume and the fault that alleviates concerns regarding the interaction between the injectate and the fault. As shown in the seismic profile, this fault does not project above the Caddo formation and is not present in the LSS. As this fault does not project into the upper confining shale layer, there is little risk of the fault acting as a conduit for the injectate to leak outside the proposed injection interval.

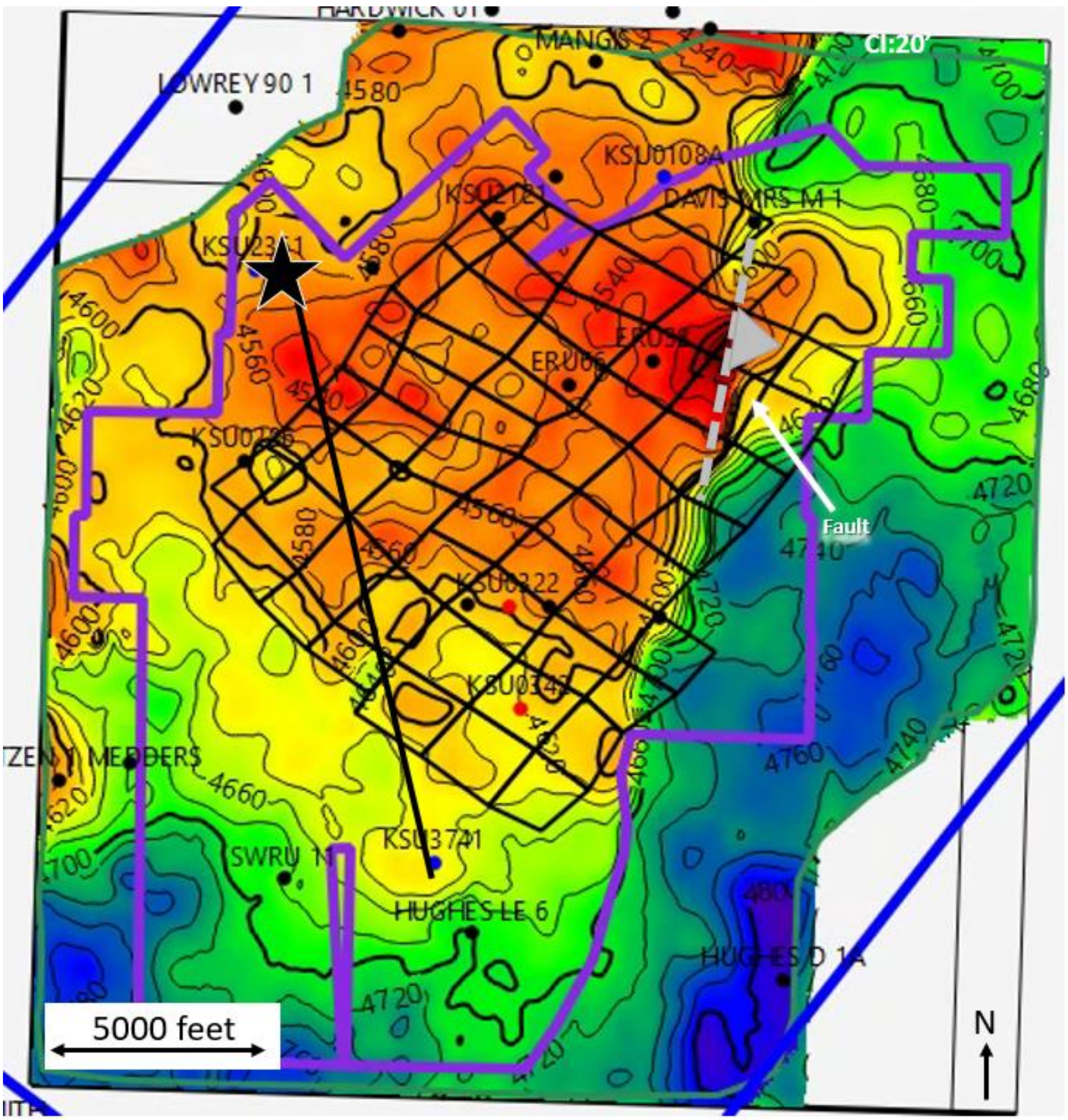


Figure 19 – Ellenburger Structure Map (Subsea Depths)

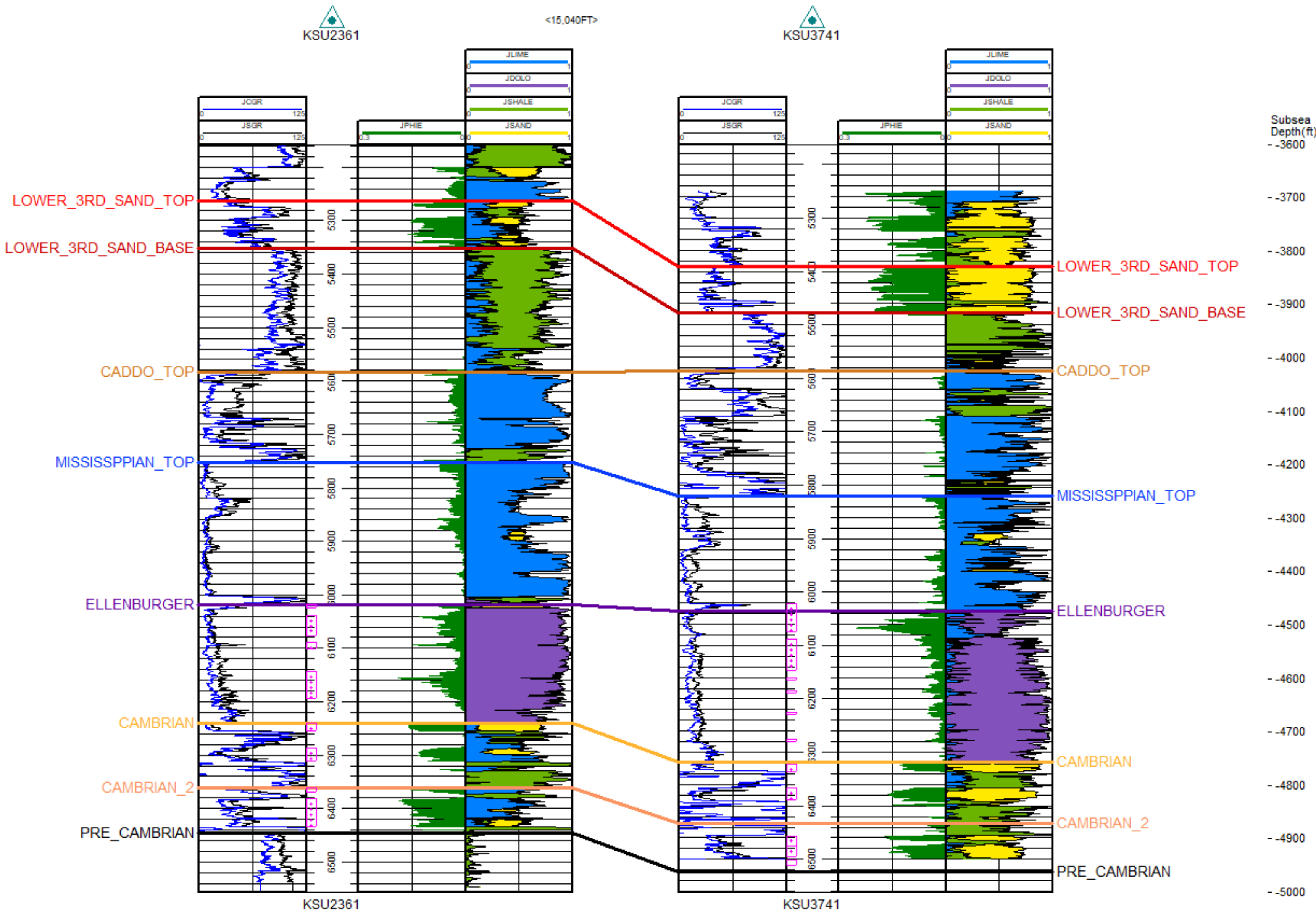


Figure 20 – Structural Northwest-Southeast Cross Section

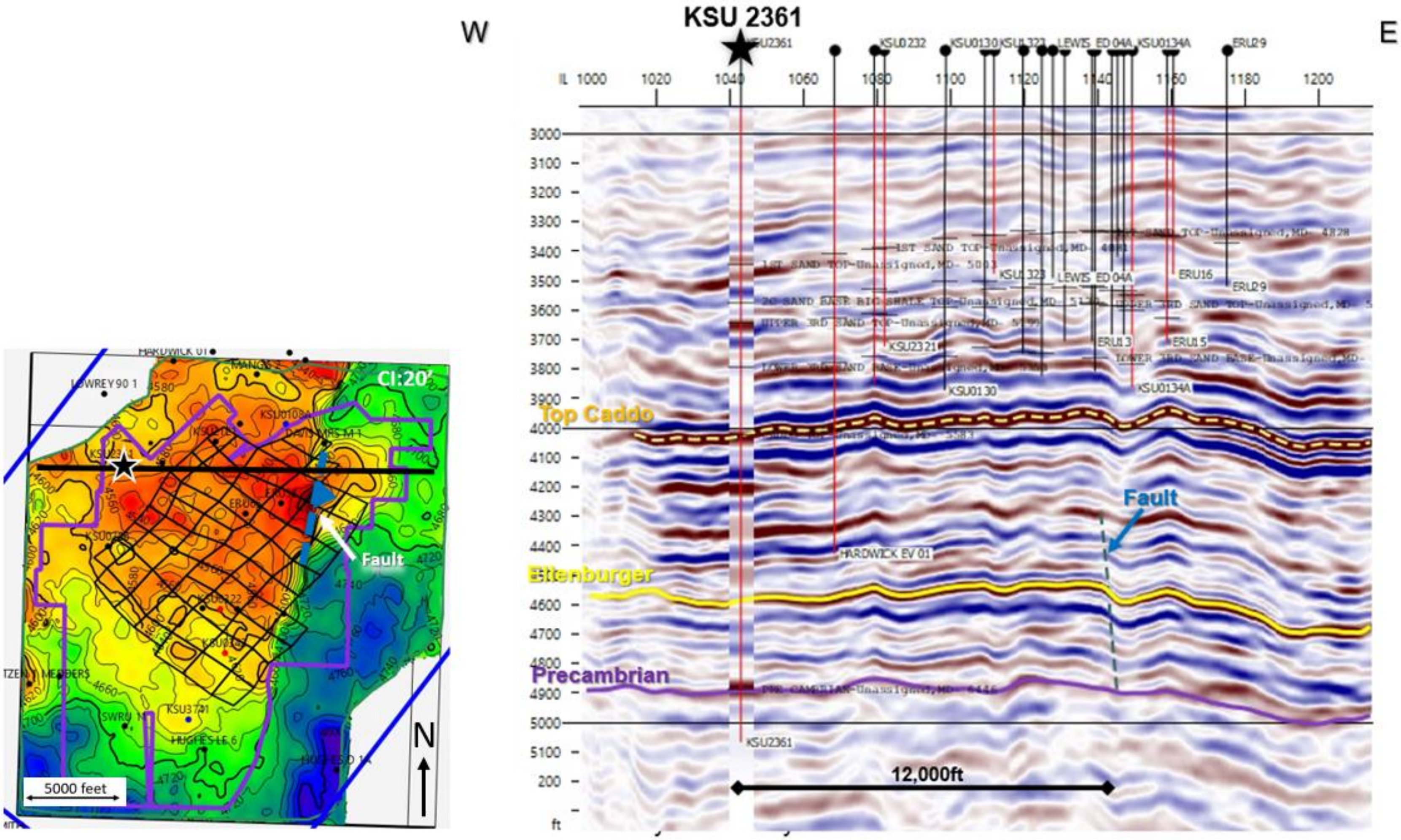


Figure 21 – Structural West to East Seismic Profile

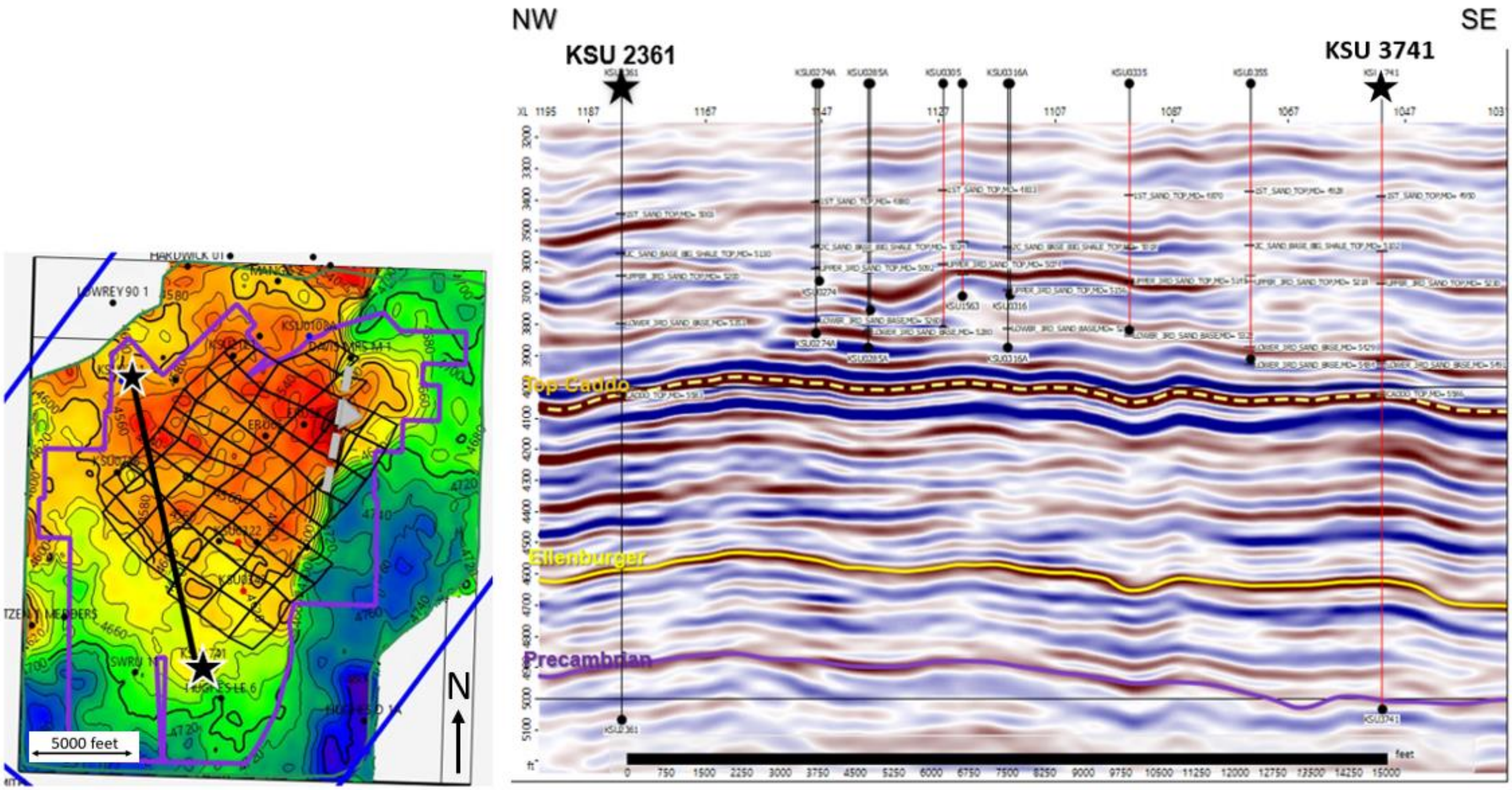


Figure 228 – Structural Northwest to Southeast Seismic Profile between the two wells that penetrate the Ellenburger within the seismic volume.

2.5 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger and Cambrian sand formations at the KSU 2361 well location indicate that the formations have sufficient thickness, porosity, permeability, and lateral continuity to accept the proposed injection fluids. The Mississippian Lime formation at the KSU 2361 well has low permeability. It is of sufficient thickness and lateral continuity to serve as the upper confining zone, with the Lower Strawn Shale acting as a secondary confining unit. Beneath the injection interval, the low permeability, low porosity Precambrian formation is unsuitable for fluid migration and serves as the lower confining zone.

The area of review has been studied to identify potential subsurface features that may affect the ability of these injection and confinement units to retain the injectate within the requested injection interval. Faults have been identified, characterized, and determined to be low risk to the containment of injectate and do not increase the risk of migration of fluids above the injection interval.

2.6 Groundwater Hydrology

Stonewall, Haskell, Knox, and King Counties fall within the boundary of the Texas Water Development Board's (TWDB) Groundwater Management Area 6. The Seymour Aquifer is identified by the TWDB's *Aquifers of Texas* report in the vicinity of the KSU 2361 well (George et al., 2011). Table 5 references the Seymour Aquifer's position in geologic time and the associated geologic formations, which include the Seymour Formation, Lingos Formation, and Quaternary alluvium (Ewing et al., 2004). A depiction of the general stratigraphy of the Seymour Aquifer is shown in Figure 23.

Table 5 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas (Ewing et al., 2004).

System	Series	Group	Formation
Quaternary	Recent to Pleistocene		Alluvium
			Seymour
Tertiary	missing		
Cretaceous			
Jurassic			
Triassic			
Permian	Ochoa		Quartermaster
	Guadalupe	Whitehorse	
		Pease River	Dog Creek Shale
			Blaine Gypsum
			Flowerpot Shale
			San Angelo
	Leonard	Clear Fork	Choza
			Vale
			Arroyo
		Wichita (upper portion only)	Lueders
			Clyde

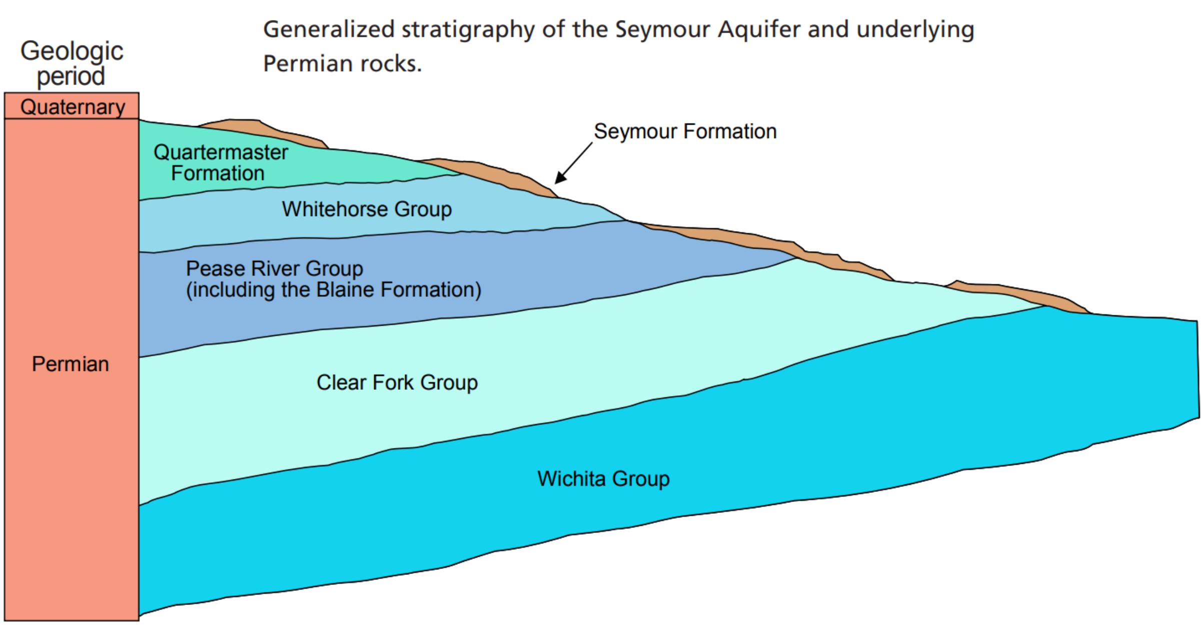


Figure 23 – Generalized Stratigraphy of the Seymour Aquifer (George et al., 2011)

The Seymour Aquifer, as defined by the TWDB, consists of isolated pods of alluvium deposits of Quaternary age, depicted in Figure 24. It extends from the southern Brazos River watershed northward to the border of Oklahoma. The Seymour Aquifer overlies Permian-age deposits that generally dip to the west. Topography, structure, and permeability variation control groundwater flow within the pods. The aquifer generally follows the topographical gradient along the major axis of the pod and discharges laterally to springs, seeps, and alluvium. Similar mechanisms can be expected within the majority of the other pods (Ewing et al., 2004).

A map showing the inferred groundwater flow pattern within a portion of one of the pods in Haskell and Knox counties is shown in Figure 25. The map approximates the natural direction of flow unaffected by pumping from wells. North of the Rule, TX, groundwater divide, the flow is toward the north, northwest, or northeast. Based on the contours of the water table and the permeabilities for the formation indicated by pumping tests, the estimated natural rate of water movement in the Seymour Aquifer, unaffected by pumping, ranges locally from approximately 200’ to 5,000’ per year. Over several miles, the estimated average rate of movement is typically between 800’ and 1,200’ per year (R.W. Harden and Associates, 1978).

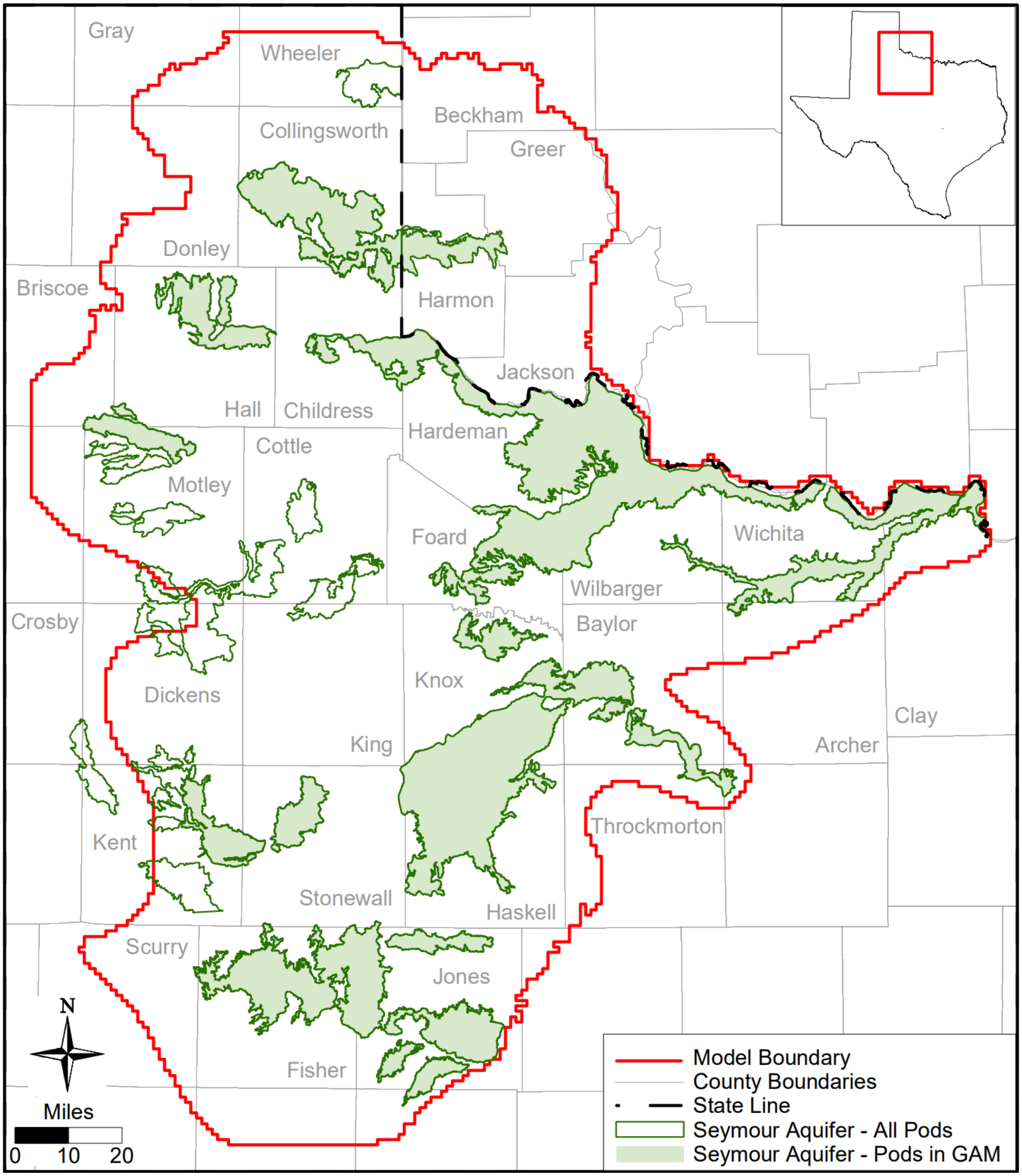


Figure 24 – Regional Extent of the Seymour Aquifer Pods (Ewing et al., 2004)

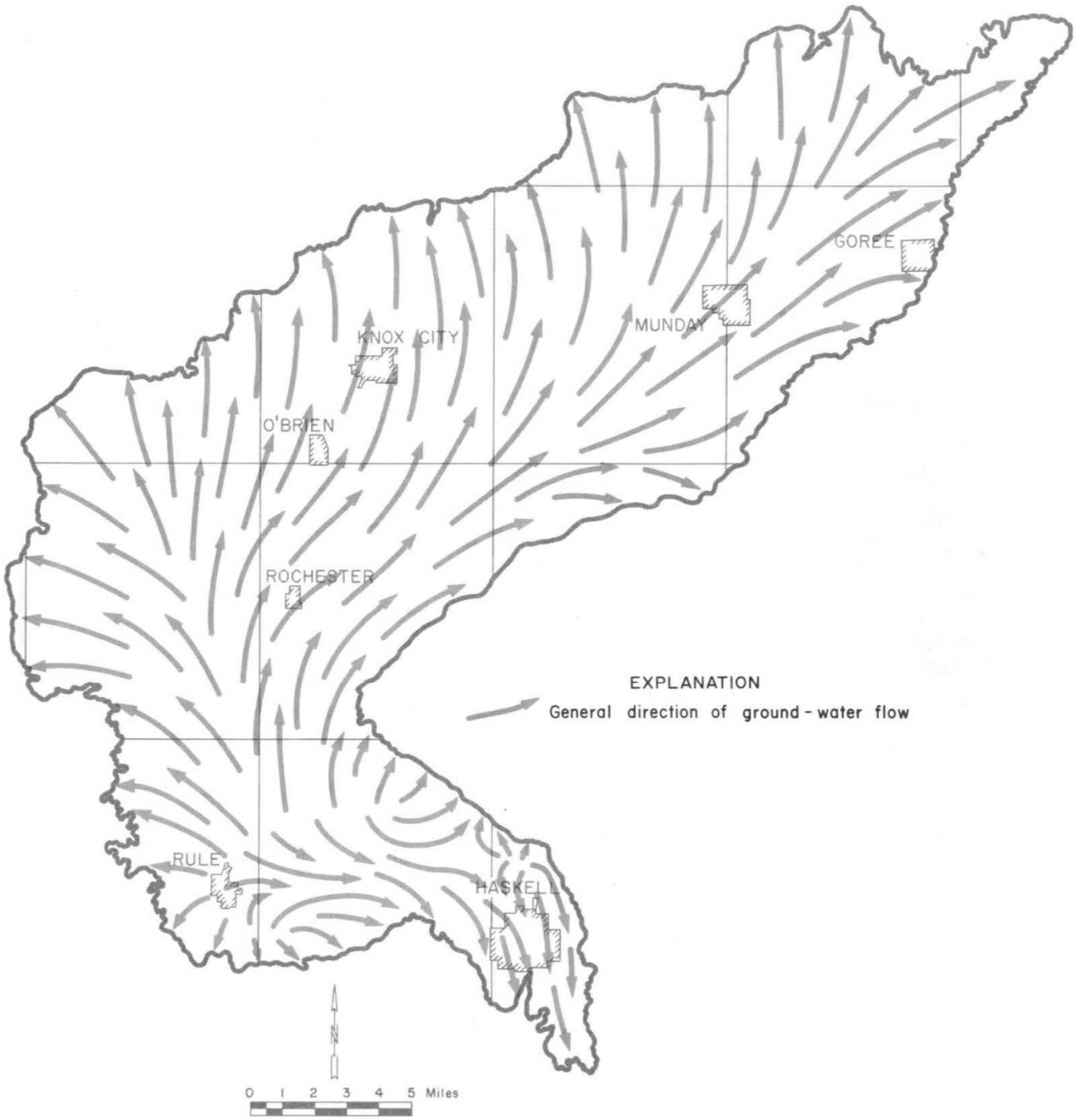


Figure 31. Direction of Ground-Water Flow in Seymour Aquifer

Figure 25 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer (R.W. Harden and Associates, 1978).

Total dissolved solids (TDS) are a measure of water saltiness, the sum of concentrations of all dissolved ions (such as sodium, calcium, magnesium, potassium, chloride, sulfate, and carbonates) plus silica. As shown in Figure 26, the total dissolved solids in 41% of the wells within the Seymour Aquifer exceed 1,000 milligrams per liter (mg/L), Texas' secondary maximum contaminant level (MCL). Therefore, the utility of water from the Seymour Aquifer as a drinking water supply is limited in many areas for health reasons, primarily due to elevated nitrate concentrations, and for taste reasons due to saltiness (Ewing et al., 2004).

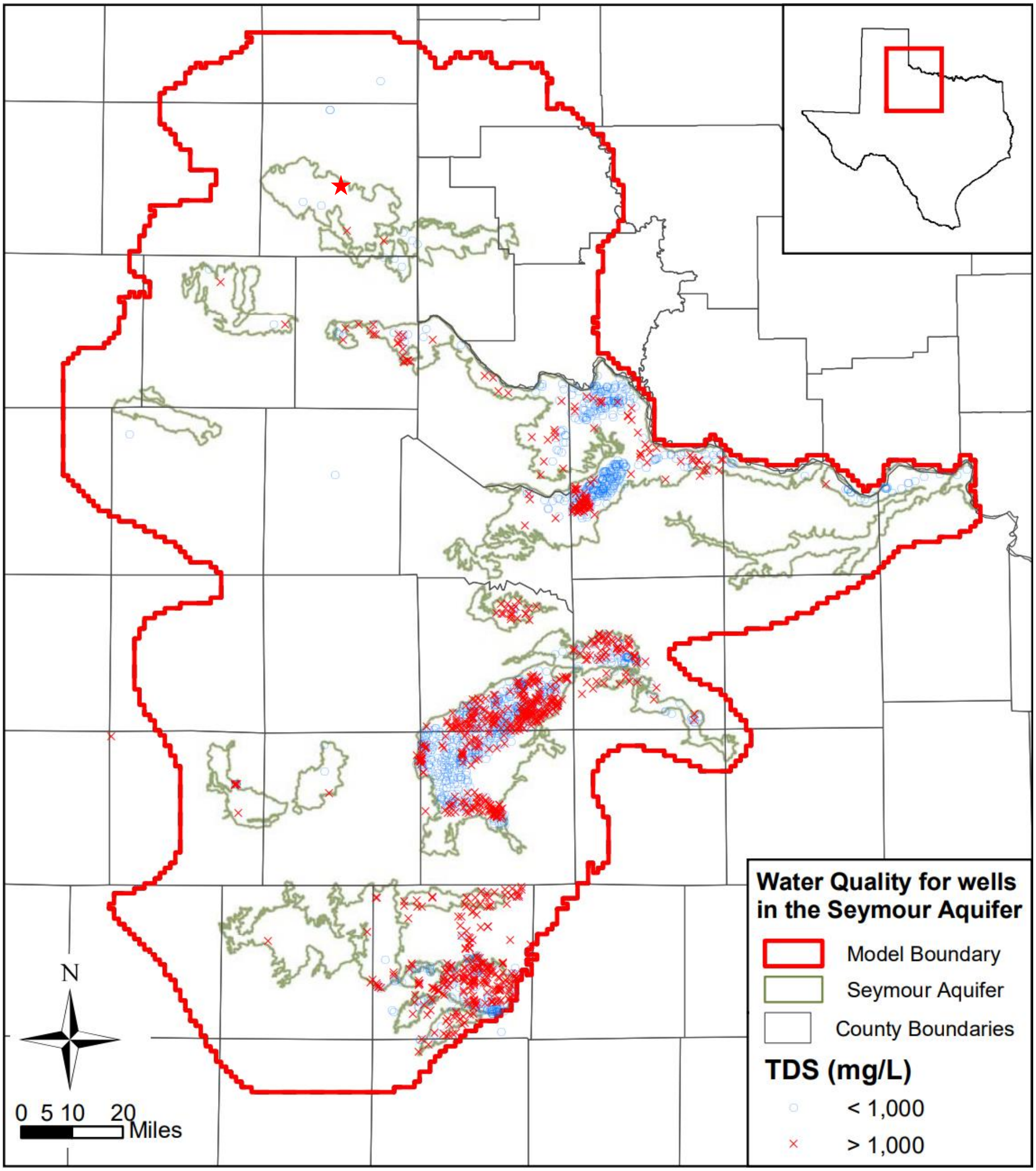


Figure 26 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer (Ewing et al., 2004)

The TRRC's Groundwater Advisory Unit (GAU) specified for the KSU 2361 well that the interval from the land surface to a depth of 100' must specifically protect usable-quality groundwater. Therefore, the base of Underground Sources of Drinking Water (USDW) can be approximated at 100' at the location of the KSU 2361 well, and there is approximately 5,920' separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued

by the TRRC as part of the Class II permitting process for the KSU 2361 well is provided in Appendix A. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Mississippian limestone, thousands of feet of tight limestone and shale beds occur between the injection interval and the lowest water-bearing aquifer.

2.6.1 Reservoir Characterization Modeling

Introduction

KSU 2361 is located in Kinder Morgan's Katz Oil Field in northeast Stonewall County. A geologic model was constructed of this area to forecast the movement of CO_2 and any pressure increases. The model is comprised of the Ellenburger and Cambrian formations, which cover 13,774 acres (~22 square miles). A single CO_2 injector was simulated for 100 years, where approximately 25 million metric tons (MMT) of CO_2 was safely stored.

Software

Paradigm's software suite was used to build the geologic and dynamic models. SKUA-GOCAD™ was utilized in building the geomodel, while Tempest™ designed the dynamic model. The EPA recognizes these software packages for an area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

SKUA-GOCAD™ is a software tool for geology that offers a range of features for structure and stratigraphy, structural analysis, fault seal, well correlation, facies interpretation, 2D/3D restoration, and basin modeling. The structure and stratigraphy module allows users to construct fully sealed structural models, while the structural analysis module provides tools for analyzing fracture probability, stress, and strain. The fault seal module enables the computation of fault displacement maps and fault SGR properties, and the well correlation module allows users to create well sections and digitize markers. The facies interpretation module offers tools for paleo-facies interpretation, and the 2D/3D restoration module provides tools for restoring 3D basin and reservoir models. Finally, the basin modeling module enables users to construct 4D basin models for transfer to basin model simulation software.

Tempest™ is another of Paradigm's industry-leading software packages for reservoir engineering. Tempest™ has history-matching capabilities, allowing for more accurate reservoir characterization modeling. In addition, this software is used to build dynamic models for CO_2 injection. Tempest™ is comprised of three modules: Tempest™ VIEW, Tempest™ ENABLE and Tempest™ MORE. Tempest™ MORE is a black oil simulator with many features and applications to simulate CO_2 injection. The Tempest™ MORE module can accept data in standard GRDECL (RMS, Petrel) file formats. It can also produce output in the ECLIPSE, Nexus/VIP, Intersect, and IMEX/GEM/STARS formats. This allows users to easily import data into the software and export it in a format compatible with other tools and systems. The standard file formats improve the interoperability and compatibility of the MORE software with other systems and tools used in the oil and gas industry

Trapping Mechanisms

To accurately simulate the CO_2 injection and predict the subsequent plume migration, Tempest™ models CO_2 trapping mechanisms in the injection zone. There are five primary trapping mechanisms: structural, hydrodynamic, residual gas (hysteresis), solubility, and geochemical. For this simulation, geochemical reactions were not considered. Each of the five mechanisms is described in further detail below.

Structural Trapping

Structural traps, a physical trapping mechanism, are underground rock formations that trap and store the injected supercritical CO_2. These traps are created by the physical properties of the cap rock, such as its porosity and permeability. For example, a structural trap may be formed by a layer of porous rock above a layer of non-porous rock, with the CO_2 being trapped in the porous rock. Some other examples of structural traps are faults or pinch-outs. Faults can limit the horizontal migration of the plume in the injected formation. The injected CO_2 is lighter than the connate brine found already in the formation. Because of this, the CO_2 floats to the top of the formation and is stored underneath the impermeable cap rock. In this model, CO_2 mass density ranges between 34.9 to 38.5 lb/ft^3 from the shallow to deep injection intervals, whereas the formation brine density is approximately 63.3 lb/ft^3.

Hydrodynamic Trapping

Hydrodynamic traps are another form of physical trapping caused by the interaction between CO_2 and the formation brine. Hydrodynamic trapping is caused by supercritical CO_2 traveling vertically upwards until it reaches the impermeable cap rock and spreads laterally through the unconfined sand layers, driven by the buoyancy and higher density of the brine in the reservoir. Once the CO_2 reaches a caprock with a capillary entry pressure greater than the buoyancy, it is effectively trapped. This type of trapping works best in laterally unconfined sedimentary basins with little to no structural traps.

Equation-of-state (EOS) calculations are performed to determine the phase of CO_2 at any given location based on pressure and temperature for structural and hydrodynamic trapping mechanisms. Several well-known EOS formulae are used within the oil and gas industry for reservoir modeling. These formulae include the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong (SRK) method. The Peng-Robinson is better suited for gas systems than the SRK method. The EOS implemented within the KSU 2361 well model was the Peng-Robinson method.

Residual Gas Trapping

Residual gas traps are also a physical form of trapping CO_2 within pore space by surface tension. This occurs when the porous rock acts as a sponge and traps the CO_2 as the displaced fluid is forced out of the pore space by the injected CO_2. As the displaced brine reenters the pore space once injection stops, small droplets of CO_2 remain in the pore space as residuals and become immobile.

Solubility Trapping

Solubility traps are a form of chemical trapping between the injected CO_2 and connate formation brine. Solubility trapping occurs when the CO_2 is dissolved in a liquid, such as the formation brine.

CO_2 is highly soluble in brine, with the resulting solution having a higher density than the connate brine. This feature affects the reservoir by causing the higher-density brine to sink within the formation, trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration. Table 6 was designed to guide the model to determine the solubility of CO_2 at various pressures and a specified salinity.

Table 6 – CO_2 Solubility Table

Pressure (psi)	CO2 Solubility (Mscf/Stb)	Salinity (ppm)
14	0.00	66,000
50	0.00	66,000
150	0.01	66,000
500	0.0198	66,000
1000	0.0297	66,000
1500	0.0388	66,000
3000	0.0660	66,000

Geochemical Trapping

Geochemical trapping is another form of chemical trapping which refers to storing CO_2 in underground rock formations by using chemical reactions to transform the CO_2 into stable, solid minerals. This process is known as mineral carbonation, and it involves the reaction of CO_2 with the minerals and rocks in underground formations to form stable carbonates. During the process of injecting CO_2 into a disposal reservoir, four (4) primary chemical compounds may be present: CO_2 in the supercritical phase, the hydrochemistry of the naturally occurring brine in the reservoir, aqueous CO_2 (an ionic bond between CO_2 gas and the brine), and the geochemistry of the formation rock. These compounds can interact, leading to the precipitation of CO_2 as a new mineral, often calcium carbonate (limestone). This process is known as mineral carbonation, a key mechanism for the long-term storage of CO_2 in underground rock formations.

Mineral trapping can also occur through the adsorption of CO_2 onto clay minerals. When modeling this process, it is important to consider both hysteresis and solubility trapping. Geochemical formulae can be included in the model using an internal geochemistry database to describe the mineral trapping reactions. These formulae can describe aqueous reactions, such as those involving CO_2 and clay minerals. For aqueous reactions, the following chemical reactions are standard formulae used in CO_2 simulation:

$$CO_2(aq) + H_2O = H^+ + HCO_3^-$$
$$CO_3^{-2} + H^+ = HCO_3^-$$
$$OH^- + H^+ = H_2O$$

The following three formulae represent three common ionic reactions that can occur between water and CO_2 within a reservoir. These reactions involve the formation of solid minerals that can be found in sandstone aquifers, and they result in the precipitation of carbon oxides. These reactions are commonly included in modeling efforts to understand and predict the behavior of CO_2 in underground storage reservoirs:

$$Anorthite\ (CaAl_2Si_2O_8) + 8H^+ = 4\ H_2O + Ca^{2+} + 2Al^{4+}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO3^-$$
$$Kaolinite\ \left(Al_2Si_2O_5(OH_4)\right) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO$$

Geochemical trapping has the potential to store CO_2 for hundreds or thousands of years, but the short-term effects of this method are relatively limited. Instead, the short-term movement and storage of CO_2 are more strongly influenced by hydrodynamic and solubility trapping mechanisms. These mechanisms involve the movement of fluids, such as water or oil, through porous rock formations and the solubilization of CO_2 in liquids, such as water or oil. As a result, these processes can be more effective in the short term at storing CO_2, although they may not have the same long-term stability as geochemical trapping.

Static Model

The geomodel was constructed to simulate the geologic structure of the Ellenburger and Cambrian formations. The grid contains 600 cells in the X-direction (East-West) and 400 cells in the Y-direction (North-South), totaling 240,000 cells per layer. Therefore, 55 layers were utilized in the model representing the gross thickness of the injection interval, totaling 13,200,000 grid blocks. The Ellenburger is comprised of 25 layers and the Cambrian is comprised of 30 layers. Each grid block is 50' by 50' by 10', resulting in a model size of 5.7 miles by 3.8 miles by 550,' as shown in Figure 27. This covers approximately 22 square miles (13,774 acres).

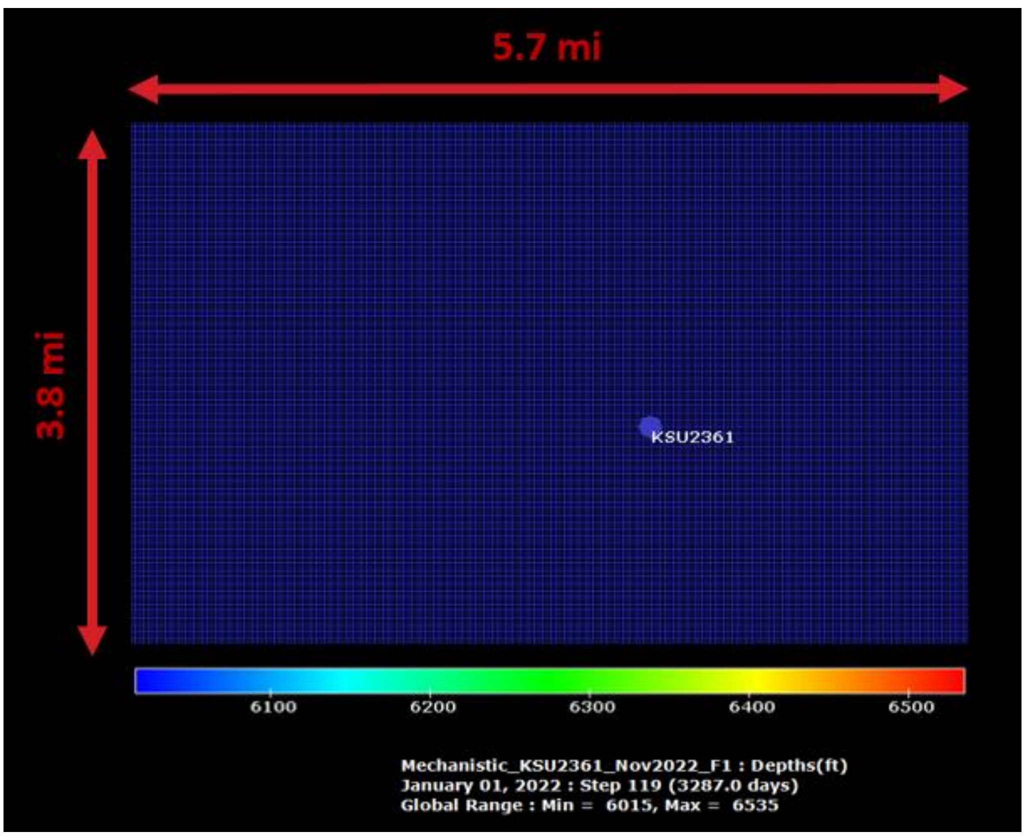


Figure 27 – Geomodel Dimensions

Well log analysis tied into seismic interpretation was used to identify any major formations tops. Four geologic units were identified and incorporated into the geomodel. Each geologic unit was used to determine the geologic structure of the injection zone. First, the Ellenburger is a carbonate formation comprised of dolomite/limestone matrix. Underlying the Ellenburger formation is the Cambrian sandstone. This sandstone was split into two geologic units, the Cambrian 1 and Cambrian 2. The Precambrian formation is at the bottom of the model. The Precambrian, comprised of granite, is the lower confining zone. Figure 28 highlights the overall structure of the target zone.

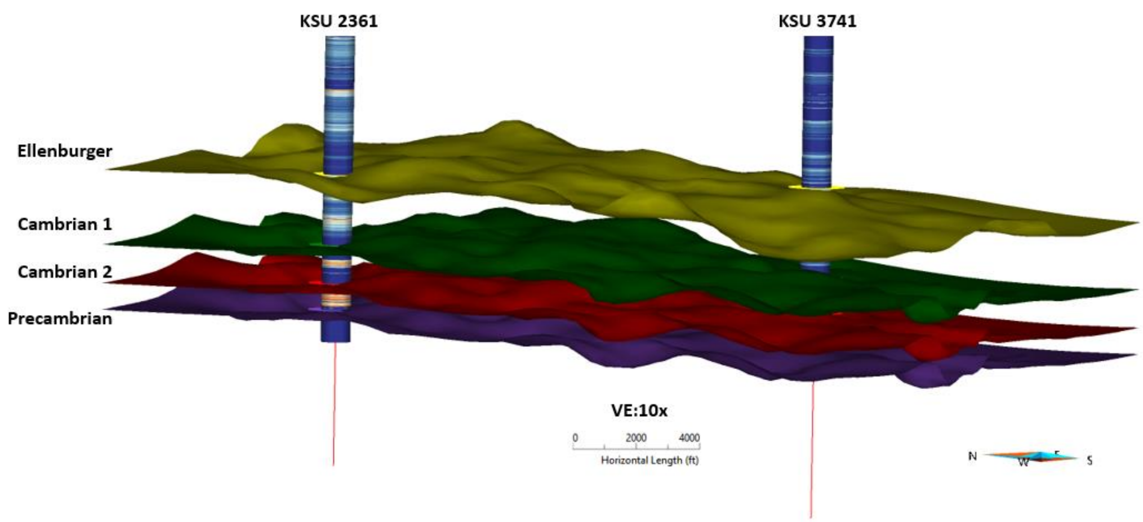


Figure 28 – Structural Horizons of the Geomodel

Permeability and porosity were distributed through the geomodel based on the formation. These rock properties were considered to be laterally homogenous in the simulation. However, vertical heterogeneity was incorporated into the model. Based on well log analysis, porosity was determined to be 10% in the Ellenburger carbonate and 12% in the Cambrian sandstone, as shown in Figure 29. Permeability was determined from history matching two wells. From this exercise, it was determined that the horizontal permeability (K_H) is 20 milliDarcy (mD) and vertical permeability (K_V) was assumed to be 10% of K_H or 2 mD. Table 7 summarizes the rock properties in the model.

Table 7 – Rock Properties

Assumptions	Values
Ellenburger Porosity (%)	10
Cambrian Porosity (%)	12
K_H (mD)	20
K_V/K_H Ratio	0.1

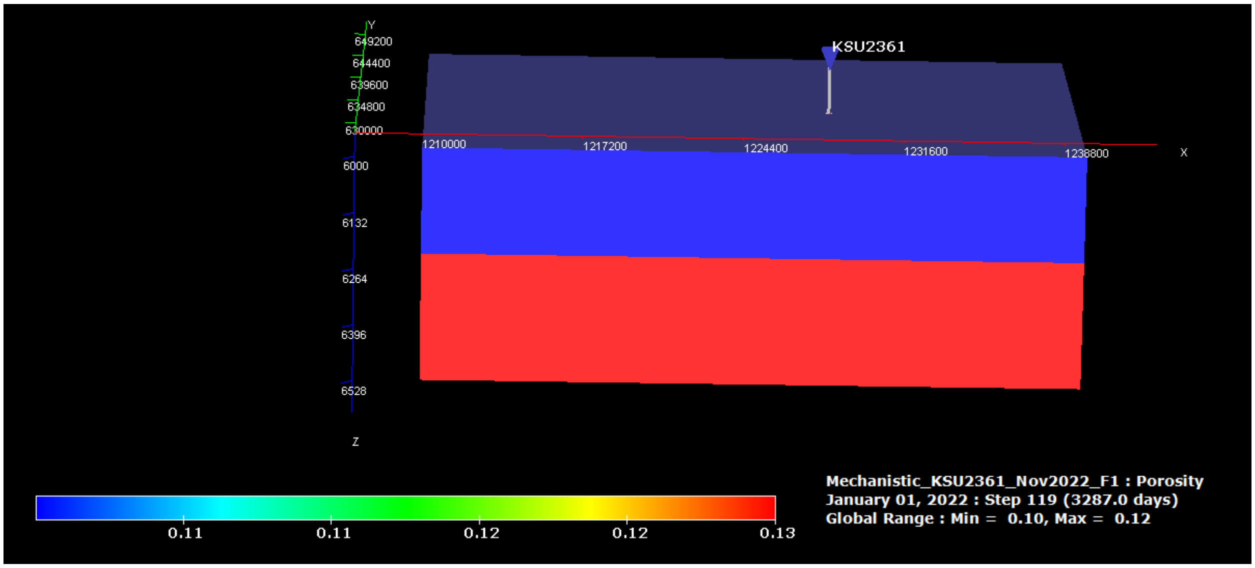


Figure 29 – Porosity Distribution in Plume Model

Dynamic Model

The primary objectives of the CO_2 plume model are as follows:

1. Determine the maximum possible injection rate without fracturing the target zone
2. Determine land acquisition strategy (i.e., maximum plume size)
3. Assess the likelihood of CO_2 leakage through potential conduits that may contaminate the Underground Source of Drinking Water (USDW)

Using the geomodel as an input, an infinite-acting model was built to simulate boundary conditions. The model assumes that the reservoir is 100% filled with brine. The formation fluid was estimated to have a salinity of 66,000 ppm. An offset step-rate test was utilized to estimate initial reservoir pressure and fracture pressure. Reservoir pressure was determined to be 2,600 psi which translates to a 0.435 psi/ft gradient. While pressure never reached high enough to propagate any fractures during the step-rate test, the fracture pressure was estimated to be approximately 4,390 psi. This translates to a fracture gradient of 0.683 psi/ft. Based off this data, a wellhead pressure of 1,850 psi was used to constrain the modelled well. An average temperature of 260 °F was also applied to the reservoir. Table 8 provides a summary of the initial conditions included in the simulation.

Table 8 – Initial Conditions Summary

Assumptions	Values
Permeability (mD)	20
Porosity (%)	10-12
Pore Gradient (psi/ft)	0.435
Frac Gradient (psi/ft)	0.683
Reservoir Temperature (°F)	260

To accurately and conservatively model the effective pore space of the rock, a net-to-gross (NTG) ratio was applied to the Ellenburger and Cambrian formations. The lateral plume extent is increased by reducing the total pore space CO_2 can flow through. Reducing the available pore space also limits

the CO_2 injection rate of the well due to higher increases in pressure. The Ellenburger had an NTG ratio of 0.5 applied, while the Cambrian formation had a 0.6 NTG ratio. This is further highlighted in Figure 30.

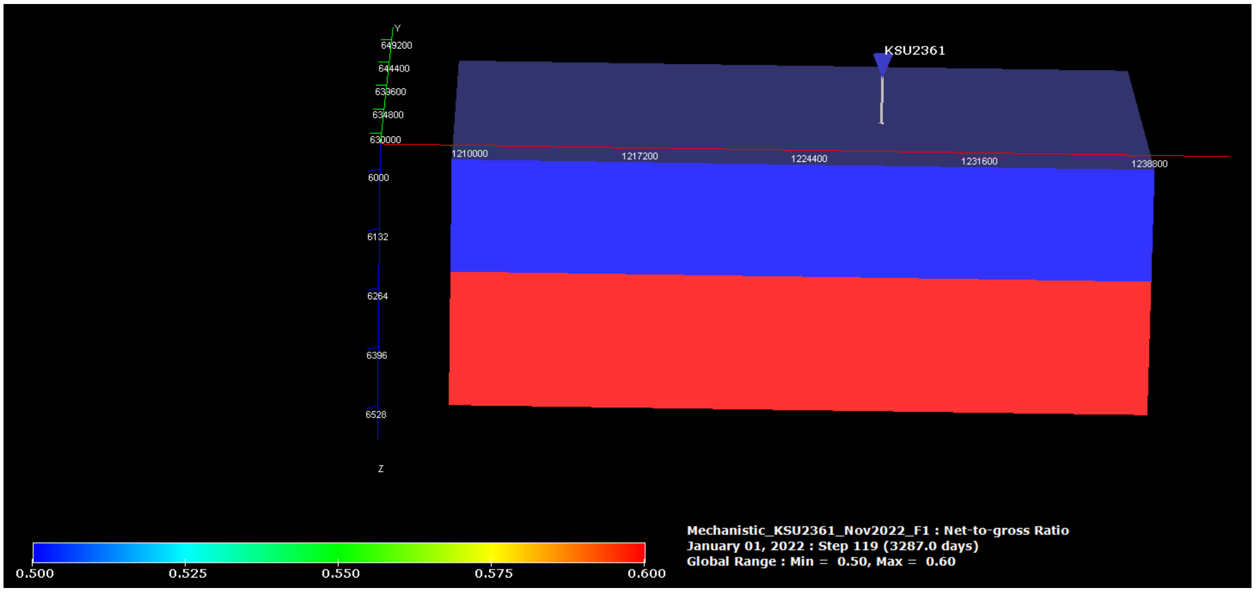


Figure 30 – NTG Ratio Applied to the Plume Model

Relative Permeability

Relative permeability curves were generated to represent a CO_2-brine system and how supercritical CO_2 will flow through a 100% brine-filled rock. Data from Kinder Morgan's McElmo Dome source models were utilized to create the relative permeability curves. The key inputs include a 9% irreducible water saturation and a 9% maximum residual gas saturation. Figure 31 shows the curves included in the simulation model.

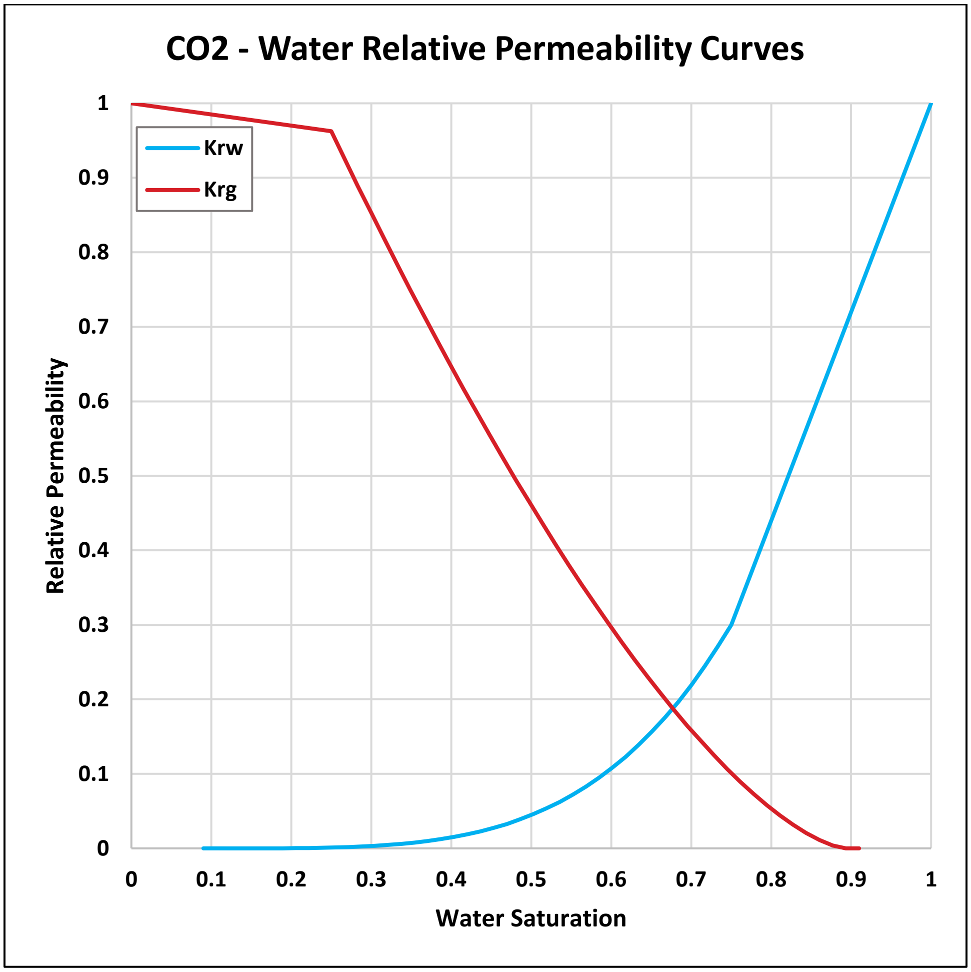


Figure 31 – CO_2-Water Relative Permeability Curves

History Matching

Two SWD wells were history-matched to determine permeability estimates. Historical injection rates were set in the model, and the simulated pressure response was compared to the recorded pressure data. This process was iterated multiple times until the simulated and real-life data matched. Monthly data points KSU 2361 (Figure 32) and KSU #3471 (Figure 33) were used to vary the injection rate in the model. These same intervals were used to compare the simulated results.

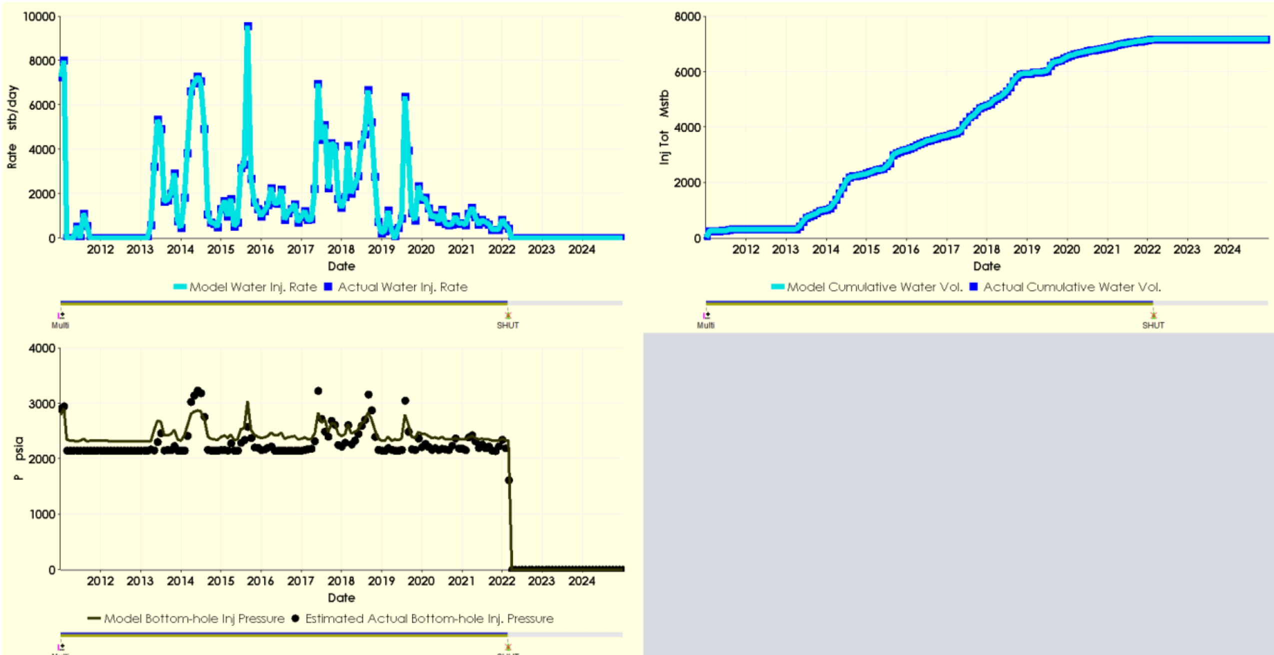


Figure 32 – History Match for KSU 2361

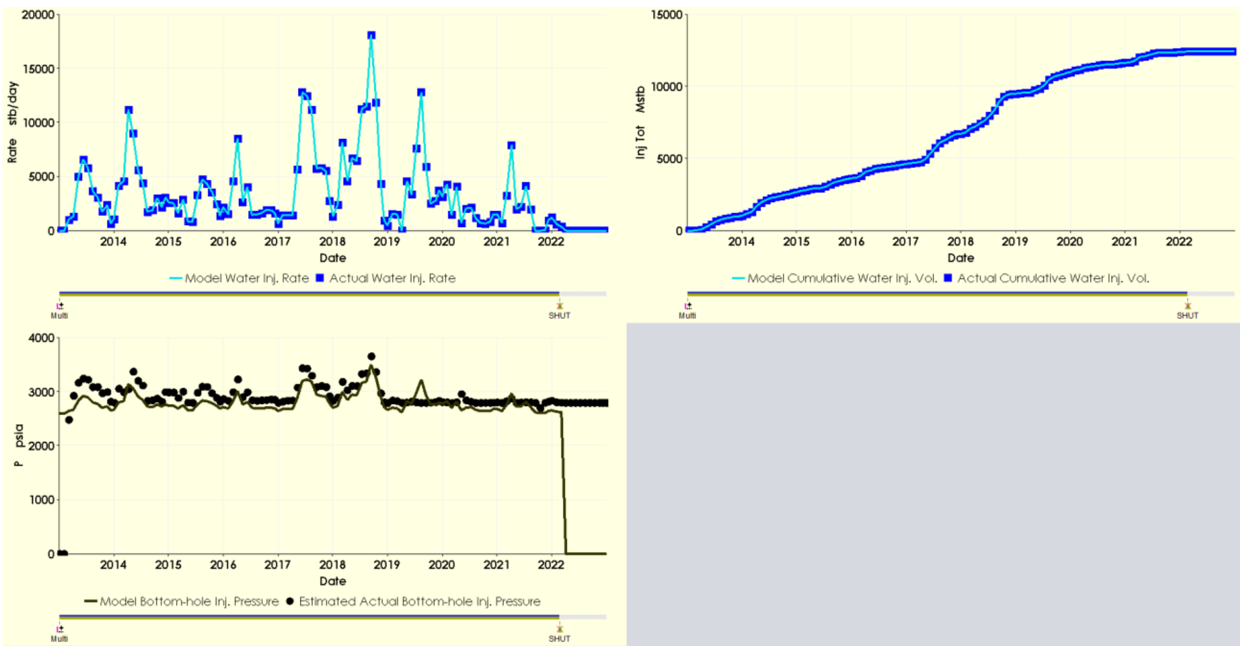


Figure 33 – History Match for KSU #3471

CO_2 Injection Operations

KSU 2361 was simulated to inject supercritical CO_2 for 21 years. A maximum wellhead pressure (WHP) was used to limit the injection rate. This value was determined from the fracture gradient estimation, and an equivalent wellhead pressure was calculated. The WHP constraint was set to 1,850 psi, equal to 84% of the fracture pressure. The injection rate was then maximized to stay

below the expected frac gradient. Figure 34 shows the simulated WHP during active injection operations.

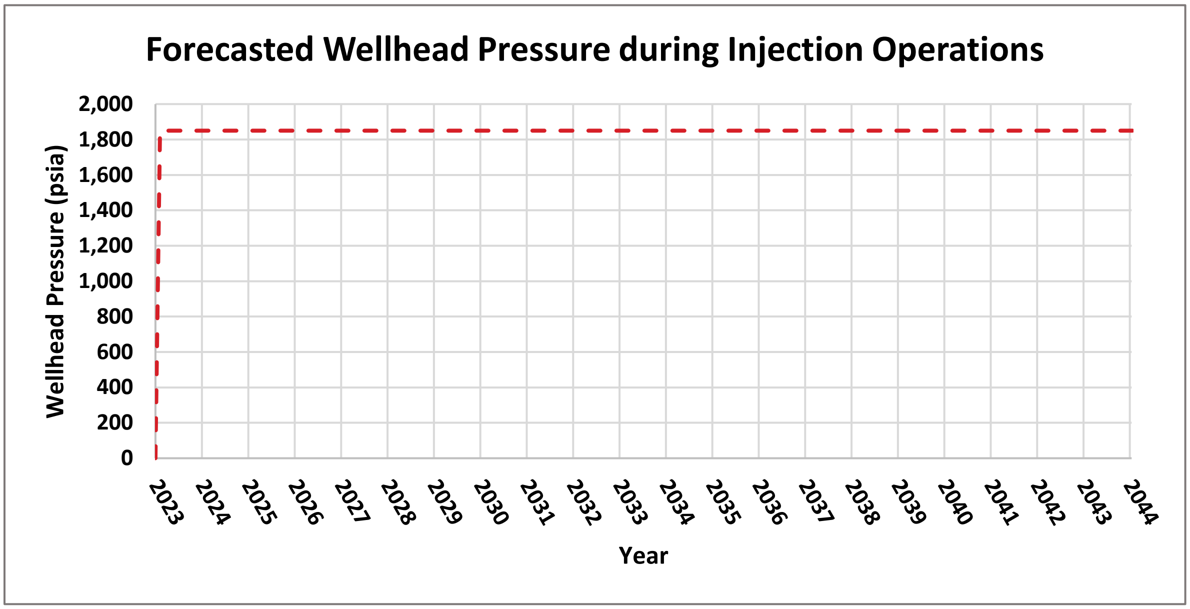


Figure 34 – Simulated Wellhead Pressure During Active Injection

During active injection, KSU 2361 achieved a maximum rate of approximately 1.22 MMT/yr. (~65 million cubic feet (MMscf)/day). During injection, the bottom hole pressure (BHP) reaches a maximum of 3,493 psi, which is safely below the fracture pressure. This is an 893-psi increase from the initial reservoir pressure. After injection ceases, the reservoir pressure decreases, reaching 65 psi buildup from the initial reservoir pressure. Figure 35 summarizes these results. The decreasing bottom-hole pressure from 2023 to 2044 is due to the relative permeability increasing over time.

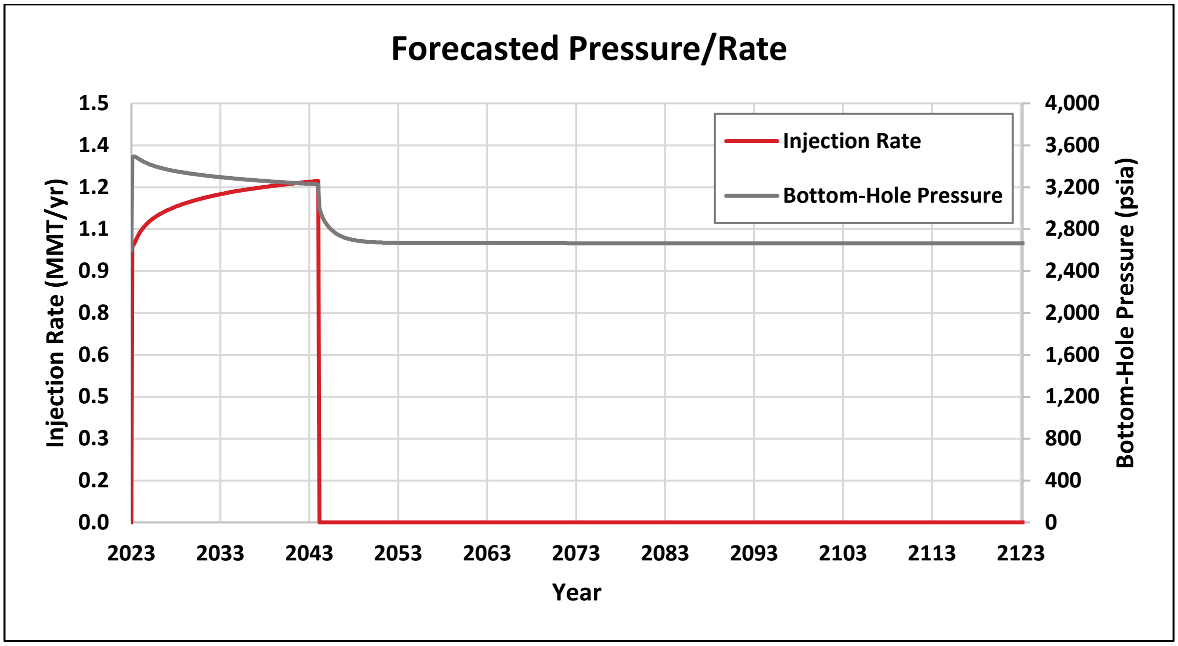


Figure 35 – Forecasted Injection Rate and BHP

Model Results

The maximum plume was determined once the plume was considered stabilized and by using a gas saturation cutoff of 3%. The plume is considered stabilized once all lateral and vertical movement of CO_2 has stopped, which also marks the end of the initial monitoring period. Aerial plume sizes were taken at 10-year intervals to determine a growth rate. As seen in Figure 36, an annualized growth rate is determined at each interval. The plume is delineated based on the maximum extent of the plume when the growth rate reaches 0%. In this model, the plume stabilizes in 2074, 30 years after the end of the injection period.

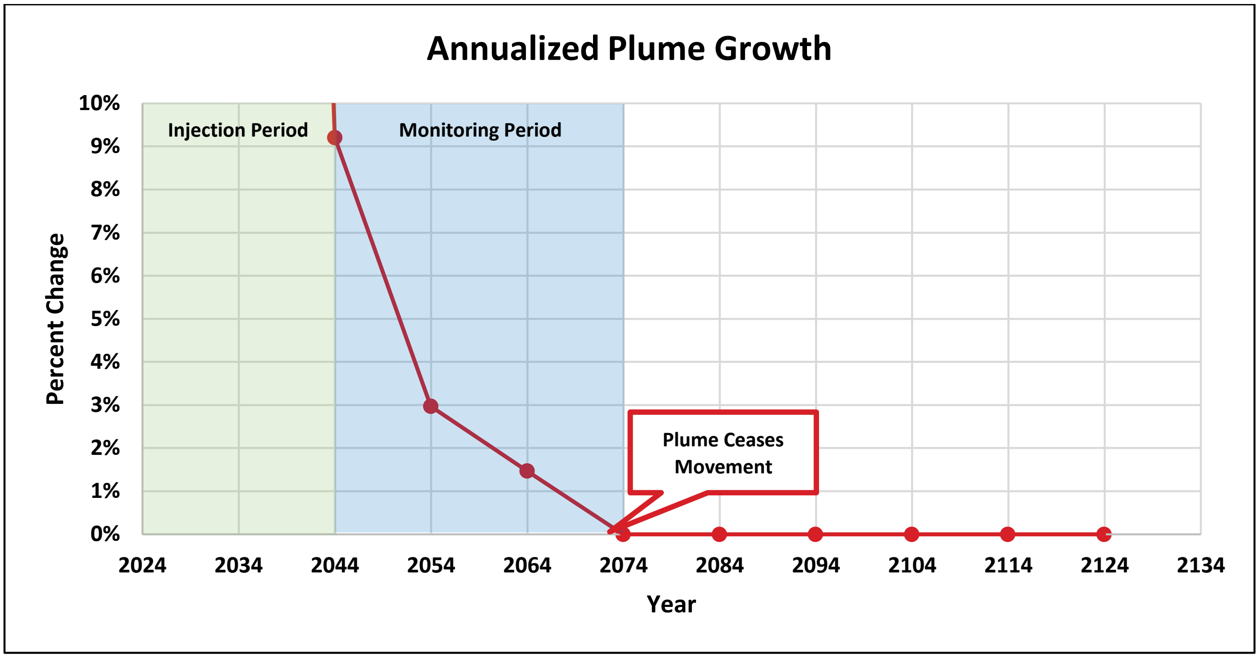


Figure 369 – Annualized Growth Rate of CO_2 Plume

The stabilized plume reaches a maximum of 3,384 ac (~5.3 sq mi). The furthest extent of this plume is to the South, as seen in Figure 37. The largest radius of the plume is 6,850' (~1.2 mi) from the wellbore. Due to the heterogeneity included in the model, the plume is not uniform from layer to layer, as seen in Figure 48. The maximum plume was chosen from the layer with the largest lateral extent of CO_2. Table 9 shows the plume radius and plume compared to time since injection starting in year zero.

Table 9 – Plume Model Radius and Area

Date	Year	Plume Radius (ft.)	Plume Area (Acres)
Jan-23	0	0	0
Jan-34	10	4650	1559
Jan-44	20	6400	2954
Jan-54	30	6700	3238
Jan-64	40	6800	3335
Jan-74	50	6850	3384
Jan-84	60	6850	3384
Jan-94	70	6850	3384
Jan-04	80	6850	3384
Jan-14	90	6850	3384
Jan-24	100	6850	3384

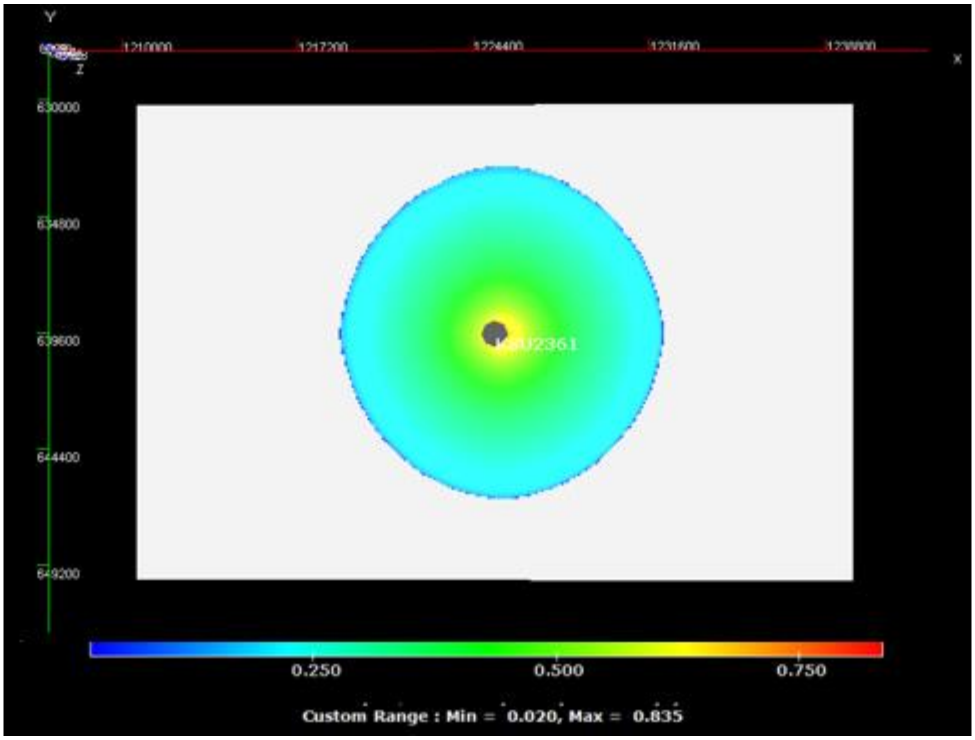


Figure 37 – Aerial View of CO_2 Plume

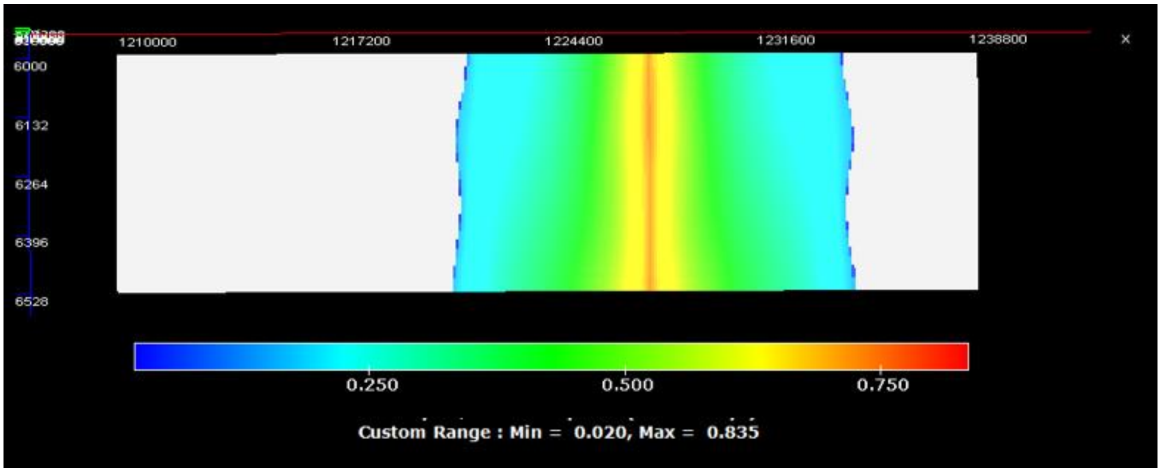


Figure 38 – Cross-Sectional View of CO_2 Plume

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA) as described in EPA 40 CFR §**98.448(a)(1**).

3.1 Maximum Monitoring Area

The EPA defines the MMA as equal to, or greater than, the area expected to contain the free-phase CO_2-occupied plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one-half mile. A numerical computer simulation was used to determine an estimate for the size and drift of the plume. Using a combination of Paradigm's SKUA-GOCAD and Aspen Technology's Tempest software packages, a geomodel, and reservoir model were used to determine the areal extent and density drift of the plume. The model accounts for the following considerations:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Kinder Morgan's pipeline gas specifications were used for the initial composition of the injectate in the model, as provided in Appendix B. The molar composition of the gas is mostly carbon dioxide, with some small amounts of nitrogen and hydrocarbons, and contained no H_2S. The molar composition was incorporated into the model as future CO_2 streams could be added for injection. As discussed in Section 2, the gas was modeled to be injected primarily into the Ellenburger and both Cambrian formations. The geomodel was created based on the rock properties seen in the Ellenburger and Cambrian rocks.

The weighted average gas saturation defined the plume boundary in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in 2044, the areal expanse of the plume will be 2,954 acres. The maximum distance between the wellbore and the edge of the plume is approximately 6,400', after injection stops, resulting in the AMA. After 80 additional years of density drift, the areal extent of the plume is 3,384 acres, with a maximum distance to the edge of the plume of approximately 6,850', resulting in the MMA. Since the plume shape is relatively circular, the maximum distance from the injection well after density drift was used to define the circular boundary of the MMA. The AMA and the MMA have close to the same areas of influence, with the AMA being marginally smaller than the MMA. Therefore, Kinder Morgan will use the MMA as the basis for the areal extent of the monitoring program throughout the life of the project.

The plume is expected to stabilize 30 years after injection ceases and does not migrate after 2050, the monitoring program of the MMA will remain active for the required amount of time.

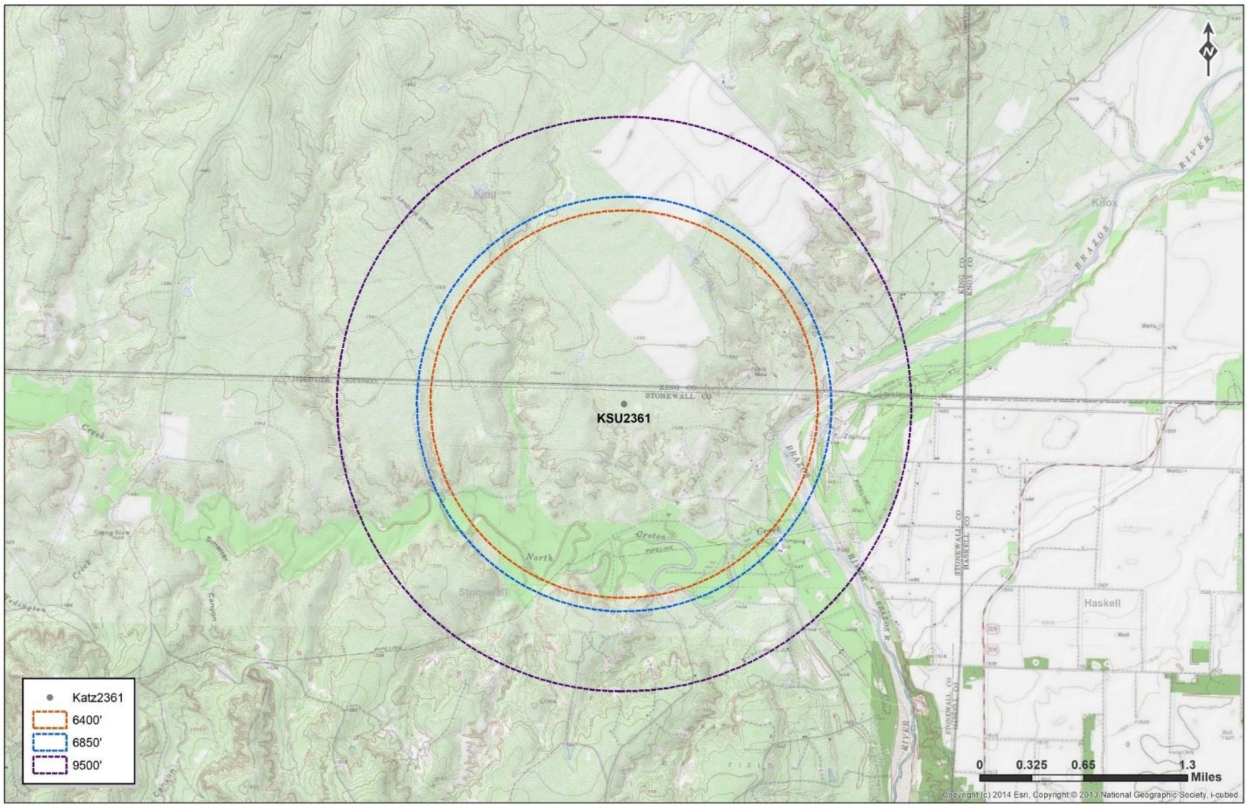


Figure 39 – Stabilized Plume Boundary, Active Monitoring Area, and Maximum Monitoring Area

3.2 Active Monitoring Area

The AMA will cover the initial 20-year monitoring period, equating to the expected total injection time. The AMA boundary was established by superimposing the area based on a half-mile buffer around the anticipated plume location at the end of injection (2044) with the area of the projected free-phase CO_2 plume at five additional years (2049). In this case, the plume boundary in 2049 is within the plume in 2044, plus a half-mile buffer. By 2044 at the latest, a revised MRV plan will be submitted to define a new AMA. Since the Active Monitoring Area boundary was determined to fall within the Maximum Monitoring Area boundary, the defined MMA was also used to define the effective AMA. Figure 39 shows the area covered by the MMA, which encompasses the AMA.

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from Natural or Induced Seismicity

4.1 Leakage from Surface Equipment

The surface facilities at the KSU 2361 well are designed for injecting acid gas primarily consisting of CO_2. One additional pipeline will be constructed to carry the acid gas from the custody transfer meter to the KSU 2361 wellhead, as shown in Figure 40. The wellbore of the KSU 2361 is designed for acid gas, as seen in the wellbore schematic in Figure 41. The facilities have been designed to minimize leakage and failure points. The design and construction of these facilities followed industry standards and best practices. CO_2 monitors are located around the facility and the well site. These gas monitor alarms will be triggered at levels set upon completion of a baseline study of the ambient air quality, followed by a gas dispersion model. An emergency shutdown valve (ESD) is located at the wellhead and is locally controlled by pressure, with a high-pressure and low-pressure shut-off.

The facilities have been designed and constructed with other safety systems to provide for safe operations. These systems include ESD valves to isolate portions of the pipeline, pressure relief valves along the pipeline to prevent over-pressurization, and venting to allow piping and equipment to be de-pressured under safe and controlled operating conditions in the event of a leak. More information on these systems and be found in Appendix C. Should Kinder Morgan construct additional CO_2 facilities other meters will be installed as needed to comply with the 40 CFR **§98.448(a)(5**) measurement. These meters will be near the existing facilities and utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meters and tied into the facility monitoring systems. No additional wells are included within this MRV facility.

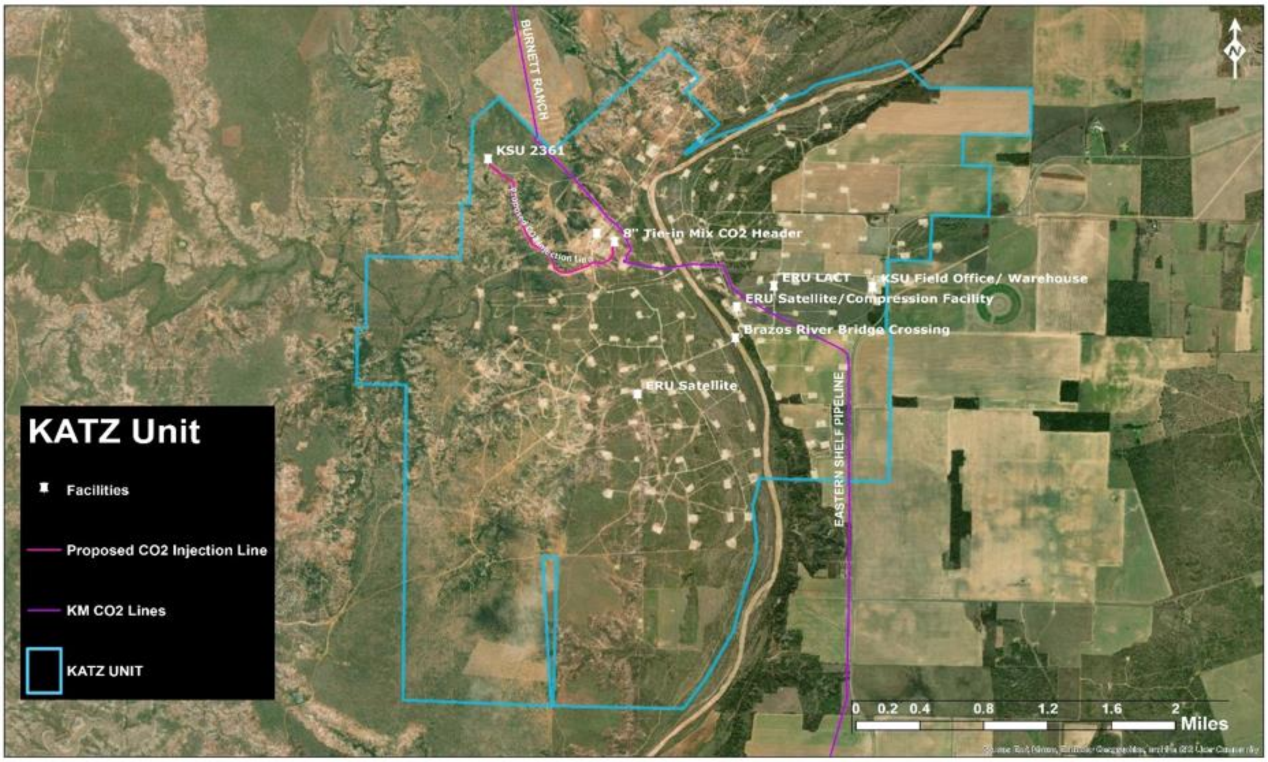


Figure 40 – Site Plan

With the level of monitoring implemented at the KSU 2361 well, a release of CO_2 would be quickly identified, and the safety systems would minimize the release volume. The CO_2 stream injected into KSU 2361 could include small amounts of methane and nitrogen, as seen in Appendix B. The CO2 injected into the Katz 2361 well is supplied by a number of different sources into the pipeline system and the composition is not expected to change over time. If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR **§98.448(a)(5)**.

4.2 Leakage from Existing Wells within MMA

4.2.1 Oil and Gas Operations within Monitoring Area

A significant number of wells have historically been drilled within the area of the KSU 2361 well. However, production has primarily been from the shallower Strawn formation in the Katz Field. The Strawn is separated from the Ellenburger-Cambrian interval by 665' in this area. In addition to the primary Strawn production, a few wells have produced from the Mississippian. The mid-Mississippian is separated from the Ellenburger-Cambrian interval by 133'. KSU 2361 is the only well penetrating the injection interval within the projected plume area of the MMA for the KSU 2361. Therefore, it is the only well that will be monitored for surface leakage. This well is designed to handle and inject acid gas, which reduces the risk and likelihood of leakage through the existing well to near-zero.

The KSU 2361 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as depicted in the schematic denoted in Figure 41. Mechanical integrity tests (MIT), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every five years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 42. The MMA review map and a summary of all the wells in the MMA are provided in Appendix D. Figure 43 highlights that no wells penetrate the MMA's gross injection zone.

KINDER MORGAN

Schematic - Current

Well Name: KSU #2361

API/UWI	Surface Location	Field Name	State	Well Configuration Type	RRC/COGC...	Account Cat/Prop...
42-433-33712	SEC 2 LONG, CB	KATZ	Texas	Vertical		26039

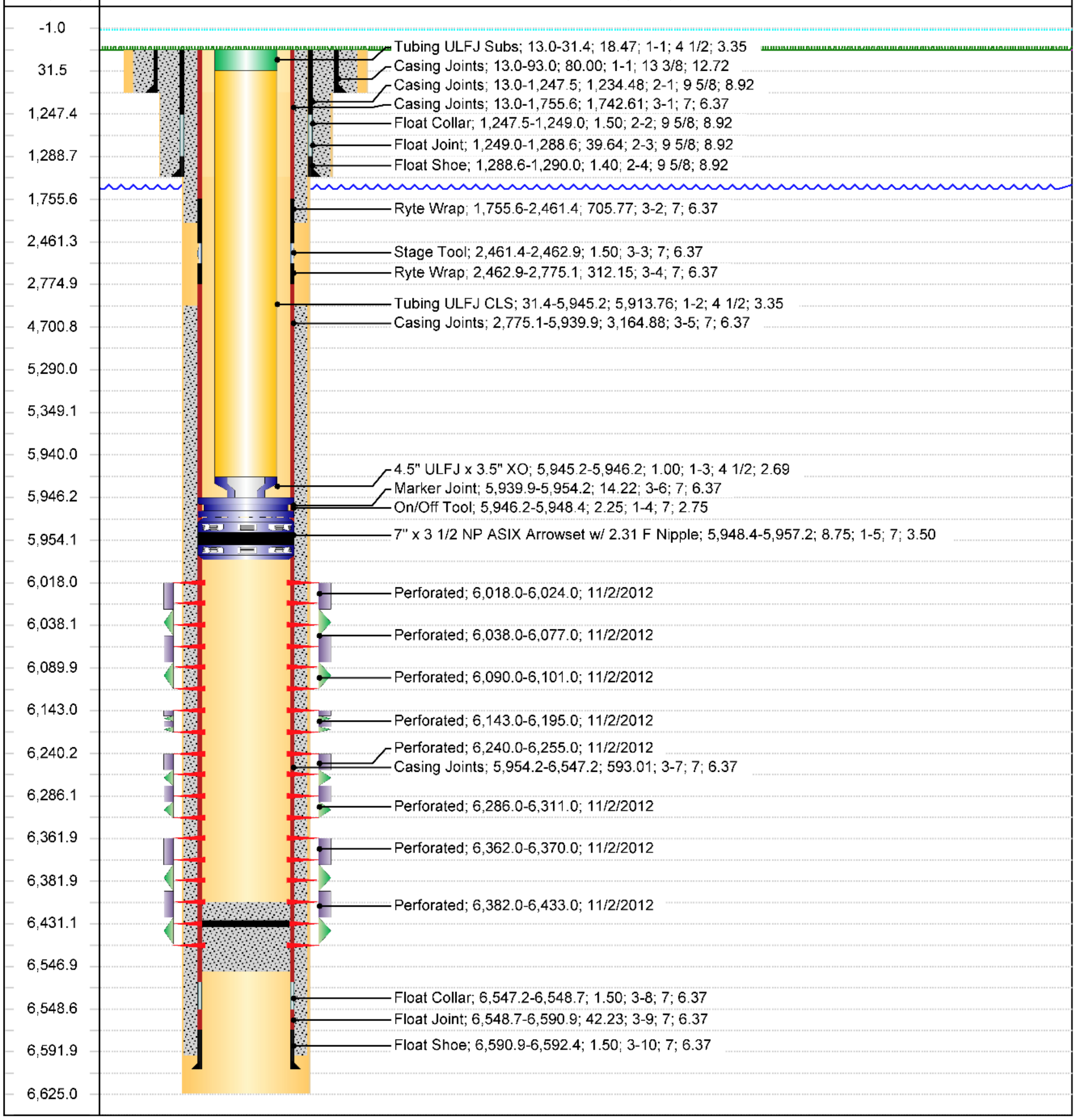
Estimated KB Elevation (ft)	KB-Tubing Head Distance (ft)	Original Well Spud Date	Rig Release Date	PBTD (All) (ftKB)	Total Depth All (TVD) (ftKB)
1,531.00	13.00	8/23/2012 18:00	9/13/2012 06:00	Original Hole - 6,431.0	

Most Recent Job

Job Category	Primary Job Type	Secondary Job Type	Start Date	End Date
Non-Rig Activity	Coil Tubing		4/2/2019	4/4/2019

TD: 6,625.0 Vertical, Original Hole, 2/21/2022 10:06:22 AM

MD (ftKB)	Vertical schematic (actual)



Page 1/1 **Report Printed: 2/21/2022**

Figure 41 – KSU 2361 Wellbore Schematic

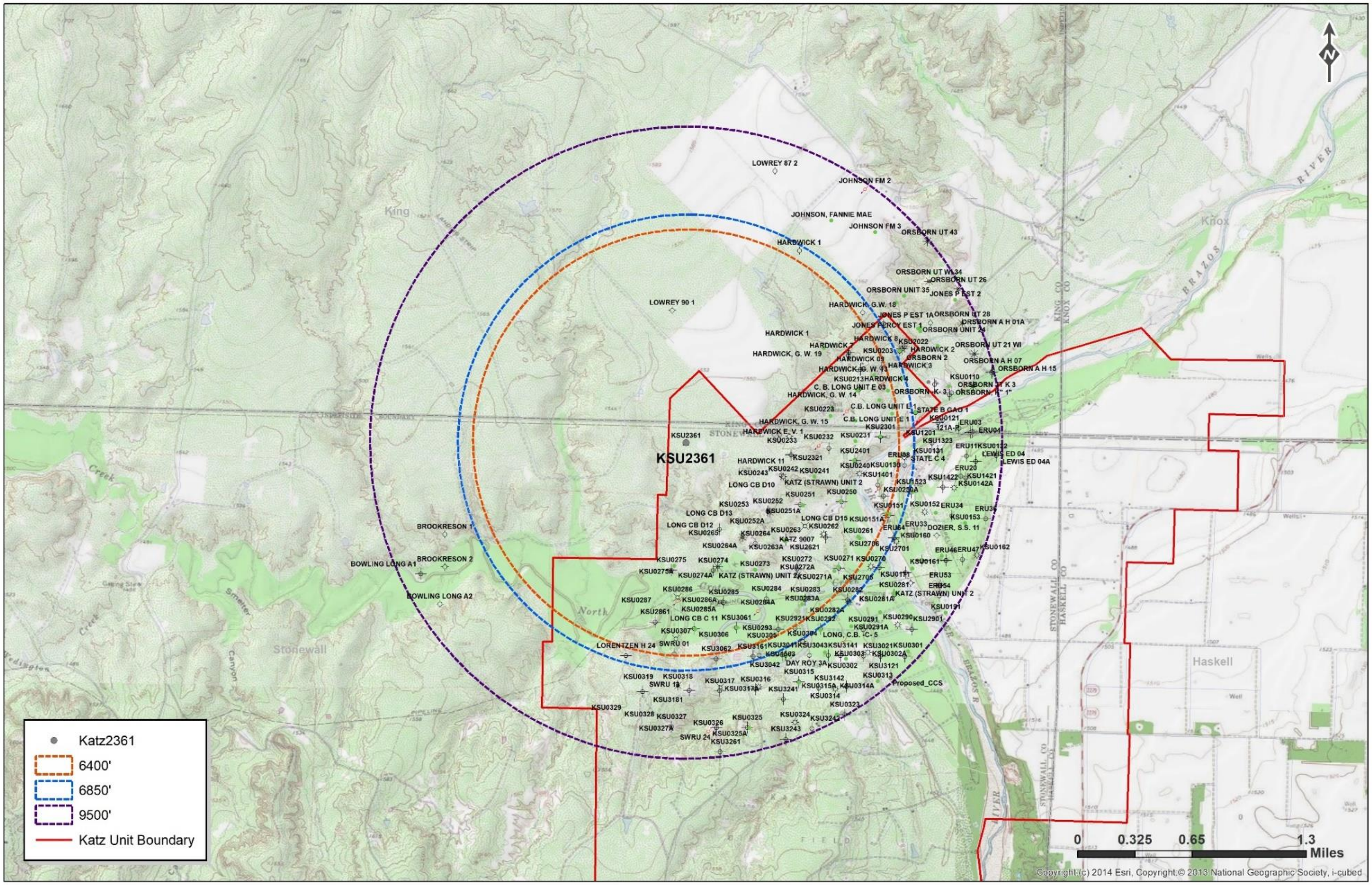


Figure 42 – All Oil and Gas Wells within the MMA

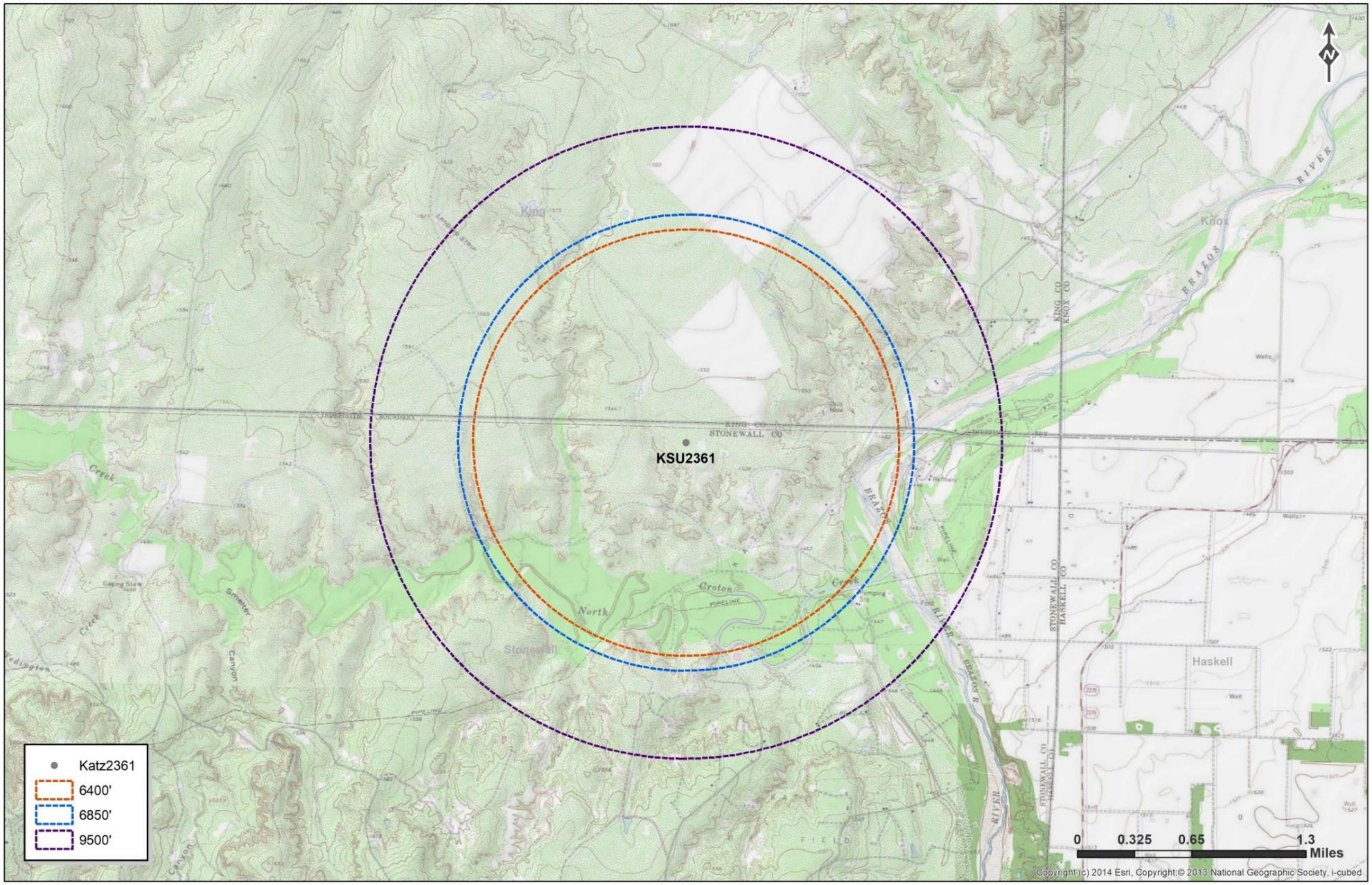


Figure 43 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA

Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Pre-Cambrian, have proven to date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC in the area of KSU 2361 include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"), 16 TAC **§3.13**. By way of example, see the KSU 2361 well drilling permit provided in Appendix A. The Ellenburger and Cambrian Sands are among the formations listed for which operators in Stonewall County and district 7B (where the KSU 2361 is located) are required to comply with TRCC Rule 13. TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. In this instance, any new well permitted and drilled to the KSU 2361 well's injection zone, and located within a one-quarter-mile radius of the KSU 2361 well, will be required under TRRC Rule 13 to set steel casing and cement above the KSU 2361 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above *all* potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued, which is also shown in the permit mentioned above in Appendix A.

4.2.2 Groundwater wells

A groundwater well search resulted in zero groundwater wells found within the MMA, as identified by the Texas Water Development Board.

The surface and intermediate casings of the KSU 2361 well, as shown in Figure 41, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See the GAU letter included in Appendix A. The wellbore casings and cements also prevent CO_2 leakage to the surface along the borehole.

4.3 Leakage Through Faults and Fractures

One fault was interpreted within the seismic coverage projecting 12,000' east of the KSU 2361 location. Initial plume models do not indicate an interaction between the injectate and the fault plane. Additionally, this fault dies within the Mississippian formation and does not penetrate the Lower Strawn Shale that acts as the upper confining unit. In the unlikely scenario in which the injection plume reaches the fault, and the fault acts as a transmissive pathway, the upper confining shale above the fault will act as an ideal sealant from injectate leaking outside of the permitted injection zone.

Should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Lower Strawn Shale, juxtaposing it against itself, preventing vertical migration.

Fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open hole logs show little to no porosity development indicating the Lower Strawn Shale or Mississippian Lime were not exposed at this location. Therefore, upward migration of injected gas through confining bed fractures is unlikely.

4.4 Leakage Through the Confining Layer

The Ellenburger and Cambrian injection zones have competent sealing rocks above and below the sand and carbonate formations. The properties of the overlying Lower Strawn Shale and its high composition of shale and mudstone make an excellent sealing rock to the underlying Ellenburger formation. Tight Mississippian Lime of roughly 266' lies between the Ellenburger and Lower Strawn Shale formations forming an impermeable upper buffer seal from the injection interval to the upper confining zone. Above this confining unit, shales found within the Homecreek Shale above the Desmoinesian formation will act as additional sealants between the injection interval and the USDW. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. Precambrian basement rock's underlying low porosity and permeability minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

4.5 Leakage from Natural or Induced Seismicity

The location of KSU 2361 is in an area of the Midland Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 44, indicates the nearest seismic event (unspecified whether natural or induced) occurred more than 40 miles away.

There is no indication of seismic activity posing a risk for loss of CO_2 to the surface within the MMA.

Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

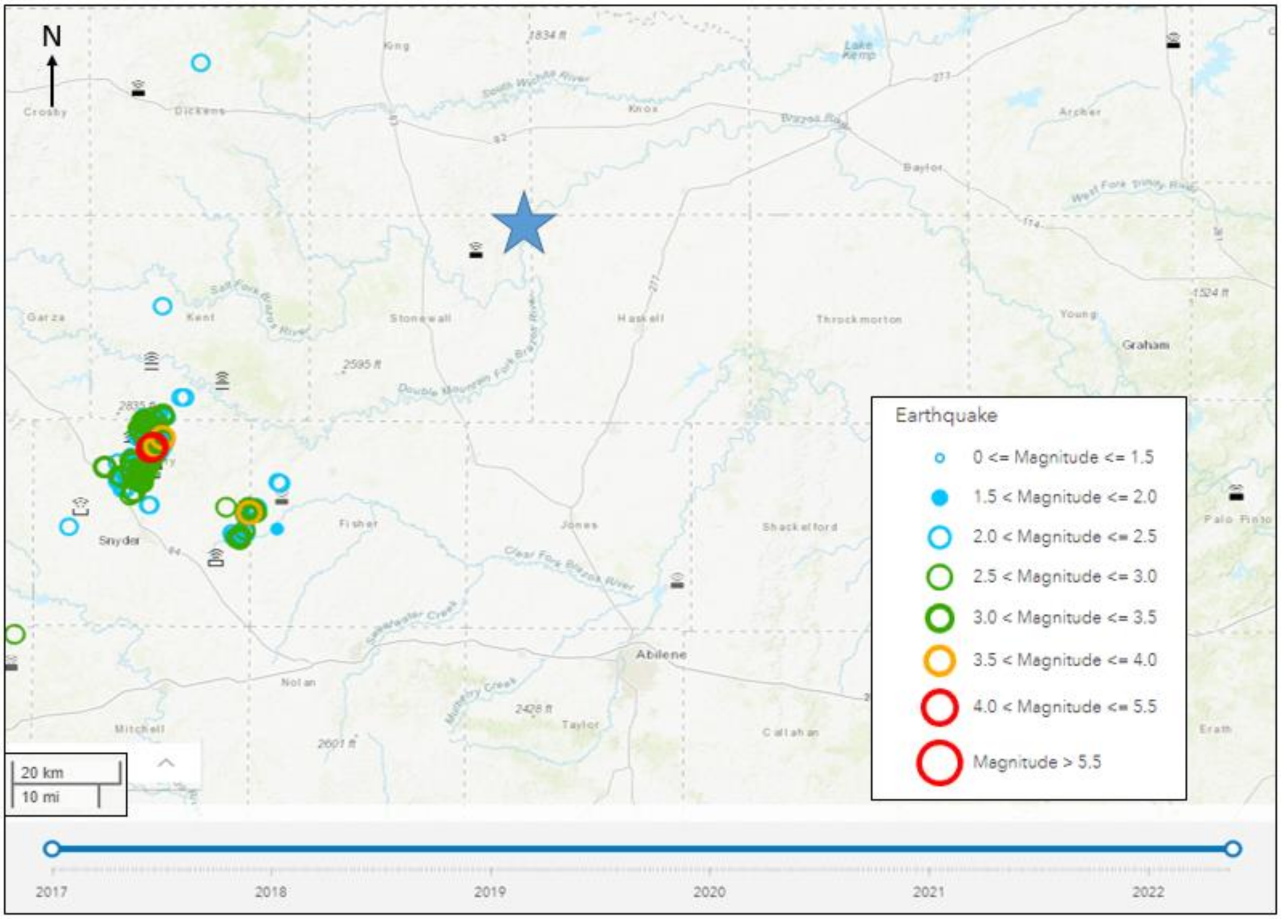


Figure 44 – Seismicity Review (TexNet – 06/01/2022)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Kinder Morgan will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 to meet the requirements of 40 CFR **§98.448(a)(3)**. Table 10 summarizes the monitoring of potential leakage pathways to the surface. Monitoring will occur during the planned 21-year injection period or cessation of injection operations, plus a proposed 5-year post-injection period.

- Leakage from surface equipment failure
- Leakage through existing and future wells within MMA
- Leakage through faults, fractures, or confining seals
- Leakage through natural or induced seismicity

Table 10 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed CO_2 monitors throughout the AGI facility
	Daily visual inspections
	Supervisory Control and Data Acquisition (SCADA)
Leakage through existing wells	Fixed CO_2 monitor at the the AGI well
	SCADA continuous monitoring at the AGI Well
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Quarterly atmospheric CO_2 measurements at well locations within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	CO_2 monitoring during offset drilling operations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage through confining layer	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage from natural or induced seismicity	Existing TexNet seismic monitoring station to be implemented

5.1 Leakage from Surface Equipment

As the facility and the KSU 2361 well are designed to handle CO_2, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used, and the connections are designed to minimize corrosion points. A baseline atmospheric CO_2 concentration will be established before injection operations begin. The facility and well site contain several CO_2 alarms with locations in close proximity.

The AGI complex is continuously monitored through automated systems. Details surrounding these systems can be found in Appendix C. In addition, field personnel conduct daily visual field inspections of gauges, monitors, and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and inspection of the cathodic protection system. These inspections and the automated systems allow Kinder Morgan to respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)**.

Pressures and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak.

5.2 Leakage From Existing and Future Wells within MMA

Kinder Morgan continuously monitors and collects injection volumes, pressures and temperatures through their SCADA systems, for the KSU 2361 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. KSU 2361 has a pressure and temperature gauge placed in the injection stream at its wellhead and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. In addition, mechanical integrity tests (MIT) performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 would ensure that new wells in the field would be constructed to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Kinder Morgan will also establish and operate an in-field monitoring program to detect CO_2 leakage within the MMA. The scope of work will include CO_2 monitoring at the AGI well site and, at minimum, quarterly atmospheric monitoring near any wells identified that penetrate the injection interval within the MMA. The collection of these measurements will be carried out by using a qualified third party. Upon approval of the MRV and through the post-injection monitoring period, Kinder Morgan will have these monitoring systems in place. No wells have been identified within the MMA that penetrate the injection interval. Additional monitoring will be added as the MMA is updated over time.

Groundwater Quality Monitoring

Kinder Morgan will monitor the groundwater quality in fluids above the confining interval by sampling from groundwater wells in the area of the facility and analyzing the sample with a third-party laboratory on an annual basis. In the case of KSU 2361, no existing groundwater wells have been identified within the MMA. At least two groundwater monitoring wells will be drilled within 1500' of KSU 2361 at a depth of approximately 100'. The final number, locations, and depths of the wells will be determined by a study completed by a certified 3rd party firm. The approximate location and depths of these wells are shown in Figure 45. A baseline sampling from these wells will occur before injection starts. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature, and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

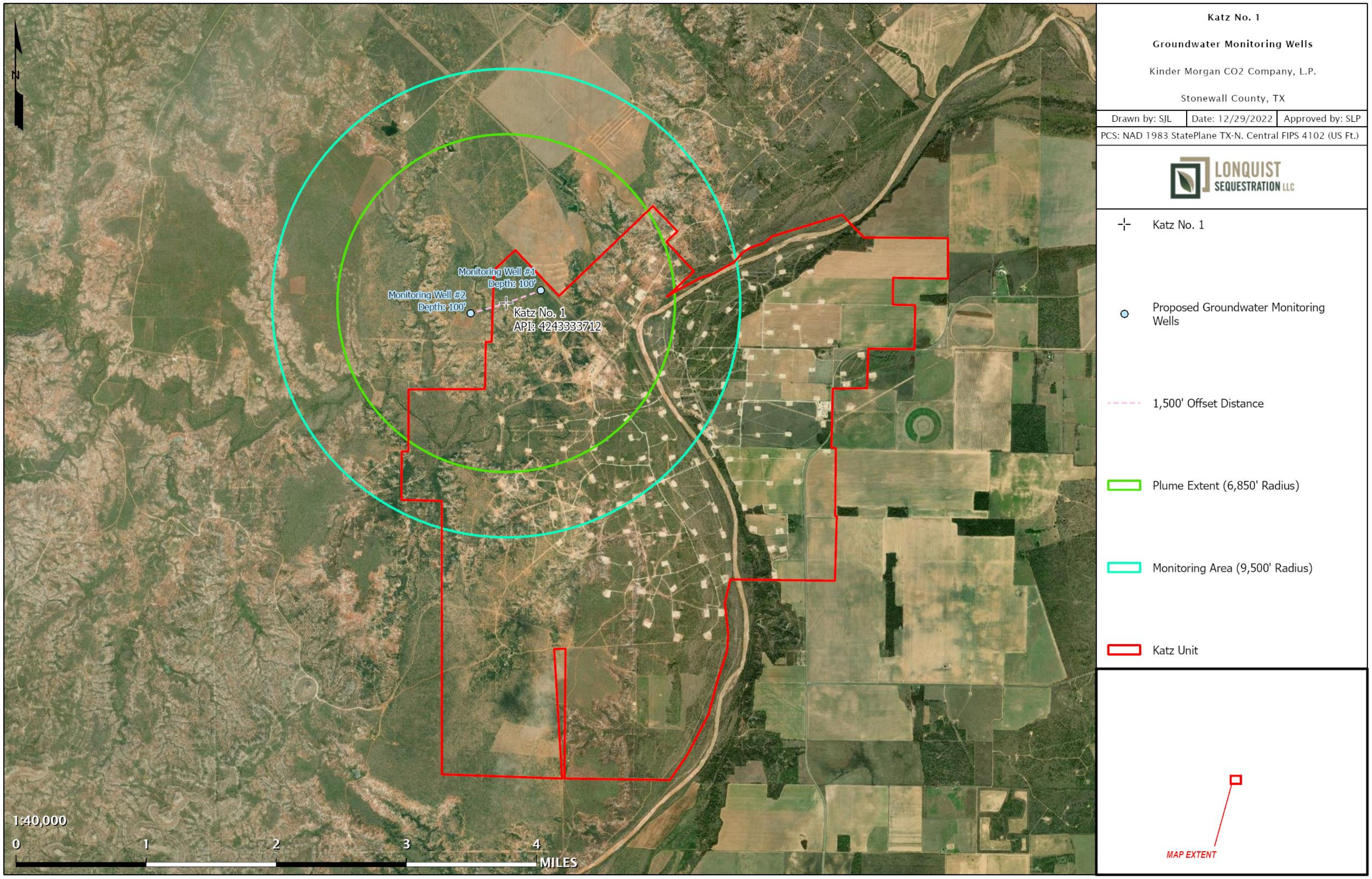


Figure 45 – Groundwater Monitoring Wells

5.3 Leakage through Faults, Fractures or Confining Seals

Kinder Morgan continuously monitors the operations of the KSU 2361 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. In addition, a field monitoring system is proposed to measure the shallow topsoil CO_2 concentrations across the MMA. These measurements will be taken quarterly by in-field gas sensors. The field CO_2 monitoring systems would alert field personnel for any release of CO_2 caused by such leakage.

5.4 Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Kinder Morgan plans to use the nearest TexNet seismic monitoring station to monitor the area of the KSU 2361 well. This station is 7.29 miles southwest of the well location, as shown below in Figure 46. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Katz Unit. Kinder Morgan will monitor this station for any seismic activity that occurs near the well. If a seismic event of 3.0 magnitude or greater is detected, Kinder Morgan will review the injection volumes and pressures at the KSU 2361 well to determine if any significant changes occur that would indicate potential leakage.

Figure 46 – Nearest TexNet Seismic Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Kinder Morgan will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Kinder Morgan will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Once the baseline concentrations are determined over a 12 month period prior to injection, the CO_2 monitors will be set to alarm at concentrations that are statistically significant deviation from baseline.

6.1 Visual Inspections

Daily inspections will be conducted by field personnel at the facility and the KSU 2361 well. These inspections will aid with identifying and addressing possible issues in order to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken to address such issues.

6.2 CO_2 Detection

In addition to the well site fixed monitors described previously, Kinder Morgan will establish and operate an in-field monitoring program to detect any CO_2 leakage within the MMA. The scope of baseline determination will include atmospheric CO_2 measurements at the AGI well site and near identified penetrations within the MMA. Topsoil CO_2 concentrations will also be measured, at pre-determined locations within the MMA, as baseline values before injection activities begin.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be taken. Any significant deviations over time will be analyzed for indication of leakage of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this project are well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a blowdown event, emissions will be sent to vent stacks and will be reported as required for the operation of the well.

6.5 Groundwater Monitoring

Initial samples will be taken from the groundwater monitoring wells drilled within 1,500 feet of the KSU 2361 well upon approval of Kinder Morgan's MRV and before commencing injection of CO_2. A third-party laboratory will analyze the samples to establish the baseline properties of the groundwater.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

This section identifies how Kinder Morgan will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR **§98.448(a)(5)**.

7.1 Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4)**." 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

Per 40 CFR **§98.444(b)**, since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters per quarter)

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (volume percent CO_2, expressed as a decimal fraction)

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The KSU 2361 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains concentrations well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released as a result of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods using equations from subpart W will be used to calculate CO2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead..

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12, assuming an expected injection start date of June 1, 2024, as this well will not actively produce oil or natural gas, or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to flares and reported as part of the required GHG reporting for the gas plant.

- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The KSU 2361 well currently reports GHGs under Subpart UU, but Kinder Morgan has elected to submit an MRV plan under, and otherwise comply with, Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed by March 31st of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Kinder Morgan plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 *Injected*

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated per the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP.

CO_2 *Emissions from Leaks and Vented Emissions*

- Gas monitors will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i) requirements**.**
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

9.2 Missing Data

In accordance with 40 CFR **§98.445**, Kinder Morgan will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Kinder Morgan will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

Kinder Morgan will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least three years and include the following:

- Quarterly records of the CO_2 injected
  - Volumetric flow at standard conditions
  - Volumetric flow at operating conditions
  - Operating temperature and pressure
  - Concentration of the CO_2 stream
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 11 - REFERENCES

Adams, Donald & Keller, Randy. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective. AAPG Bulletin. 80. 410-431. 10.1306/64ED87FA-1724-11D7-8645000102C1865D.

Broadhead, Ronald E., 2005. Regional Aspects of the Wristen petroleum system, southeastern New Mexico: New Mexico Bureau of Geology and Mineral Resources Open File Report, no. 485.

Comer, John B., 1991. Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas and Southeastern New Mexico: Bureau of Economic Geology Report of Investigations, no. 201.

Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.

Ewing et al. (2004). Groundwater Availability Model for the Seymour Aquifer. *Texas Water Development Board.*

Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.

George, Peter G., Mace, Robert E., and Petrossian, Rima, 2011. Aquifers of Texas: Texas Water Development Board Report, no 380.

Gunn, R. D. (1982). Desmoinesian Depositional Systems in the Knox Baylor Trough. *North Texas Geological Society*.

Harding, R.W. and Associates. (1978). THE SEYMOUR AQUIFER: Ground-Water Quality and Availability in Haskell and Knox Counties, Texas. *Texas Department of Water Resources.*

Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.

Hoak, T., Sundberg, K., and Ortoleva, P. Overview of the Structural Geology and Tectonics of the Central Basin Platform, Delaware Basin, and Midland Basin, West Texas and New Mexico: Department of Energy Open File Report.

Holtz, M.H., and Kerans, C. (1992). Characterization and categorization of West Texas Ellenburger reservoirs. *Permian Basin Section SEPM Publication No. 92-22, p. 31-44.*

Hornhach, M. J. (2016). Ellenburger wastewater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.

Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas*.

Kane, S. C. (n.d.). THE MISSISSIPPIAN BARNETT FORMATION: A SOURCE-ROCK, SEAL, AND RESERVOIR PRODUCED BY EARLYCARBONIFEROUS FLOODING OF THE TEXAS CRATON. *BEG*.

Kerans, C. (1989). Karst-controlled reservoir heterogeneity and an example from the Ellenburger Group (Lower Ordovician) of West Texas. *Bureau of Economic Geology.*

Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.

Kupecz, J.A., and L.S. Land. (1991). Late-stage dolomitization of the Lower Ordovician Ellenburger Group, West Texas. *Journal of Sedimentary Petrology.*

Kyle, J.R. and E.F. McBride. (2014). Geology of the Voca Frac Sand District, western Llano Uplift, Texas. *Arizona Geological Survey Special Paper #9, Chapter 2, p. 1-13.*

Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.

Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

Molina, Oscar, Vilarras, Victor, and Zeidouni, Mehdi, 2016. Geologic carbon storage for shale gas recovery: 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18.

Ruppel, Stephen C. and Holtz, Mark H., 1994. Depositional and Diagenetic Facies Patterns and Reservoir Development in Silurian and Devonian Rocks of the Permian Basin: Bureau of Economic Geology Report of Investigations, no. 216.

Snee, Jens-Erik Lund and Zoback, Mark D., 2016. State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity.

Teeple, Andrew P., Ging, Patricia B., Thomas, Jonathan V., Wallace, David S., and Payne, Jason D., 2021. Hydrogeologic Framework, Geochemistry, Groundwater-Flow System, and Aquifer Hydraulic Properties Used in the Development of a Conceptual Model of the Ogallala, Edwards-Trinity (High Plains), and Dockum Aquifers In and Near Gaines, Terry, and Yoakum Counties, Texas: USGS Scientific Investigations Report 2021-5009.

SECTION 12 - APPENDICES

APPENDICES

APPENDIX A – TRRC FORMS KSU #2361

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

A-1

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 13453 AMENDMENT

KINDER MORGAN PRODUCTION CO LLC
6 DESTA DRIVE STE 6000
MIDLAND, TX 79705

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated August 27, 2018 for the permitted interval of the ELLENBURGER, and CAMBRIAN formations and subject to the following terms and special conditions:

KATZ (STRAWN) UNIT (30524) LEASE
KATZ (STRAWN) FIELD
STONEWALL COUNTY, DISTRICT 7B

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
2361	43333712	000104281	Salt Water, and Other Non-Hazardous O/G Waste	5,800	6, 435	30,000	N/A	2,900	N/A

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
2361	43333712	**1. According to the cross-section submitted by the operator the Pre-Cambrian top is at 6440 feet and hence the PBTD shall be at 6435 feet (deepest perforations are at 6433 feet per RRC records). Operator agreed to this permit special condition provision in the email dated on 11-29-2018. A copy of Form W-15 Cementing Record must be filed with the Form H-5 Injection Well Pressure Test Report prior to injection documenting compliance with this Special Condition.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON December 31, 2018.

Sean Avitt, Manager
Injection-Storage Permits Unit

Amendment Comments:

Well No.	API No.	Amendment Comments
2361	43333712	1. Amends maximum daily injection volume for liquid from 20000 bbl/day. 2. Amends packer setting depth from 5750 feet. 3. Amends permit dated November 21, 2011.

Note: This document will only be distributed electronically.

Texas Commission on Environmental Quality
Surface Casing Program

DEPTH OF USABLE-QUALITY GROUND WATER TO BE PROTECTED

Date: July 21, 2010

TCEQ File No.: SC- 5504

API Number: 43333592

Attention: ROSE BURDITT

RRC Lease No. 000000

SC_463316_43333592_000000_5504.pdf

KINDER MORGAN PRODUCTION CO LL
500 W ILLINOIS
STE 500
MIDLAND TX 79701

P-5# 463316

--Measured--
3545 ft FNEL
72 ft FNWL
MRL: SURVEY

Digital Map Location:
X-coord/Long: 1232566
Y-coord/Lat: 638341
Datum: 27 Zone: NC

County: STONEWALL

Lease & Well No.: KATZ (STRAWN) UNIT #232&ALL

Purpose: ND

Location: SUR-EUSTIS J.,SEC-2,--[TD=5500],[RRC 7B],

To protect usable-quality ground water at this location, the Texas Commission on Environmental Quality recommends:

The interval from the land surface to a depth of 100 feet must be protected.

This recommendation is applicable to all wells drilled in this LEASE IN SECTION 2.

Note: Unless stated otherwise, this recommendation is intended to apply only to the subject well and not for area-wide use. Approval of the well completion methods for protection of this groundwater falls under the jurisdiction of the Railroad Commission of Texas. **This recommendation is intended for normal drilling, production, and plugging operations only. It does not apply to saltwater disposal operation into a nonproductive zone (RRC Form W-14).**

If you have any questions, please contact us at 512-239-0515, sc@tceq.state.tx.us, or by mail MC-151.

Sincerely,

T. Wesley McCoy

Digitally signed by Thomas Wesley McCoy
DN: c=US, st=Texas, l=Austin, ou=Surface Casing, o=Texas Commission on Environmental Quality, cn=Thomas Wesley McCoy, email=wmccoy@tceq.state.tx.us
Date: 2010.07.21 11:46:18 -05'00'

T. Wesley McCoy, P.G.

Geologist, Surface Casing Team
Waste Permits Division

GEOLOGIST SEAL

STATE OF TEXAS
T. WESLEY McCOY
GEOLOGY
117
LICENSED
PROFESSIONAL GEOSCIENTIST

The seal appearing on this document was authorized by *T. Wesley McCoy* on 7/21/2010
Note: Alteration of this electronic document will invalidate the digital signature.

A-3

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 718131	DATE PERMIT ISSUED OR AMENDED Jun 14, 2011	DISTRICT * 7B
API NUMBER 42-433-33712	FORM W-1 RECEIVED Jun 09, 2011	COUNTY STONEWALL
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 7194
OPERATOR 463316 KINDER MORGAN PRODUCTION CO LLC 6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (325) 677-3545
LEASE NAME KATZ (STRAWN) UNIT		WELL NUMBER 2361
LOCATION 21.9 miles NE direction from ASPERMONT		TOTAL DEPTH 7500
Section, Block and/or Survey SECTION SURVEY LONG, C B	BLOCK	ABSTRACT 1939
DISTANCE TO SURVEY LINES 3511 ft. S 539 ft. W		DISTANCE TO NEAREST LEASE LINE 539 ft.
DISTANCE TO LEASE LINES 1751 ft. NE 539 ft. W		DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
KATZ (STRAWN) KATZ (STRAWN) UNIT	7194.00 539	7,500	2361 3991	7B

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office. This is a hydrogen sulfide field. Hydrogen Sulfide Fields with perforations must be isolated and tested per State Wide Rule 36 and a Form H-9 filed with the district office. Fields with SWR 10 authority to downhole commingle must be isolated and tested individually prior to commingling production.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

Currently there are no identified formations listed for this county. It is still the operators responsibility to isolate and report any potential flow zones that are encountered in the completion of this well.

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Approved
Date: 10/04/2013
Tracking No.: 62859

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator	KINDER MORGAN PRODUCTION CO LLC	**Operator**	463316
Operator	6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000		

WELL INFORMATION

API 42-433-33712 — **County:** STONEWALL
Well No.: 2361 — **RRC District** 7B
Lease KATZ (STRAWN) UNIT — **Field** KATZ (STRAWN)
RRC Lease 30524 — **Field No.:** 48294600
Location Section: ,Block: , Survey: LONG, C B SVY, Abstract: 1939

Latitude — **Longitud**
This well is **miles in a**
direction from 21.9 MILES IN A NE DIRECTION FROM ASPERMONT, TX,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC — **Completion or Recompletion** 12/15/2012

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	06/14/2011	718131
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal	11/21/2011	13453
Other:		

COMPLETION INFORMATION

Spud		**Date of first production after rig**	12/15/2012
Date plug back, deepening, drilling operation	08/24/2012	**Date plug back, deepening, recompletion, drilling operation**	09/13/2012
Number of producing wells on this lease this field (reservoir) including this	66	**Distance to nearest well in lease & reservoir**	3991.0
Total number of acres in	7194.00	**Elevation**	1518 GL
Total depth TVD	6625	**Total depth MD**	
Plug back depth TVD	6547	**Plug back depth MD**	
Was directional survey made other inclination (Form W-	No	**Rotation time within surface casing Is Cementing Affidavit (Form W-15)**	Yes
Recompletion or	No	**Multiple**	No
Type(s) of electric or other log(s)	Induction only		
Electric Log Other Description:			

Location of well, relative to nearest lease — **Off Lease :** No
of lease on which this well is 1751.0 **Feet from the** NE **Line and**
539.0 **Feet from the** West **Line of the**
KATZ (STRAWN) UNIT **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

	Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type
PACKET:	N/A			

W2: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination	**Depth**	**Date**
SWR 13 Exception	**Depth**	

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		**Production**	
Number of hours	24	**Choke**	
Was swab used during this	No	**Oil produced prior to**	

PRODUCTION DURING TEST PERIOD:

Oil		**Gas**	
Gas - Oil	0	**Flowing Tubing**	
Water			

CALCULATED 24-HOUR RATE

Oil		**Gas**	
Oil Gravity - API - 60.:		**Casing**	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1		9 5/8	12 1/4	1290			C	491	837.0	SURF ACE	
2		7	8 3/4	6592			C	750	1248.0	3256	
3		7	8 3/4	6592	2463		C	450	618.0	SURF ACE	

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	4 1/2	5945	5957 /

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	No	L 6018	6024.0
2	No	L 6038	6077.0
3	No	L 6090	6101.0
4	No	L 6143	6195.0
5	No	L 6240	6255.0
6	No	L 6286	6311.0
7	No	L 6362	6370.0
8	No	L 6382	6433.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1		PUMP 2800 GALLONS 15% HCL, FLUSH WITH 36 BARRELS TREATED WATER.	6018	6101
2		PUMP 2600 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6143	6195
3		PUMP 2440 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6240	6311
4		PUMP 2960 GALLONS 15% HCL, FLUSH WITH 76 BARRELS TREATED WATER.	6362	6433

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
BASE PALO PINTO		3215.2			
ELLENBURGER		6018.0			
CAMBRIAN		6240.0			

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

THE PURPOSE OF THIS FILING IS TO REPORT A DRILLED AND COMPLETED SALT WATER DISPOSAL WELL.

OPERATOR'S CERTIFICATION

Printed	Dorothy Horrell	**Title:**	Administrator
Telephone	(432) 688-2448	**Date**	01/14/2013

APPENDIX B – GAS COMPOSITION

CO2 Pipeline - Gas Quality Specifications

Kinder Morgan CO2 Company

Revision: 2019 11 12

Product delivered at the Origination Point shall meet the following specifications, which herein are called Quality Specifications:

(a) **CO2 Content** Product composition shall be not less than ninety five per cent (95%) CO_2 by mole fraction.

(b) **Water** Product shall contain no free water, and shall not contain more than thirty (30) pounds of water per million standard cubic feet (MMscf) in the vapor phase.

(c) **Pressure** Product shall be delivered at a pressure sufficient to get into the pipeline.

(d) **Temperature** Product shall be delivered at a temperature not greater than 120 degrees F, and not less than 65 degrees F.

(e) **H2S** Product shall not contain more than twenty (20) parts per million H_2S, by volume.

(f) **Nitrogen** Product shall not contain more than four per cent (4%) nitrogen, by mole fraction.

(g) **Sulphur** Product shall not contain more than thirty five (35) parts per million sulphur, by weight.

(h) **Oxygen** Product shall not contain more than ten (10) parts per million, oxygen, by weight.

(i) **Hydrocarbons** Product shall not contain more than five percent (5%) hydrocarbons, by mole fraction.

(j) **Glycol** Product shall not contain more than 0.3 gallon glycol, per million standard cubic feet, and at no time shall glycol be present in a liquid state at temperature and pressure conditions of the pipeline.

(k) **Carbon Monoxide** Product shall not contain more than 4,250 parts per million, carbon monoxide, by weight.

(l) **NOx** Product shall not contain more than one (1) part per million, NO_x, by weight.

(m) **SOx** Product shall not contain more than one (1) part per million, SO_x, by weight.

(n) **Particulates** Product shall not contain more than one (1) part per million, particulates, by weight.

(o) **Amines** Product shall not contain more than one (1) part per million, amines, by weight.

(p) **Hydrogen** Product shall not contain more than one per cent (1%) hydrogen, by mole fraction.

(q) **Mercury** Product shall not contain more than five (5) nano grams per liter (ng/l) mercury.

(r) **Ammonia** Product shall not contain more than fifty (50) parts per million, ammonia, by weight.

(s) **Argon** Product shall not contain more than one volume percent (1% by volume) argon.

(t) **Liquids** Product shall be free of liquids at delivery conditions and shall not produce condensed liquids in the pipeline at pipeline pressure and temperature.

(u) **Compressor Lube Oil Carry Over** Compressor lube oil carry over in the product shall not exceed fifty (50) parts per million, by weight, and shall not cause fouling of pipeline, pipeline equipment downstream systems or reservoirs.

(v) **Impurities Deleterious to Pipeline, Equipment, Downstream Systems or Reservoirs** In addition to compositional limits listed above, product shall not contain impurities deleterious to pipeline, equipment, downstream systems or reservoirs.

APPENDIX C – PIPELINE SAFETY PLAN

Kinder Morgan CO_2 pipelines are monitored 24 hours a day, 7 days a week by personnel in control centers using a SCADA computer system. This electronic surveillance system gathers pipeline pressures, volume and flow rates and the status of pumping equipment and valves. Whenever operating conditions change, an alarm warns the operator on duty and the condition is investigated. Both automated and manual valves are strategically placed along the pipeline system to enable the pipeline to be shut down immediately and sections to be isolated quickly, if necessary. Visual inspections of the pipeline right-of-way, a narrow strip of land reserved for the pipeline, are conducted by air and ground on a regular basis.

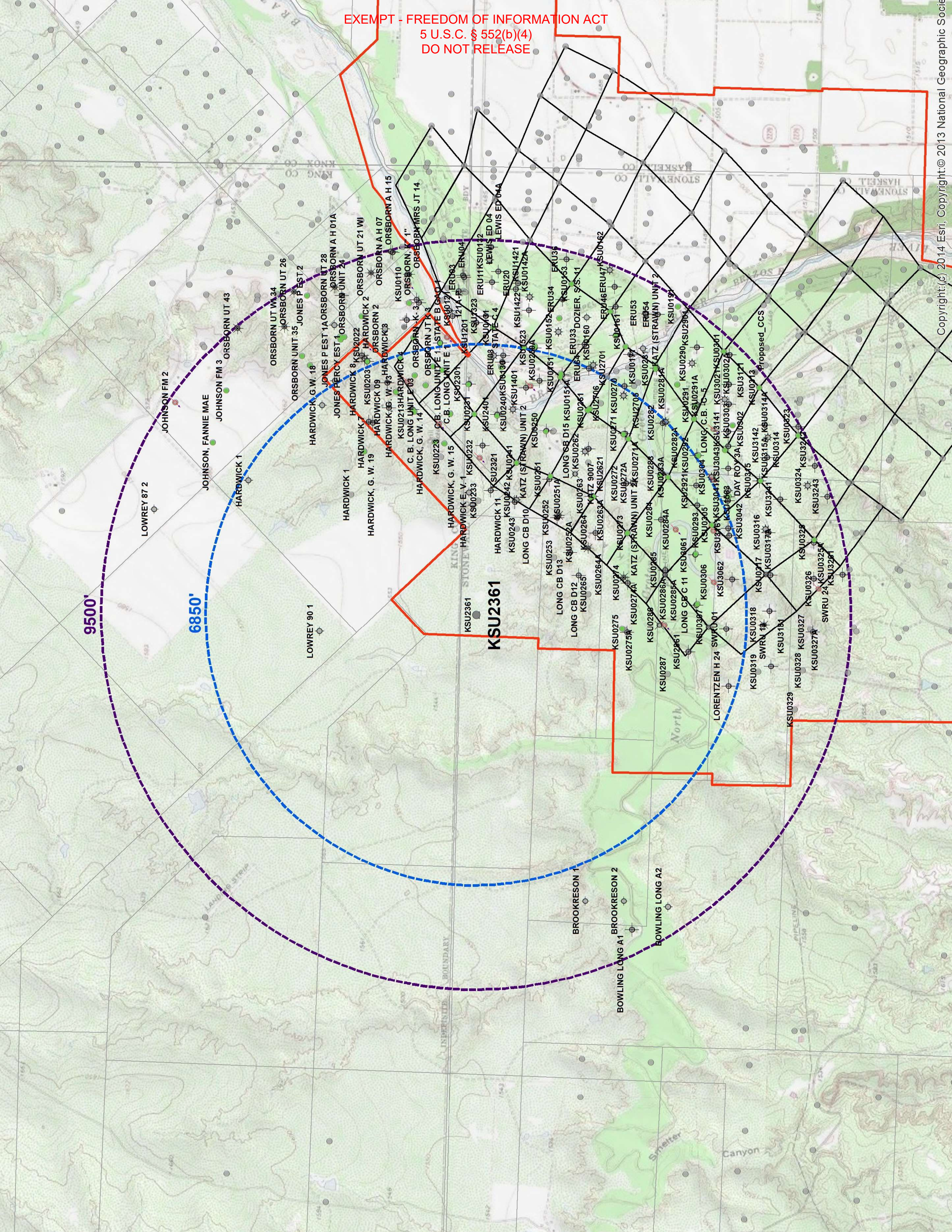
In the event of a CO_2 pipeline rupture, the Kinder Morgan CO_2 Supervisory Control and Data Acquisition (SCADA) computer system will shut down the pipeline and isolate the impacted section with automated valves. Kinder Morgan will notify the appropriate public safety answering point (i.e., 9-1-1 emergency call center) and initiate the internal Emergency Response Line to alert the operations team. An emergency response plan would be initiated with implementation of an incident command system, and Kinder Morgan will work with local emergency responders to isolate the impacted area.

APPENDIX D – MMA/AMA REVIEW MAPS

APPENDIX D-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX D-2: OIL AND GAS WELLS WITHIN THE MMA LIST

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE



Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332238	BOWLING-LONG A	2	P & A	5,815	WILDCAT	4/20/1987	5/7/1987
4243332229	BROOKRESON	1	P & A	5,730	WILDCAT	3/7/1987	5/14/1987
4243332319	BROOKRESON	2	P & A	5,745	WILDCAT	12/2/1987	12/13/1987
4226932003	C. B. LONG UNIT	E 03	P & A	5,300	KATZ	--	--
4243300422	C.B. LONG UNIT	C 11	P & A	5,127	KATZ	7/11/1989	5/15/2009
4243332388	C.B. LONG UNIT	C 16	P & A	5,200	KATZ	11/18/1989	12/8/2010
4243300585	C.B. LONG UNIT	D 10	P & A	5,197	KATZ	6/30/1989	1/13/2009
4243332465	C.B. LONG UNIT	D 13	P & A	5,201	KATZ	12/27/1989	9/23/2005
4243301965	C.B. LONG UNIT	D 4	P & A	5,188	KATZ		11/30/2010
4226900122	C.B. LONG UNIT	E 1	P & A	5,165	KATZ		9/15/2009
4226932006	C.B. LONG UNIT	E 2	P & A	5,200	KATZ	10/11/1990	2/24/2011
4243332116	DOZIER, S.S.	11	P & A	5,950	WILDCAT	6/12/1986	06/23/1986
4226900308	EAST RIVER UNIT	4	INACTIVE	4,931	KATZ		02/21/1995
4243332303	EAST RIVER UNIT	8	P & A	5,200	KATZ	11/17/1987	06/24/2009
4243332302	EAST RIVER UNIT	11	P & A	5,200	KATZ	11/26/1987	3/18/2004
4243300796	EAST RIVER UNIT	18	ACTIVE	5,300	KATZ	7/26/1951	--
4243300802	EAST RIVER UNIT	20	P & A	5,184	KATZ	8/22/1988	7/6/2009
4243300798	EAST RIVER UNIT	21	P & A	4,957	KATZ		12/5/1989
4243300787	EAST RIVER UNIT	33	P & A	5,155	KATZ		10/21/2009
4243300781	EAST RIVER UNIT	34	P & A	5,120	KATZ		10/30/2009
4243332306	EAST RIVER UNIT	36	P & A	5,200	KATZ	12/15/1987	2/28/2006
4243300849	EAST RIVER UNIT	45	P & A	5,167	KATZ		12/7/2010
4243300848	EAST RIVER UNIT	46	INACTIVE	4,875	KATZ		2/15/1990
4243332308	EAST RIVER UNIT	47	P & A	5,200	KATZ	12/5/1987	10/13/2009
4243300780	EAST RIVER UNIT	53	P & A	4,918	KATZ		2/14/1995
4243300788	EAST RIVER UNIT	54	P & A	5,211	KATZ		2/11/2009
4243332417	EAST RIVER UNIT	64	P & A	5,245	KATZ	8/8/1988	1/23/2009
4243333510	EAST RIVER UNIT	105	ACTIVE	5,325	KATZ	11/3/2009	--
4243333368	EAST RIVER UNIT	73H	P & A	4,750	KATZ	8/8/2007	9/3/2007
4243381146	EDD LEWIS		P & A	4,967	KATZ		10/14/2005
4226932269	HARDWICK	1	P & A	5,820	WILDCAT	6/19/1997	7/1/1997
4226900006	HARDWICK	2	P & A	5,147	KATZ		5/15/1975
4226900007	HARDWICK	3	P & A	5,168	KATZ		7/27/1970
4226900008	HARDWICK	4	P & A	5,146	KATZ		1/26/1984
4226900011	HARDWICK	6	P & A	5,152	KATZ		7/24/1970
4226900009	HARDWICK	7	P & A	5,150	KATZ		8/19/1967
4226900010	HARDWICK	8	P & A	5,152	KATZ		6/18/1976
4226980016	HARDWICK	9	P & A	2,171	KATZ		1/27/1984
4243301905	HARDWICK	11	P & A	5,152	KATZ		7/22/1970
4226900005	HARDWICK E. V.	1	P & A	5,960	KATZ		7/14/1951
4226931776	HARDWICK, G. W.	12	P & A	5,200	KATZ	3/10/1988	11/6/2009
4226931777	HARDWICK, G. W.	13	P & A	5,200	KATZ	3/11/1988	11/19/2009
4226931775	HARDWICK, G. W.	14	P & A	5,200	KATZ	5/29/1988	11/16/2009
4226931771	HARDWICK, G. W.	15	P & A	5,200	KATZ	3/15/1988	11/12/2009
4226931774	HARDWICK, G. W.	16	P & A	5,200	KATZ	3/8/1988	5/13/2004
4226931772	HARDWICK, G. W.	17	P & A	5,250	KATZ	3/9/1988	11/10/2009
4226932431	HARDWICK, G.W.	18	P & A	5,300	KATZ	8/13/2001	8/24/2001
4226932178	JOHNSON, FANNIE MAE	1	P & A	5,840	KATZ	4/11/1995	2/2/2016
4226932197	JOHNSON, FANNIE MAE	2	P & A	5,825	KATZ	10/5/1995	2/3/2016
4226932236	JOHNSON, FANNIE MAE	3	P & A	5,830	KATZ	11/2/1996	2/1/2016
4226900420	JONES PERCY EST	1	P & A	5,200	KATZ		1/1/1962
4226900428	JONES PERCY ESTATE	3	P & A	4,940	KATZ		7/1/1958
4226932805	KATZ (STRAWN) UNIT	110	ACTIVE	5,312	KATZ	3/13/2011	--
4226931666	KATZ (STRAWN) UNIT	121	P & A	4,879	KATZ	2/9/1987	10/24/2019
4243300797	KATZ (STRAWN) UNIT	131	ACTIVE	5,200	KATZ	9/24/1951	--
4243333513	KATZ (STRAWN) UNIT	132	ACTIVE	5,320	KATZ	12/2/2009	--
4243332296	KATZ (STRAWN) UNIT	143	P & A	5,200	KATZ	12/13/1987	7/30/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332304	KATZ (STRAWN) UNIT	151	P & A	5,200	KATZ	11/20/1987	7/20/2010
4243300779	KATZ (STRAWN) UNIT	152	ACTIVE	5,255	KATZ		--
4243300783	KATZ (STRAWN) UNIT	153	ACTIVE	5,299	KATZ	4/25/1952	--
4243333511	KATZ (STRAWN) UNIT	160	ACTIVE	5,302	KATZ	11/20/2009	--
4243333518	KATZ (STRAWN) UNIT	161	ACTIVE	5,308	KATZ	1/22/2010	--
4243333512	KATZ (STRAWN) UNIT	162	ACTIVE	5,328	KATZ	12/30/2009	--
4243333521	KATZ (STRAWN) UNIT	171	ACTIVE	5,334	KATZ	2/2/2010	--
4243333580	KATZ (STRAWN) UNIT	180	ACTIVE	5,327	KATZ	6/29/2010	--
4243333665	KATZ (STRAWN) UNIT	191	ACTIVE	5,423	KATZ	5/2/2011	--
4226932789	KATZ (STRAWN) UNIT	211	ACTIVE	5,316	KATZ	11/7/2010	--
4226932795	KATZ (STRAWN) UNIT	212	P & A	5,294	KATZ	8/21/2010	6/8/2022
4226932783	KATZ (STRAWN) UNIT	220	ACTIVE	5,308	KATZ	3/9/2010	--
4226932788	KATZ (STRAWN) UNIT	221	ACTIVE	4,863	KATZ	6/6/2010	--
4226932793	KATZ (STRAWN) UNIT	222	ACTIVE	5,308	KATZ	6/18/2010	--
4243333534	KATZ (STRAWN) UNIT	231	ACTIVE	5,315	KATZ	4/23/2010	--
4243333592	KATZ (STRAWN) UNIT	232	ACTIVE	5,340	KATZ	8/10/2010	--
4243333523	KATZ (STRAWN) UNIT	240	ACTIVE	5,309	KATZ	3/18/2010	--
4243300584	KATZ (STRAWN) UNIT	241	ACTIVE	5,250	KATZ	6/8/1957	--
4243333615	KATZ (STRAWN) UNIT	242	ACTIVE	5,297	KATZ	11/30/2010	--
4243300403	KATZ (STRAWN) UNIT	250	P & A	5,206	KATZ	10/25/1951	12/13/2019
4243300400	KATZ (STRAWN) UNIT	261	ACTIVE	5,150	KATZ		--
4243333573	KATZ (STRAWN) UNIT	262	ACTIVE	5,314	KATZ	5/25/2010	--
4243300583	KATZ (STRAWN) UNIT	264	P & A	5,242	KATZ		4/29/2011
4243333524	KATZ (STRAWN) UNIT	270	ACTIVE	5,300	KATZ	4/13/2010	--
4243300405	KATZ (STRAWN) UNIT	271	P & A	5,150	KATZ		11/4/2010
4243300421	KATZ (STRAWN) UNIT	273	ACTIVE	5,127	KATZ	7/11/1953	--
4243300424	KATZ (STRAWN) UNIT	274	P & A	5,131	KATZ	5/16/1989	12/27/2010
4243301970	KATZ (STRAWN) UNIT	275	P & A	5,185	KATZ		3/14/2011
4243300417	KATZ (STRAWN) UNIT	281	P & A	5,156	KATZ		8/16/2010
4243332387	KATZ (STRAWN) UNIT	282	P & A	5,189	KATZ	11/2/1989	9/20/2010
4243332389	KATZ (STRAWN) UNIT	284	P & A	5,210	KATZ	10/15/1989	1/10/2011
4243332390	KATZ (STRAWN) UNIT	285	P & A	5,219	KATZ		11/3/2010
4243332461	KATZ (STRAWN) UNIT	286	P & A	5,730	KATZ	12/8/1989	4/29/2013
4243333526	KATZ (STRAWN) UNIT	290	ACTIVE	5,315	KATZ	5/6/2010	--
4243333704	KATZ (STRAWN) UNIT	301	ACTIVE	5,365	KATZ	7/27/2011	--
4243301620	KATZ (STRAWN) UNIT	302	P & A	5,138	KATZ	3/28/1953	1/5/2012
4243333738	KATZ (STRAWN) UNIT	304	ACTIVE	5,300	KATZ	12/3/2011	--
4243333778	KATZ (STRAWN) UNIT	305	ACTIVE	5,330	KATZ	4/6/2012	--
4243333569	KATZ (STRAWN) UNIT	306	ACTIVE	5,328	KATZ	5/16/2010	--
4243333813	KATZ (STRAWN) UNIT	307	INACTIVE	5,365	KATZ	6/26/2012	--
4243333746	KATZ (STRAWN) UNIT	313	ACTIVE	5,380	KATZ	11/20/2011	--
4243332561	KATZ (STRAWN) UNIT	314	P & A	5,225	KATZ	12/16/1989	2/7/2012
4243333788	KATZ (STRAWN) UNIT	315	P & A	5,320	KATZ	3/17/2012	7/1/2014
4243332553	KATZ (STRAWN) UNIT	317	P & A	5,200	KATZ	12/11/1989	10/14/2013
4243333822	KATZ (STRAWN) UNIT	318	P & A	5,320	KATZ	7/5/2012	5/24/2021
4243333736	KATZ (STRAWN) UNIT	324	ACTIVE	5,380	KATZ	2/6/2012	--
4243333527	KATZ (STRAWN) UNIT	326	ACTIVE	5,503	KATZ	3/30/2010	--
4243300819	KATZ (STRAWN) UNIT	327	P & A	4,952	KATZ		12/23/2010
4243332509	KATZ (STRAWN) UNIT	1201	P & A	5,295	KATZ	7/1/1989	11/29/2010
4226931752	KATZ (STRAWN) UNIT	1221	P & A	5,200	KATZ	1/23/1988	10/11/2011
4243300800	KATZ (STRAWN) UNIT	1323	P & A	4,930	KATZ		3/23/2010
4243332298	KATZ (STRAWN) UNIT	1401	P & A	5,261	KATZ	1/24/1988	3/19/2010
4243332274	KATZ (STRAWN) UNIT	1422	P & A	5,220	KATZ	9/2/1987	11/16/2009
4243300801	KATZ (STRAWN) UNIT	1523	P & A	5,101	KATZ	5/20/1952	11/24/2009
4243332299	KATZ (STRAWN) UNIT	1801	P & A	4,879	KATZ	2/2/1988	3/31/2011
4226932806	KATZ (STRAWN) UNIT	2022	ACTIVE	5,313	KATZ	3/25/2011	--
4226932345	KATZ (STRAWN) UNIT	2121	P & A	5,800	KATZ	8/8/1999	11/12/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932002	KATZ (STRAWN) UNIT	2221	P & A	5,200	KATZ	10/25/1990	6/1/2010
4243332753	KATZ (STRAWN) UNIT	2321	P & A	5,200	KATZ	12/10/1991	3/3/2011
4243333712	KATZ (STRAWN) UNIT	2361	ACTIVE	6,625	KATZ	8/23/2012	--
4243300406	KATZ (STRAWN) UNIT	2401	P & A	5,173	KATZ	5/23/1989	12/31/2009
4243332541	KATZ (STRAWN) UNIT	2701	INACTIVE	100	KATZ	9/27/1989	--
4243332565	KATZ (STRAWN) UNIT	2702	INACTIVE	100	KATZ	12/7/1989	--
4243300401	KATZ (STRAWN) UNIT	2705	P & A	5,116	KATZ	5/12/1989	3/2/2010
4243333713	KATZ (STRAWN) UNIT	2706	COMPLETED	7,500	KATZ		--
4243300423	KATZ (STRAWN) UNIT	2861	P & A	5,161	KATZ	7/17/1989	11/21/2013
4243300399	KATZ (STRAWN) UNIT	2901	P & A	5,150	KATZ		2/17/2011
4243333160	KATZ (STRAWN) UNIT	2921	P & A	5,725	KATZ	12/10/1998	1/13/2010
4243380198	KATZ (STRAWN) UNIT	3041	P & A	5,113	KATZ	7/18/2005	6/17/2010
4243301606	KATZ (STRAWN) UNIT	3042	P & A	5,113	KATZ	11/6/1989	3/22/2012
4243300838	KATZ (STRAWN) UNIT	3062	P & A	5,240	KATZ	11/16/1989	7/1/2010
4243301610	KATZ (STRAWN) UNIT	3141	P & A	5,115	KATZ		2/16/2012
4243300837	KATZ (STRAWN) UNIT	3161	P & A	5,190	KATZ	2/13/1990	8/18/2010
4243300842	KATZ (STRAWN) UNIT	3181	P & A	4,961	KATZ		2/16/2011
4243301605	KATZ (STRAWN) UNIT	3241	P & A	5,170	KATZ		4/12/2013
4243332570	KATZ (STRAWN) UNIT	3243	P & A	5,240	KATZ	1/14/1990	2/10/2010
4243332588	KATZ (STRAWN) UNIT	3261	P & A	5,150	KATZ	2/12/1990	3/31/2010
4226932987	KATZ (STRAWN) UNIT	121A	ACTIVE	5,337	KATZ	12/3/2019	--
4243333496	KATZ (STRAWN) UNIT	142A	ACTIVE	5,305	KATZ	10/20/2009	--
4243333595	KATZ (STRAWN) UNIT	151A	ACTIVE	5,317	KATZ	9/7/2010	--
4243334217	KATZ (STRAWN) UNIT	250A	INACTIVE	5,314	KATZ	12/19/2019	--
4243333630	KATZ (STRAWN) UNIT	251A	ACTIVE	5,315	KATZ	12/10/2010	--
4243333598	KATZ (STRAWN) UNIT	252A	TA	5,300	KATZ	10/17/2010	--
4243333599	KATZ (STRAWN) UNIT	263A	ACTIVE	5,315	KATZ	9/29/2010	--
4243333639	KATZ (STRAWN) UNIT	264A	P & A	5,333	KATZ	4/5/2011	6/1/2021
4243333627	KATZ (STRAWN) UNIT	271A	ACTIVE	5,302	KATZ	12/20/2010	--
4243333632	KATZ (STRAWN) UNIT	272A	ACTIVE	5,318	KATZ	3/1/2011	--
4243333807	KATZ (STRAWN) UNIT	274A	TA	5,300	KATZ	5/24/2012	7/1/2022
4243333607	KATZ (STRAWN) UNIT	281A	ACTIVE	5,324	KATZ	10/9/2010	--
4243333617	KATZ (STRAWN) UNIT	282A	ACTIVE	5,297	KATZ	11/18/2010	--
4243333735	KATZ (STRAWN) UNIT	283A	ACTIVE	5,380	KATZ	10/7/2011	--
4243333722	KATZ (STRAWN) UNIT	284A	ACTIVE	5,345	KATZ	12/15/2011	--
4243333799	KATZ (STRAWN) UNIT	285A	INACTIVE	5,350	KATZ	4/16/2012	--
4243333927	KATZ (STRAWN) UNIT	286A	TA	5,337	KATZ	3/24/2014	--
4243333730	KATZ (STRAWN) UNIT	291A	ACTIVE	5,364	KATZ	9/24/2011	--
4243333695	KATZ (STRAWN) UNIT	302A	ACTIVE	5,390	KATZ	7/6/2011	--
4243333771	KATZ (STRAWN) UNIT	303A	ACTIVE	5,330	KATZ	2/27/2012	--
4243333753	KATZ (STRAWN) UNIT	314A	ACTIVE	5,375	KATZ	10/27/2011	--
4243334002	KATZ (STRAWN) UNIT	315A	ACTIVE	5,348	KATZ	7/11/2014	--
4243333770	KATZ (STRAWN) UNIT	316A	ACTIVE	5,400	KATZ	1/25/2012	--
4243333820	KATZ (STRAWN) UNIT	317A	INACTIVE	5,336	KATZ	12/29/2013	--
4243333776	KATZ (STRAWN) UNIT	323A	ACTIVE	5,408	KATZ	3/7/2012	--
4243333821	KATZ (STRAWN) UNIT	325A	ACTIVE	5,385	KATZ	12/10/2013	--
4226900309	LEWIS, W. D.	2	P & A	5,090	KATZ		9/29/2008
4243300412	LONG, C. B. -D-	5	P & A	5,165	KATZ		3/12/2010
4243300415	LONG, C. B. -D-	6	P & A	5,188	KATZ		11/8/2010
4243300408	LONG, C.B. -C-	4	P & A	5,214	KATZ		3/9/2011
4243300411	LONG, C.B. -C-	5	P & A	5,165	KATZ		11/30/2010
4243300420	LONG, C.B. -C-	9	INACTIVE	5,163	KATZ		5/13/2010
4243300414	LONG, C.B. -C-	6 T	P & A	5,168	KATZ		11/12/2010
4243300419	LONG, C.B. -C-	8 T	P & A	5,165	KATZ		11/15/2010
4243300418	LONG, C.B. -D-	7	P & A	5,190	KATZ	8/1/1989	8/10/2010
4243300586	LONG, C.B. -D-	11	P & A	5,183	KATZ	6/15/1989	8/30/2010
4243300587	LONG, C.B. -D-	12	P & A	4,896	KATZ		1/13/1986

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932293	LOWERY 87	2	P & A	5,835	WILDCAT	11/11/1997	11/24/1997
4226932268	LOWREY 90	1	P & A	5,800	WILDCAT	5/25/1997	6/4/1997
4226932270	MANGIS	2	P & A	5,770	KAIA	7/10/1997	7/20/1997
4226932325	ORSBORN	2	P & A	5,718	KAIA	10/22/1998	11/4/1998
4226900108	ORSBORN	7	P & A	4,940	KATZ		8/30/2006
4226932955	ORSBORN K	14	INACTIVE	5,235	KATZ	11/5/2015	--
4226900077	ORSBORN -K-	3	P & A	5,091	KATZ		7/19/1993
4226900082	ORSBORN UNIT	1	INACTIVE	5,155	KATZ	8/14/1952	--
4226900081	ORSBORN UNIT	14	P & A	5,077	KATZ		8/30/2018
4226900105	ORSBORN UNIT	15	P & A	5,211	KATZ		8/25/1994
4226910001	ORSBORN UNIT	19	P & A	5,144	KATZ	9/1/1984	9/6/1984
4226931306	ORSBORN UNIT	21	P & A	5,170	KATZ	9/25/1984	11/11/2021
4226931395	ORSBORN UNIT	24	P & A	5,200	KATZ	1/23/1985	3/25/2022
4226931398	ORSBORN UNIT	26	P & A	5,247	KATZ	2/4/1985	5/9/2019
4226931397	ORSBORN UNIT	28	P & A	5,220	KATZ	2/18/1985	3/1/2013
4226931738	ORSBORN UNIT	34	P & A	5,250	KATZ	10/9/1987	8/28/2018
4226932314	ORSBORN UNIT	43	P & A	5,350	KATZ	4/24/1998	4/29/2019
4226932956	ORSBORN UNIT	44	INACTIVE	5,230	KATZ	6/28/2016	--
4226900076	ORSBORN, "K"	1	P & A	5,099	KATZ		7/12/1993
4226900104	ORSBORN, ALMA H.	1	P & A	5,155	KATZ		5/7/1957
4243300841	SOUTHWEST RIVER UNIT	1	P & A	4,903	KATZ		7/17/1998
4243301612	SOUTHWEST RIVER UNIT	5	P & A	5,115	KATZ		2/20/2012
4243301621	SOUTHWEST RIVER UNIT	6	P & A	5,154	KATZ	4/14/1953	1/25/2012
4243301609	SOUTHWEST RIVER UNIT	9	P & A	5,150	KATZ		4/13/2011
4243301619	SOUTHWEST RIVER UNIT	10	P & A	5,104	KATZ	2/17/1953	12/14/2010
4243300844	SOUTHWEST RIVER UNIT	13	P & A	4,987	KATZ		9/18/1995
4243300836	SOUTHWEST RIVER UNIT	16	P & A	5,170	KATZ		1/5/2011
4243332587	SOUTHWEST RIVER UNIT	18	P & A	5,300	KATZ	2/1/1990	1/27/2010
4243300811	SOUTHWEST RIVER UNIT	24	P & A	4,920	KATZ		11/28/2002
4243301444	SOUTHWEST RIVER UNIT	28	P & A	4,950	KATZ	8/13/2007	4/13/2011
4243300823	SOUTHWEST RIVER UNIT	36	P & A	4,963	KATZ		--
4243300815	SOUTHWEST RIVER UNIT	37	P & A	4,972	KATZ		10/15/1991
4243300835	SOUTHWEST RIVER UNIT	71	P & A	5,171	KATZ		10/4/1991
4243300809	SOUTHWEST RIVER UNIT	25W	P & A	5,230	KATZ		10/22/2013
4243332560	SOUTHWEST RIVER UNIT	27W	P & A	5,206	KATZ	1/9/1990	3/12/2013
4226900069	STATE A GAO	1	P & A	5,085	KATZ		4/19/1985
4226900070	STATE B GAO	1	P & A	4,876	KATZ		4/17/1985
4243301761	STATE OF TEXAS -C-	1	P & A	5,296	KATZ		2/11/1983
4243301762	STATE OF TEXAS -C-	2	P & A	5,205	KATZ		12/4/1982
4243301764	STATE OF TEXAS -C-	4	P & A	5,205	KATZ		11/29/1982
4226900012			ACTIVE	5,105			--
4226900016			ACTIVE	5,175			--
4243300005			P & A	3,251			--

Request for Additional Information: Kinder Morgan CCS Complex
February 23, 2023

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	NA	NA	Please add details on the source of the injected TAG/CO_2 to the MRV plan.	Completed. Page 2 – verbiage added **"The source of this injected CO_2 gas is from Red Cedar natural gas processing plants in southern Colorado."**
2.	NA	NA	The address listed for the facility in e-GGRT is in Houston, Texas, while the MRV plan describes the facility located in Stonewall County, Texas. The facility address should be that associated with the actual facility, so we request that the address be updated in e-GGRT. Per 40 CFR 98.3(c)(1), if the facility does not have a physical street address, then you can provide a latitude and longitude for the facility.	Coordinates in NAD27 for this facility: Latitude: 33.3960287 Longitude: -100.0278067
3.	NA	NA	The MRV plan discusses the utilization of CO_2 monitors for leak detection. Please add details about the detection limits and concentrations that would alarm these monitors.	Completed. Section 6 – Page 73 – Verbiage added for further clarification "**Once the baseline concentrations are determined over a 12 month period prior to injection, the CO2 monitors will be set to alarm at concentrations that are statistically significant deviation from baseline.**"
4.	NA	NA	We recommend adding subsection numbers to the Table of contents and throughout the MRV plan.	Subsections added in Table of contents and throughout the MRV Plan

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	NA	NA	Throughout the MRV plan, inconsistent units are used when discussing injection volumes (barrels vs. scf). We recommend discussing injection volume units consistently for clarity.	Completed throughout document.
6.	NA	NA	Some of the maps in the MRV plan are unclear. Please ensure that all maps/figures have appropriate legends, scale bars, and an indication of cardinal direction. Please also ensure that the project site is consistently displayed as applicable. For example, Figure 41 does not have a scale bar, legend, or indication of cardinal direction.	Completed throughout document. For example - Figure 39, previously Figure 41, on page 57 has been updated with a scale bar, legend and indication of cardinal direction.
7.	NA	NA	Please ensure that all acronyms are defined once during their first use within the MRV plan. For example, "GL" and "SWR" are never defined within the MRV plan.	Completed. SWR – Statewide Rule – Added to text. – page 60 GL – ground level elevation – added to acronym list – Page 3
8.	Introduction	1	Kinder Morgan previously submitted annual reports for Katz Field Injection under subpart UU, Injection of CO_2 under e-GGRT facility ID 544697. Please clarify the relationship between the previous Katz Field facility and the Kinder Morgan CCUS Complex. Are these the same facility, or are there differences? Typically, a facility that has previously reported under UU and then opts into to RR would do so under the same facility ID.	Completed. These are separate facilities. They are only related in proximity and tie in location to the CO2 pipeline. The CCUS facility is solely focused on sequestration activities and has nothing to do with the Katz Field EOR complex adjacent to it.

<table>
<tr><th rowspan="2">No.</th><th colspan="2">MRV Plan</th><th rowspan="2">EPA Questions</th><th rowspan="2">Responses</th></tr>
<tr><th>Section</th><th>Page</th></tr>
<tr><td>9.</td><td>Introduction</td><td>2</td><td>“In the future, Kinder Morgan may provide surplus injection capacity to dispose oil and gas waste derived TAG from similar third-party gas processing facilities”

Please clarify whether the disposal of additional TAG is included in the Class II permit amendment application for the KSU 2361 well to inject up to 63 MMSCF/d for 21 years. Does the current MRV plan account for this potential additional volume, or would the MRV plan be revised/resubmitted in this scenario?</td><td>Completed.

Table 1 – page 2 – Expected Gas Composition
Table 2 – page 2 - Expected volume commitment and status.

Tables 1 and 2 have been added for more clarity on injected sequestered CO2 volumes for the KSU 2361.

Page 2 – verbiage added for clarity:

“The source of this injected CO2 gas is from Red Cedar natural gas processing plants in southern Colorado. Table 1 below shows the expected composition of the gas stream to be injected. Table 2 shows the expected average volume of CO2 gas commitments from similar type emission sources in the same area, along with the contract status as of March 2023.”</td></tr>
<tr><td>10.</td><td>2</td><td>11</td><td>Figure 3 is unclear. We recommend adjusting the Figure’s size and improving the resolution.

We recommend ensuring that all figures in the MRV plan are legible.</td><td>Figure 3 – page 11 – Updated with callout boxes for formations of discussion.</td></tr>
<tr><td>11.</td><td>2</td><td>11</td><td>“Upper Cambrian-age sandstone units of the Bliss, Wilberns, and Riley Formations, comprise the lower target injection interval, as seen in Figure 5.”

Figure 3 shows that there is a Hickory Formation of Upper Cambrian age. Is there any importance associated with the Hickory Formation? Please ensure that the stratigraphic column aligns with the text.</td><td>Completed.

Section 2.1 – Page 11 - Omitted language discussing the Bliss and Riley Formations for further clarity, as they are immaterial to this discussion.</td></tr>
<tr><td>12.</td><td>2</td><td>12</td><td>Figure 5 suggests that the Bliss and Wilberns Formations are one connected formation. Please clarify.</td><td>Completed. Deleted figure 5 as it did not help clarify the discussion within the section and is immaterial to this discussion.</td></tr>
</table>

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
13.	2	13	"In Figure 9, formation tops from gamma-ray data indicate the thickness of this group is approximately 223' at the KSU 2361 well location." Please clarify what formation this text is referring to.	Completed. Section 2.1 – Page 13 - verbiage added to clarify: "In **Figure 8**, formation tops from gamma-ray data **indicate the net pay thickness of the Ellenburger and Cambrian** is approximately 223' within this interval in the KSU 2361 well location."
14.	2	15	The contour interval description of Figure 8 does not match the map. The legend shows that the contour intervals are 1,000 feet, but the contour lines on the map have 500-foot differences. Please clarify.	Completed. Figure 7, previously Figure 8, – page 15 - Contour interval on map updated to 500'
15.	2	16	Please clarify the following with regard to Figure 9 in the MRV plan: 1. The Caddo formation is not introduced in the above stratigraphic columns or in the text above Figure 9. 2. There is inconsistency between displayed formation tops and bases. For example, LOWER_3RD_SAND is the only formation that has a displayed bottom. What formation is between the LOWER_3RD_SAND_BASE and the CADDO_TOP. 3. The caption states that yellow represents the lower injection interval, but there is yellow displayed above the lower injection interval. 4. What do the pink boxes represent?	Completed. Figure 8, previously Figure 9, – Page 16 1. Added Caddo to Figure 3 on Page 11 2. LOWER_3RD_SAND_BASE – Updated to "LOWER STRAWN SHALE" 3. Added additional explanation to Figure 8 caption "The yellow represents sandstone, which is present in the pay interval." 4. Added additional explanation to Figure 8 caption: "Pink boxes within depth column indicate active perforated intervals."
16.	2	17	Figure 10 was copied and pasted into the document; however, the figure was not pasted squarely into the document and the bottom left portion of the figure is cut off above the caption.	Completed. Deleted figure 10 and associated language from referencing paragraph because it did not add clear context to the discussion.
17.	2	24	Figure 16 does not clearly show the relationship of the LSS between the two wells. Please clarify.	Completed. Figure 14, previously Figure 16, – Page 24 - Added red correlation line to Figure 14 to clarify the relationship of the LSS between the two wells.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
18.	2	26	"Permeability assumptions remain the same as the Ellenburger ranging from 12-20 mD, due to these zones being commingled during injection and the inability to isolate zones within the injection zone when history-matching injection volumes and pressures." Please revise this sentence for clarity.	Completed – reworded sentence for further clarity. Section 2.2.4 – Page 26 "Due to nature of the Ellenburger and Cambrian zones being commingled during injection tests, modeling makes the assumption of 12-20mD average permeability for the interval, for history matched injection volumes and pressures."
19.	2	26	"The average effective porosity within the CAMBRIAN_2 sands is 8.4%. These effective porosity values are plotted as the JPHIE curve in Figure 13." This is the first instance of JPHIE being used in the text. In addition, the acronym does not appear in the list of acronyms. Please spell out the acronym here for first use and also add to the list of acronyms.	Completed. Section 2.2.4 – Page 26 "These effective porosity values are plotted as the **JPHIE (effective porosity)** curve in Figure 13."
20.	2	27	"Four wells were identified within approximately 20 miles…" Please clarify whether these are salt water disposal wells.	Completed. Section 2.2.4 – Page 27 – Sentence added for further clarity. **"None of these four wells are salt water disposal wells"**
21.	2	29	"Gamma-ray log values of the Precambrian section are consistently above 90 GAPI, indicating a high radioactive response." This is the first instance of GAPI being used in the text. In addition, the acronym does not appear in the list of acronyms. Please spell out the acronym here for first use and also add to the list of acronyms.	Completed. Section 2.2.5 – Page 29 – verbiage added for further clarity "Gamma-ray log values of the Precambrian section are consistently above **90 GAPI (Gamma Units of the American Petroleum Institute**), indicating a high radioactive response."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
22.	2	32	"Only two wells penetrated the Ellenburger formation within the **data limits** and are shown in the northwest to southeast seismic profile along with the cross-section in Figure 24." It is unclear what "data limits" refers to. Please clarify.	Completed. Section 2.4 – Page 32 – verbiage updated for further clarity "Only two wells penetrated the Ellenburger formation within the **3D seismic data volume** and are shown in the northwest to southeast seismic profile along with the cross-section in Figure 24."
23.	2	36	Figure 22: Due to the very small print in Figure 22, we suggest highlighting the Katz #3741 similar to the Katz 2361 so that it is easily identified in the figure.	Completed. Figure 22 – Page 36 – Figure updated with "KSU 3741" label and black star to further identify within the cross section.
24.	2	46	"Each grid block is 50 feet by 50' by 10'…" The above text uses inconsistent measurement unit indicators in the same sentence. We recommend ensuring that measurement units and symbols are consistent throughout the MRV plan.	Completed Section 2.6.1 – Page 46 "Each grid block is 50' by 50' by 10'…"
25.	2	48	"Using the geomodel as an input, an infinite-acting model was built to simulate boundary conditions. The model assumes that the reservoir is 100% filled with brine. The formation fluid was estimated to have a salinity of 66,000 ppm." This value is lower than the actual salinity values presented in Table 3.	Completed No changes - Salinity values in Table 3 (Page 29) are presented as "chlorides in ppm", which are in-line with the model assumption for formation fluid salinity (Chlorides) of 66,000ppm.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
26.	2	52	"…injection period is expected to be 1.16 MMT/yr (~62 MMscf/day)" A figure of 63 MMscf/day is given previously in the MRV plan. Please ensure that all injection volumes are consistent throughout the MRV plan"	Completed. Omitted the language regarding the average injection rate over the life of injection, to help clarify the discussion and now only refers to the maximum injection rate of 65MMCF/day to stay consistent. Language omitted from page 52: "The average rate throughout the injection period is expected to be 1.16 MMT/yr (~62 MMscf/day)." 62MMcf/day is average injection rate throughout the active lifespan of KSU 2361. 65mmcf/day is max rate. Both from modeling results. 63MMCF/day injection rate on page 2 was updated to 65 MMCF/day because 65/MMCF/day is the maximum injection rate.
27.	2	53	"The plume is considered stabilized once all lateral and vertical movement of CO2 has stopped, which also marks the end of the initial **monitoring period**." Is this meant to be the <u>initial</u> monitoring period? Please clarify.	Completed. Section 2.6.1 – Page 53 Yes – it is mean to be the initial monitoring period.
28.	2	53	Figure 35 shows the injection rate increasing while the bottom-hole pressure is decreasing from 2023 to 2043. Please clarify.	Completed. Section 2.6.1 – Page 52 – verbiage added for further clarity **"The decreasing bottom-hole pressure from 2023 to 2044 is due to the relative permeability increasing over time".**

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
29.	2	56	"Kinder Morgan analyzed acid gas injectate was used as the initial composition in the model. The composition is provided in Appendix B." Please clarify whether there is any H_2S in the injectate stream and whether that affects any of the monitoring strategies.	Completed. Section 3.1 – Page 56 – added verbiage and reworded sentence for additional clarity "Kinder Morgan's **pipeline gas specifications** were used for the initial composition of the injectate in the model, as provided in Appendix B. The molar composition of the gas is mostly carbon dioxide, with some small amounts of nitrogen and hydrocarbons, **and contained no H_2S."** **The lack of H2S will not affect any of the defined monitoring strategies.**

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
30.	3	56-57	Per 40 CFR 98.449, "Active monitoring area" is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile. (2) The area projected to contain the free phase CO2 plume at the end of year t + 5. **From the discussion in this section, it is not clear how the delineation of the AMA and the MMA comply with the definitions for the AMA and MMA** in 40 CFR 98.449 or the requirements to delineate the AMA and MMA in 40 CFR 98.448(a)(1). Per 40 CFR 98.449, "Maximum monitoring area" means the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO2 plume until the CO2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Please ensure that the discussion in this section clearly identifies the AMA and MMA boundaries. Furthermore, please explain in the MRV plan whether the AMA and MMA conform to the definitions above. We recommend clarifying the description of the AMA and the MMA and more clearly describing how the AMA and MMA meet the requirements in 40 CFR 98.448(a)(1). **For example, it is unclear on page 56 whether the one-half mile buffer was added to the modeled plume boundary to get the MMA**.	Completed. Section 3.1 – Page 56 – added verbiage for additional clarity "The maximum distance between the wellbore and the edge of the plume is approximately 6,400', after injection stops, **resulting in the AMA."** **"…**with a maximum distance to the edge of the plume of approximately 6,850', **resulting in the MMA."** Added Table 9 – Page 54 - Plume radius growth over time. AMA = 6400' after 21 years of injection. Injection stops after 21 years. MMA – 6850' after plume stabilizes post injection – 30 years after The one-half mile buffer is in addition to the MMA of 6850', resulting in the 9500' boundary, as seen in the updated Figure 39 on page 57.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
31.	3	56	"Since the AMA falls within the MMA, for defining the area of influence, only the MMA was used for this project. Figure 41 shows the stabilized plume boundary, the AMA, and the MMA." 40 CFR 98.448(a)(1) require, "Delineation of the maximum monitoring area and the active monitoring areas". The above statement implies that the AMA was not considered for the project, though there is a section dedicated to the AMA. If you mean that the AMA and the MMA have the same boundaries, please clarify this.	Completed. Section 3.1 – Page 56 – added verbiage for additional clarity **"The AMA and the MMA have close to the same areas of influence, with the AMA being marginally smaller than the MMA."** **"Therefore, Kinder Morgan will use the MMA as the basis for the areal extent of the monitoring program throughout the life of the project."**
32.	3	57	"Figure 41 – Stabilized Plume Boundary, Active Monitoring Area, and Maximum Monitoring Area." Figure 41 suggests that the plume boundary is perfectly round. However, Figure 39 displays that the plume boundary is not perfectly round. We recommend displaying the actual projected plume boundary in addition to the MMA and AMA in Figure 41. The figure is also unclear on what is the AMA, MMA, and plume boundary. Please include a clear legend and scale bar for all maps in the MRV plan. Furthermore, based on other figures in the MRV plan, the KSU 2361 is located on the northwest edge of the facility boundary. Does Kinder Morgan have access to monitor the plume through the life of the project?	Completed. Updated Figure 39, previously Figure 41 – page 57 - to show three different boundaries. Updated Figure 37 (page 55), previously Figure 39 – To show higher resolution of model results, depicting the circular boundary shape. Added Table 9 – plume radius over time – page 54 Kinder Morgan plans to obtain all necessary access rights within the (AMA/MMA) in order to meet the MRV plan requirements for baseline, active injection and post-injection monitoring periods. .
33.	4	58	"**Future Drilling**" is a section heading on page 64 that has a corresponding discussion. However, the section heading is not included in the Section 4 introduction. Please address.	Completed. Formatting fixed – page 64.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
34.	4	58	"The surface facilities at the KSU 2361 well are designed for injecting acid gas primarily consisting of CO2." Since the class II permit has not yet been approved, please clarify whether the current facilities have been designed for injecting acid gas or if modifications will need to be made.	Completed. Section 4.1 – Page 58 – Verbiage added "**One additional pipeline will be constructed to carry the acid gas from the custody transfer meter to the KSU 2361 wellhead, as shown in Figure 42. The wellbore of the KSU 2361 is designed for acid gas, as seen in the wellbore schematic in Figure 41**"
35.	4	58	"Should Kinder Morgan construct additional CO_2 facilities other meters will be installed as needed to comply with the 40 CFR §98.448(a)(5) measurement. These meters will be near the existing facilities and utilize the existing monitoring programs discussed previously." Please be more specific about future plans and also be aware that additional wells or other changes to operations could result in a material change requiring submission of a revised MRV plan (see 40 CFR 98.448(d)). Furthermore, please be aware each individual facility would need to have its own approved MRV plan in order to report data under subpart RR.	Completed. Section 4.1 – Page 58 – Verbiage added "**No additional wells are included within this MRV facility**" Kinder Morgan is aware of these specified points.
36.	4	58	The terms "CO_2 gas detectors" and "CO_2 monitors" appear to be used interchangeably. We encourage you to be consistent in terminology to ensure clarity within the MRV plan. If you intend different meanings for the two terms, please clarify.	Completed. Omitted the term "CO_2 gas detectors" from six total instances (two in Section 4, two in section 6 and two references in section 9) and replaced with "CO_2 monitors" in order to remain consistent in the terminology used throughout the MRV Plan

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
37.	4	59	"The CO_2 stream injected into KSU 2361 includes small amounts of methane (0.2%) and nitrogen (2.0%)." Since the Katz 2361 is not yet permitted to inject TAG, should this be "will include"? Please clarify the source of the injectate, the gas composition, and whether you expect the composition to change over time.	Completed. Section 4.1 – Page 59 – verbiage added "The CO2 stream injected into KSU 2361 **could include** up to small amounts of methane and nitrogen, as seen in Appendix B." **"The CO2 injected into the Katz 2361 well is supplied by a number of different sources into the pipeline system and the composition is not expected to change overtime."** Please Reference Table 1 on page 2.
38.	4	59-66	Several of the sections covering potential pathways for leakage do not address the likelihood of leakage from that particular pathway. For example, the MRV plan does not identify the likelihood of leakage through existing wells within the MMA. Please ensure that each section characterizes the likelihood, magnitude, and timing of potential leakage.	Completed Section 4.2.1 – Page 59 – verbiage added **"KSU 2361 is the only well penetrating the injection interval within the projected plume area of the MMA for the KSU 2361. Therefore, it is the only well that will be monitored for surface leakage. This well is designed to handle and inject acid gas, which reduces the risk and likelihood of leakage through the existing well to near-zero."**
39.	4	59	Figure 42's legend shows that "Facilities/Wells" are displayed by a white box. This is unclear since other maps show a larger number of wells within the Katz Unit. Furthermore, the white box is difficult to see. We recommend that the legend is adjusted to better display where wells and facilities are located within the Katz Unit.	Completed. Removed "Wells" and updated legend within Figure 40, previously Figure 42, page 59.

No.	MRV Plan Section	MRV Plan Page	EPA Questions	Responses
40.	4	59	"Within the projected plume area of the KSU 2361 well, there are zero penetrations of the injection interval." Does KSU 3741 penetrate the injection zone. Please clarify if it is outside the modeled plume.	Completed. KSU 3741 is 5500' outside of the MMA as modeled by the plume model.
41.	4	65	"A review of historical seismic events on the USGS's Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology's TexNet catalog (from 2017 to present), as shown in Figure 46, indicates the nearest seismic event occurred more than 40 miles away." Please clarify if this statement applies to natural seismic events, induced seismic events or both. Also, please indicate whether a minimum magnitude for the seismic event was applied for this analysis.	Completed. Section 4.5 – Page 65 "…as shown in Figure 44, indicates the nearest seismic event (**unspecified whether natural or induced)** occurred more than 40 miles away." Figure 44 – Page 66 – The legend displays the magnitude of the seismic events and shows that there was no minimum magnitude applied to this analysis.
42.	6	73	"These inspections will aid with identifying and addressing issues timely to minimize the possibility of leakage." Please clarify the above sentence.	Completed. Section 6.1 – Page 73 – Verbiage added for further clarity "These inspections will aid with identifying and addressing possible issues **in order to minimize the possibility of leakage**."
43.	6	74	Per 40 CFR 98.448(a)(7), please include a date on which the collection of data for calculating total amount sequestered according to equation RR-12 will begin.	Completed. Section 7.5 – Page 76 – verbiage added for further clarity "The mass of CO2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12, **assuming an expected injection start date of June 1, 2024…"**

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
44.	7	75	Mass of CO_2 Injected $C_{CO2,p,u}$ = Quarterly CO2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO2, expressed as a decimal fraction) This equation is based on volumetric flow. The reference to "wt. percent" should be changed to "volume percent" to accurately reflect the calculation methodology as set forth in 98.443.	Completed.
45.	7	76	Mass of CO_2 Emitted by Surface Leakage As described, measurement and quantification of surface leakage appears specific to equipment leaks. Equation RR-10 applies to surface leakage pathways (CO2E), which are different from equipment leaks (CO2FI). Please clarify the approach for calculating surface leakage.	Completed. Section 7.4 – Page 76 – verbiage added for further clarity "Calculation methods using equations from subpart W will be used to calculate CO2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead."
46.	7	76	Mass of CO_2 Emitted by Surface Leakage "Any leakage would be detected and managed as an upset event." Does use of the term "upset event" include blowdowns and other events that are intentional release events?	Correct. Section 7.5 – Page 77 – verbiage added for further clarity "**Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions sent to flares and reported as part of the required GHG reporting for the gas plant.**" Yes – the term "upset event" does include blowdowns and other events that are intentional release events.

No.	MRV Plan Section	MRV Plan Page	EPA Questions	Responses
47.	7	77	Mass of CO_2 Sequestered "Because no venting is expected to occur, the calculations would be based on the blowdown emissions sent to flares and reported as part of the required GHG reporting for the gas plant." Please elaborate – is it typical for CO_2 blowdowns to be sent to flare?	Completed. Section 7.5 – Page 77 "Because no venting is expected to occur, the calculations would be based on the **unusual event that a blowdown is required and those** emissions sent to flares and reported as part of the required GHG reporting for the gas plant." No – it is not typical.
48.	9	79	Monitoring QA/QC "The CO2 measurement equipment will be calibrated according to Kinder Morgan Standards." "Gas detectors will be calibrated according to Kinder Morgan and industry standards." You must also calibrate measurement equipment per the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP in addition to your own calibration and industry standards.	Completed. Section 9.1 – Page 79 Updated all language to clarify the calibration requirements of measurement equipment. "The CO2 measurement equipment will be calibrated per the **requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP."** "Gas monitors will be calibrated according to **the requirements of 40 CFR 98.444(e) and 98.3(i) of the GHGRP."**
49.	NA	NA		All Figure and Table numbers and associated referenced page numbers have been renumbered and updated in this current version 2.0 of the MRV Plan. This is the result of deleting Figure 5 and Figure 10, as previously numbered from original document. As well as the addition of Table 1, Table 2 and Table 9 in the current document. All responses are current and reference the current figure and table number scheme.

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Kinder Morgan Permian CCS LLC

Prepared for *Kinder Morgan Permian CCS LLC*
Houston, TX

By

Lonquist Sequestration, LLC
Austin, TX

January 2023

INTRODUCTION

Kinder Morgan Production Co. LLC (Kinder Morgan) currently has a Class II disposal permit issued by the Texas Railroad Commission (TRRC) for the Katz Strawn Unit 2361 well (KSU 2361), API# 42-433-33712. The permit was originally issued in November 2011 for saltwater disposal operations, and the well has actively injected saltwater since 2013. This permit currently authorizes Kinder Morgan to inject up to 30,000 barrels per day (bbls/d) into the Ellenburger and Cambrian formations at a depth of 5,800' to 6,800' with a maximum allowable surface pressure of 2,900 psi. The KSU 2361 well is located in a rural, sparsely populated area of Stonewall County, Texas, approximately twelve miles west of the town of Knox City, as shown in Figure 1.

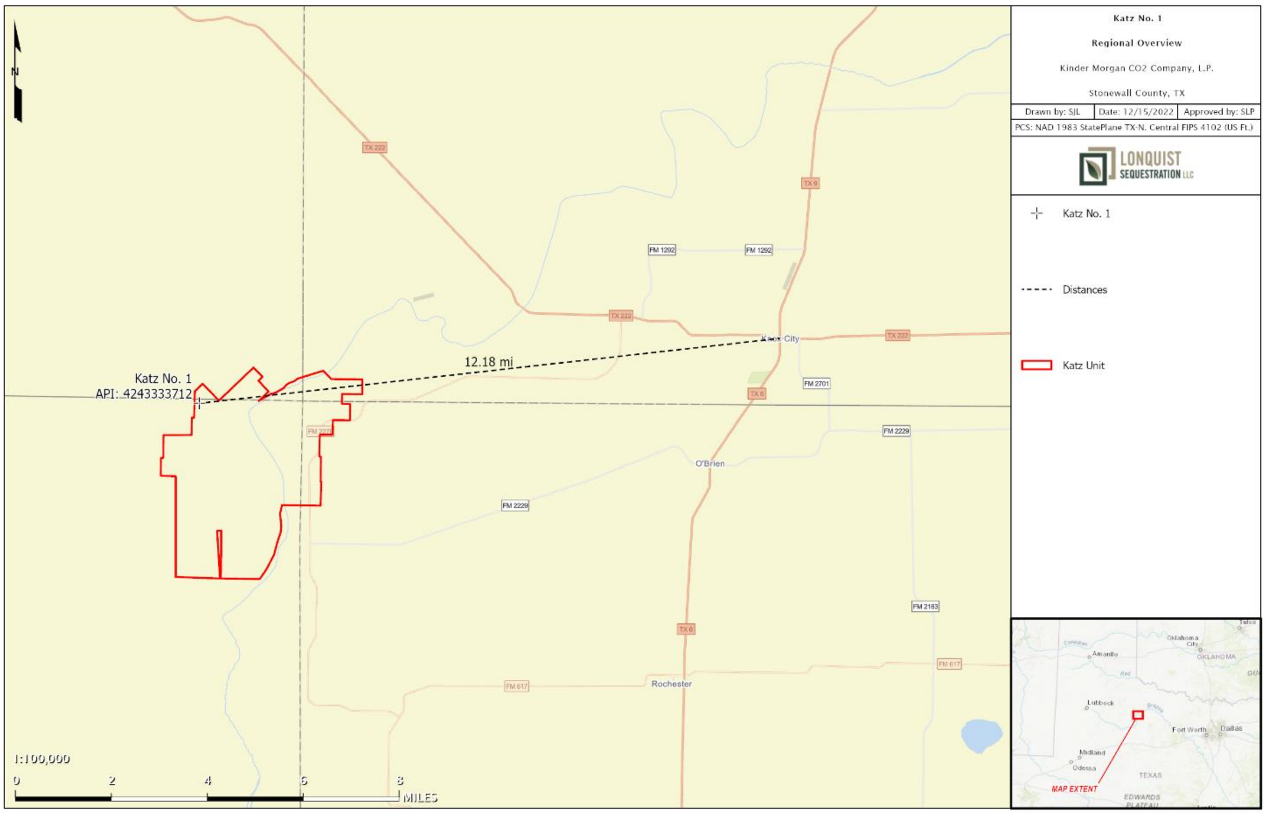


Figure 1 – Location of KSU 2361 Well

Kinder Morgan is seeking TRRC approval to amend the existing KSU 2361 Class II saltwater disposal permit to inject treated acid gas (TAG), including CO_2. In the future, Kinder Morgan may provide surplus injection capacity to dispose oil and gas waste derived TAG from similar third-party gas processing facilities. Kinder Morgan intends to inject into this well for 21 years at a capacity ranging up to 63 million standard cubic feet per day (MMSCF/d).

Kinder Morgan is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval under 40 CFR **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

ACRONYMS AND ABBREVIATIONS

‘	Feet
%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group’s GEM 2020.11
GHGs	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
H_2S	Hydrogen Sulfide
mD	MilliDarcy(ies)
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMCF	Million Cubic Feet

MMSCF	Million Standard Cubic Feet
MSCF/D	Thousand Cubic Feet per Day
MMSCF/d	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

TABLE OF CONTENTS

INTRODUCTION 1
ACRONYMS AND ABBREVIATIONS....3
SECTION 1 – UIC INFORMATION....8
Underground Injection Control (UIC) Permit Class: Class II....8
UIC Well Identification Number: 8
SECTION 2 – PROJECT DESCRIPTION 9
Regional Geology....10
Regional Faulting 18
Site Characterization 19
Stratigraphy and Lithologic Characteristics....19
Upper Confining Zone – Mississippian Lime....21
Secondary Confining Interval – Lower Strawn Shale....22
Injection Interval – Ellenburger/Cambrian Sands....25
Lower Confining Zone – Precambrian 30
Fracture Pressure Gradient 32
Local Structure....33
Injection and Confinement Summary....38
Groundwater Hydrology....38
Reservoir Characterization Modeling....44
SECTION 3 – DELINEATION OF MONITORING AREA....56
Maximum Monitoring Area....56
Active Monitoring Area 57
SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE....58
Leakage from Surface Equipment 58
Leakage from Existing Wells within MMA....59
Oil and Gas Operations within Monitoring Area 59
Groundwater wells 64
Leakage Through Faults and Fractures....65
Leakage Through the Confining Layer 65
Leakage from Natural or Induced Seismicity....65
SECTION 5 – MONITORING FOR LEAKAGE....67
Leakage from Surface Equipment 68
Leakage From Existing and Future Wells within MMA....68
Leakage through Faults, Fractures or Confining Seals....71
Leakage through Natural or Induced Seismicity....71
SECTION 6 – BASELINE DETERMINATIONS 73
Visual Inspections....73
CO_2 Detection 73
Operational Data 73
Continuous Monitoring 73
Groundwater Monitoring....74
SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION 75
Mass of CO_2 Received....75
Mass of CO_2 Injected 75
Mass of CO_2 Produced....75
Mass of CO_2 Emitted by Surface Leakage....76

Mass of CO_2 Sequestered 76
SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN 78
SECTION 9 – QUALITY ASSURANCE 79
Monitoring QA/QC 79
Missing Data 79
MRV Plan Revisions 79
SECTION 10 – RECORDS RETENTION 81
References 82
APPENDICES 84

LIST OF FIGURES

Figure 1 – Location of KSU 2361 Well 1
Figure 2 – Regional Map of the Permian Basin. 10
Figure 3 – Stratigraphic Column of the Eastern Shelf 11
Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations 12
Figure 5 – Stratigraphic Column Depicting the Composition of Cambrian-age Formations 12
Figure 6 – Top of Structure Map of the Ellenburger Group in West Texas 13
Figure 7 – Generalized Isopach Map of the Ellenburger Group in West Texas 14
Figure 8 – Thickness of Cambrian and Lower Ordovician Strata 15
Figure 9 – Formation Tops at KSU 2361. 16
Figure 10 – Stratigraphy, Lithology, and Generalized Thickness of Cambrian-age formations in Central Texas 17
Figure 11 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma. 18
Figure 12 – KSU 2361 Type Log 19
Figure 13 – Type Log of Zones of Interest 20
Figure 14 – Depositional Map of the Mississippian 21
Figure 15 – Core Description 23
Figure 16 – Cross Section Depicting Corelative Offset Core with Lower Strawn Shale 24
Figure 17 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003) 25
Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003) 27
Figure 19 – Offset Wells used for Formation Fluid Characterization. 29
Figure 20 – Pre-Cambrian Distribution Map 31
Figure 21 – Ellenburger Structure Map 34
Figure 22 – Structural Northwest-Southeast Cross Section 35
Figure 23 – Structural West to East Seismic Profile 36
Figure 24 – Structural Northwest to Southeast Seismic Profile 37
Figure 25 – Generalized Stratigraphy of the Seymour Aquifer 39
Figure 26 – Regional Extent of the Seymour Aquifer Pods 41
Figure 27 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer 42
Figure 28 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer 43
Figure 29 – Geomodel Dimensions 47
Figure 30 – Structural Horizons of the Geomodel 48
Figure 31 – Porosity Distribution in Plume Model 49
Figure 32 – NTG Ratio Applied to the Plume Model 50
Figure 33 – CO_2-Water Relative Permeability Curves 51
Figure 34 – History Match for KSU 2361 52
Figure 35 – History Match for KSU #3471 52

Figure 36 – Simulated Wellhead Pressure During Active Injection 53
Figure 37 – Forecasted Injection Rate and BHP 53
Figure 38 – Annualized Growth Rate of CO_2 Plume 54
Figure 39 – Aerial View of CO_2 Plume....55
Figure 40 – Cross-Sectional View of CO_2 Plume 55
Figure 41 – Stabilized Plume Boundary, Active Monitoring Area, and Maximum Monitoring Area....57
Figure 42 – Site Plan 59
Figure 43 – KSU 2361 Wellbore Schematic 61
Figure 44 – All Oil and Gas Wells within the MMA....62
Figure 45 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA 63
Figure 46 – Seismicity Review (TexNet – 06/01/2022)....66
Figure 47 – Groundwater Monitoring Wells....70
Figure 48 – Nearest TexNet Seismic Station....72

LIST OF TABLES

Table 1 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples 30
Table 2 – Fracture Gradient Assumptions 32
Table 3 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas 39
Table 4 – Rock Properties 48
Table 5 – Initial Conditions Summary....49
Table 6 – Summary of Leakage Monitoring Methods 67

SECTION 1 – UIC INFORMATION

This section contains key information regarding the UIC Permit.

Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. TRRC classifies the KSU 2361 well as UIC Class II. A Class II permit was issued to Kinder Morgan under TRRC Rule 9 (entitled "Disposal into Non-Productive Formations") and Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas").

UIC Well Identification Number:

Katz Strawn Unit 2361, API No. 42-433-33712, UIC #000104281.

SECTION 2 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the KSU 2361 well.

The injection interval for KSU 2361 is approximately 670' below the base of the Strawn formation, the primary producing formation in the area, and approximately 5,900' below the base of the lowest useable-quality aquifer. Therefore, the location, facility, and the well design of the KSU 2361 well are planned to protect against the migration of CO_2 out of the injection interval, protect against contamination of subsurface resources and, most critical, to prevent surface releases.

Regional Geology

The KSU 2361 well is located on the Eastern Shelf, a broad marine shelf located in the eastern portion of the Permian Basin, shown in Figure 2. Figure 3 depicts an Eastern Shelf stratigraphic column representative of the strata found at the KSU 2361 well location. The red stars reference the injection formations, and a green star indicates the historically productive interval in the area.

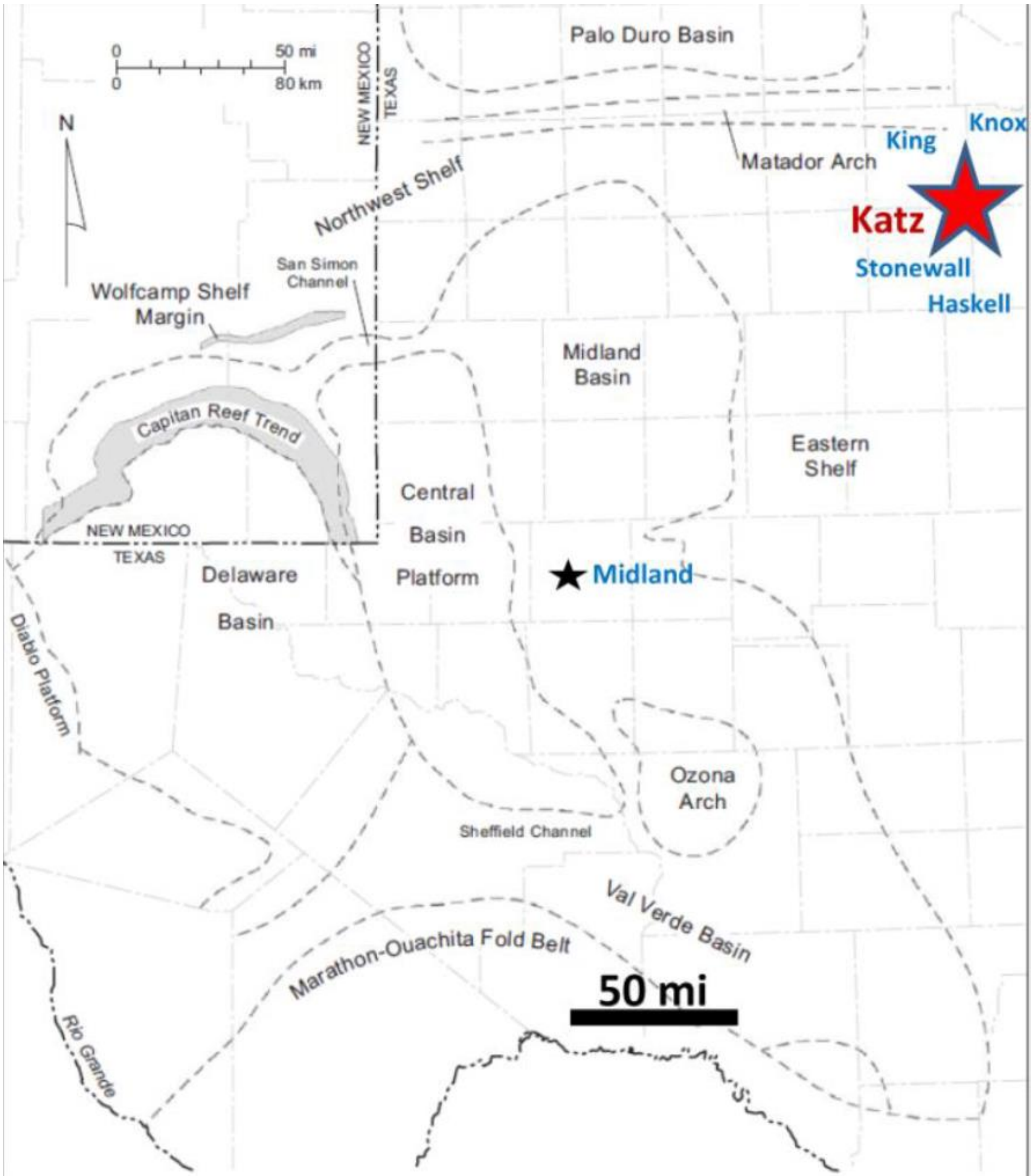


Figure 2 – Regional Map of the Permian Basin. The red star is the approximate location of KSU 2361 well.

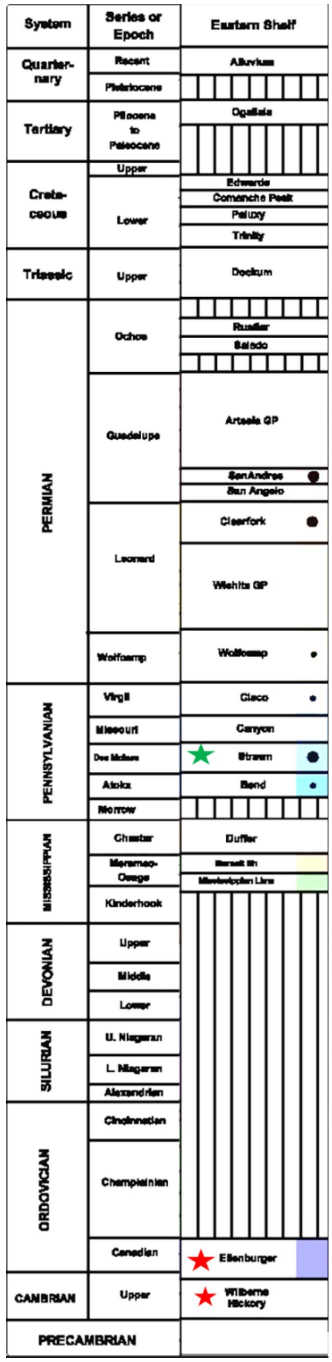


Figure 3 – Stratigraphic Column of the Eastern Shelf.

The upper target injection interval is the lower Ordovician-age Ellenburger Group, which is subdivided into the Honeycut, Gorman, and Tanyard Formations, as seen in Figure 4. Upper Cambrian-age sandstone units of the Bliss, Wilberns, and Riley Formations, comprise the lower target injection interval, as seen in Figure 5. Exact stratigraphy at the Katz 2361 well location may not feature all of the individual formations shown in the diagrams due to differential erosion across the depositional environment during the late Cambrian and early Ordovician Periods.

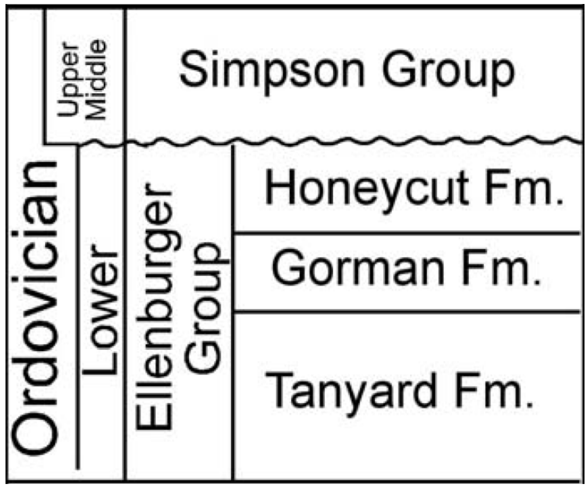


Figure 4 – Stratigraphic Column Depicting the Composition of the Ordovician-age Formations (Kupecz, 1992).

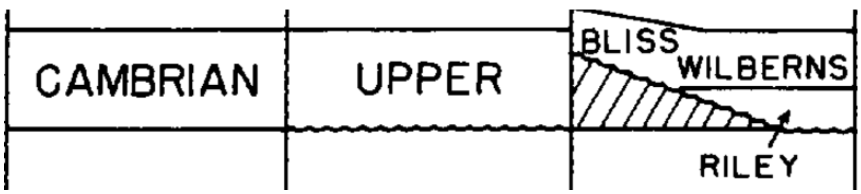


Figure 5 – Stratigraphic Column Depicting the Composition of Cambrian-age Formations (Galley, 1955).

The Ellenburger Group is present at varying depths in each of the provinces of the Permian Basin. In the Midland Basin area, the top of Ellenburger carbonate is as deep as 11,000' (GL) (Loucks, 2003). Due to regional structural dip of the Eastern Shelf, in northeast Stonewall County, the top of Ellenburger is found at only approximately 6,000' deep (GL). The depositional environment over the Stonewall, King, Knox, and Haskell County intersection during the Ordovician Period was a broad, shallow water carbonate platform with an interior of dolomite and an outer area of limestone. This was interpreted by Kerans (1990) as the dolomite being a restricted shelf interior and the limestone being an outer rim of more open-shelf deposits (Loucks, 2003).

Kerans (1990) performed the most complete regional analysis on Ellenburger depositional systems and facies. He recognized six general lithofacies as follows: litharenite: fan delta – marginal marine depositional system; mixed siliciclastic-carbonate packstone/grainstone: lower tidal-flat depositional system; ooid and peloid grainstone: high-energy restricted-shelf depositional system; mottled mudstone: low-energy restricted-shelf depositional system; laminated mudstone: upper tidal-flat depositional system; and gastropod-intraclast-peloid packstone/grainstone: open shallow-water-shelf depositional system.

According to Loucks, the diagenesis of the Ellenburger Group is complex, and the processes that produced the diagenesis spanned millions of years. The three major diagenetic processes of note are dolomitization, karsting, and tectonic fracturing. Dolomitization favors the preservation of fractures and pores due to its greater chemical and mechanical stability relative to limestone. Kupecz and Land (1991) delineated generations of dolomite into early-stage and late-stage. They attributed 90% of the dolomite as early-stage, wherein the source of magnesium was probably seawater. The other 10% of dolomite was attributed as late-stage, in which warm, reactive fluids were expelled from basinal shales during the Ouachita Orogeny. Karsting can affect only the surface of a carbonate terrain, forming terra rosa, or it can extensively dissolve the carbonate surface, forming karst towers (Loucks, 2003). It can also produce extensive subsurface dissolution in the form of caves and other structures, which increases porosity and permeability. Fracturing can be tectonic or karst-related. Tectonic fractures are commonly the youngest fractures in the rock and generally crosscut karst-related fractures (Kerans, 1989). Holtz and Kerans (1992) divided Ellenburger reservoirs into three groups based on these fracture types. The Eastern Shelf of the Permian Basin falls within the ramp carbonates group, in which predominant pore types are intercrystalline and interparticle. These reservoirs are characterized by the thinnest net pay, highest porosity, moderate permeability, highest initial water saturation, and highest residual oil saturation.

Figures 6 and 7 show the regional structure contours and isopachs of the Ellenburger Group, respectively. Figure 8 shows isopachs of Cambrian and lower Ordovician strata. Stars depict the KSU 2361 well location in each of these figures. In Figure 9, formation tops from gamma-ray data indicate the thickness of this group is approximately 223' at the KSU 2361 well location.

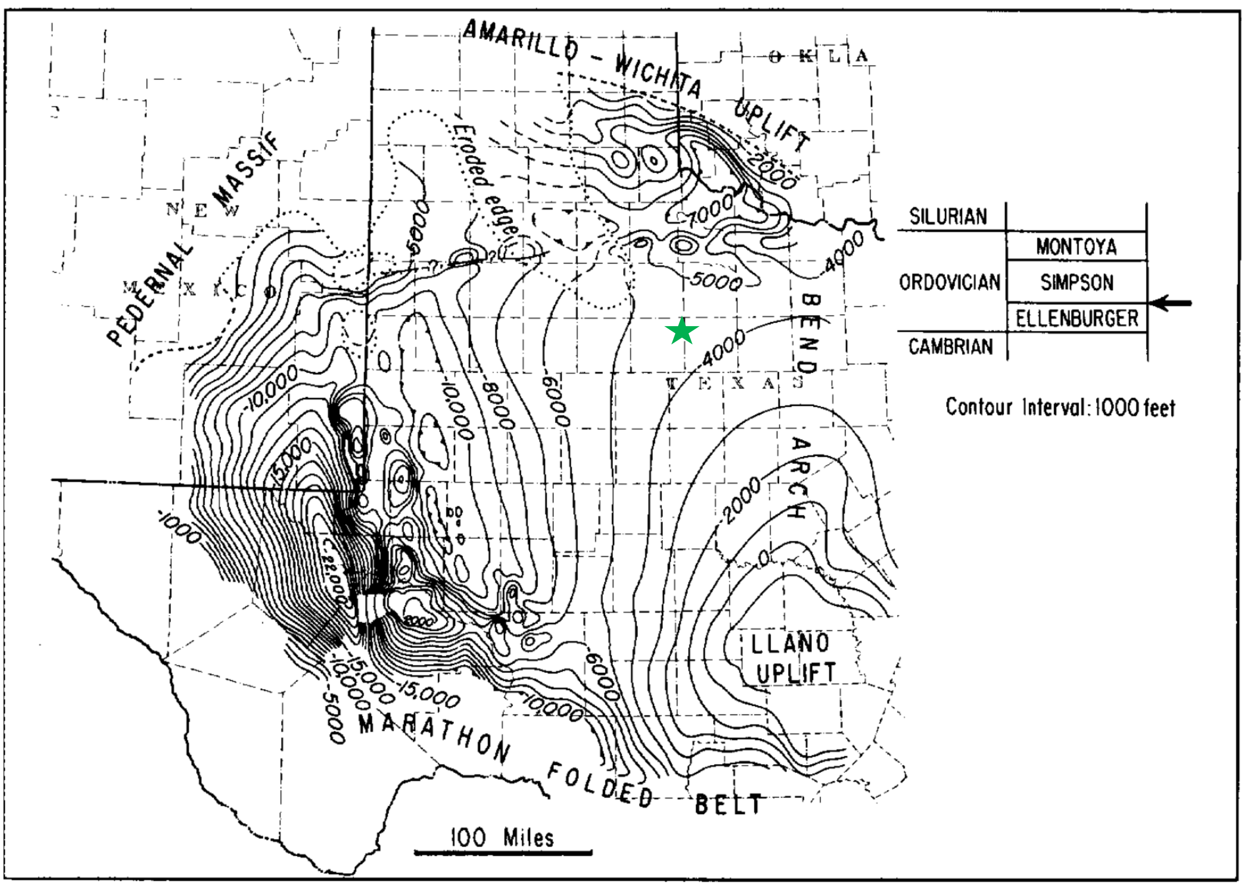


Figure 6 – Top of Structure Map of the Ellenburger Group in West Texas (Subsea Values) (Galley, 1955).

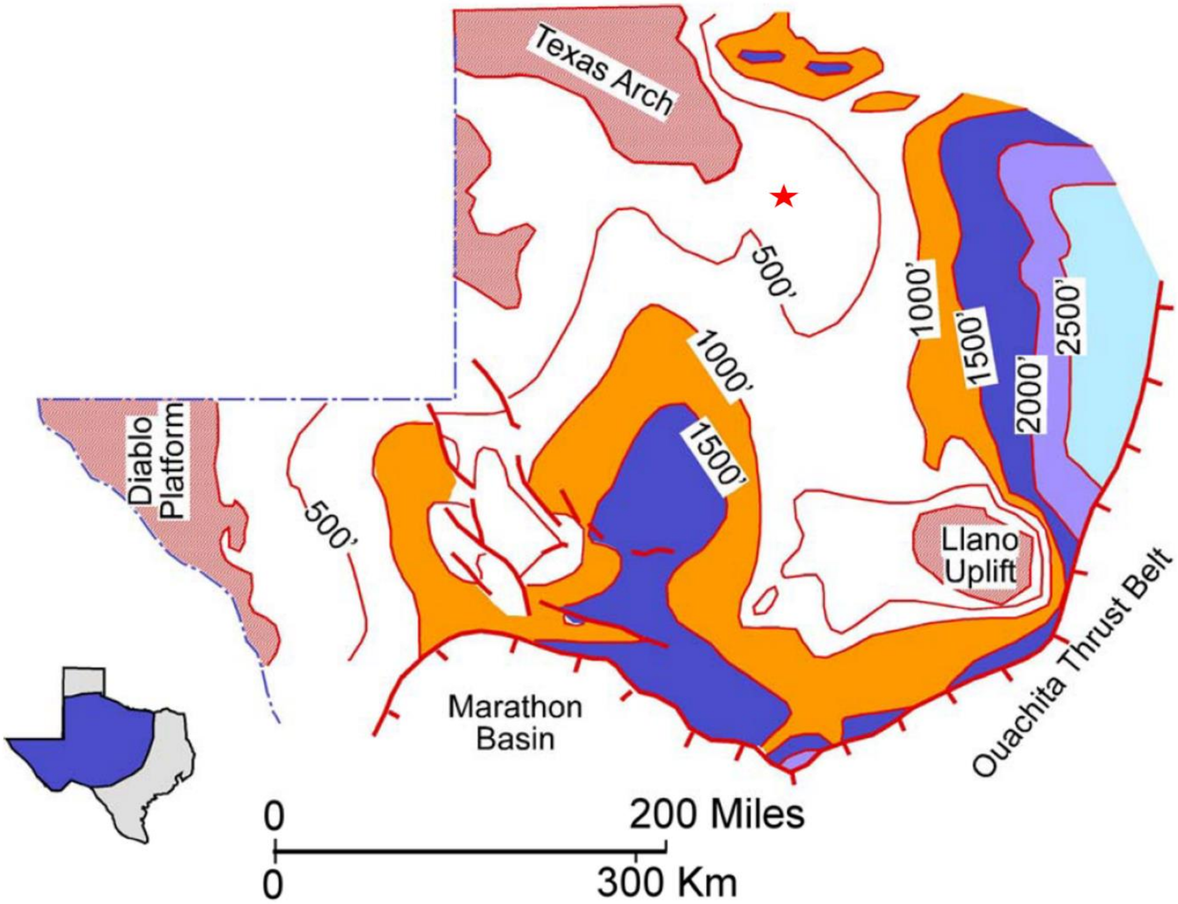


Figure 7 – Generalized Isopach Map of the Ellenburger Group in West Texas (Kerans, 1989).

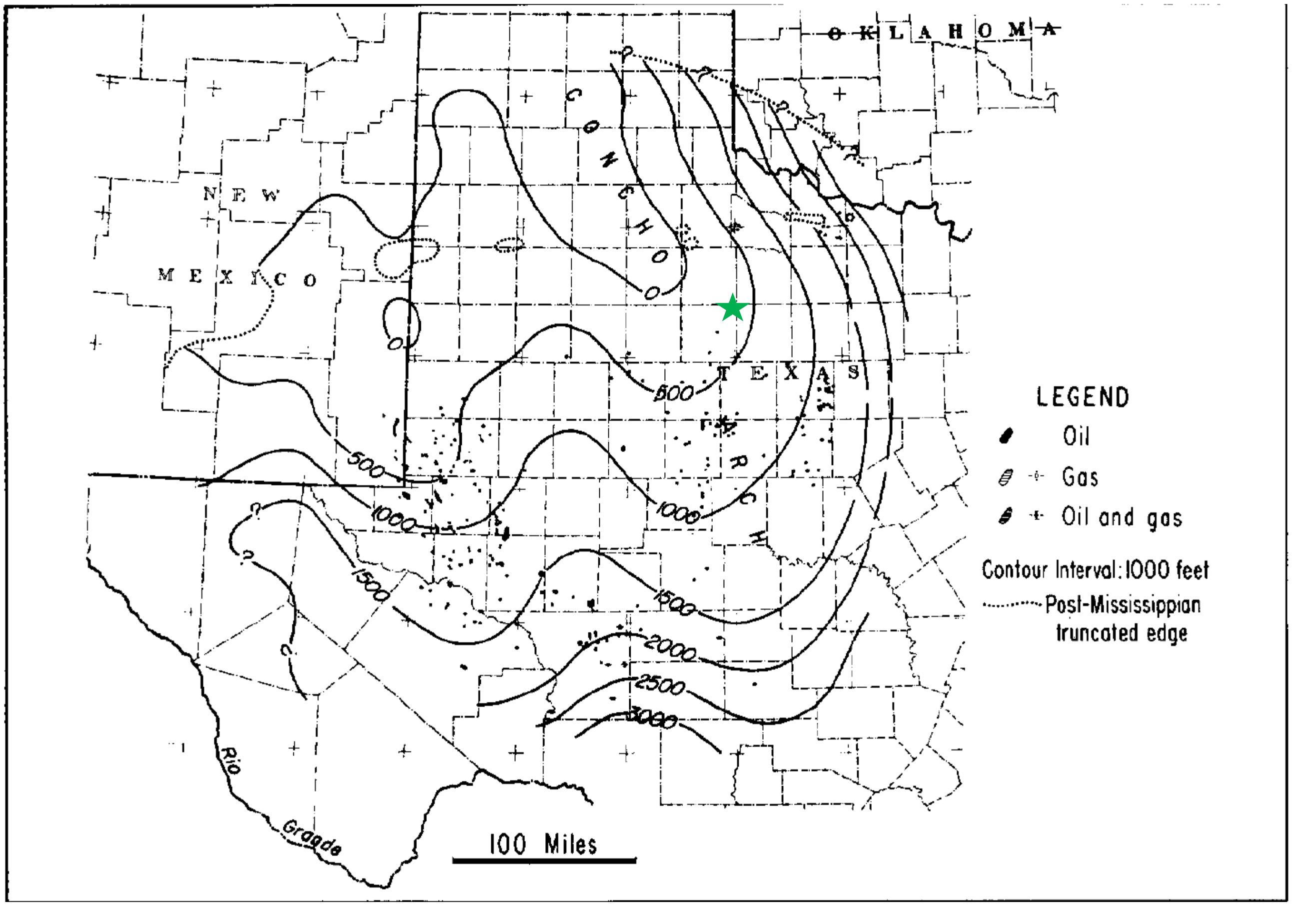


Figure 8 – Thickness of Cambrian and Lower Ordovician Strata
(Galley, 1955).

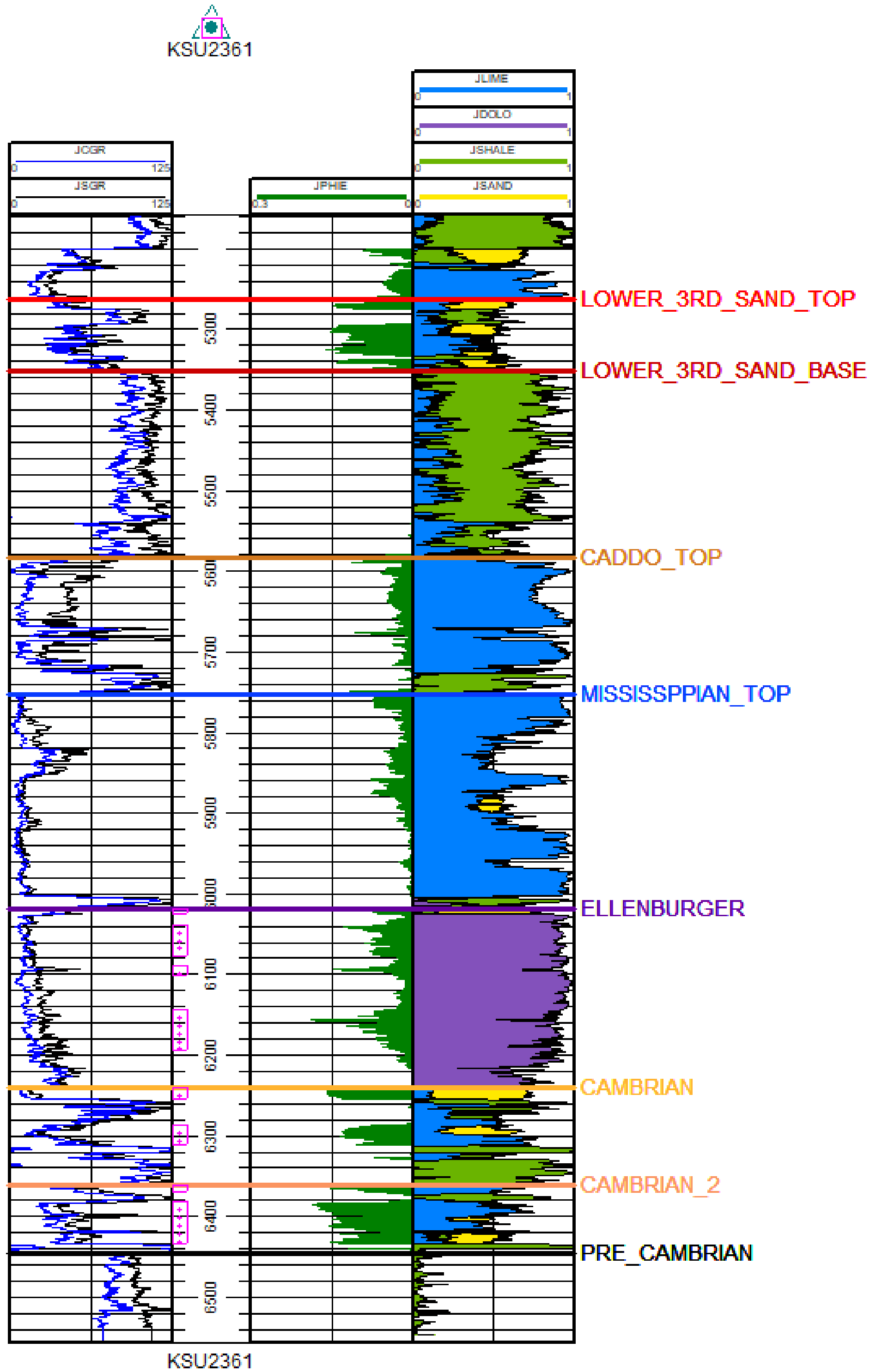


Figure 9 – Formation Tops at KSU 2361. Purple represents dolomite and the upper injection interval. Yellow represents sandstone and the lower injection interval (Kinder Morgan).

Cambrian-age strata consist of interbedded sandstone, limestone, and shale members, as seen in Figure 10. The initial deposits laid down on the eroded surface of Precambrian rocks were sandstone and arenaceous carbonates. Shale members are thickest in the southeast and nonexistent on the west side of the Permian Basin (Galley, 1955).

Cambrian		Wilberns formation	San Saba limestone member	0-280	Chiefly glauconitic limestone
			Point Peak shale member	0-160	Well-bedded soft greenish calcareous shale, including beds of dolomite and glauconitic limestone. Reef-like masses of limestone in the upper part
			Morgan Creek limestone member	0-140	Medium to coarse-grained glauconitic limestone
			Welge sandstone member	0-50	Brown nonglauconitic sandstone
		Riley formation	Lion Mountain sandstone member	0-50	Glauconitic sandstone; beds of glauconitic limestone in the upper part and lenses of fossiliferous limestone in the lower part
			Cap Mountain limestone member	0-280	Nearly pure granular limestone containing beds of impure dark-brown limestone and calcareous sandstone in the lower part
			Hickory sandstone member	0-500	Yellow, brown, and red sandstone. Numerous thin lenses of red or gray clay

Figure 10 – Stratigraphy, Lithology, and Generalized Thickness of Cambrian-age formations in Central Texas (Mason, 1961).

Overlying the Precambrian basement rock is the Riley Formation. This, in turn, is overlain by transgressive and progradational shallow-water marine sandstone, siltstone, limestone, and dolomite of the Wilberns Formation. The Riley Formation consists of sandstone packages whose thicknesses vary from place to place in response to the paleotopography of the underlying Precambrian surface (Kyle and McBride, 2014). The depositional environment in this area during the Cambrian was influenced by the sea, which advanced from the southeast (Galley, 1955). This led to the formation of a complex succession of transgressive and regressive sandstone units, both glauconitic and non-glauconitic (Kyle and McBride, 2014).

The Riley Formation is probably thickest south of the Llano region and laps out about 100 miles west and a slightly greater distance northwestward from the Llano region. It has accumulated in a northwestward-extending arm of the sea and likely extended beyond its present limits since there is a disconformity at its top. The Wilberns Formation thins appreciably northwestward from the Llano region to about 230' in Nolan County and to 70' in Lubbock County. West and north of the Llano region, usage suggested by Cloud and Barnes and adopted by petroleum geologists places the Tanyard-Wilberns boundary in the vicinity of the first appearance downward of glauconite (Barnes et al., 1959).

Figure 11 indicates that the Riley Formation's northwestern extent ends in Jones and Fisher counties, which implies that Cambrian strata at KSU 2361 may be limited to the Wilberns Formation only.

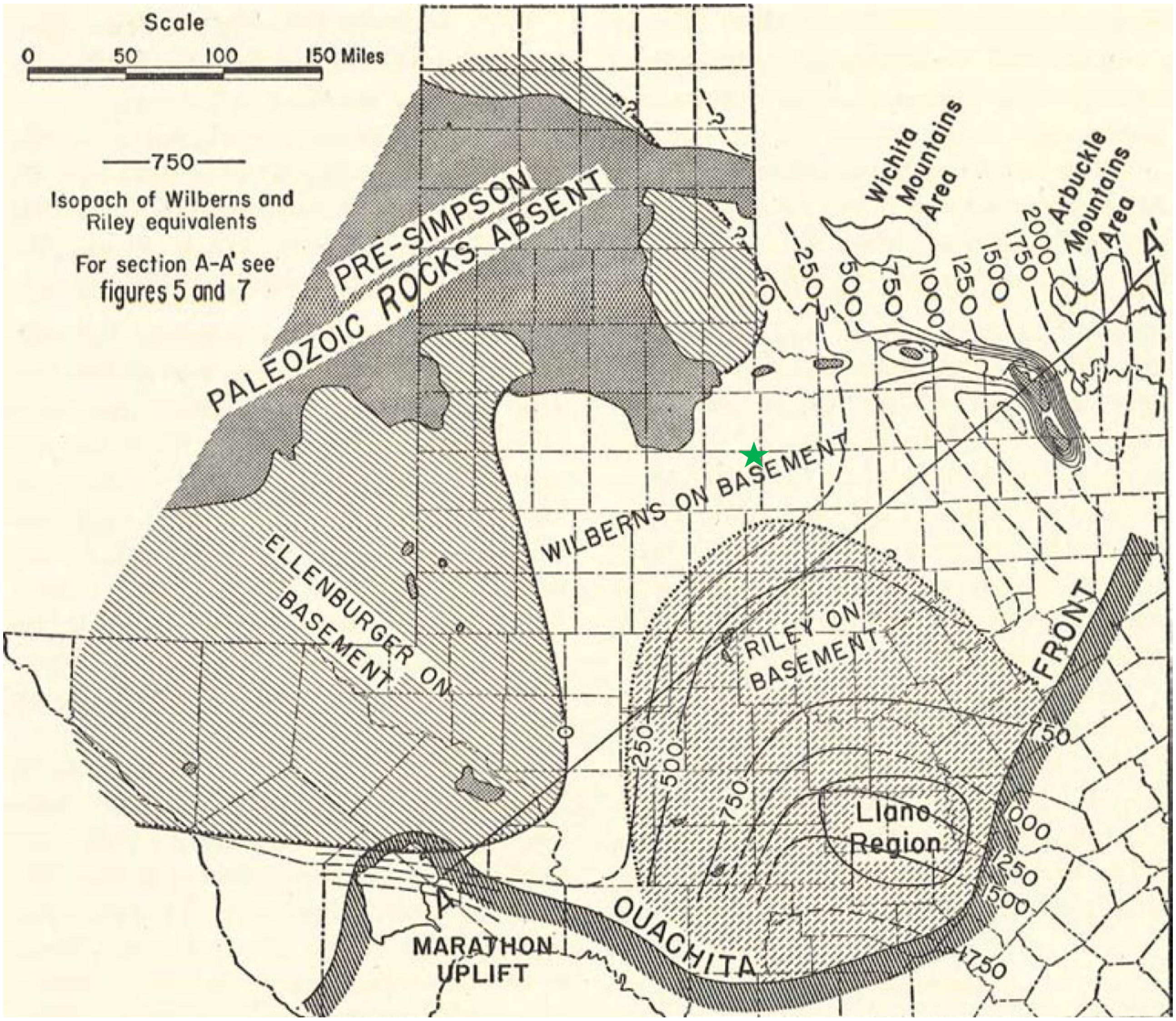


Figure 11 – Isopach Map of Riley and Wilberns equivalents in Texas and Southern Oklahoma. The green star approximates the location of KSU 2361 (Barnes et al., 1959).

Regional Faulting

Regional faulting in the KSU 2361 area trends primarily N-S in direction. This is the result of the dip rotation from a SW-NE trend seen in the Fort Worth basin to the east that rotates N-S as you move west towards the Bend-Arch and the edge of the basin (Hornhach, 2016). This trend then carries towards the Eastern Shelf closer to the KSU 2361 location. The most common faults are high-angle basement faults that primarily die within the Pennsylvanian in the KSU 2361 well area. Faulting is discussed in more detail in the Site characterization.

<u>Site Characterization</u>

The following section discusses site-specific geological characteristics of the KSU 2361 well.

Stratigraphy and Lithologic Characteristics

Figure 12 depicts an annotated open hole log from the surface to the total depth of the KSU 2361 well, with regional formation tops indicating the injection and primary upper confining units. Figure 13 provides a magnified view of the zones of interest, from above the Lower Strawn to the Precambrian, with general lithologic descriptions along the right edge of the figure.

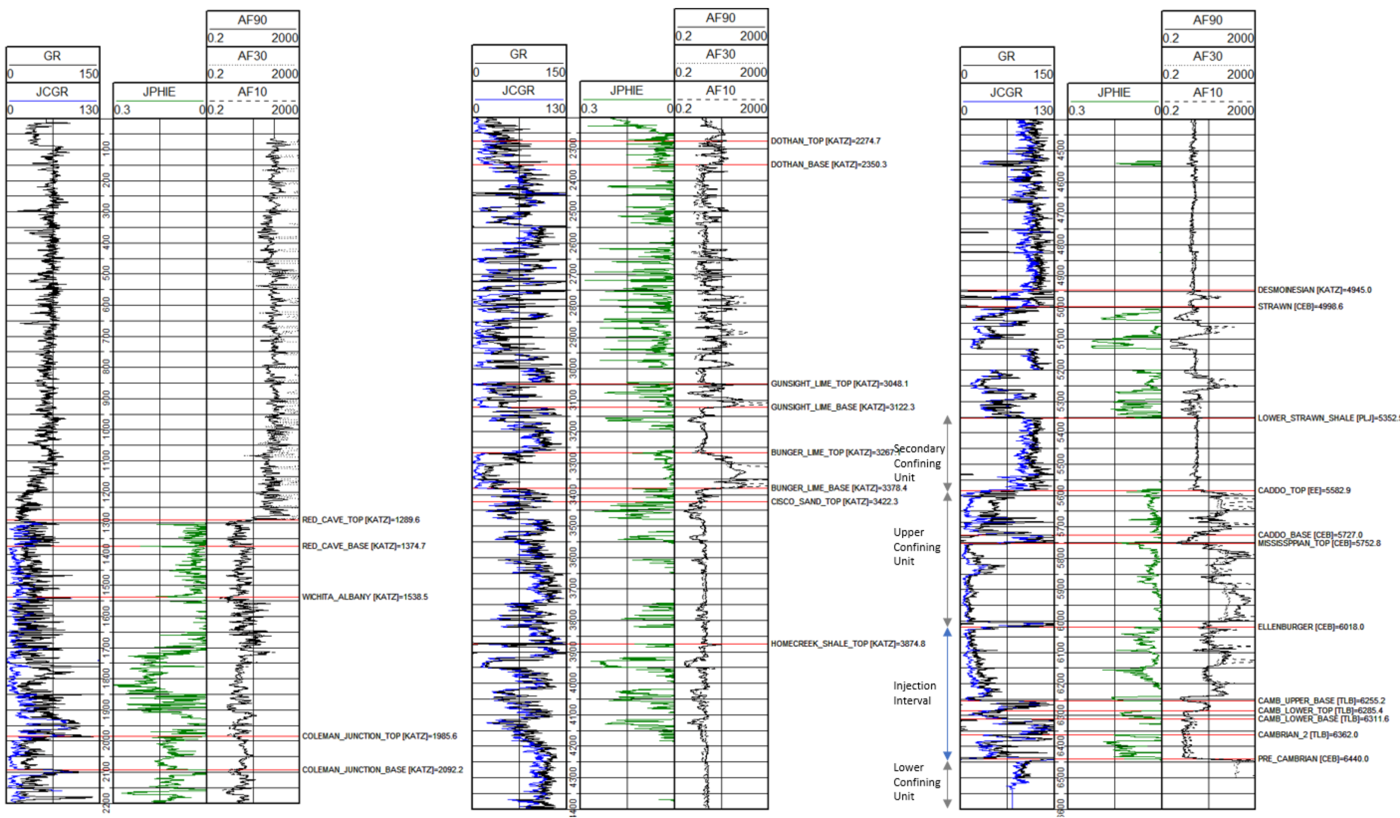


Figure 12 – KSU 2361 Type Log

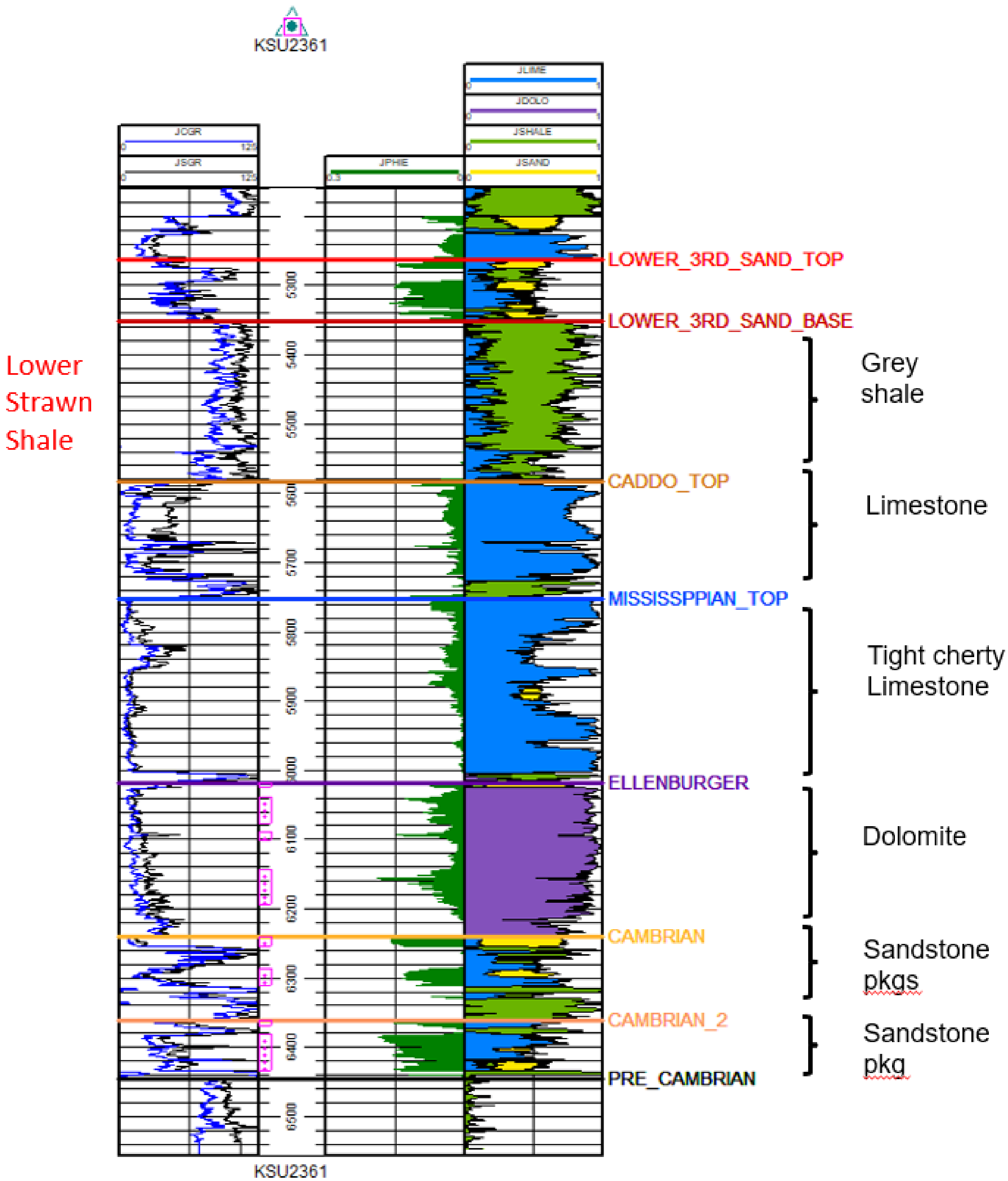


Figure 13 – Type Log of Zones of Interest

Upper Confining Zone – Mississippian Lime

The Mississippian Lime is the primary confining unit for the KSU 2361. This formation is the product of a large extensive shallow water carbonate platform that covered much of the southern and western Laurussia (Kane). Figure 14 shows the location of the KSU 2361 well to be found within the Chappel Shelf of the Mississippian Age. Representative cores of the Mississippian Lime formation found on the Chappel Shelf in the Llano uplift area consist of light-colored, fine- to coarse-grained, skeletal packstone (Kane). The open hole log seen in Figure 13 depicts the Mississippian Lime as predominantly cherty limestone. The basal carbonate section has little to no effective porosity development, which should translate to no permeability development. The Mississippian Platform Carbonate play is the smallest oil-producing play in the Permian Basin, which is tied to the abundance of crinoidal, grain-rich facies in platform successions. Most production from Mississippian reservoirs comes from more porous upper Mississippian ooid grainstones (Kane). This indicates that little to no reservoir characteristics are developed within the lower Mississippian Lime, creating an optimal seal.

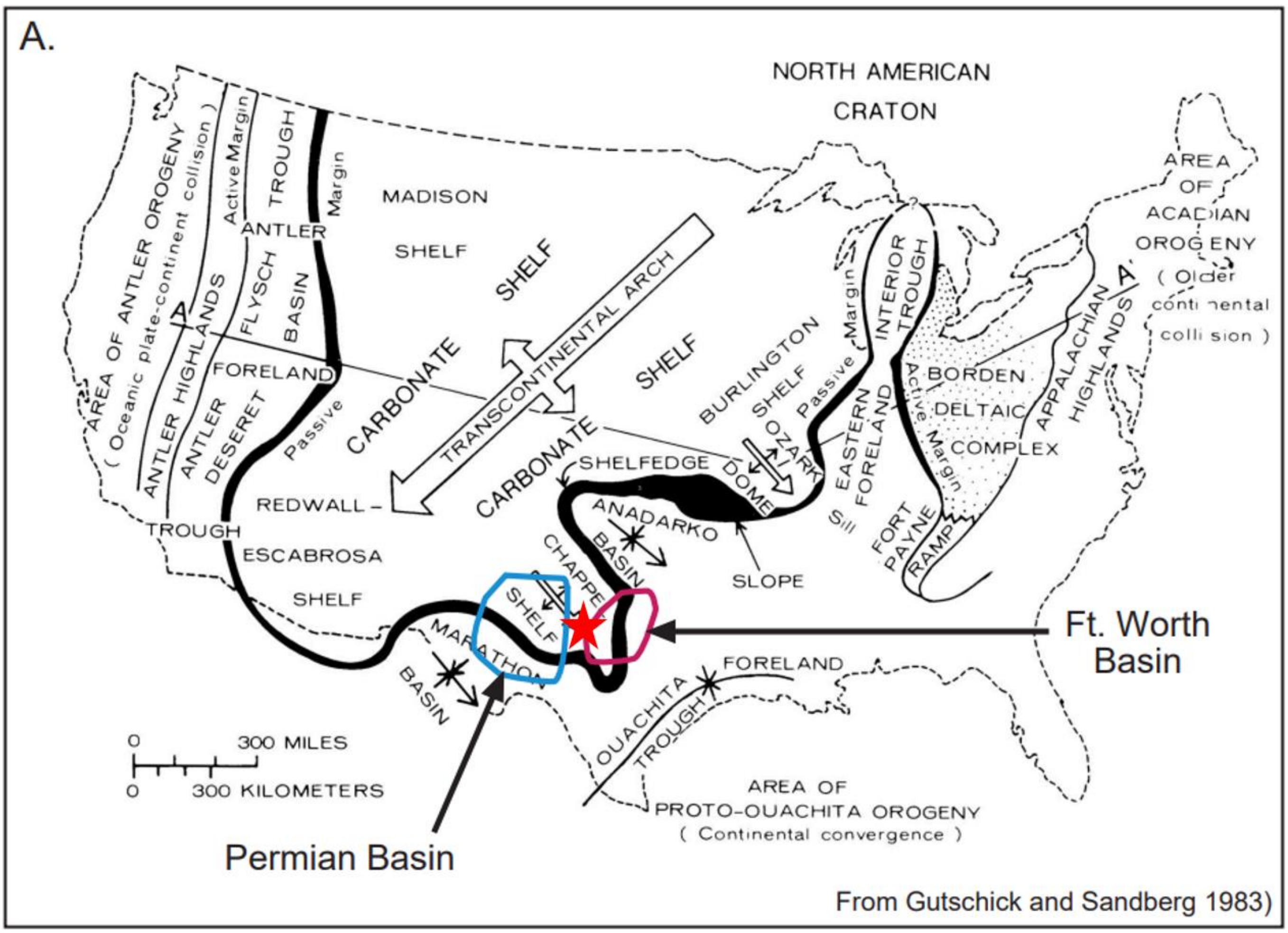


Figure 14 – Depositional Map of the Mississippian (Kane)

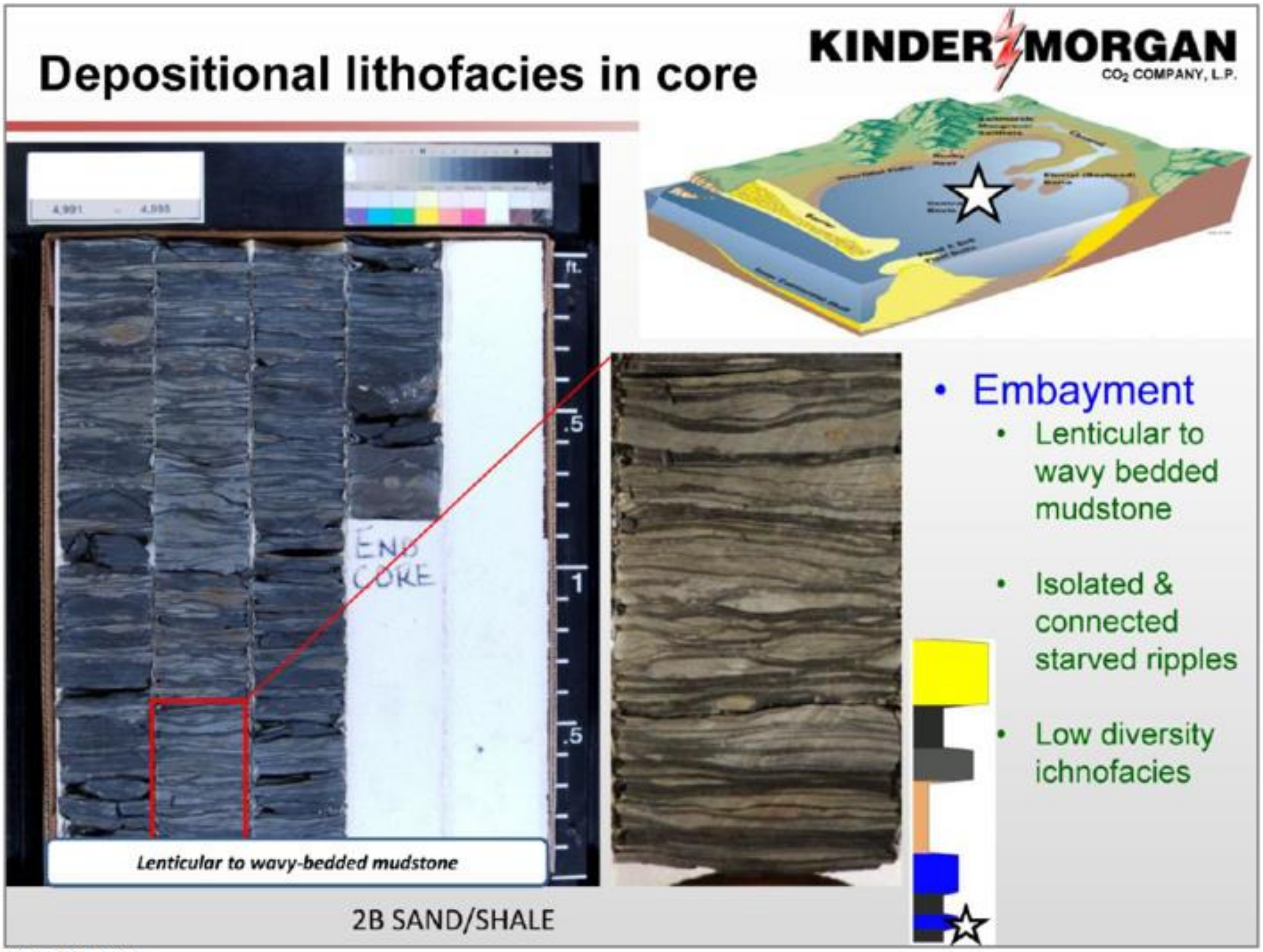
Secondary Confining Interval – Lower Strawn Shale

The Lower Strawn Shale (LSS) is Desmoinesian in age and was heavily influenced by the Knox Baylor Trough, which is near the KSU 2361 location and is late-Desmoinesian in age. The trough resulted from the Ouachita-Marathon overthrust movement that disrupted the Fort Worth basin depositional center, moving the Desmoinesian depocenter further to the west to form the Knox Baylor Trough. This trough allowed sediments to be transported west to the Midland Basin. These sediments were derived from the destruction of the elongated Bowie Delta System, which derived its sediments from the Muenster-Wichita Mountain system (Gunn, 1982).

Depositional facies within the Strawn unit resemble assemblages typical of a mixed siliciclastic-carbonate continental-to-shelf transitional succession found along a complex embayed coastline. Six petrophysically distinct lithofacies were identified: (1) lenticular to wavy-bedded mudstone, (2) flaser to wavy-bedded sandstone, (3) carbonate-rich sandstone, (4) ripple-to-trough cross-laminated sandstone with common convolute bedding, (5) trough cross-laminated sandstone with abundant mud rip ups and mud balls, and (6) heavily bioturbated sandstone. Combined lithofacies and ichnofacies observations suggest that paleoenvironments of the Katz Field included a bayhead delta, back-barrier estuary embayment, tidal flood delta, tidal flat, and upper to middle shoreface (Jesse G. White, 2014). The LSS is associated with the back-barrier estuary embayment depositional environment, evidenced by the abundance of mudstone.

Figure 15 provides core photos and associated descriptions of a core sample taken in the Katz field within an embayment environment. Core descriptions of this core sample observed characteristics that serve as excellent sealant properties to prohibit the migration of injection fluids above the injection zone. Conventional core data was collected in an offset well near the LSS depths in the API #42-433-33534 well, 5,089' away from the KSU 2361 well. Figure 16 is a cross-section relating the KSU 2361 well and the API #42-433-33534 well, indicating the cored interval alongside pictures of the lower portion of the core that most closely resembles the LSS. Horizontal permeabilities within the pictured core data range from 0.05 to 0.3 mD, with a vertical permeability value of less than 0.01 mD.

Along with the core reports and descriptions, Figure 16 plots calculated log curves from petrophysical analyses run on open-hole log data from the KSU 2361 well. Figure 16 indicates no effective porosity within the LSS (JPHIE green curve, 2nd track from the left) with a shale lithology reading (JHSHALE, green shading, 3rd track from the left). The petrophysical properties and lithology indicated by core and log data demonstrate that the LSS possesses characteristics of an excellent sealing formation.



4991 TO 4998:

4991.00 – 4997.4: Black to dark gray lenticular to wavy bedded mudstone encasing light gray lenticular siltstone to muddy very-fine sandstone. Abundant light gray calcareous horizons. Note zones of reddish color.

4997.4 – 4997.5: Burrowed transgressive bioclastic lag deposit? Abundant crinoid and bioclastic debris over burrowed laminated to contorted black shale.

4997.5 - 4997.7: Black laminated shale

4997.7 - 4998.0: Dark gray to gray black crinoid mudstone interbedded with a single tan algal mudstone-wackestone hardground exhibiting mudcracks.

Trace fossils shown in blow-ups include *Paleophycus, Planolites, Thalassinoides* and *Teichichnus*.

Sedimentology infers **brackish water deposits** (Brackish water is water that has more salinity than fresh water, but not as much as seawater. It may result from mixing of seawater with fresh water, as in estuaries.

4991 - 4998: Estuary – embayment. Brackish water deposit. Muddy.

Figure 15 – Core Description

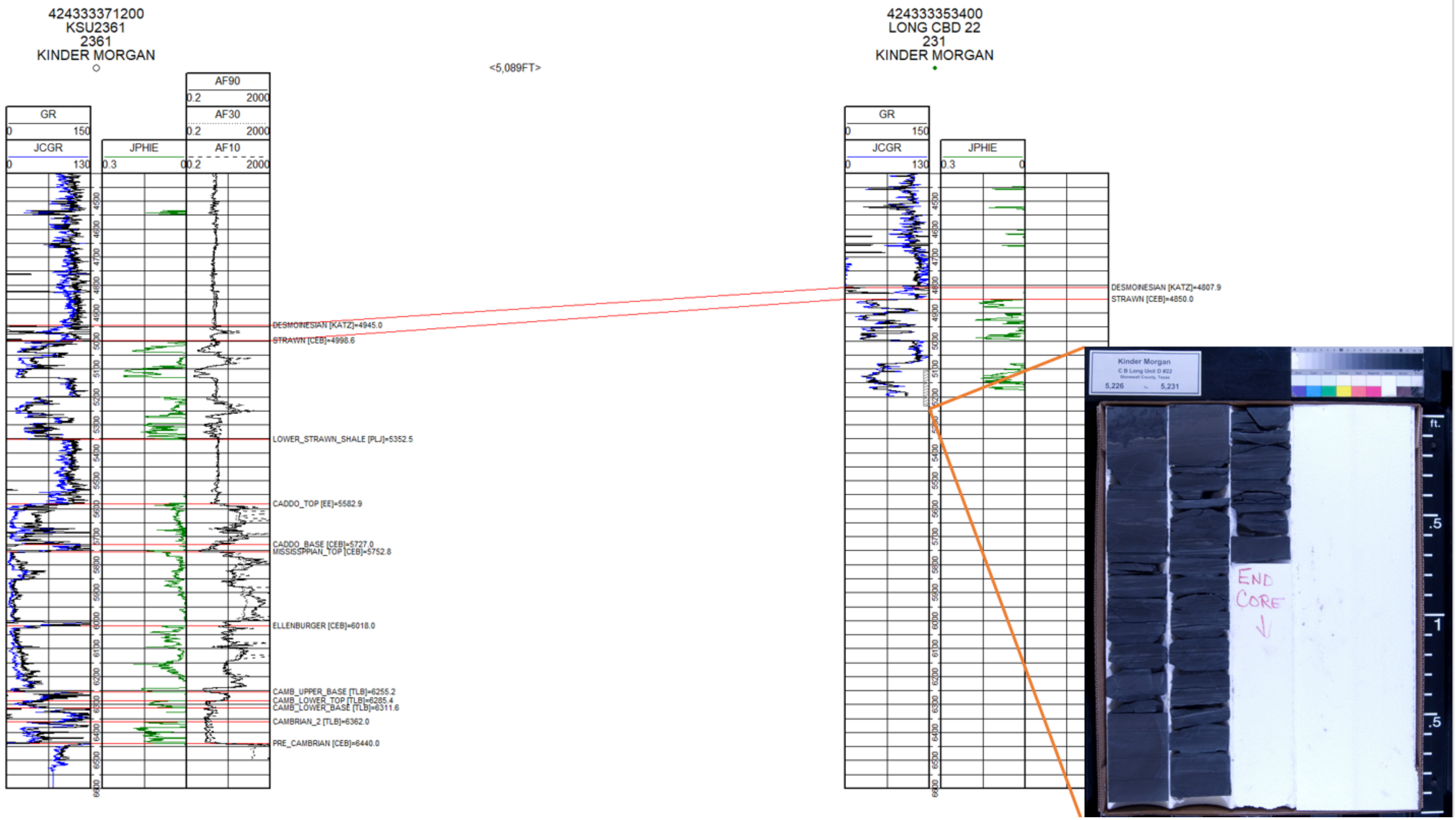


Figure 16 – Cross Section Depicting Corelative Offset Core with Lower Strawn Shale

Injection Interval – Ellenburger/Cambrian Sands

Ellenburger

The Ellenburger is a widespread lower Ordovician carbonate deposited over the entire north Texas area, indicating a relatively uniform depositional condition (Hendricks, 1964). North Central Texas experienced a low-energy, restricted shelf environment comprised of a homogeneous sequence of gray to dark-gray, fine to medium crystalline dolomite containing irregular mottling (probable bioturbation structures) and lesser parallel-laminated mudstone and peloid-wackestone (Kerans, 1990). Figure 17 is a map depicting the different depositional environments of the lower Ordovician, with associated lithologies. This map confirms the inferred dolomite lithology of the open hole log analysis in Figure 13 of the KSU 2361 well.

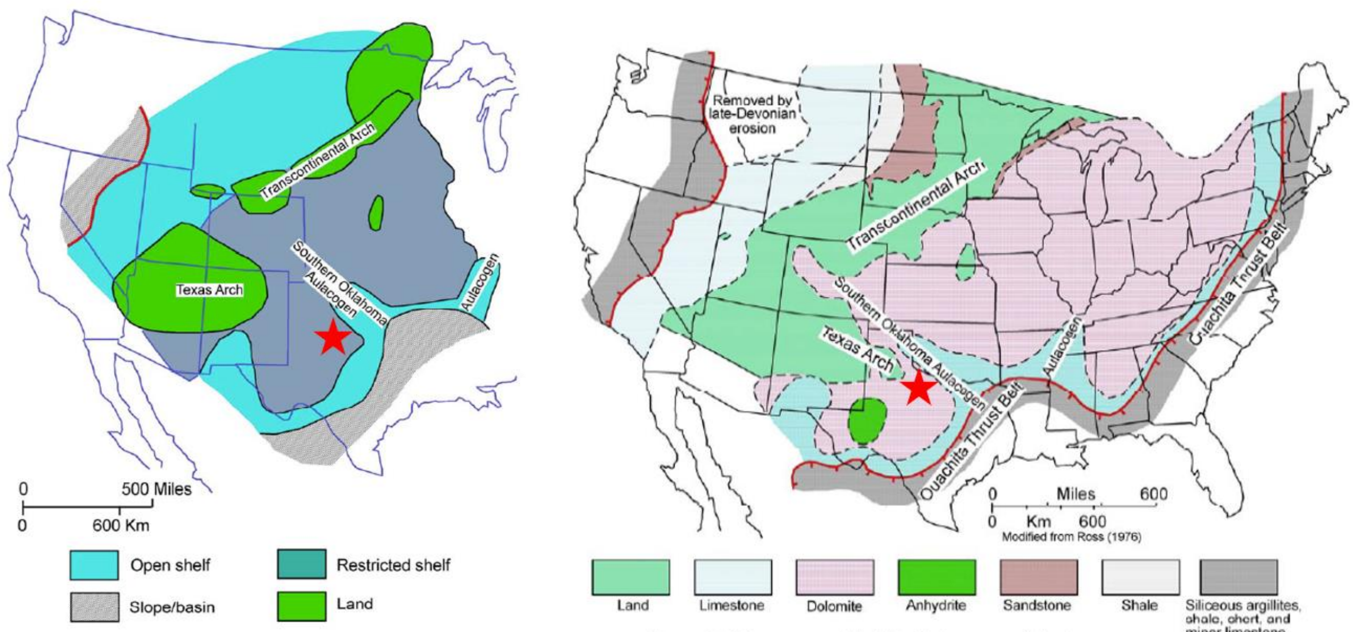


Figure 3. Interpreted regional depositional setting during Early Ordovician time. After Ross (1976) and Kerans (1990).

Figure 2. Paleogeographic lithofacies map of the Lower Ordovician section in the United States. From Ross (1976).

Figure 17 – Depositional Environments of the Lower Ordovician and Associated Lithofacies (Loucks, 2003)

Ellenburger Porosity/Permeability Development

Within the low-energy, restricted shelf environment, facies are highly dolomitized and have a heavy presence of bioturbation resulting in mottling (Loucks, 2003). The dolomitization led to porosity development within the Ellenburger, along with diagenetic leaching processes and other secondary porosity features such as karsts and vugs. The tables in Figure 18 show permeability and porosity values tabulated from Ellenburger reservoirs within Texas, categorized by their diagenetic facies into three groups: Karst Modified, Ramp Carbonates, and Tectonically Fractured Dolostones. Based on the descriptions in Figure 18, the Ellenburger of the KSU 2361 would fall within the Karst Modified Reservoirs category outlined in red with average porosity and permeability values of 3% and 32 mD, respectively. This corresponds with the data collected from the KSU 2361 well. As shown in Figure 13 above, the calculated effective porosity curve in green (JPHIE) is an average of roughly 3% over the Ellenburger formation. Permeability was estimated from volumes injected plotted against pressure responses within the KSU 2361 well; these permeabilities ranged from 12-20 mD. Similarities between these two datasets validate reservoir characteristics used for model inputs.

Cambrian

The deposition of Cambrian and lower Ordovician strata on the early Paleozoic shelf was initiated by a transgressing sea which, entering the area from the south, first laid down a clastic sequence. Initial deposits were sandstone and arenaceous carbonates that grade upward into the slightly cherty carbonates of the Ellenburger group (Galley, 1958). Lithologies include glauconitic and phosphatic to clean sandstones of various textures, intergrading and alternating with chemical, clastic, and even local limestones and dolomites, together with intercalated thin shales (Conselman, 1954).

Cambrian Porosity/Permeability Development

Few reservoir characteristics have been published on the Cambrian sands. Porosity and permeability were estimated based on the KSU 2361 wells open hole log and injection data. As shown in Figure 13, Cambrian sands are divided into two units and labeled as CAMBRIAN and CAMBRIAN_2. The two sands identified in the upper CAMBRIAN package have an average effective porosity of 12.9% and 8.8%. The average effective porosity within the CAMBRIAN_2 sands is 8.4%. These effective porosity values are plotted as the JPHIE curve in Figure 13. Permeability assumptions remain the same as the Ellenburger ranging from 12-20 mD, due to these zones being commingled during injection and the inability to isolate zones within the injection zone when history-matching injection volumes and pressures.

	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Lithology	Dolostone	Dolostone	Dolostone
Depositional setting	Inner ramp	Mid- to outer ramp	Inner ramp
Karst facies	Extensive sub-Middle Ordovician	Sub-Middle Ordovician, sub-Silurian/Devonian, sub-Mississippian, sub-Permian/ Pennsylvanian	Variable intra-Ellenburger, sub-Middle Ordovician
Fault-related fracturing	Subsidiary	Subsidiary	Locally extensive
Dominant pore type	Karst-related fractures and interbreccia	Intercrystalline in dolomite	Fault-related fractures
Dolomitization	Pervasive	Partial, stratigraphic and fracture-controlled	Pervasive

Parameter	Karst Modified	Ramp Carbonate	Tectonically Fractured Dolostone
Net pay (ft)	Avg. = 181, Range = 20 - 410	Avg. = 43 Range = 4 - 223	Avg. = 293, Range = 7 - 790
Porosity (%)	Avg. = 3 Range = 1.6 - 7	Avg. = 14 Range = 2 - 14	Avg. = 4 Range = 1 - 8
Permeability (md)	Avg. = 32 Range = 2 - 750	Avg. = 12 Range = 0.8 - 44	Avg. = 4 Range = 1 - 100
Initial water saturation (%)	Avg. = 21 Range = 4 - 54	Avg. = 32 Range = 20 - 60	Avg. = 22, Range = 10 - 35
Residual oil saturation (%)	Avg. = 31 Range = 20 - 44	Avg. = 36 Range = 25 - 62	NA

Figure 18 – Geologic and Petrophysical Parameters of the Ellenburger (Loucks, 2003)

Formation Fluid

Four wells were identified within approximately 20 miles of the KSU 2361 well through a review of oil-field brine compositions of the Ellenburger formation from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3. The location of these wells is shown in Figure 19. Results from the synthesis of this data are provided in Table 1. The fluids have higher than 20,000 parts per million (ppm) total dissolved solids. Therefore, these aquifers are considered saline. These analyses indicate that the in situ reservoir fluid of the Ellenburger Formation is compatible with the proposed injection fluids.

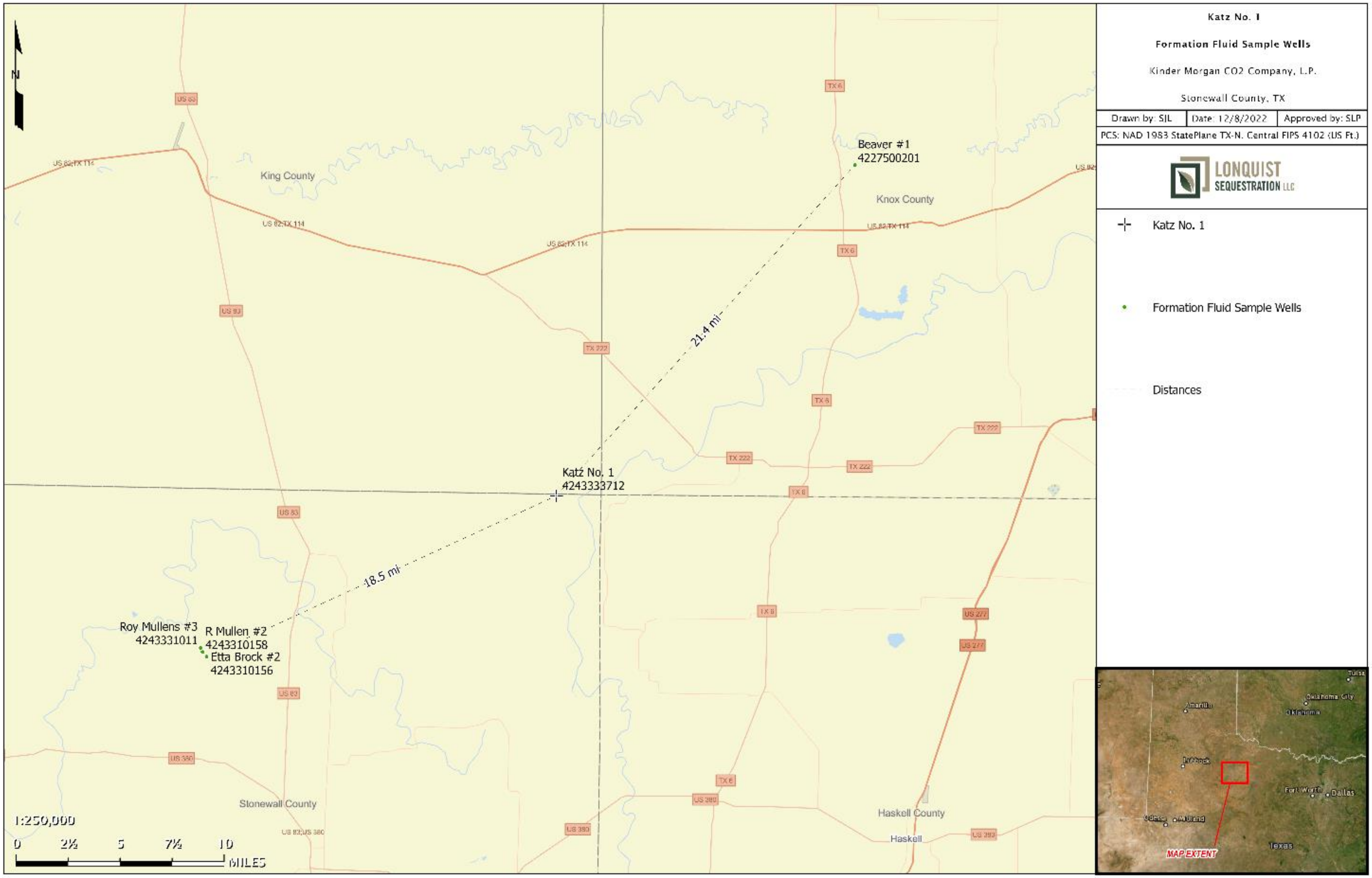


Figure 19 – Offset Wells used for Formation Fluid Characterization.

Table 1 – Analysis of Ordovician-age formation fluids from nearby oil-field brine samples

	Average	Low	High
Total Dissolved Solids (ppm)	144065	98802	210131
pH	6.15	5	7
Sodium (ppm)	43391	30833	64222
Calcium (ppm)	9275	5128	13200
Chlorides (ppm)	88355	60061	128685

Lower Confining Zone – Precambrian

The Precambrian outcrops to the south at the Llano uplift and the west in the Trans-Pecos regions of Texas and central New Mexico. Outcrops near the Llano Uplift in McCulloch County consist of highly weathered granite, schist, and gneiss. The granite is fine- to coarse-grained and contains numerous pegmatite veins. The schist has a high percentage of biotite, which gives it a dark-gray color, and it is often referred to as "gray shale" or "blue mud" by well drillers. The gneiss is pinkish and fine-grained (Mason, 1961). A study in 1996 was performed by Adams and Keller to better understand the Precambrian distribution in Texas indicates that Precambrian at the Katz 2361 location should contain an average metamorphic rock, as seen in Figure 20. This agrees with the open hole log response in the Precambrian formation in the open hole log section of Katz 2361. Gamma-ray log values of the Precambrian section are consistently above 90 GAPI, indicating a high radioactive response. A very high resistivity reading within this section indicates little to no porosity, as shown in the JPHIE, validating the characteristics described above. These traits are ideal attributes of a tight, lower confining basement.

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE

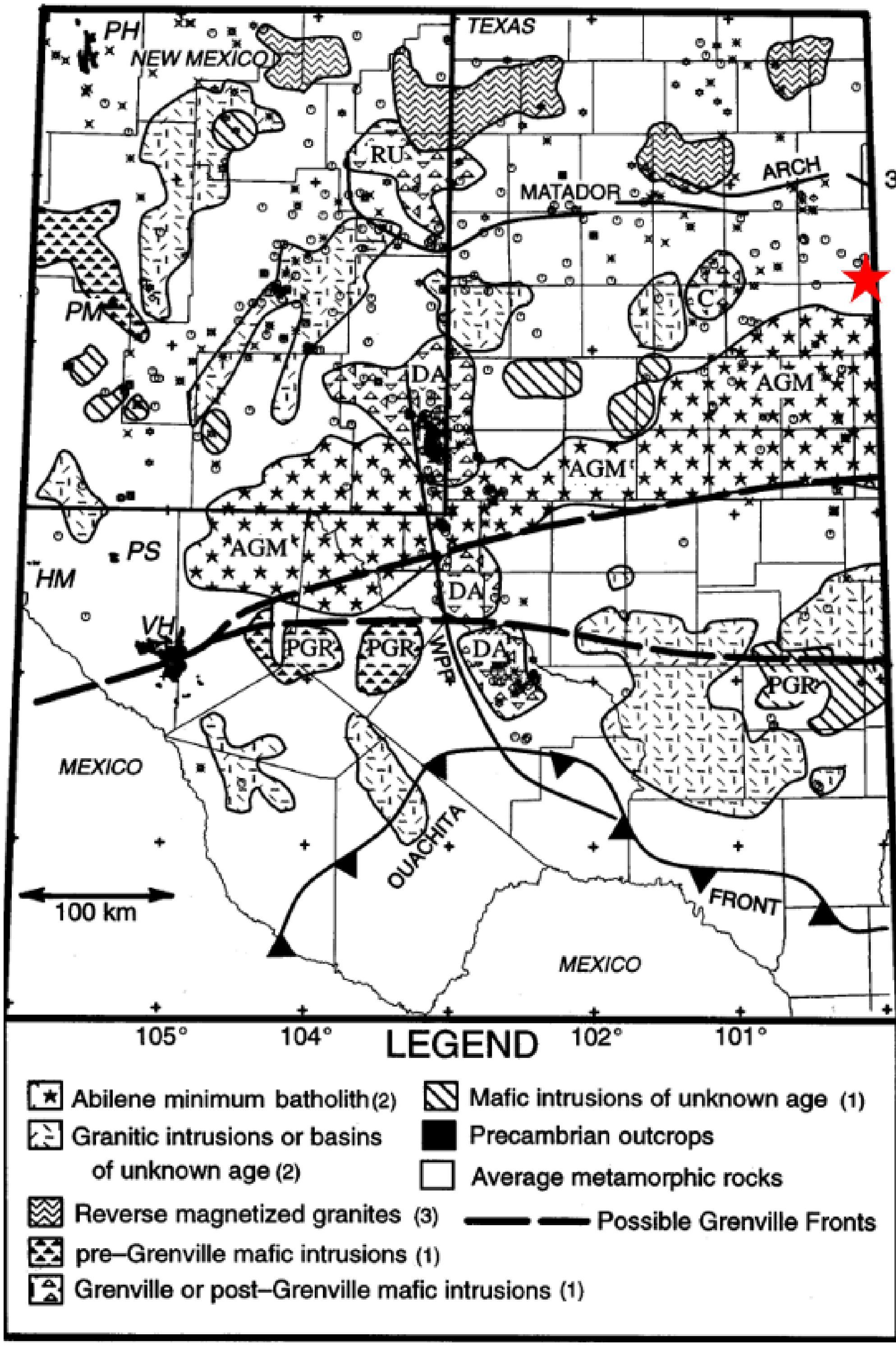


Figure 20 – Pre-Cambrian Distribution Map (Adams and Keller, 1996)

Fracture Pressure Gradient

Fracture pressure gradients were estimated using Eaton's equation. Eaton's equation is commonly accepted as the standard practice for determining fracture gradients. Poisson's ratio (ν), overburden gradient (OBG), and pore gradient (PG) are all variables that can be changed to match the site-specific injection zone. The expected fracture gradient was determined using industry standards and a literature review. The overburden gradient was assumed to be 1.05 psi/ft. This value is considered best practice when there are no site-specific numbers available. The pore pressure gradient was calculated to be 0.43 psi/ft from the bottom hole pressure data. For limestone/dolomite rock in the injection zone, the Poisson's ratio was assumed to be 0.3 through literature review (Molina, Vilarras, Zeidouni 2016). Using these values in the equation below, a fracture gradient of 0.70 psi/ft was calculated for the injection zone.

For the upper confining interval, a similar fracture gradient was calculated. The upper confining shale has an increased chance to vertically fracture if the injection interval below is fractured (Molina, Vilarras, Zeidouni 2016). Therefore, a Poisson's ratio equal to that of the injection interval was used as a conservative estimate. The lower confining zone was assumed to be of a similar matrix to the injection interval, with the key difference being that the formation is much tighter (lower porosity/permeability). Therefore, the Poisson's ratio was assumed to be slightly higher in this rock. As seen in Table 2, the fracture gradient of .64 psi/ft is slightly higher in the lower confining zone.

Multiple approaches can be taken to manage reservoir pressure. Current engineering practices for acid gas CO_2 injection recommend applying a 10% safety factor to the fracture pressure of the geology being injected into, resulting a 0.63 psi/ft gradient. This new value represents the maximum allowable bottom-hole pressure during injection. Another approach is to maintain a maximum wellhead pressure (WHP). In the reservoir model, a WHP of 1,850 psi was used to constrain the simulated well. This translates to a value that is 84% of the frac gradient or a 16% safety factor. By using either approach, there is a reduced risk of fracture propagation in the injection zone.

A conservative maximum pressure constraint of 0.60 psi/ft was used for injection modeling, which is well below the calculated fracture gradient for each zone. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

Table 2 – Fracture Gradient Assumptions

	Injection Interval	Upper Confining	Lower Confining
Overburden Gradient (psi/ft)	1.05	1.05	1.05
Pore Gradient (psi/ft)	0.43	0.43	0.43
Poisson's Ratio	0.30	0.30	0.31
Fracture Gradient (psi/ft)	0.70	0.70	0.71
FG + 10% Safety Factor (psi/ft)	**0.63**	**0.63**	**0.64**

The following calculations were used to obtain fracture gradient estimates:

$$FG = \frac{n}{1-n}(OBG - PG) + PG$$

$$FG = \frac{0.3}{1-0.3}(1.05 - 0.43) + 0.43 = 0.70$$

$FG\ with\ SF = 0.70 \times (1 - 0.1) = \mathbf{0.63}$ **(Injection and Upper Confining intervals)**

$FG\ with\ SF = 0.71 \times (1 - 0.1) =$ **.64 (Lower Confining interval)**

Local Structure

Regional structure in the area of the KSU 2361 well is influenced by a shallow angle ramp downdip to the southwest towards the Midland Basin, which is set up by a north-south regional fault to the east. Specifically, the KSU 2361 well is located on the western portion of a shelf-like feature that dips slightly away from the fault to the east. Figure 21 is a structure map on the top of the Ellenburger with the KSU 2361 well indicated by the black star.

Subsurface interpretations of the Ellenburger formation heavily relied on 3D seismic coverage in the area. The seismic coverage outline is represented by the purple boundary seen in Figure 21. Only two wells penetrated the Ellenburger formation within the data limits and are shown in the northwest to southeast seismic profile along with the cross-section in Figure 24. These two wells are active injection wells within the proposed injection interval operated by Kinder Morgan, one being the Katz 2361 well while the other is the Katz #3741 well. Both wells were used to create time-to-depth conversions for the Ellenburger horizon. Shallower formations provide additional well control to assist in creating time-to-depth conversions displayed in the seismic profiles in Figures 22 and 23.

The KSU 2361 well is located roughly 12,000' west of the mapped fault seen in Figure 21. This distance provides a buffer between the injection plume and the fault that alleviates concerns regarding the interaction between the injectate and the fault. As shown in the seismic profile, this fault does not project above the Caddo formation and is not present in the LSS. As this fault does not project into the upper confining shale layer, there is little risk of the fault acting as a conduit for the injectate to leak outside the proposed injection interval.

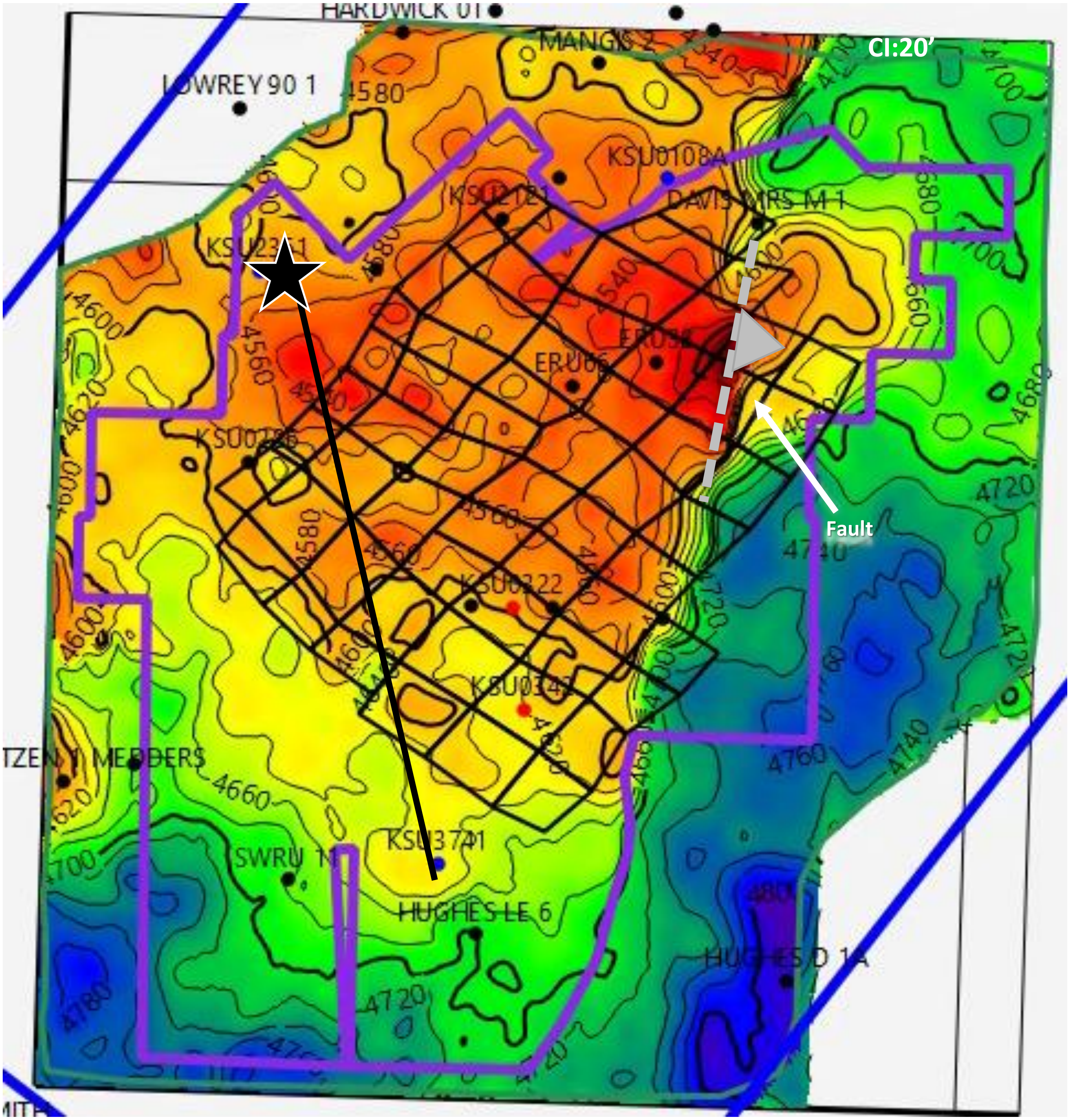


Figure 21 – Ellenburger Structure Map (Subsea Depths)

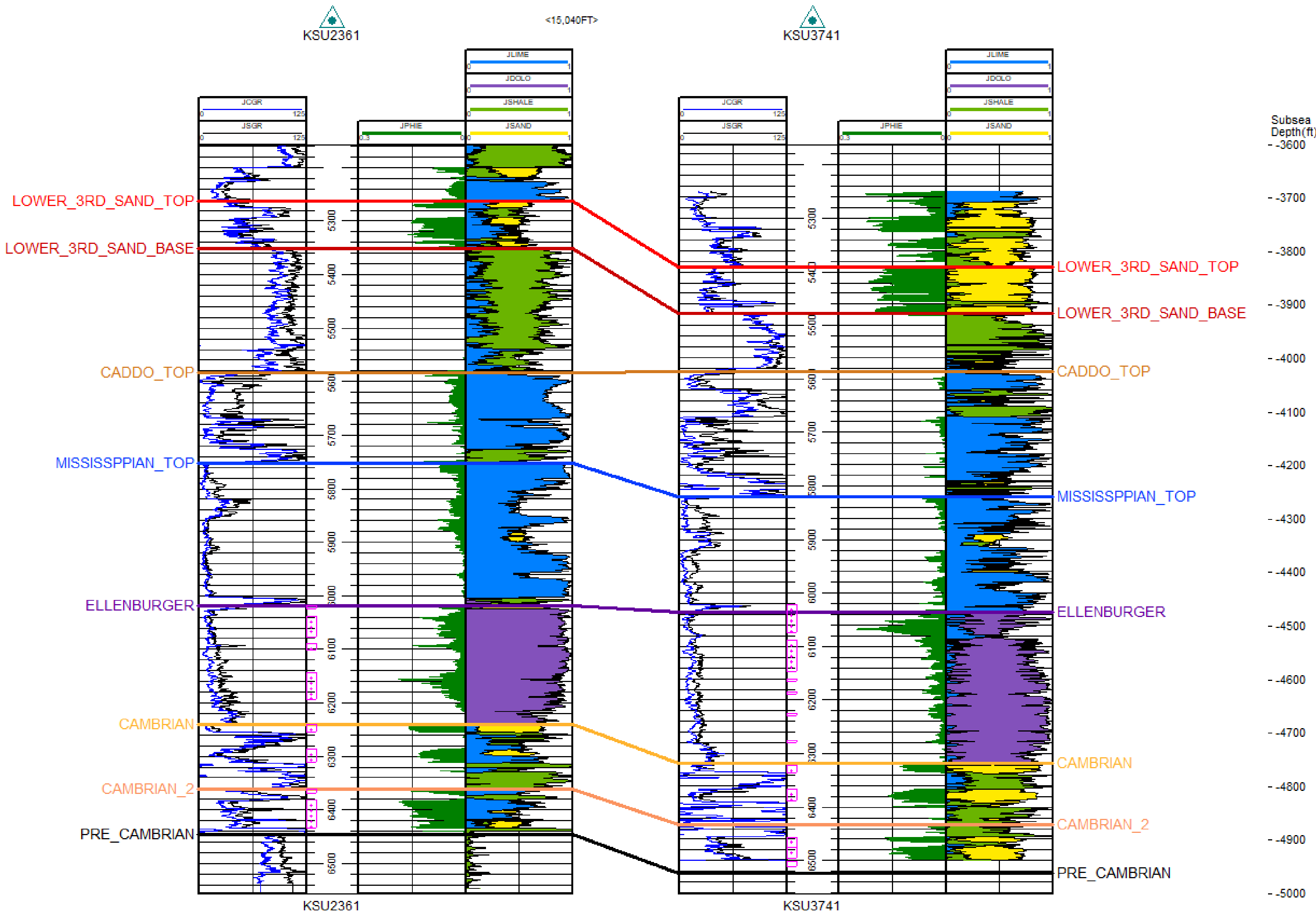


Figure 22 – Structural Northwest-Southeast Cross Section

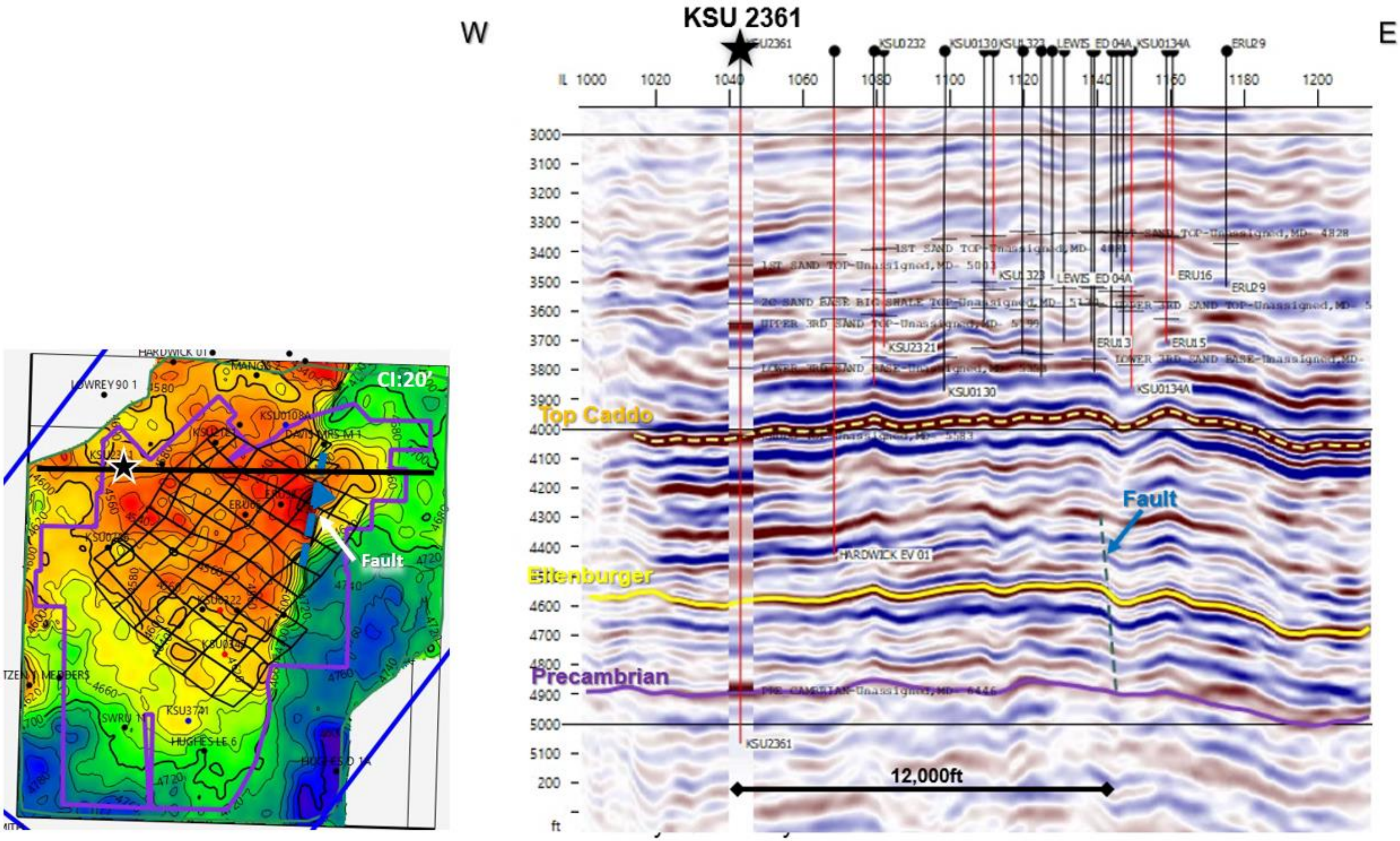


Figure 23 – Structural West to East Seismic Profile

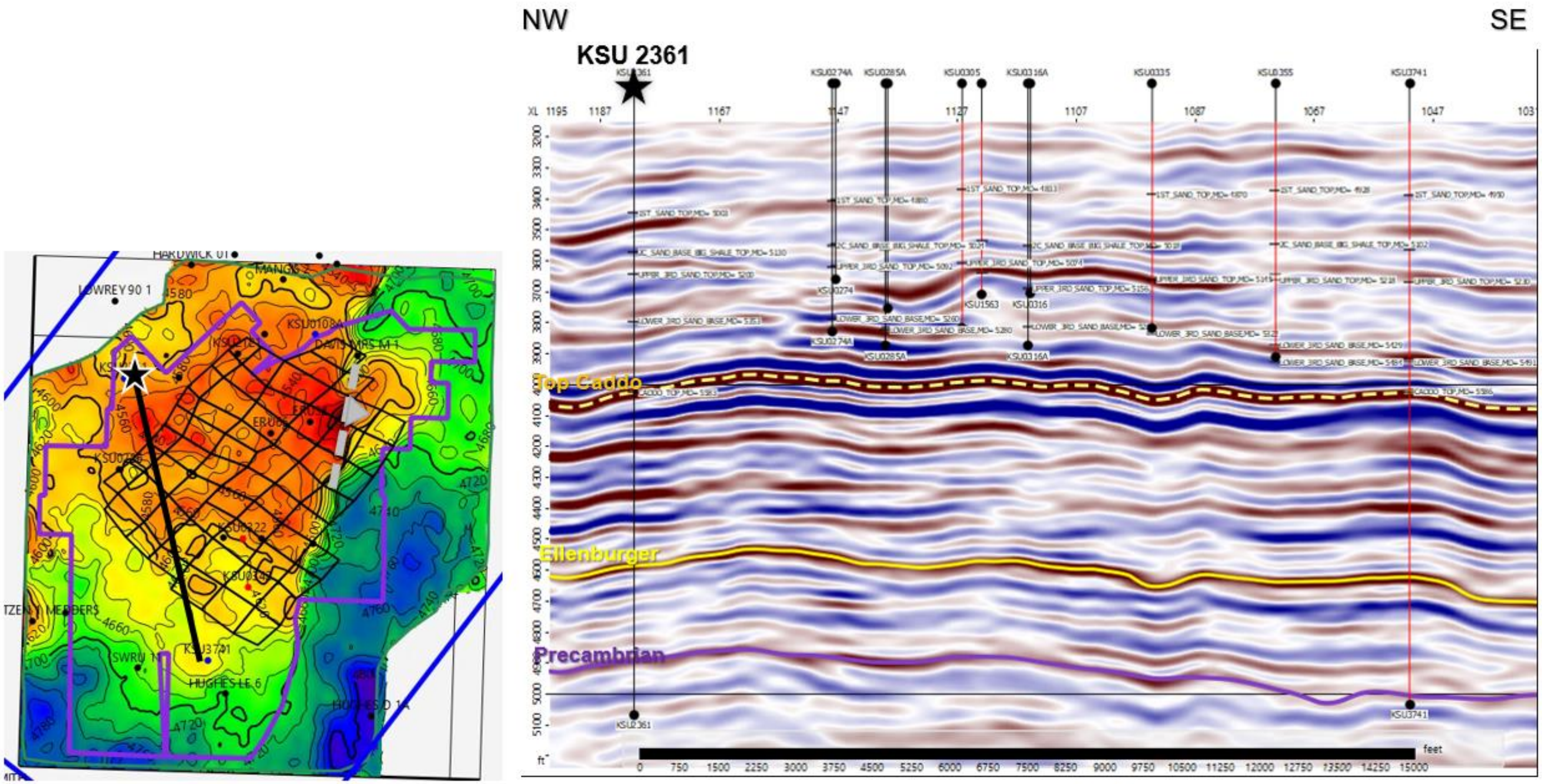


Figure 24 – Structural Northwest to Southeast Seismic Profile

Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Ellenburger and Cambrian sand formations at the KSU 2361 well location indicate that the formations have sufficient thickness, porosity, permeability, and lateral continuity to accept the proposed injection fluids. The Mississippian Lime formation at the KSU 2361 well has low permeability. It is of sufficient thickness and lateral continuity to serve as the upper confining zone, with the Lower Strawn Shale acting as a secondary confining unit. Beneath the injection interval, the low permeability, low porosity Precambrian formation is unsuitable for fluid migration and serves as the lower confining zone.

The area of review has been studied to identify potential subsurface features that may affect the ability of these injection and confinement units to retain the injectate within the requested injection interval. Faults have been identified, characterized, and determined to be low risk to the containment of injectate and do not increase the risk of migration of fluids above the injection interval.

Groundwater Hydrology

Stonewall, Haskell, Knox, and King Counties fall within the boundary of the Texas Water Development Board's (TWDB) Groundwater Management Area 6. The Seymour Aquifer is identified by the TWDB's *Aquifers of Texas* report in the vicinity of the KSU 2361 well (George et al., 2011). Table 3 references the Seymour Aquifer's position in geologic time and the associated geologic formations, which include the Seymour Formation, Lingos Formation, and Quaternary alluvium (Ewing et al., 2004). A depiction of the general stratigraphy of the Seymour Aquifer is shown in Figure 25.

Table 3 – Geologic and Hydrogeologic Units near Stonewall, Haskell, Knox, and King Counties, Texas (Ewing et al., 2004).

System	Series	Group	Formation
Quaternary	Recent to Pleistocene		Alluvium
			Seymour
Tertiary	missing		
Cretaceous			
Jurassic			
Triassic			
Permian	Ochoa		Quartermaster
	Guadalupe	Whitehorse	
		Pease River	Dog Creek Shale
			Blaine Gypsum
			Flowerpot Shale
			San Angelo
	Leonard	Clear Fork	Choza
			Vale
			Arroyo
		Wichita (upper portion only)	Lueders
			Clyde

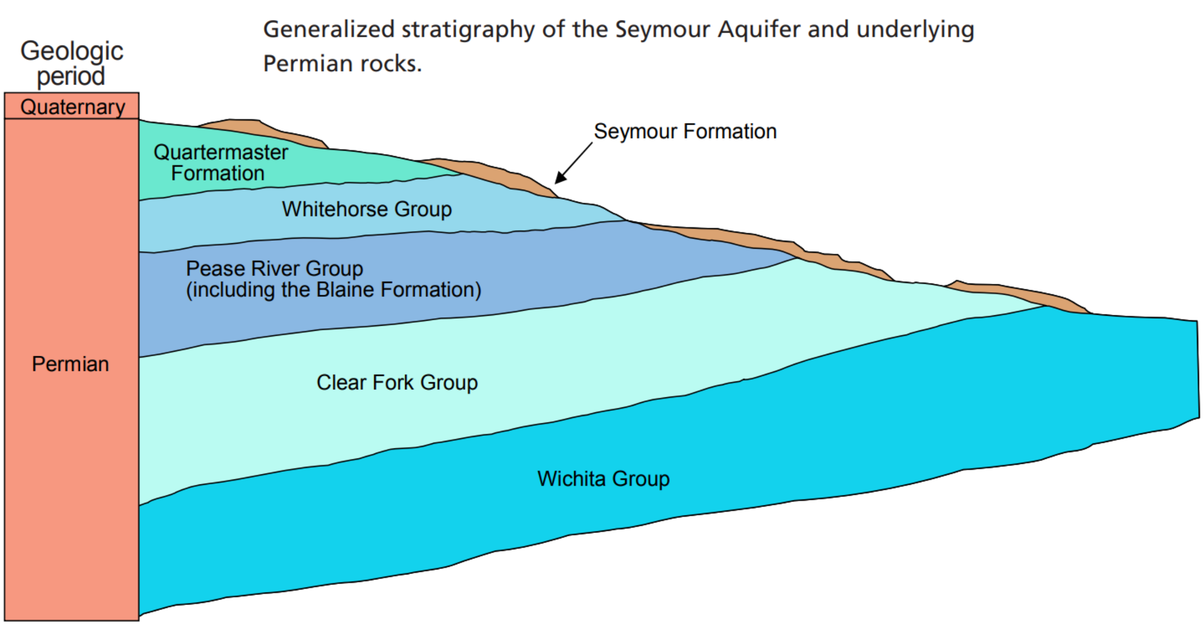


Figure 25 – Generalized Stratigraphy of the Seymour Aquifer (George et al., 2011)

The Seymour Aquifer, as defined by the TWDB, consists of isolated pods of alluvium deposits of Quaternary age, depicted in Figure 26. It extends from the southern Brazos River watershed northward to the border of Oklahoma. The Seymour Aquifer overlies Permian-age deposits that generally dip to the west. Topography, structure, and permeability variation control groundwater flow within the pods. The aquifer generally follows the topographical gradient along the major axis of the pod and discharges laterally to springs, seeps, and alluvium. Similar mechanisms can be expected within the majority of the other pods (Ewing et al., 2004).

A map showing the inferred groundwater flow pattern within a portion of one of the pods in Haskell and Knox counties is shown in Figure 27. The map approximates the natural direction of flow unaffected by pumping from wells. North of the Rule, TX, groundwater divide, the flow is toward the north, northwest, or northeast. Based on the contours of the water table and the permeabilities for the formation indicated by pumping tests, the estimated natural rate of water movement in the Seymour Aquifer, unaffected by pumping, ranges locally from approximately 200’ to 5,000’ per year. Over several miles, the estimated average rate of movement is typically between 800’ and 1,200’ per year (R.W. Harden and Associates, 1978).

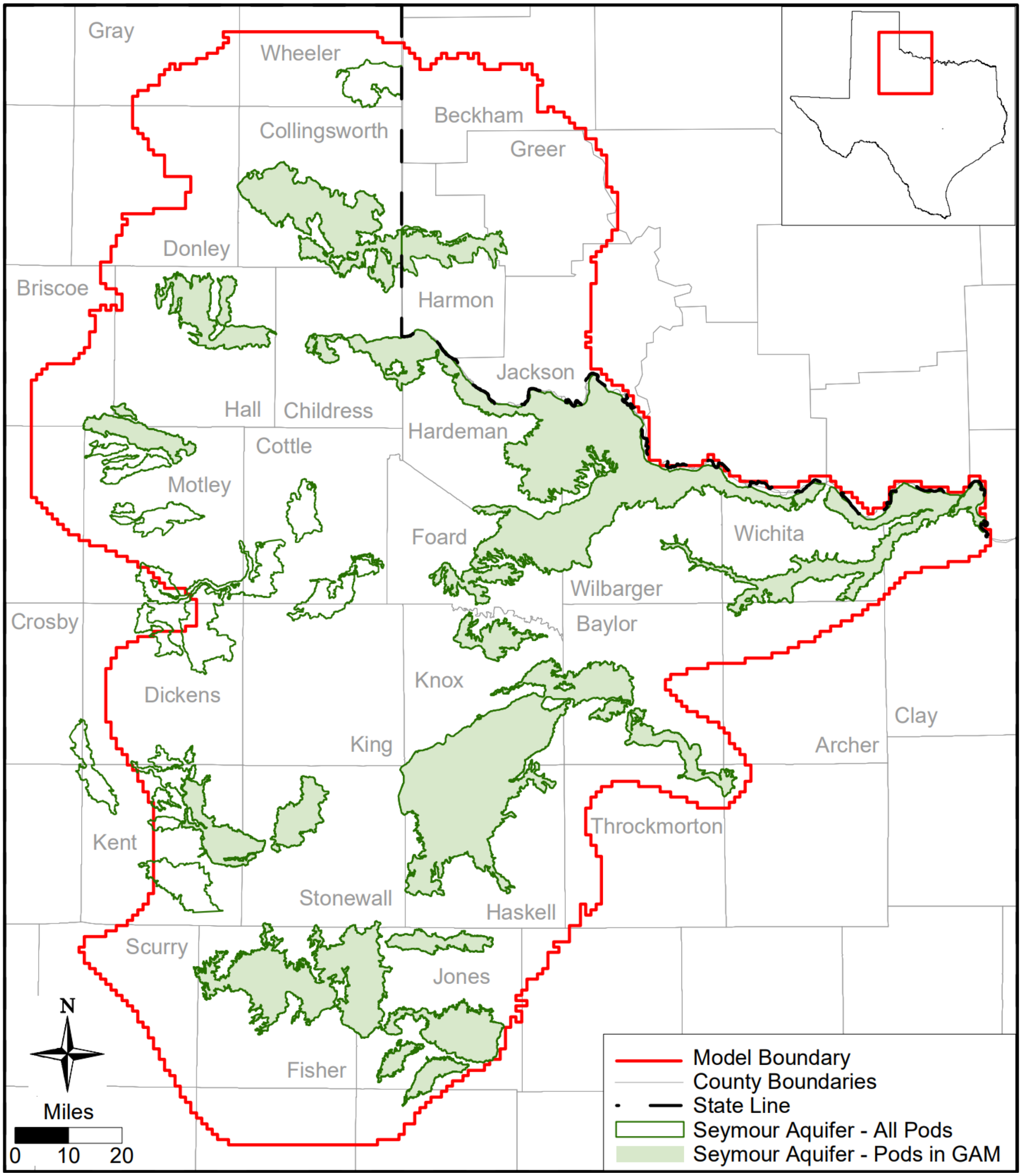


Figure 26 – Regional Extent of the Seymour Aquifer Pods (Ewing et al., 2004)

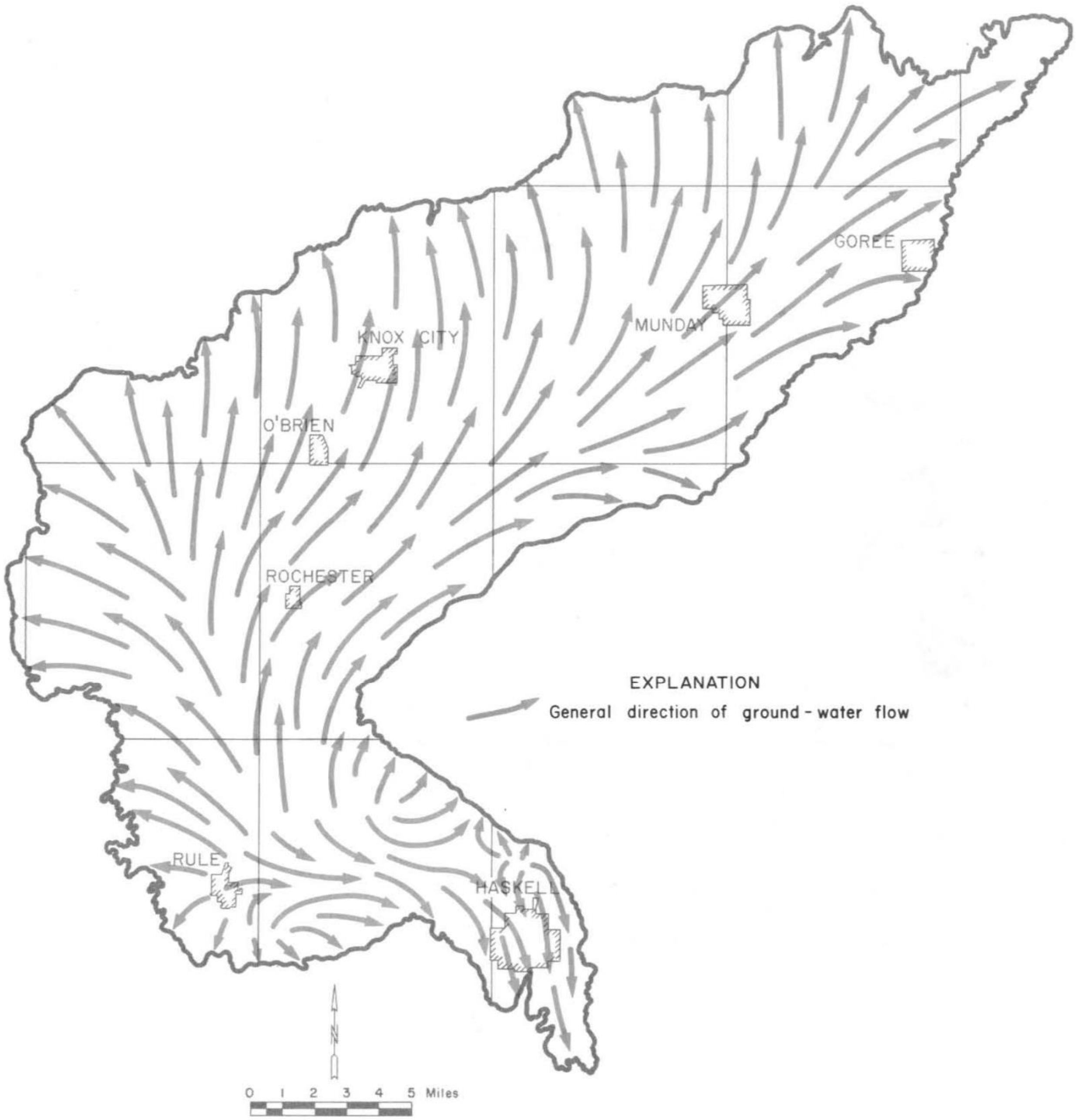


Figure 31. Direction of Ground-Water Flow in Seymour Aquifer

Figure 27 – Direction of Groundwater Flow in a Portion of one Pod of the Seymour Aquifer (R.W. Harden and Associates, 1978).

Total dissolved solids (TDS) are a measure of water saltiness, the sum of concentrations of all dissolved ions (such as sodium, calcium, magnesium, potassium, chloride, sulfate, and carbonates) plus silica. As shown in Figure 28, the total dissolved solids in 41% of the wells within the Seymour Aquifer exceed 1,000 milligrams per liter (mg/L), Texas' secondary maximum contaminant level (MCL). Therefore, the utility of water from the Seymour Aquifer as a drinking water supply is limited in many areas for health reasons, primarily due to elevated nitrate concentrations, and for taste reasons due to saltiness (Ewing et al., 2004).

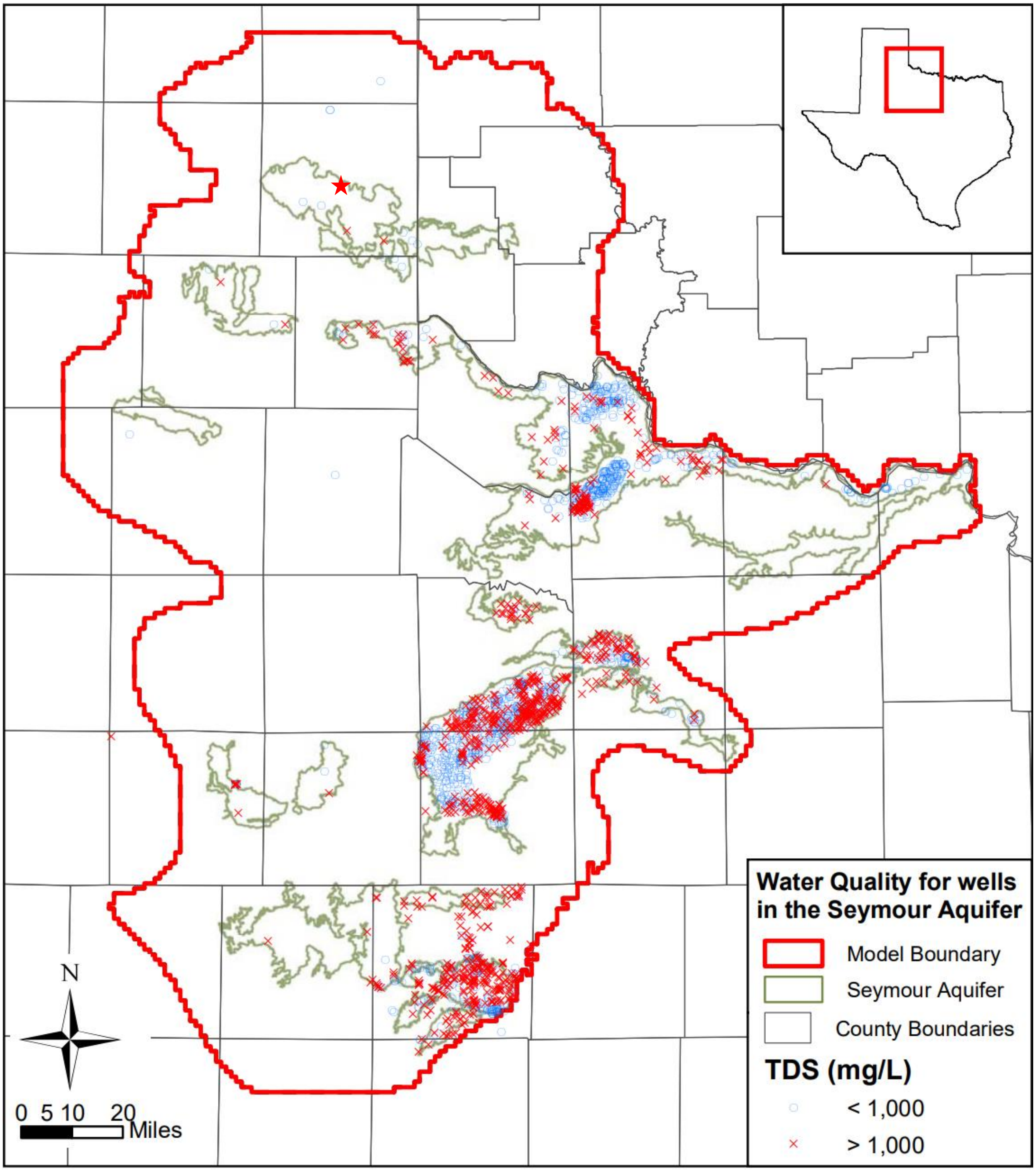


Figure 28 – Total Dissolved Solids (TDS) in Groundwater from the Seymour Aquifer (Ewing et al., 2004)

The TRRC's Groundwater Advisory Unit (GAU) specified for the KSU 2361 well that the interval from the land surface to a depth of 100' must specifically protect usable-quality groundwater. Therefore, the base of Underground Sources of Drinking Water (USDW) can be approximated at 100' at the location of the KSU 2361 well, and there is approximately 5,920' separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued

by the TRRC as part of the Class II permitting process for the KSU 2361 well is provided in Appendix A. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Mississippian limestone, thousands of feet of tight limestone and shale beds occur between the injection interval and the lowest water-bearing aquifer.

Reservoir Characterization Modeling

Introduction

KSU 2361 is located in Kinder Morgan's Katz Oil Field in northeast Stonewall County. A geologic model was constructed of this area to forecast the movement of CO_2 and any pressure increases. The model is comprised of the Ellenburger and Cambrian formations, which cover 13,774 acres (~22 square miles). A single CO_2 injector was simulated for 100 years, where approximately 25 million metric tons (MMT) of CO_2 was safely stored.

Software

Paradigm's software suite was used to build the geologic and dynamic models. SKUA-GOCAD™ was utilized in building the geomodel, while Tempest™ designed the dynamic model. The EPA recognizes these software packages for an area of review delineation modeling as listed in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

SKUA-GOCAD™ is a software tool for geology that offers a range of features for structure and stratigraphy, structural analysis, fault seal, well correlation, facies interpretation, 2D/3D restoration, and basin modeling. The structure and stratigraphy module allows users to construct fully sealed structural models, while the structural analysis module provides tools for analyzing fracture probability, stress, and strain. The fault seal module enables the computation of fault displacement maps and fault SGR properties, and the well correlation module allows users to create well sections and digitize markers. The facies interpretation module offers tools for paleo-facies interpretation, and the 2D/3D restoration module provides tools for restoring 3D basin and reservoir models. Finally, the basin modeling module enables users to construct 4D basin models for transfer to basin model simulation software.

Tempest™ is another of Paradigm's industry-leading software packages for reservoir engineering. Tempest™ has history-matching capabilities, allowing for more accurate reservoir characterization modeling. In addition, this software is used to build dynamic models for CO_2 injection. Tempest™ is comprised of three modules: Tempest™ VIEW, Tempest™ ENABLE and Tempest™ MORE. Tempest™ MORE is a black oil simulator with many features and applications to simulate CO_2 injection. The Tempest™ MORE module can accept data in standard GRDECL (RMS, Petrel) file formats. It can also produce output in the ECLIPSE, Nexus/VIP, Intersect, and IMEX/GEM/STARS formats. This allows users to easily import data into the software and export it in a format compatible with other tools and systems. The standard file formats improve the interoperability and compatibility of the MORE software with other systems and tools used in the oil and gas industry

Trapping Mechanisms

To accurately simulate the CO_2 injection and predict the subsequent plume migration, Tempest™ models CO_2 trapping mechanisms in the injection zone. There are five primary trapping mechanisms: structural, hydrodynamic, residual gas (hysteresis), solubility, and geochemical. For this simulation, geochemical reactions were not considered. Each of the five mechanisms is described in further detail below.

Structural Trapping

Structural traps, a physical trapping mechanism, are underground rock formations that trap and store the injected supercritical CO_2. These traps are created by the physical properties of the cap rock, such as its porosity and permeability. For example, a structural trap may be formed by a layer of porous rock above a layer of non-porous rock, with the CO_2 being trapped in the porous rock. Some other examples of structural traps are faults or pinch-outs. Faults can limit the horizontal migration of the plume in the injected formation. The injected CO_2 is lighter than the connate brine found already in the formation. Because of this, the CO_2 floats to the top of the formation and is stored underneath the impermeable cap rock. In this model, CO_2 mass density ranges between 34.9 to 38.5 lb/ft^3 from the shallow to deep injection intervals, whereas the formation brine density is approximately 63.3 lb/ft^3.

Hydrodynamic Trapping

Hydrodynamic traps are another form of physical trapping caused by the interaction between CO_2 and the formation brine. Hydrodynamic trapping is caused by supercritical CO_2 traveling vertically upwards until it reaches the impermeable cap rock and spreads laterally through the unconfined sand layers, driven by the buoyancy and higher density of the brine in the reservoir. Once the CO_2 reaches a caprock with a capillary entry pressure greater than the buoyancy, it is effectively trapped. This type of trapping works best in laterally unconfined sedimentary basins with little to no structural traps.

Equation-of-state (EOS) calculations are performed to determine the phase of CO_2 at any given location based on pressure and temperature for structural and hydrodynamic trapping mechanisms. Several well-known EOS formulae are used within the oil and gas industry for reservoir modeling. These formulae include the Van der Waals equation, the Peng-Robinson method, and the Soave-Redlich-Kwong (SRK) method. The Peng-Robinson is better suited for gas systems than the SRK method. The EOS implemented within the KSU 2361 well model was the Peng-Robinson method.

Residual Gas Trapping

Residual gas traps are also a physical form of trapping CO_2 within pore space by surface tension. This occurs when the porous rock acts as a sponge and traps the CO_2 as the displaced fluid is forced out of the pore space by the injected CO_2. As the displaced brine reenters the pore space once injection stops, small droplets of CO_2 remain in the pore space as residuals and become immobile.

Solubility Trapping

Solubility traps are a form of chemical trapping between the injected CO_2 and connate formation brine. Solubility trapping occurs when the CO_2 is dissolved in a liquid, such as the formation brine.

CO_2 is highly soluble in brine, with the resulting solution having a higher density than the connate brine. This feature affects the reservoir by causing the higher-density brine to sink within the formation, trapping the CO_2-entrained brine. This dissolution allows for an increased storage capacity and decreased fluid migration. Table 4 was designed to guide the model to determine the solubility of CO_2 at various pressures and a specified salinity.

Table 4 – CO_2 Solubility Table

Pressure (psi)	CO2 Solubility (Mscf/Stb)	Salinity (ppm)
14	0.00	66,000
50	0.00	66,000
150	0.01	66,000
500	0.0198	66,000
1000	0.0297	66,000
1500	0.0388	66,000
3000	0.0660	66,000

Geochemical Trapping

Geochemical trapping is another form of chemical trapping which refers to storing CO_2 in underground rock formations by using chemical reactions to transform the CO_2 into stable, solid minerals. This process is known as mineral carbonation, and it involves the reaction of CO_2 with the minerals and rocks in underground formations to form stable carbonates. During the process of injecting CO_2 into a disposal reservoir, four (4) primary chemical compounds may be present: CO_2 in the supercritical phase, the hydrochemistry of the naturally occurring brine in the reservoir, aqueous CO_2 (an ionic bond between CO_2 gas and the brine), and the geochemistry of the formation rock. These compounds can interact, leading to the precipitation of CO_2 as a new mineral, often calcium carbonate (limestone). This process is known as mineral carbonation, a key mechanism for the long-term storage of CO_2 in underground rock formations.

Mineral trapping can also occur through the adsorption of CO_2 onto clay minerals. When modeling this process, it is important to consider both hysteresis and solubility trapping. Geochemical formulae can be included in the model using an internal geochemistry database to describe the mineral trapping reactions. These formulae can describe aqueous reactions, such as those involving CO_2 and clay minerals. For aqueous reactions, the following chemical reactions are standard formulae used in CO_2 simulation:

$$CO_2(aq) + H_2O = H^+ + HCO_3^-$$
$$CO_3^{-2} + H^+ = HCO_3^-$$
$$OH^- + H^+ = H_2O$$

The following three formulae represent three common ionic reactions that can occur between water and CO_2 within a reservoir. These reactions involve the formation of solid minerals that can be found in sandstone aquifers, and they result in the precipitation of carbon oxides. These reactions are commonly included in modeling efforts to understand and predict the behavior of CO_2 in underground storage reservoirs:

$$Anorthite\ (CaAl_2Si_2O_8) + 8H^+ = 4\ H_2O + Ca^{2+} + 2Al^{4+}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO3^-$$
$$Kaolinite\ \left(Al_2Si_2O_5(OH_4)\right) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO$$

Geochemical trapping has the potential to store CO_2 for hundreds or thousands of years, but the short-term effects of this method are relatively limited. Instead, the short-term movement and storage of CO_2 are more strongly influenced by hydrodynamic and solubility trapping mechanisms. These mechanisms involve the movement of fluids, such as water or oil, through porous rock formations and the solubilization of CO_2 in liquids, such as water or oil. As a result, these processes can be more effective in the short term at storing CO_2, although they may not have the same long-term stability as geochemical trapping.

Static Model

The geomodel was constructed to simulate the geologic structure of the Ellenburger and Cambrian formations. The grid contains 600 cells in the X-direction (East-West) and 400 cells in the Y-direction (North-South), totaling 240,000 cells per layer. Therefore, 55 layers were utilized in the model representing the gross thickness of the injection interval, totaling 13,200,000 grid blocks. The Ellenburger is comprised of 25 layers and the Cambrian is comprised of 30 layers. Each grid block is 50 feet by 50' by 10', resulting in a model size of 5.7 miles by 3.8 miles by 550,' as shown in Figure 29. This covers approximately 22 square miles (13,774 acres).

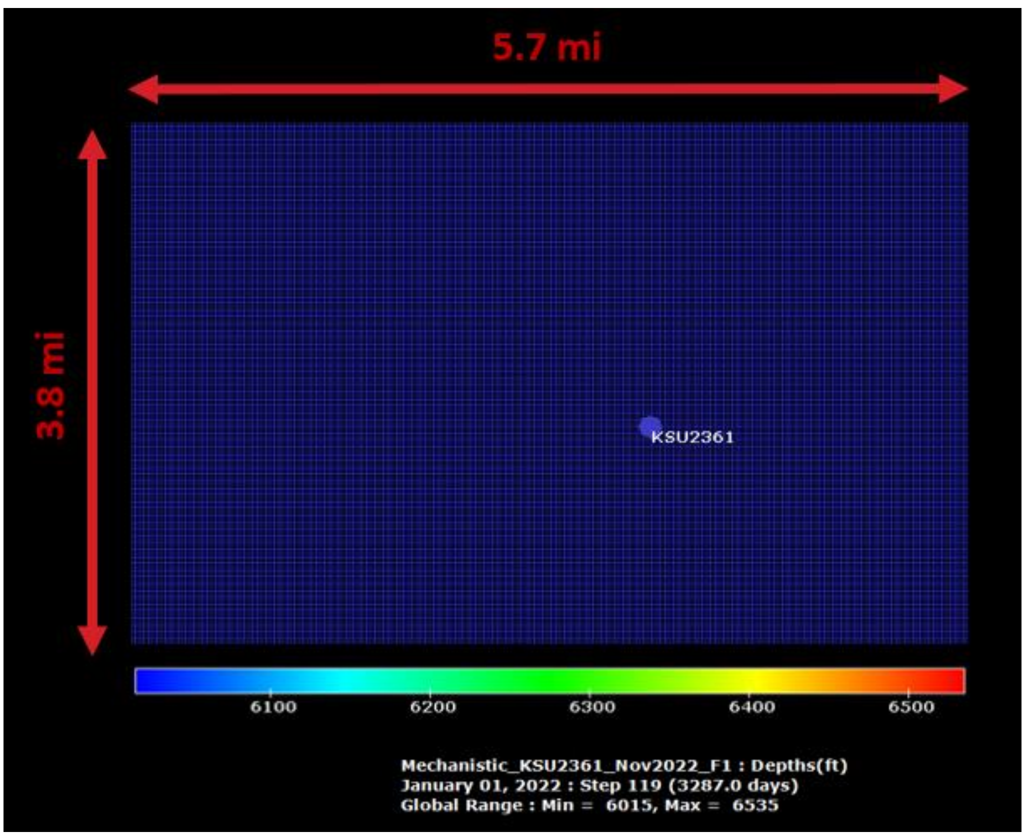


Figure 29 – Geomodel Dimensions

Well log analysis tied into seismic interpretation was used to identify any major formations tops. Four geologic units were identified and incorporated into the geomodel. Each geologic unit was used to determine the geologic structure of the injection zone. First, the Ellenburger is a carbonate formation comprised of dolomite/limestone matrix. Underlying the Ellenburger formation is the Cambrian sandstone. This sandstone was split into two geologic units, the Cambrian 1 and Cambrian 2. The Precambrian formation is at the bottom of the model. The Precambrian, comprised of granite, is the lower confining zone. Figure 30 highlights the overall structure of the target zone.

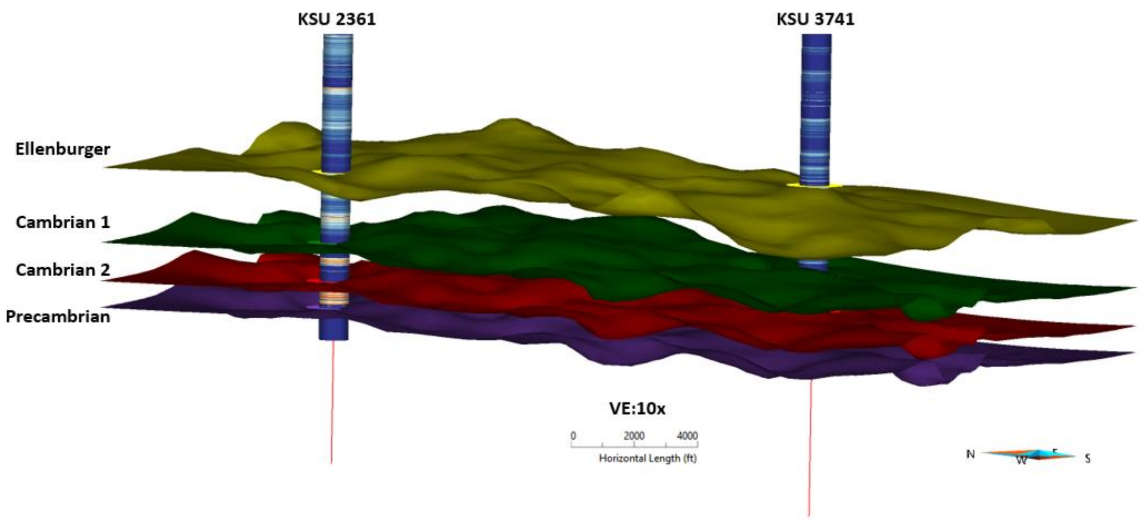


Figure 30 – Structural Horizons of the Geomodel

Permeability and porosity were distributed through the geomodel based on the formation. These rock properties were considered to be laterally homogenous in the simulation. However, vertical heterogeneity was incorporated into the model. Based on well log analysis, porosity was determined to be 10% in the Ellenburger carbonate and 12% in the Cambrian sandstone, as shown in Figure 31. Permeability was determined from history matching two wells. From this exercise, it was determined that the horizontal permeability (K_H) is 20 milliDarcy (mD) and vertical permeability (K_V) was assumed to be 10% of K_H or 2 mD. Table 5 summarizes the rock properties in the model.

Table 5 – Rock Properties

Assumptions	Values
Ellenburger Porosity (%)	10
Cambrian Porosity (%)	12
K_H (mD)	20
K_V/K_H Ratio	0.1

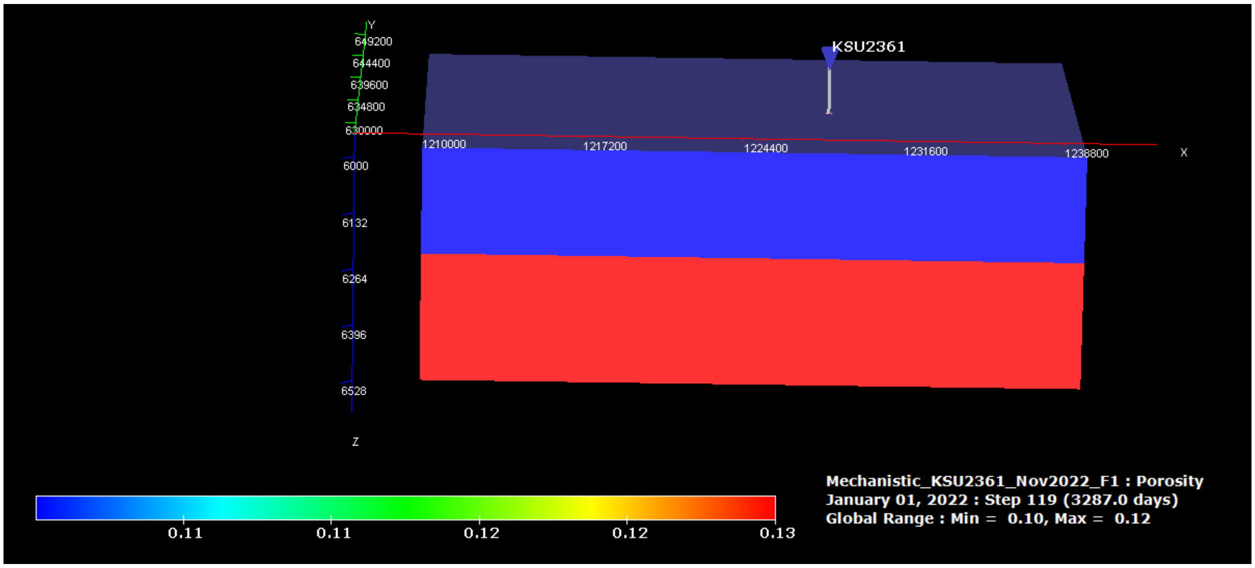


Figure 31 – Porosity Distribution in Plume Model

<u>Dynamic Model</u>

The primary objectives of the CO_2 plume model are as follows:

1. Determine the maximum possible injection rate without fracturing the target zone
2. Determine land acquisition strategy (i.e., maximum plume size)
3. Assess the likelihood of CO_2 leakage through potential conduits that may contaminate the Underground Source of Drinking Water (USDW)

Using the geomodel as an input, an infinite-acting model was built to simulate boundary conditions. The model assumes that the reservoir is 100% filled with brine. The formation fluid was estimated to have a salinity of 66,000 ppm. An offset step-rate test was utilized to estimate initial reservoir pressure and fracture pressure. Reservoir pressure was determined to be 2,600 psi which translates to a 0.435 psi/ft gradient. While pressure never reached high enough to propagate any fractures during the step-rate test, the fracture pressure was estimated to be approximately 4,390 psi. This translates to a fracture gradient of 0.683 psi/ft. Based off this data, a wellhead pressure of 1,850 psi was used to constrain the modelled well. An average temperature of 260 °F was also applied to the reservoir. Table 6 provides a summary of the initial conditions included in the simulation.

Table 6 – Initial Conditions Summary

Assumptions	Values
Permeability (mD)	20
Porosity (%)	10-12
Pore Gradient (psi/ft)	0.435
Frac Gradient (psi/ft)	0.683
Reservoir Temperature (°F)	260

To accurately and conservatively model the effective pore space of the rock, a net-to-gross (NTG) ratio was applied to the Ellenburger and Cambrian formations. The lateral plume extent is increased by reducing the total pore space CO_2 can flow through. Reducing the available pore space also limits

the CO_2 injection rate of the well due to higher increases in pressure. The Ellenburger had an NTG ratio of 0.5 applied, while the Cambrian formation had a 0.6 NTG ratio. This is further highlighted in Figure 32.

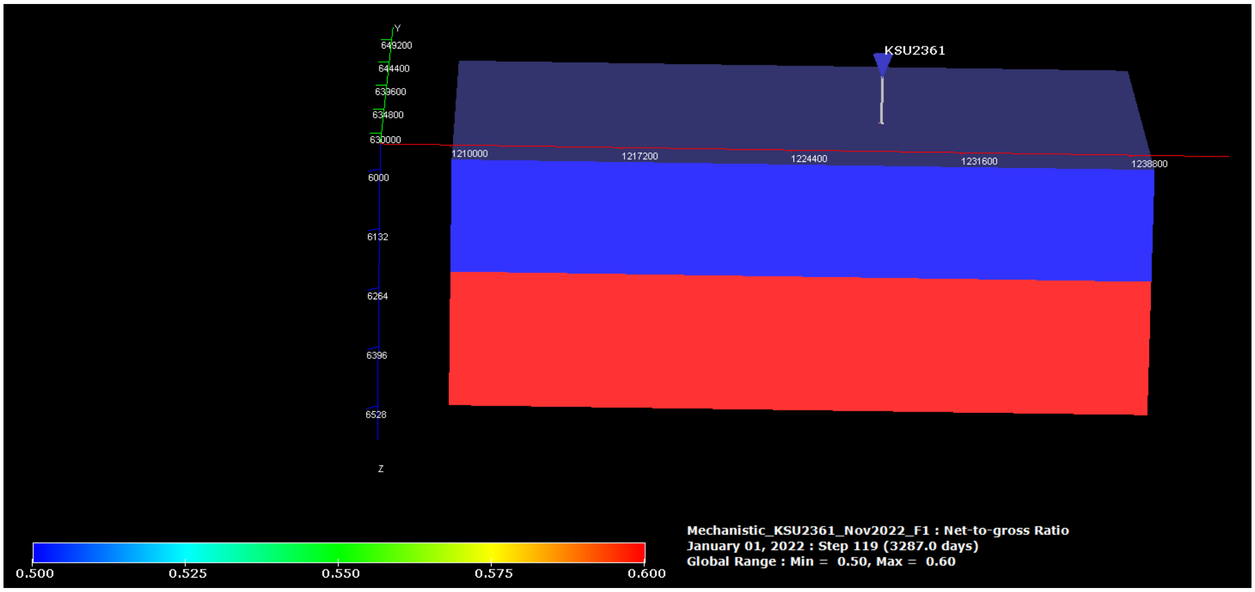


Figure 32 – NTG Ratio Applied to the Plume Model

Relative Permeability

Relative permeability curves were generated to represent a CO_2-brine system and how supercritical CO_2 will flow through a 100% brine-filled rock. Data from Kinder Morgan's McElmo Dome source models were utilized to create the relative permeability curves. The key inputs include a 9% irreducible water saturation and a 9% maximum residual gas saturation. Figure 33 shows the curves included in the simulation model.

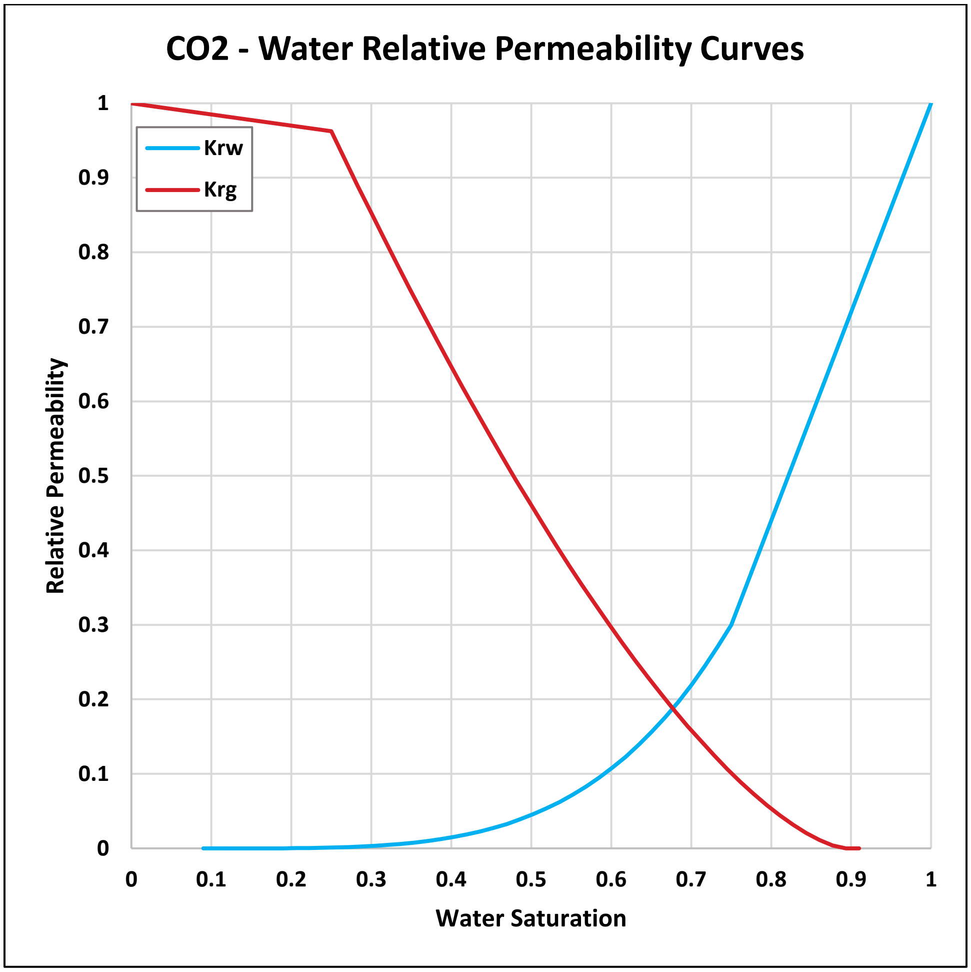


Figure 33 – CO_2-Water Relative Permeability Curves

History Matching

Two SWD wells were history-matched to determine permeability estimates. Historical injection rates were set in the model, and the simulated pressure response was compared to the recorded pressure data. This process was iterated multiple times until the simulated and real-life data matched. Monthly data points KSU 2361 (Figure 34) and KSU #3471 (Figure 35) were used to vary the injection rate in the model. These same intervals were used to compare the simulated results.

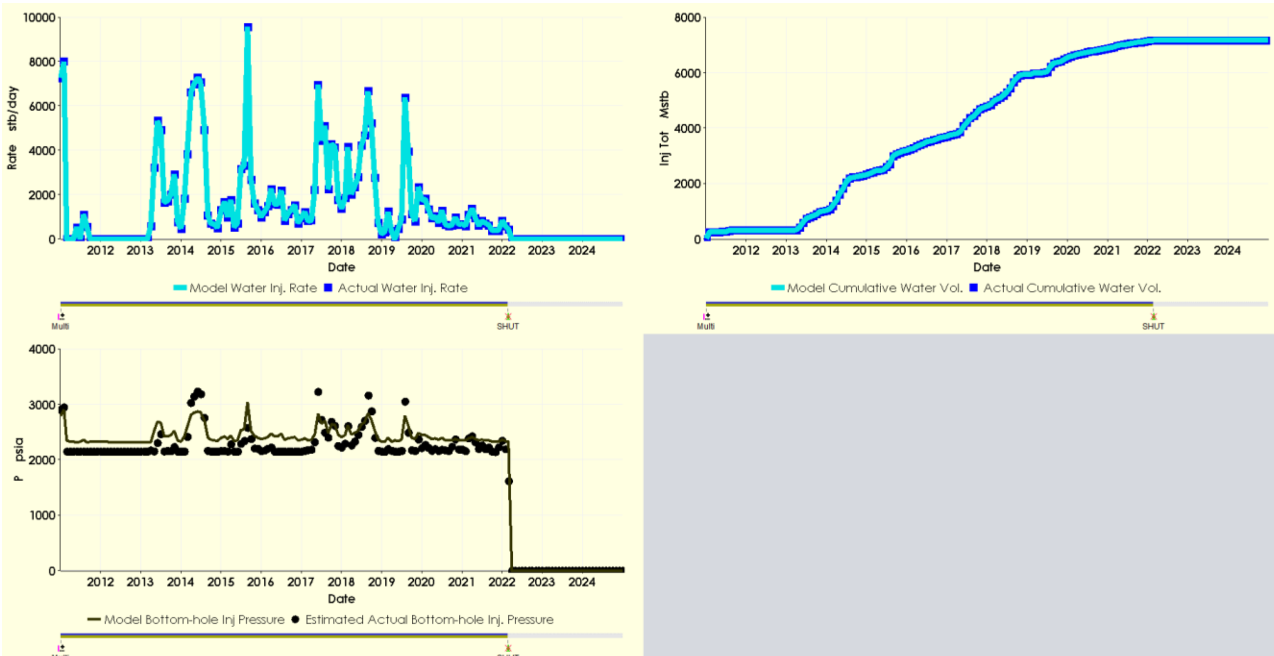


Figure 34 – History Match for KSU 2361

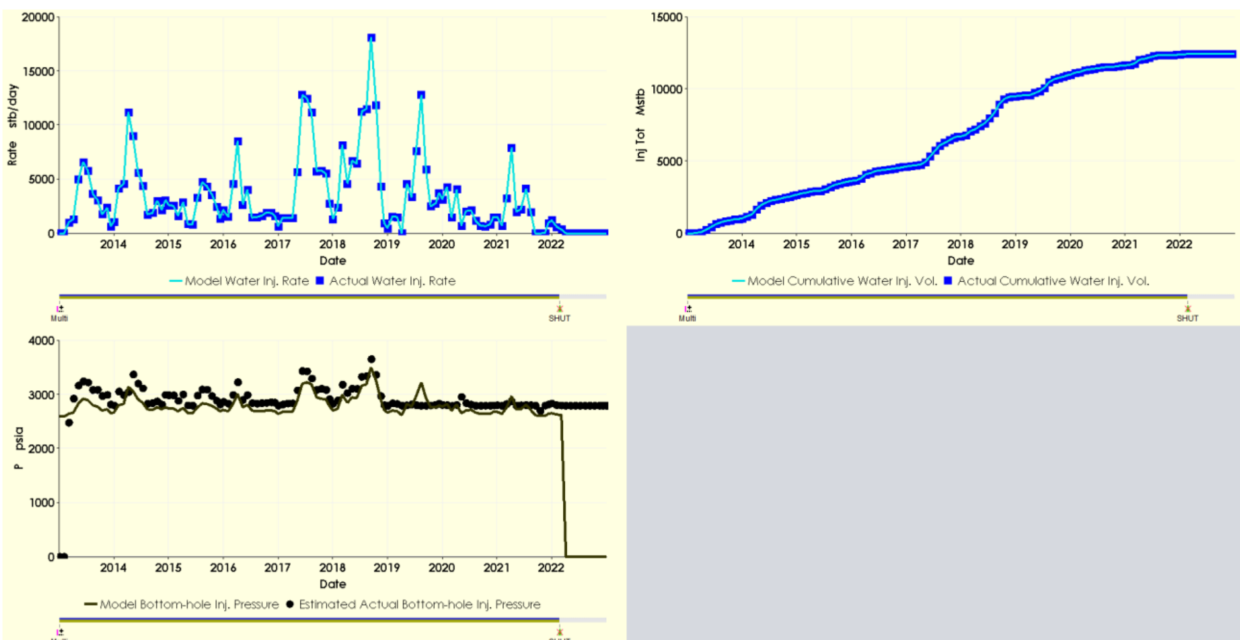


Figure 35 – History Match for KSU #3471

<u>CO_2 Injection Operations</u>

KSU 2361 was simulated to inject supercritical CO_2 for 21 years. A maximum wellhead pressure (WHP) was used to limit the injection rate. This value was determined from the fracture gradient estimation, and an equivalent wellhead pressure was calculated. The WHP constraint was set to 1,850 psi, equal to 84% of the fracture pressure. The injection rate was then maximized to stay

below the expected frac gradient. Figure 36 shows the simulated WHP during active injection operations.

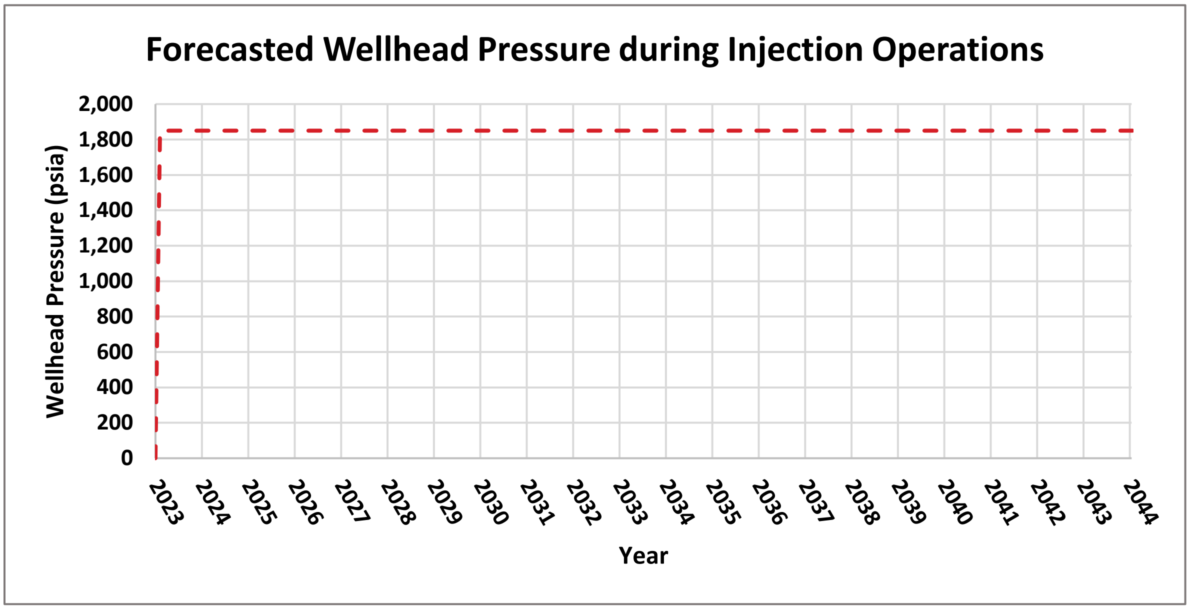


Figure 36 – Simulated Wellhead Pressure During Active Injection

During active injection, KSU 2361 achieved a maximum rate of approximately 1.22 MMT/yr. (~65 million cubic feet (MMscf)/day). The average rate throughout the injection period is expected to be 1.16 MMT/yr (~62 MMscf/day). During injection, the bottom hole pressure (BHP) reaches a maximum of 3,493 psi, which is safely below the fracture pressure. This is an 893-psi increase from the initial reservoir pressure. After injection ceases, the reservoir pressure decreases, reaching 65 psi buildup from the initial reservoir pressure. Figure 37 summarizes these results.

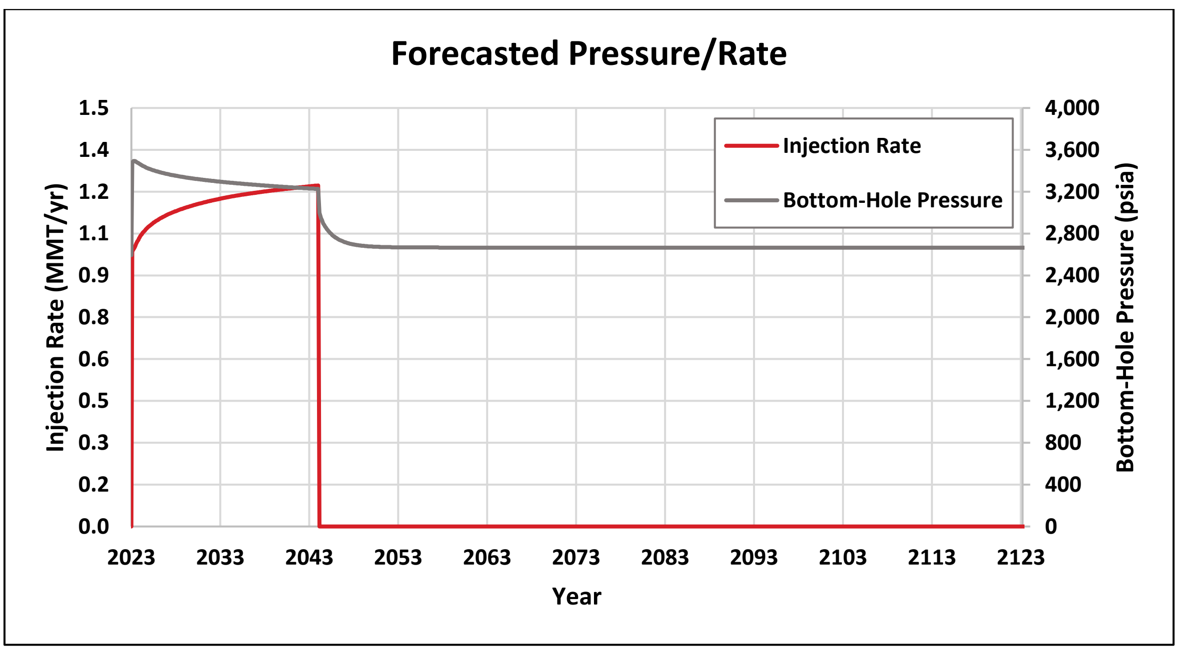


Figure 37 – Forecasted Injection Rate and BHP

Model Results

The maximum plume was determined once the plume was considered stabilized and by using a gas saturation cutoff of 3%. The plume is considered stabilized once all lateral and vertical movement of CO_2 has stopped, which also marks the end of the monitoring period. Aerial plume sizes were taken at 10-year intervals to determine a growth rate. As seen in Figure 38, an annualized growth rate is determined at each interval. The plume is delineated based on the maximum extent of the plume when the growth rate reaches 0%. In this model, the plume stabilizes in 2074, 30 years after the end of the injection period.

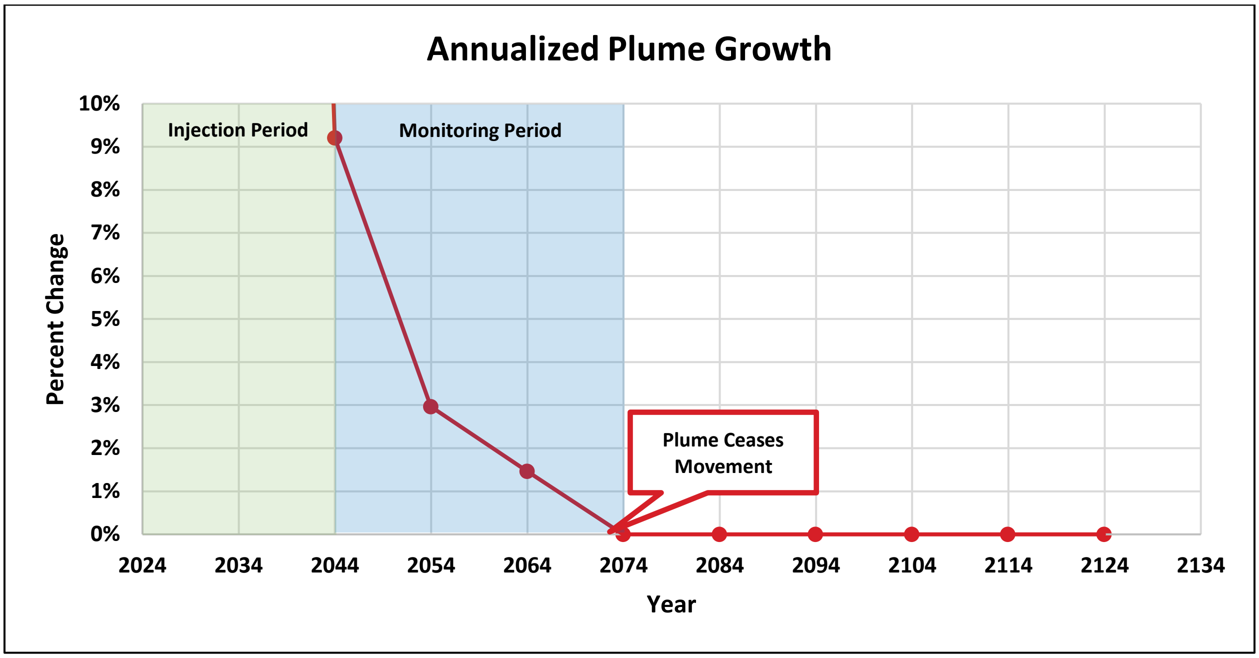


Figure 38 – Annualized Growth Rate of CO_2 Plume

The stabilized plume reaches a maximum of 3,384 ac (~5.3 sq mi). The furthest extent of this plume is to the South, as seen in Figure 39. The largest radius of the plume is 6,850' (~1.2 mi) from the wellbore. Due to the heterogeneity included in the model, the plume is not uniform from layer to layer, as seen in Figure 40. The maximum plume was chosen from the layer with the largest lateral extent of CO_2.

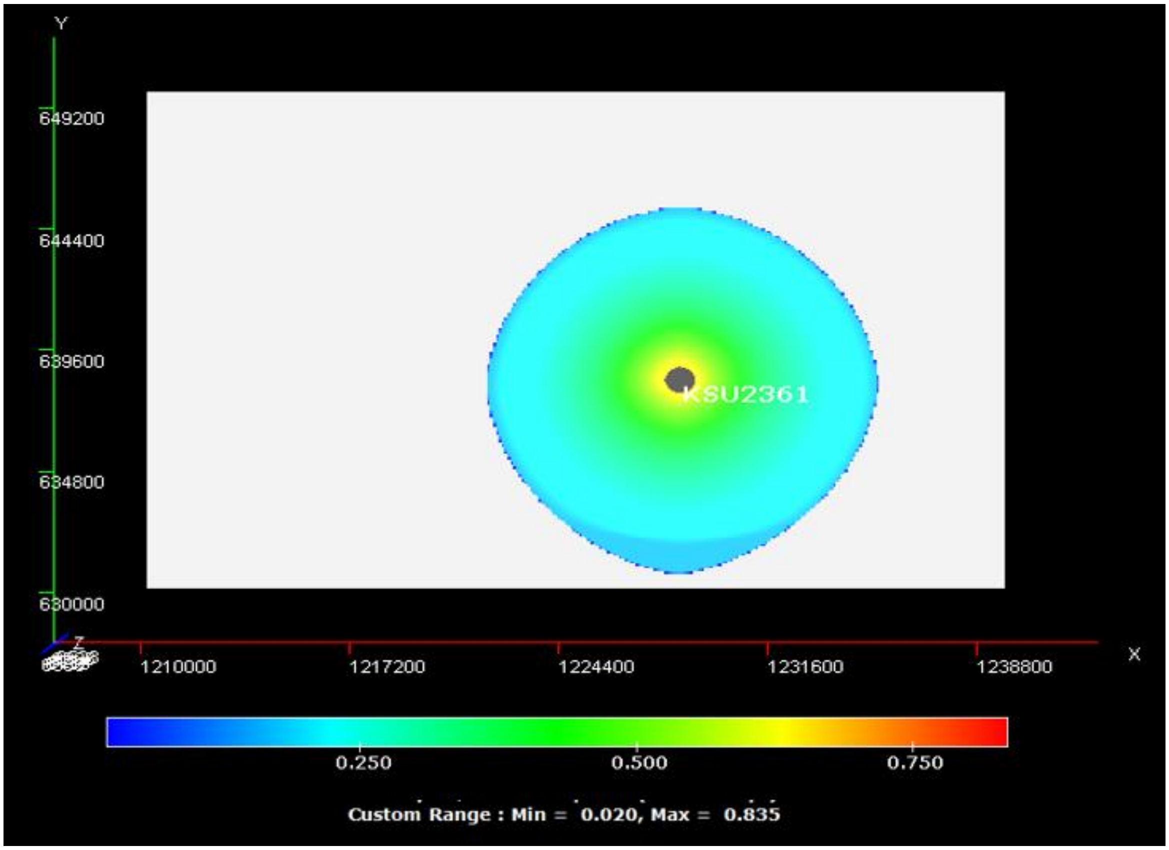


Figure 39 – Aerial View of CO_2 Plume

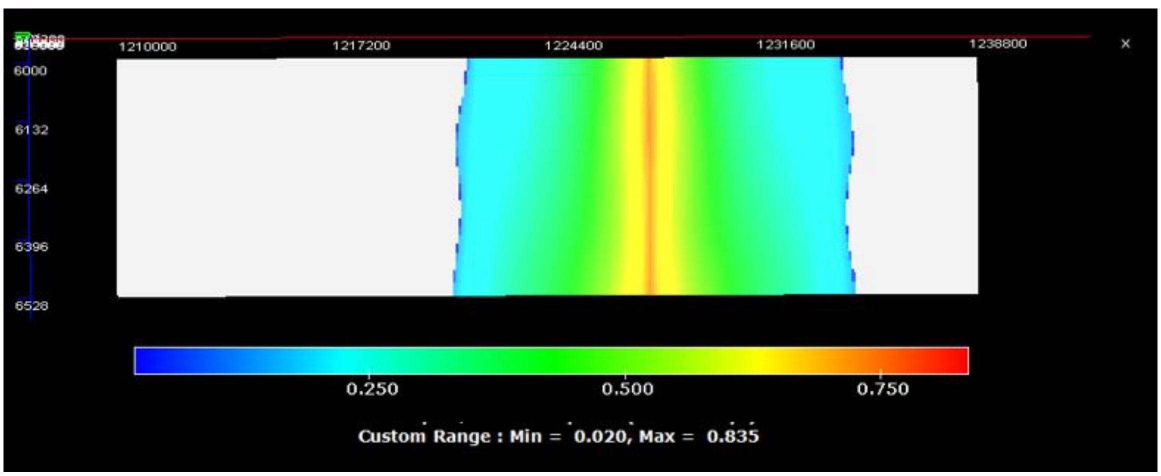


Figure 40 – Cross-Sectional View of CO_2 Plume

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA) as described in EPA 40 CFR §**98.448(a)(1**).

Maximum Monitoring Area

The EPA defines the MMA as equal to or greater than the area expected to contain the free-phase CO_2-occupied plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one-half mile. A numerical computer simulation was used to determine an estimate for the size and drift of the plume. Using a combination of Paradigm's SKUA-GOCAD and Aspen Technology's Tempest software packages, a geomodel, and reservoir model were used to determine the areal extent and density drift of the plume. The model accounts for the following considerations:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Kinder Morgan analyzed acid gas injectate was used as the initial composition in the model. The composition is provided in Appendix B. The molar composition of the gas is mostly carbon dioxide, with some small amounts of nitrogen and hydrocarbons. The molar composition was incorporated into the model as future CO_2 streams could be added for injection. As discussed in Section 2, the gas was modeled to be injected primarily into the Ellenburger and both Cambrian formations. The geomodel was created based on the rock properties seen in the Ellenburger and Cambrian rocks.

The weighted average gas saturation defined the plume boundary in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in 2044, the areal expanse of the plume will be 2,954 acres. The maximum distance between the wellbore and the edge of the plume is approximately 6,400'. After 80 additional years of density drift, the areal extent of the plume is 3,384 acres, with a maximum distance to the edge of the plume of approximately 6,850'. Since the plume shape is relatively circular, the maximum distance from the injection well after density drift was used to define the circular boundary of the MMA.

Since the AMA falls within the MMA, for defining the area of influence, only the MMA was used for this project. Figure 41 shows the stabilized plume boundary, the AMA, and the MMA.

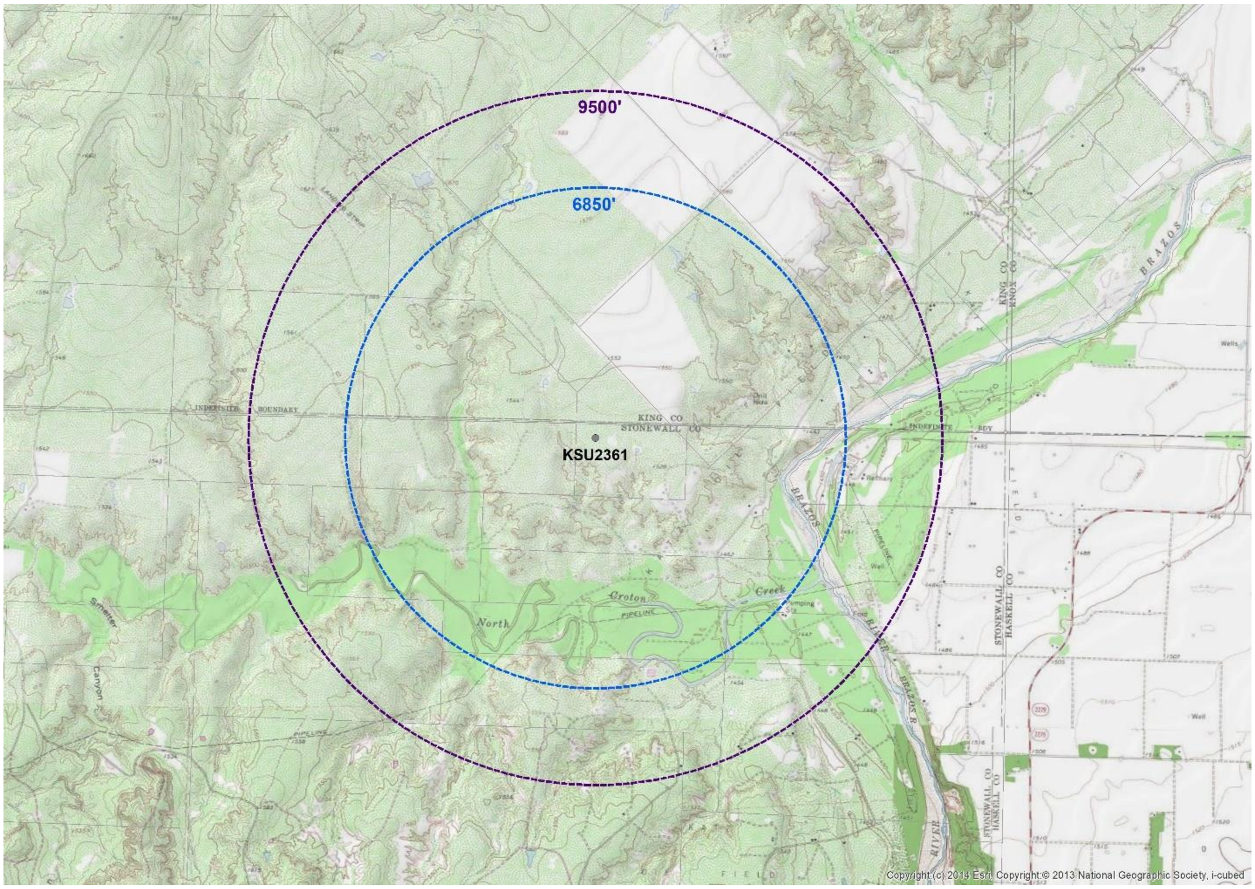


Figure 41 – Stabilized Plume Boundary, Active Monitoring Area, and Maximum Monitoring Area

Active Monitoring Area

The AMA will cover the initial 20-year monitoring period, equating to the expected total injection time. The AMA boundary was established by superimposing the area based on a half-mile buffer around the anticipated plume location at the end of injection (2044) with the area of the projected free-phase CO_2 plume at five additional years (2049). In this case, the plume boundary in 2049 is within the plume in 2044, plus a half-mile buffer. By 2044 at the latest, a revised MRV plan will be submitted to define a new AMA. Since the Active Monitoring Area boundary was determined to fall within the Maximum Monitoring Area boundary, the defined MMA was also used to define the effective AMA. Figure 41 shows the area covered by the MMA, which encompasses the AMA.

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies the potential pathways for CO_2 to leak to the surface within the MMA. Also included are the likelihood, magnitude, and timing of such leakage. The potential leakage pathways are:

- Leakage from surface equipment
- Leakage through existing wells within the MMA
- Leakage through faults and fractures
- Leakage through the confining layer
- Leakage from Natural or Induced Seismicity

Leakage from Surface Equipment

The surface facilities at the KSU 2361 well are designed for injecting acid gas primarily consisting of CO_2. The facilities have been designed to minimize leakage and failure points. The design and construction of these facilities followed industry standards and best practices. CO_2 gas detectors are located around the facility and the well site. These gas detector alarms will be triggered at levels set upon completion of a baseline study of the ambient air quality, followed by a gas dispersion model. An emergency shutdown valve (ESD) is located at the wellhead and is locally controlled by pressure, with a high-pressure and low-pressure shut-off.

The facilities have been designed and constructed with other safety systems to provide for safe operations. These systems include ESD valves to isolate portions of the pipeline, pressure relief valves along the pipeline to prevent over-pressurization, and venting to allow piping and equipment to be de-pressured under safe and controlled operating conditions in the event of a leak. More information on these systems and be found in Appendix C. Should Kinder Morgan construct additional CO_2 facilities other meters will be installed as needed to comply with the 40 CFR **§98.448(a)(5**) measurement. These meters will be near the existing facilities and utilize the existing monitoring programs discussed previously. Additionally, CO_2 monitors will be installed near the new meters and tied into the facility monitoring systems.

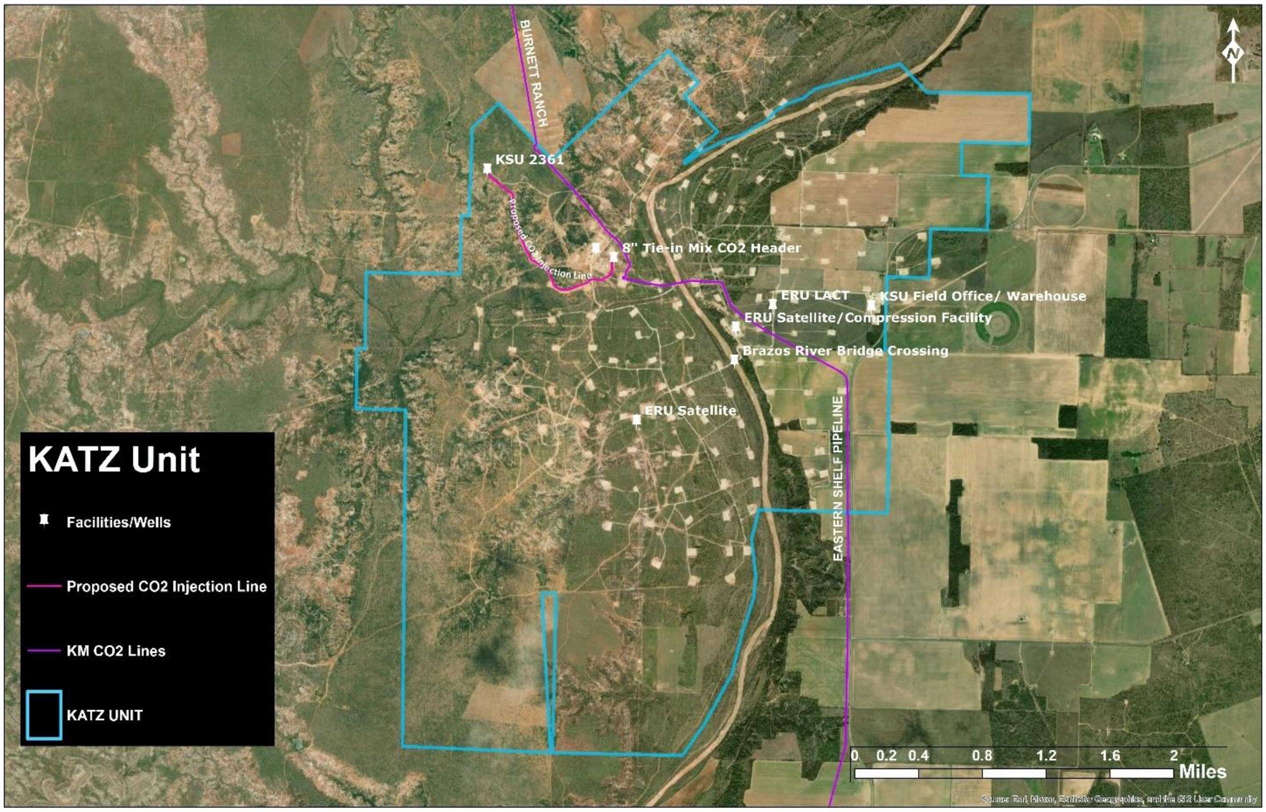


Figure 42 – Site Plan

With the level of monitoring implemented at the KSU 2361 well, a release of CO_2 would be quickly identified, and the safety systems would minimize the release volume. The CO_2 stream injected into KSU 2361 includes small amounts of methane (0.2%) and nitrogen (2.0%). If any leakage were to be detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release, as stated in Section 7 in accordance with 40 CFR **§98.448(a)(5)**.

Leakage from Existing Wells within MMA

Oil and Gas Operations within Monitoring Area

A significant number of wells have historically been drilled within the area of the KSU 2361 well. However, production has primarily been from the shallower Strawn formation in the Katz Field. The Strawn is separated from the Ellenburger-Cambrian interval by 665' in this area. In addition to the primary Strawn production, a few wells have produced from the Mississippian. The mid-Mississippian is separated from the Ellenburger-Cambrian interval by 133'. **Within the projected plume area of the KSU 2361 well, there are zero penetrations of the injection interval.**

The KSU 2361 well was designed to prevent migration from the injection interval to the surface through the casing and cement placed in the well, as depicted in the schematic denoted in Figure 43. Mechanical integrity tests (MIT), required under SWR **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every five years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 44. The MMA review map and a summary of all the wells in the MMA are provided in Appendix D. Figure 45 highlights that no wells penetrate the MMA's gross injection zone.

KINDER MORGAN

Schematic - Current

Well Name: KSU #2361

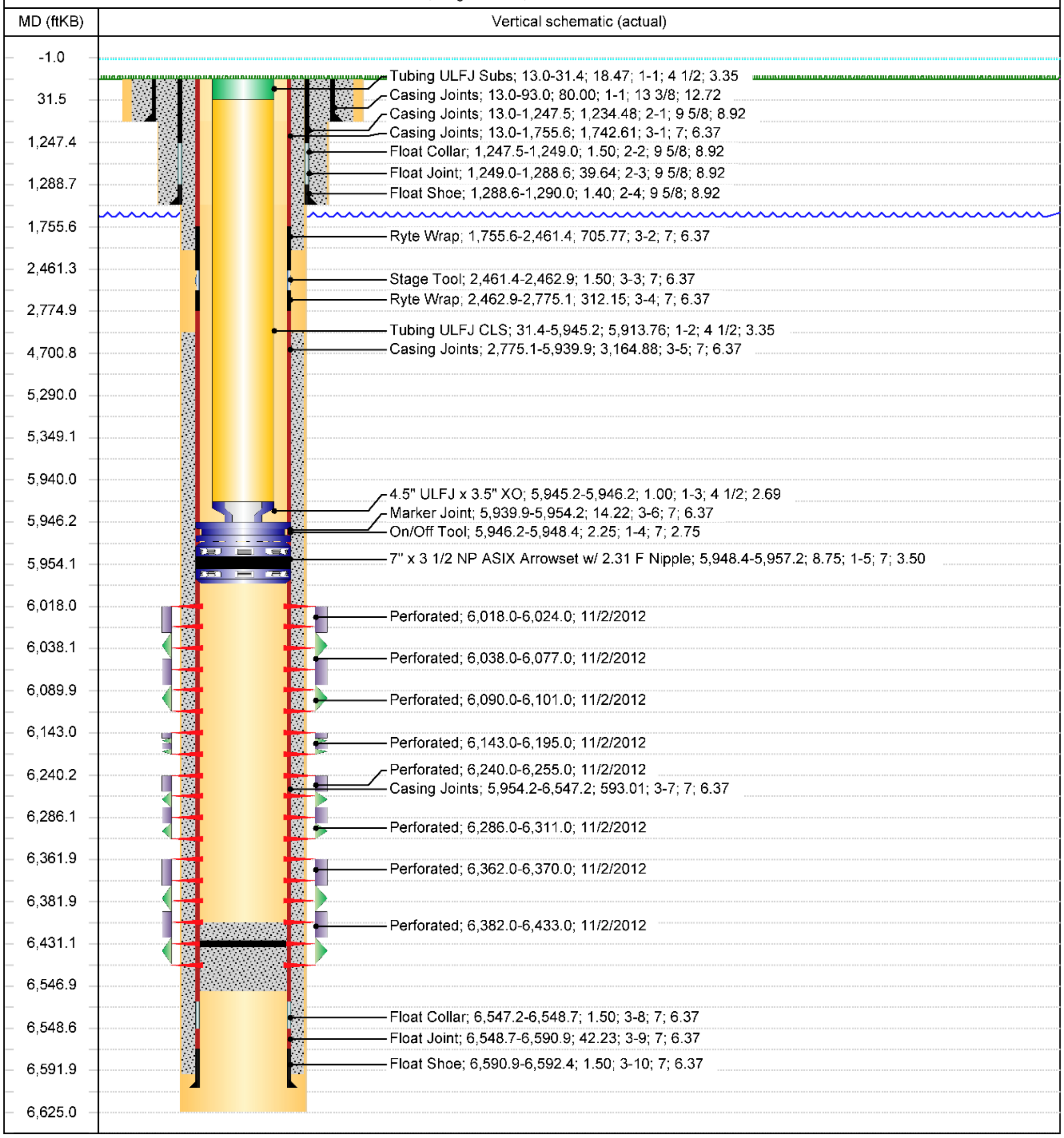
API/UWI	Surface Location	Field Name	State	Well Configuration Type	RRC/COGC...	Account Cat/Prop...
42-433-33712	SEC 2 LONG, CB	KATZ	Texas	Vertical		26039

Estimated KB Elevation (ft)	KB-Tubing Head Distance (ft)	Original Well Spud Date	Rig Release Date	PBTD (All) (ftKB)	Total Depth All (TVD) (ftKB)
1,531.00	13.00	8/23/2012 18:00	9/13/2012 06:00	Original Hole - 6,431.0	

Most Recent Job

Job Category	Primary Job Type	Secondary Job Type	Start Date	End Date
Non-Rig Activity	Coil Tubing		4/2/2019	4/4/2019

TD: 6,625.0 Vertical, Original Hole, 2/21/2022 10:06:22 AM



Page 1/1 **Report Printed: 2/21/2022**

Figure 43 – KSU 2361 Wellbore Schematic

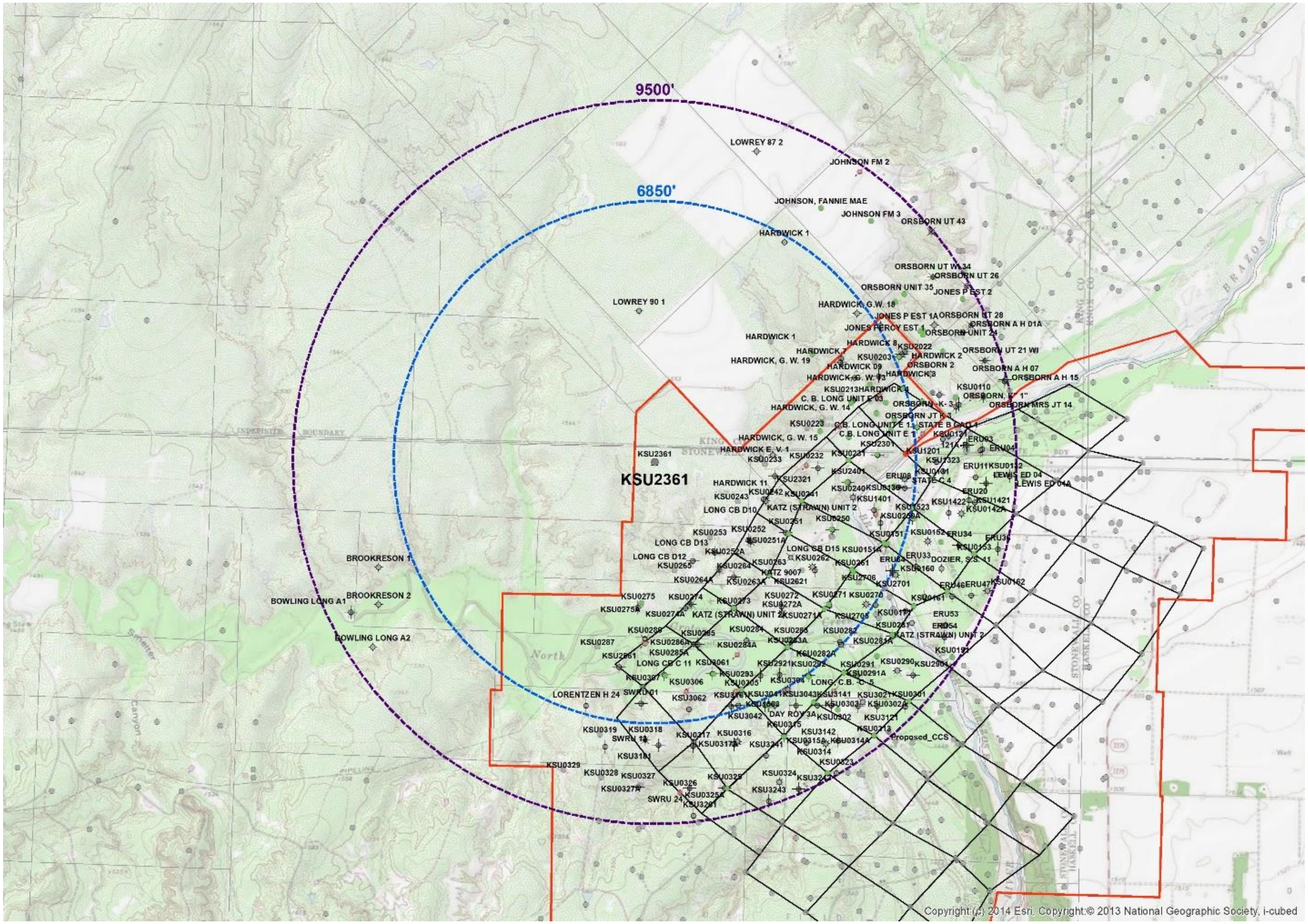


Figure 44 – All Oil and Gas Wells within the MMA

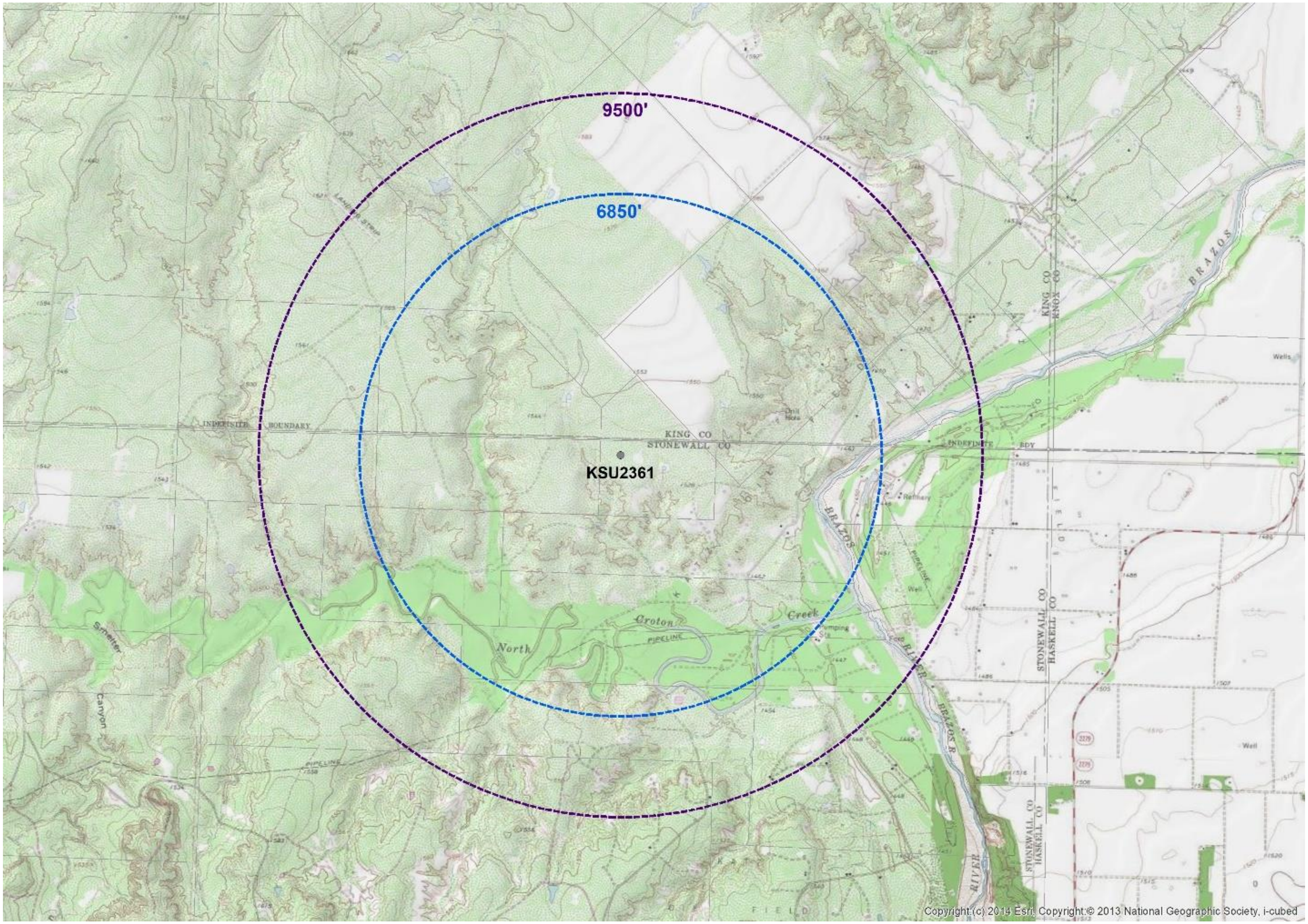


Figure 45 – Oil and Gas Wells Penetrating the Gross Injection Interval within the MMA

Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations, such as the Pre-Cambrian, have proven to date to be less productive or non-productive in this area, which is why the location was selected for injection. Furthermore, any drilling permits issued by the TRRC in the area of KSU 2361 include a list of formations for which oil and gas operators are required to comply with TRRC Rule 13 (entitled "Casing, Cementing, Drilling, Well Control, and Completion Requirements"), 16 TAC **§3.13**. By way of example, see the KSU 2361 well drilling permit provided in Appendix A. The Ellenburger and Cambrian Sands are among the formations listed for which operators in Stonewall County and district 7B (where the KSU 2361 is located) are required to comply with TRCC Rule 13. TRRC Rule 13 requires oil and gas operators to set steel casing and cement across and above all formations permitted for injection under TRRC Rule 9 or immediately above all formations permitted for injection under Rule 46 for any well proposed within a one-quarter mile radius of an injection well. In this instance, any new well permitted and drilled to the KSU 2361 well's injection zone, and located within a one-quarter-mile radius of the KSU 2361 well, will be required under TRRC Rule 13 to set steel casing and cement above the KSU 2361 well injection zone. Additionally, Rule 13 requires operators to case and cement across and above *all* potential flow zones and zones with corrosive formation fluids. The TRRC maintains a list of such known zones by TRRC district and county and provides that list with each drilling permit issued, which is also shown in the permit mentioned above in Appendix A.

Groundwater wells

A groundwater well search resulted in zero groundwater wells found within the MMA, as identified by the Texas Water Development Board.

The surface and intermediate casings of the KSU 2361 well, as shown in Figure 43, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the GAU letter issued for this location. See the GAU letter included in Appendix A. The wellbore casings and cements also prevent CO_2 leakage to the surface along the borehole.

Leakage Through Faults and Fractures

One fault was interpreted within the seismic coverage projecting 12,000’ east of the KSU 2361 location. Initial plume models do not indicate an interaction between the injectate and the fault plane. Additionally, this fault dies within the Mississippian formation and does not penetrate the Lower Strawn Shale that acts as the upper confining unit. In the unlikely scenario in which the injection plume reaches the fault, and the fault acts as a transmissive pathway, the upper confining shale above the fault will act as an ideal sealant from injectate leaking outside of the permitted injection zone.

Should an unmapped fault exist within the plume boundary, the offset would be below 3D seismic resolution. The offset would be less than the thickness of the Lower Strawn Shale, juxtaposing it against itself, preventing vertical migration.

Fractures and subsequent subaerial exposure are responsible for porosity development within the injection intervals. Open hole logs show little to no porosity development indicating the Lower Strawn Shale or Mississippian Lime were not exposed at this location. Therefore, upward migration of injected gas through confining bed fractures is unlikely.

Leakage Through the Confining Layer

The Ellenburger and Cambrian injection zones have competent sealing rocks above and below the sand and carbonate formations. The properties of the overlying Lower Strawn Shale and its high composition of shale and mudstone make an excellent sealing rock to the underlying Ellenburger formation. Tight Mississippian Lime of roughly 266’ lies between the Ellenburger and Lower Strawn Shale formations forming an impermeable upper buffer seal from the injection interval to the upper confining zone. Above this confining unit, shales found within the Homecreek Shale above the Desmoinesian formation will act as additional sealants between the injection interval and the USDW. The USDW lies above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. Precambrian basement rock's underlying low porosity and permeability minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injected gas to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

Leakage from Natural or Induced Seismicity

The location of KSU 2361 is in an area of the Midland Basin that is inactive from a seismicity perspective, whether induced or natural. A review of historical seismic events on the USGS’s Advanced National Seismic System site (from 1971 to present) and the Bureau of Economic Geology’s TexNet catalog (from 2017 to present), as shown in Figure 46, indicates the nearest seismic event occurred more than 40 miles away.

There is no indication of seismic activity posing a risk for loss of CO_2 to the surface within the MMA.

Pressures will be kept significantly below the fracture gradient of the injection and confining intervals. Additionally, continuous well monitoring combined with seismic monitoring will identify any operational anomalies associated with a seismicity event.

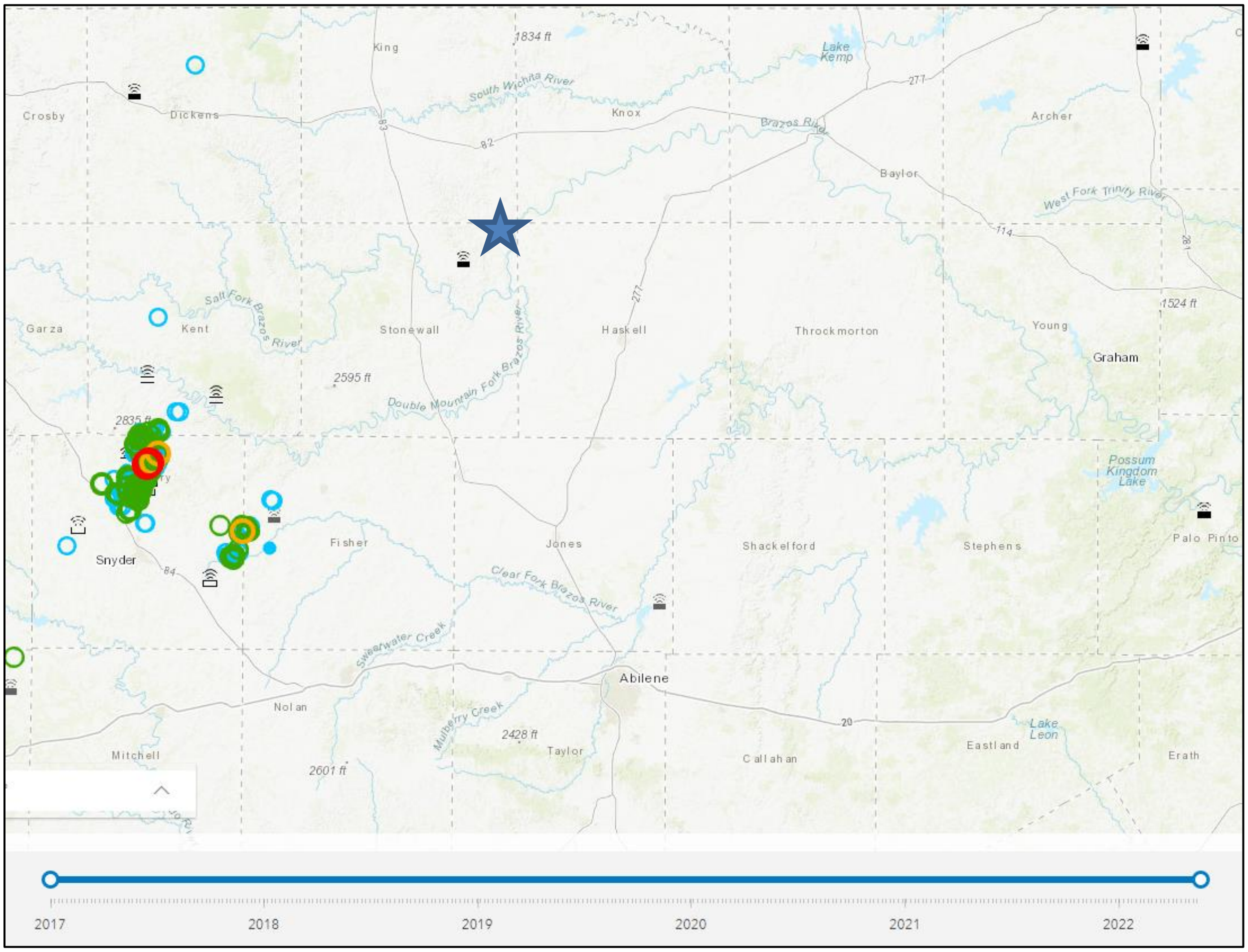


Figure 46 – Seismicity Review (TexNet – 06/01/2022)

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Kinder Morgan will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4 to meet the requirements of 40 CFR **§98.448(a)(3)**. Table 7 summarizes the monitoring of potential leakage pathways to the surface. Monitoring will occur during the planned 21-year injection period or cessation of injection operations, plus a proposed 5-year post-injection period.

- Leakage from surface equipment failure
- Leakage through existing and future wells within MMA
- Leakage through faults, fractures, or confining seals
- Leakage through natural or induced seismicity

Table 7 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed CO_2 monitors throughout the AGI facility
	Daily visual inspections
	Supervisory Control and Data Acquisition (SCADA)
Leakage through existing wells	Fixed CO_2 monitor at the the AGI well
	SCADA continuous monitoring at the AGI Well
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Quarterly atmospheric CO_2 measurements at well locations within the AMA
Leakage through groundwater wells	Annual groundwater samples from monitoring wells
Leakage from future wells	CO_2 monitoring during offset drilling operations
Leakage through faults and fractures	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage through confining layer	SCADA continuous monitoring at the AGI Well (volumes and pressures)
	In-field CO_2 monitors
Leakage from natural or induced seismicity	Existing TexNet seismic monitoring station to be implemented

Leakage from Surface Equipment

As the facility and the KSU 2361 well are designed to handle CO_2, leakage from surface equipment is unlikely to occur and would be quickly detected and addressed. The facility design minimizes leak points through the equipment used, and the connections are designed to minimize corrosion points. A baseline atmospheric CO_2 concentration will be established before injection operations begin. The facility and well site contain several CO_2 alarms with locations in close proximity.

The AGI complex is continuously monitored through automated systems. Details surrounding these systems can be found in Appendix C. In addition, field personnel conduct daily visual field inspections of gauges, monitors, and leak indicators such as vapor plumes. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and inspection of the cathodic protection system. These inspections and the automated systems allow Kinder Morgan to respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)**.

Pressures and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak.

Leakage From Existing and Future Wells within MMA

Kinder Morgan continuously monitors and collects injection volumes, pressures and temperatures through their SCADA systems, for the KSU 2361 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. KSU 2361 has a pressure and temperature gauge placed in the injection stream at its wellhead and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. In addition, mechanical integrity tests (MIT) performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and the leak mitigated.

As discussed previously, Rule 13 would ensure that new wells in the field would be constructed to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Kinder Morgan will also establish and operate an in-field monitoring program to detect CO_2 leakage within the MMA. The scope of work will include CO_2 monitoring at the AGI well site and, at minimum, quarterly atmospheric monitoring near any wells identified that penetrate the injection interval within the MMA. The collection of these measurements will be carried out by using a qualified third party. Upon approval of the MRV and through the post-injection monitoring period, Kinder Morgan will have these monitoring systems in place. No wells have been identified within the MMA that penetrate the injection interval. Additional monitoring will be added as the MMA is updated over time.

Groundwater Quality Monitoring

Kinder Morgan will monitor the groundwater quality in fluids above the confining interval by sampling from groundwater wells in the area of the facility and analyzing the sample with a third-party laboratory on an annual basis. In the case of KSU 2361, no existing groundwater wells have been identified within the MMA. At least two groundwater monitoring wells will be drilled within 1500' of KSU 2361 at a depth of approximately 100'. The final number, locations, and depths of the wells will be determined by a study completed by a certified 3rd party firm. The approximate location and depths of these wells are shown in Figure 47. A baseline sampling from these wells will occur before injection starts. The parameters to be measured will include pH, total dissolved solids, total inorganic and organic carbons, density, temperature, and other standard laboratory measurements. Any significant differences in these parameters from the baseline sample will be evaluated to determine if leakage of CO_2 to the USDW may have occurred.

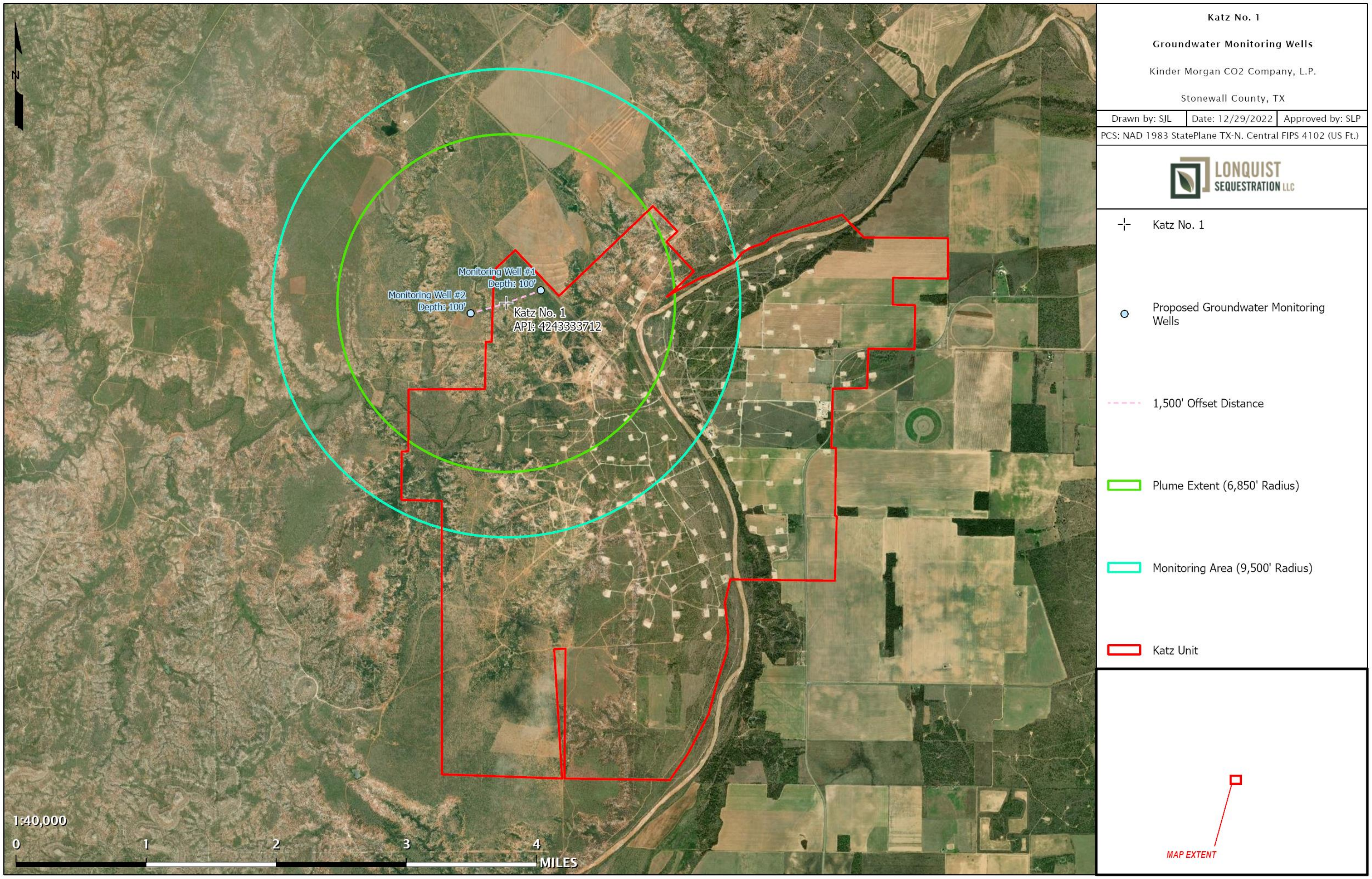


Figure 47 – Groundwater Monitoring Wells

Leakage through Faults, Fractures or Confining Seals

Kinder Morgan continuously monitors the operations of the KSU 2361 well through automated systems. Any deviation from normal operating conditions indicating movement into a potential pathway, such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. In addition, a field monitoring system is proposed to measure the shallow topsoil CO_2 concentrations across the MMA. These measurements will be taken quarterly by in-field gas sensors. The field CO_2 monitoring systems would alert field personnel for any release of CO_2 caused by such leakage.

Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, Kinder Morgan plans to use the nearest TexNet seismic monitoring station to monitor the area of the KSU 2361 well. This station is 7.29 miles southwest of the well location, as shown below in Figure 48. This is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity surrounding the Katz Unit. Kinder Morgan will monitor this station for any seismic activity that occurs near the well. If a seismic event of 3.0 magnitude or greater is detected, Kinder Morgan will review the injection volumes and pressures at the KSU 2361 well to determine if any significant changes occur that would indicate potential leakage.

Figure 48 – Nearest TexNet Seismic Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Kinder Morgan will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Kinder Morgan will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2.

Visual Inspections

Daily inspections will be conducted by field personnel at the facility and the KSU 2361 well. These inspections will aid with identifying and addressing issues timely to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken to address such issues.

CO_2 Detection

In addition to the well site fixed monitors described previously, Kinder Morgan will establish and operate an in-field monitoring program to detect any CO_2 leakage within the MMA. The scope of baseline determination will include atmospheric CO_2 measurements at the AGI well site and near identified penetrations within the MMA. Topsoil CO_2 concentrations will also be measured, at pre-determined locations within the MMA, as baseline values before injection activities begin.

Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be taken. Any significant deviations over time will be analyzed for indication of leakage of CO_2.

Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this project are well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Gas detectors and continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a blowdown event, emissions will be sent to vent stacks and will be reported as required for the operation of the well.

Groundwater Monitoring

Initial samples will be taken from the groundwater monitoring wells drilled within 1,500 feet of the KSU 2361 well upon approval of Kinder Morgan's MRV and before commencing injection of CO_2. A third-party laboratory will analyze the samples to establish the baseline properties of the groundwater.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

This section identifies how Kinder Morgan will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR **§98.448(a)(5)**.

Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

Mass of CO_2 Injected

Per 40 CFR **§98.444(b)**, since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters per quarter)

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction)

p = Quarter of the year

u = Flow meter

Mass of CO_2 Produced

The KSU 2361 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains concentrations well beyond the OSHA PEL 8-hour TWA limit of 5,000 ppm. Direct leak surveys are dangerous and present a hazard to personnel. Any leakage would be detected and managed as an upset event. Gas detectors and continuous monitoring systems should trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released as a result of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_2 = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12, as this well will not actively produce oil or natural gas, or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

CO_{2FI} will be calculated in accordance with Subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the blowdown emissions sent to flares and reported as part of the required GHG reporting for the gas plant.

- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The KSU 2361 well currently reports GHGs under Subpart UU, but Kinder Morgan has elected to submit an MRV plan under, and otherwise comply with, Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed by March 31st of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Kinder Morgan plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

Monitoring QA/QC

CO_2 *Injected*

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to Kinder Morgan Standards.

CO_2 *Emissions from Leaks and Vented Emissions*

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to Kinder Morgan and industry standards.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR §98.3(i) requirements**.**
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1 atmosphere.

Missing Data

In accordance with 40 CFR **§98.445**, Kinder Morgan will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR **§98.**

MRV Plan Revisions

If any changes outlined in 40 CFR **§98.448(d)** occur, Kinder Morgan will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

SECTION 10 – RECORDS RETENTION

Kinder Morgan will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least three years and include the following:

- Quarterly records of the CO_2 injected
  - Volumetric flow at standard conditions
  - Volumetric flow at operating conditions
  - Operating temperature and pressure
  - Concentration of the CO_2 stream
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of the information used to calculate CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

References

Adams, Donald & Keller, Randy. (1996). Precambrian Basement Geology of the Permian Basin Region of West Texas and Eastern New Mexico: A Geophysical Perspective. AAPG Bulletin. 80. 410-431. 10.1306/64ED87FA-1724-11D7-8645000102C1865D.

Broadhead, Ronald E., 2005. Regional Aspects of the Wristen petroleum system, southeastern New Mexico: New Mexico Bureau of Geology and Mineral Resources Open File Report, no. 485.

Comer, John B., 1991. Stratigraphic Analysis of the Upper Devonian Woodford Formation, Permian Basin, West Texas and Southeastern New Mexico: Bureau of Economic Geology Report of Investigations, no. 201.

Conselman, F. B. (1954). Preliminary Report on the Geology of the Cambrian Trend of West Central Texas. *Abilene Geologic Society*.

Ewing et al. (2004). Groundwater Availability Model for the Seymour Aquifer. *Texas Water Development Board.*

Galley, J. (1958). Oil and Geology in the Permian Basin of Texas and New Mexico. *Basin or Areal Analysis or Evaluation*.

George, Peter G., Mace, Robert E., and Petrossian, Rima, 2011. Aquifers of Texas: Texas Water Development Board Report, no 380.

Gunn, R. D. (1982). Desmoinesian Depositional Systems in the Knox Baylor Trough. *North Texas Geological Society*.

Harding, R.W. and Associates. (1978). THE SEYMOUR AQUIFER: Ground-Water Quality and Availability in Haskell and Knox Counties, Texas. *Texas Department of Water Resources.*

Hendricks, L. (1964). STRATIGRAPHIC SUMMARY OF THE ELLENBURGER GROUP OF NORTH TEXAS. *Tulsa Geological Society Digest, Volume 32*.

Hoak, T., Sundberg, K., and Ortoleva, P. Overview of the Structural Geology and Tectonics of the Central Basin Platform, Delaware Basin, and Midland Basin, West Texas and New Mexico: Department of Energy Open File Report.

Holtz, M.H., and Kerans, C. (1992). Characterization and categorization of West Texas Ellenburger reservoirs. *Permian Basin Section SEPM Publication No. 92-22, p. 31-44.*

Hornhach, M. J. (2016). Ellenburger wastewater injection and seismicity in North Texas. *Physics of the Earth and Planetary Interiors*.

Jesse G. White, P. P. (2014). Reconstruction of Paleoenvironments through Integrative Sedimentology and Ichnology of the Pennsylvanian Strawn Formation. *AAPG Southwest Section Annual Convention, Midland, Texas*.

Kane, S. C. (n.d.). THE MISSISSIPPIAN BARNETT FORMATION: A SOURCE-ROCK, SEAL, AND RESERVOIR PRODUCED BY EARLYCARBONIFEROUS FLOODING OF THE TEXAS CRATON. *BEG*.

Kerans, C. (1989). Karst-controlled reservoir heterogeneity and an example from the Ellenburger Group (Lower Ordovician) of West Texas. *Bureau of Economic Geology.*

Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas. *Bureau of Economic Geology*.

Kupecz, J.A., and L.S. Land. (1991). Late-stage dolomitization of the Lower Ordovician Ellenburger Group, West Texas. *Journal of Sedimentary Petrology.*

Kyle, J.R. and E.F. McBride. (2014). Geology of the Voca Frac Sand District, western Llano Uplift, Texas. *Arizona Geological Survey Special Paper #9, Chapter 2, p. 1-13.*

Loucks, R. (2003). REVIEW OF THE LOWER ORDOVICIAN ELLENBURGER GROUP OF THE PERMIAN BASIN, WEST TEXAS. *Bureau of Economic Geology*.

Mason, C. C. (1961). GROUND-WATER GEOLOGY OF THE HICKORYSANDSTONE MEMBER OF THE RILEY FORMATION. McCULLOCH COUNTY. TEXAS. *TEXAS BOARD OF WATER ENGINEERS*.

Molina, Oscar, Vilarras, Victor, and Zeidouni, Mehdi, 2016. Geologic carbon storage for shale gas recovery: 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18.

Ruppel, Stephen C. and Holtz, Mark H., 1994. Depositional and Diagenetic Facies Patterns and Reservoir Development in Silurian and Devonian Rocks of the Permian Basin: Bureau of Economic Geology Report of Investigations, no. 216.

Snee, Jens-Erik Lund and Zoback, Mark D., 2016. State of stress in the Permian Basin, Texas and New Mexico: Implications for induced seismicity.

Teeple, Andrew P., Ging, Patricia B., Thomas, Jonathan V., Wallace, David S., and Payne, Jason D., 2021. Hydrogeologic Framework, Geochemistry, Groundwater-Flow System, and Aquifer Hydraulic Properties Used in the Development of a Conceptual Model of the Ogallala, Edwards-Trinity (High Plains), and Dockum Aquifers In and Near Gaines, Terry, and Yoakum Counties, Texas: USGS Scientific Investigations Report 2021-5009.

APPENDICES

APPENDICES

APPENDIX A – TRRC FORMS KSU #2361

APPENDIX A-1: UIC CLASS II ORDER

APPENDIX A-2: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-3: DRILLING PERMIT

APPENDIX A-4: COMPLETION REPORT

A-1

CHRISTI CRADDICK, CHAIRMAN
RYAN SITTON, COMMISSIONER
WAYNE CHRISTIAN, COMMISSIONER

DANNY SORRELLS
ASSISTANT EXECUTIVE DIRECTOR
DIRECTOR, OIL AND GAS DIVISION
PAUL DUBOIS
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 13453 AMENDMENT

KINDER MORGAN PRODUCTION CO LLC
6 DESTA DRIVE STE 6000
MIDLAND, TX 79705

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated August 27, 2018 for the permitted interval of the ELLENBURGER, and CAMBRIAN formations and subject to the following terms and special conditions:

KATZ (STRAWN) UNIT (30524) LEASE
KATZ (STRAWN) FIELD
STONEWALL COUNTY, DISTRICT 7B

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
2361	43333712	000104281	Salt Water, and Other Non-Hazardous O/G Waste	5,800	6, 435	30,000	N/A	2,900	N/A

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
2361	43333712	**1. According to the cross-section submitted by the operator the Pre-Cambrian top is at 6440 feet and hence the PBTD shall be at 6435 feet (deepest perforations are at 6433 feet per RRC records). Operator agreed to this permit special condition provision in the email dated on 11-29-2018. A copy of Form W-15 Cementing Record must be filed with the Form H-5 Injection Well Pressure Test Report prior to injection documenting compliance with this Special Condition.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer;
   b. beginning any work over or remedial operation;
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500 psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON December 31, 2018.

Sean Avitt, Manager
Injection-Storage Permits Unit

Amendment Comments:

Well No.	API No.	Amendment Comments
2361	43333712	**1. Amends maximum daily injection volume for liquid from 20000 bbl/day.** **2. Amends packer setting depth from 5750 feet.** **3. Amends permit dated November 21, 2011.**

Note: This document will only be distributed electronically.

DEPTH OF USABLE-QUALITY GROUND WATER TO BE PROTECTED

Texas Commission on Environmental Quality
Surface Casing Program

TCEQ

Date: July 21, 2010

TCEQ File No.: SC- 5504

API Number: 43333592

Attention: ROSE BURDITT

RRC Lease No. 000000

SC_463316_43333592_000000_5504.pdf

KINDER MORGAN PRODUCTION CO LL
500 W ILLINOIS
STE 500
MIDLAND TX 79701

P-5# 463316

--Measured--
3545 ft FNEL
72 ft FNWL
MRL: SURVEY

Digital Map Location:
X-coord/Long: 1232566
Y-coord/Lat: 638341
Datum: 27 Zone: NC

County: STONEWALL
Lease & Well No.: KATZ (STRAWN) UNIT #232&ALL
Purpose: ND

Location: SUR-EUSTIS J.,SEC-2,--[TD=5500],[RRC 7B],

To protect usable-quality ground water at this location, the Texas Commission on Environmental Quality recommends:

The interval from the land surface to a depth of 100 feet must be protected.

This recommendation is applicable to all wells drilled in this LEASE IN SECTION 2.

Note: Unless stated otherwise, this recommendation is intended to apply only to the subject well and not for area-wide use. Approval of the well completion methods for protection of this groundwater falls under the jurisdiction of the Railroad Commission of Texas. **This recommendation is intended for normal drilling, production, and plugging operations only. It does not apply to saltwater disposal operation into a nonproductive zone (RRC Form W-14).**

If you have any questions, please contact us at 512-239-0515, sc@tceq.state.tx.us, or by mail MC-151.

Sincerely,

T. Wesley McCoy

Digitally signed by Thomas Wesley McCoy
DN: c=US, st=Texas, l=Austin, ou=Surface Casing, o=Texas Commission on Environmental Quality, cn=Thomas Wesley McCoy, email=wmccoy@tceq.state.tx.us
Date: 2010.07.21 11:46:18 -05'00'

T. Wesley McCoy, P.G.

Geologist, Surface Casing Team
Waste Permits Division

GEOLOGIST SEAL

STATE OF TEXAS
T. WESLEY McCOY
GEOLOGY
117
LICENSED
PROFESSIONAL GEOSCIENTIST

The seal appearing on this document was authorized by *T. Wesley McCoy* on 7/21/2010
Note: Alteration of this electronic document will invalidate the digital signature.

A-3

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 718131	DATE PERMIT ISSUED OR AMENDED Jun 14, 2011	DISTRICT * 7B
API NUMBER 42-433-33712	FORM W-1 RECEIVED Jun 09, 2011	COUNTY STONEWALL
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 7194
OPERATOR 463316 KINDER MORGAN PRODUCTION CO LLC 6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (325) 677-3545
LEASE NAME KATZ (STRAWN) UNIT		WELL NUMBER 2361
LOCATION 21.9 miles NE direction from ASPERMONT		TOTAL DEPTH 7500
Section, Block and/or Survey SECTION SURVEY LONG, C B	BLOCK	ABSTRACT 1939
DISTANCE TO SURVEY LINES 3511 ft. S 539 ft. W		DISTANCE TO NEAREST LEASE LINE 539 ft.
DISTANCE TO LEASE LINES 1751 ft. NE 539 ft. W		DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
KATZ (STRAWN) KATZ (STRAWN) UNIT	7194.00 539	7,500	2361 3991	7B

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office. This is a hydrogen sulfide field. Hydrogen Sulfide Fields with perforations must be isolated and tested per State Wide Rule 36 and a Form H-9 filed with the district office. Fields with SWR 10 authority to downhole commingle must be isolated and tested individually prior to commingling production.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

Currently there are no identified formations listed for this county. It is still the operators responsibility to isolate and report any potential flow zones that are encountered in the completion of this well.

A-4

RAILROAD COMMISSION OF TEXAS

Form W-2

1701 N. Congress
P.O. Box 12967
Austin, Texas 78701-2967

Status: Approved
Date: 10/04/2013
Tracking No.: 62859

OIL WELL POTENTIAL TEST, COMPLETION OR RECOMPLETION REPORT,

OPERATOR INFORMATION

Operator KINDER MORGAN PRODUCTION CO LLC **Operator** 463316
Operator 6 DESTA DRIVE STE 6000 MIDLAND, TX 79705-0000

WELL INFORMATION

API 42-433-33712
County: STONEWALL
Well No.: 2361
RRC District 7B
Lease KATZ (STRAWN) UNIT
Field KATZ (STRAWN)
RRC Lease 30524
Field No.: 48294600
Location Section: ,Block: , Survey: LONG, C B SVY, Abstract: 1939

Latitude
Longitud
This well is **miles in a**
direction from 21.9 MILES IN A NE DIRECTION FROM ASPERMONT, TX,
which is the nearest town in the

FILING INFORMATION

Purpose of Initial Potential
Type of New Well
Well Type: Active UIC
Completion or Recompletion 12/15/2012

Type of Permit	Date	Permit No.
Permit to Drill, Plug Back, or	06/14/2011	718131
Rule 37 Exception		
Fluid Injection		
O&G Waste Disposal	11/21/2011	13453
Other:		

COMPLETION INFORMATION

Spud
Date of first production after rig 12/15/2012
Date plug back, deepening, drilling operation 08/24/2012
Date plug back, deepening, recompletion, drilling operation 09/13/2012
Number of producing wells on this lease this field (reservoir) including this 66
Distance to nearest well in lease & reservoir 3991.0
Total number of acres in 7194.00
Elevation 1518 GL
Total depth TVD 6625
Total depth MD
Plug back depth TVD 6547
Plug back depth MD
Was directional survey made other inclination (Form W- No
Rotation time within surface casing
Is Cementing Affidavit (Form W-15) Yes
Recompletion or No
Multiple No
Type(s) of electric or other log(s) Induction only
Electric Log Other Description:
Location of well, relative to nearest lease
Off Lease : No
of lease on which this well is 1751.0 **Feet from the** NE **Line and**
539.0 **Feet from the** West **Line of the**
KATZ (STRAWN) UNIT **Lease.**

FORMER FIELD (WITH RESERVOIR) & GAS ID OR OIL LEASE NO.

Field & Reservoir	Gas ID or Oil Lease	Well No.	Prior Service Type

PACKET: N/A

W2: N/A

FOR NEW DRILL OR RE-ENTRY, SURFACE CASING DEPTH DETERMINED BY:

GAU Groundwater Protection Determination	Depth	Date
SWR 13 Exception	Depth	

INITIAL POTENTIAL TEST DATA FOR NEW COMPLETION OR RECOMPLETION

Date of		Production	
Number of hours	24	Choke	
Was swab used during this	No	Oil produced prior to	

PRODUCTION DURING TEST PERIOD:

Oil		Gas	
Gas - Oil	0	Flowing Tubing	
Water			

CALCULATED 24-HOUR RATE

Oil		Gas	
Oil Gravity - API - 60.:		Casing	
Water			

CASING RECORD

Ro	Type of Casing	Casing Size (in.)	Hole Size	Setting Depth	Multi - Stage Tool	Multi - Stage Shoe	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined By
1		9 5/8	12 1/4	1290			C	491	837.0	SURF ACE	
2		7	8 3/4	6592			C	750	1248.0	3256	
3		7	8 3/4	6592	2463		C	450	618.0	SURF ACE	

LINER RECORD

Ro	Liner Size	Hole Size	Liner Top	Liner Bottom	Cement Class	Cement Amoun	Slurry Volume (cu.	Top of Cement (ft.)	TOC Determined

N/A

TUBING RECORD

Ro	Size (in.)	Depth Size (ft.)	Packer Depth (ft.)/Type
1	4 1/2	5945	5957 /

PRODUCING/INJECTION/DISPOSAL INTERVAL

Ro	Open hole?	From (ft.)	To (ft.)
1	No	L 6018	6024.0
2	No	L 6038	6077.0
3	No	L 6090	6101.0
4	No	L 6143	6195.0
5	No	L 6240	6255.0
6	No	L 6286	6311.0
7	No	L 6362	6370.0
8	No	L 6382	6433.0

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC.

Was hydraulic fracturing treatment No

Is well equipped with a downhole sleeve? No

If yes, actuation pressure

Production casing test pressure (PSIG) hydraulic fracturing

Actual maximum pressure (PSIG) during fracturin

Has the hydraulic fracturing fluid disclosure been No

Ro	Type of Operation	Amount and Kind of Material Used	Depth Interval (ft.)	
1		PUMP 2800 GALLONS 15% HCL, FLUSH WITH 36 BARRELS TREATED WATER.	6018	6101
2		PUMP 2600 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6143	6195
3		PUMP 2440 GALLONS 15% HCL, FLUSH WITH 38 BARRELS TREATED WATER.	6240	6311
4		PUMP 2960 GALLONS 15% HCL, FLUSH WITH 76 BARRELS TREATED WATER.	6362	6433

FORMATION RECORD

Formations	Encountere	Depth TVD	Depth MD	Is formation	Remarks
BASE PALO PINTO		3215.2			
ELLENBURGER		6018.0			
CAMBRIAN		6240.0			

Do the producing interval of this well produce H2S with a concentration in excess of 100 ppm No

Is the completion being downhole commingled No

REMARKS

RRC REMARKS

PUBLIC COMMENTS:

CASING RECORD :

TUBING RECORD:

PRODUCING/INJECTION/DISPOSAL INTERVAL :

ACID, FRACTURE, CEMENT SQUEEZE, CAST IRON BRIDGE PLUG, RETAINER, ETC. :

POTENTIAL TEST DATA:

THE PURPOSE OF THIS FILING IS TO REPORT A DRILLED AND COMPLETED SALT WATER DISPOSAL WELL.

OPERATOR'S CERTIFICATION

Printed	Dorothy Horrell	**Title:**	Administrator
Telephone	(432) 688-2448	**Date**	01/14/2013

APPENDIX B – GAS COMPOSITION

CO2 Pipeline - Gas Quality Specifications

Kinder Morgan CO2 Company

Revision: 2019 11 12

Product delivered at the Origination Point shall meet the following specifications, which herein are called Quality Specifications:

(a) **CO2 Content** Product composition shall be not less than ninety five per cent (95%) CO_2 by mole fraction.

(b) **Water** Product shall contain no free water, and shall not contain more than thirty (30) pounds of water per million standard cubic feet (MMscf) in the vapor phase.

(c) **Pressure** Product shall be delivered at a pressure sufficient to get into the pipeline.

(d) **Temperature** Product shall be delivered at a temperature not greater than 120 degrees F, and not less than 65 degrees F.

(e) **H2S** Product shall not contain more than twenty (20) parts per million H_2S, by volume.

(f) **Nitrogen** Product shall not contain more than four per cent (4%) nitrogen, by mole fraction.

(g) **Sulphur** Product shall not contain more than thirty five (35) parts per million sulphur, by weight.

(h) **Oxygen** Product shall not contain more than ten (10) parts per million, oxygen, by weight.

(i) **Hydrocarbons** Product shall not contain more than five percent (5%) hydrocarbons, by mole fraction.

(j) **Glycol** Product shall not contain more than 0.3 gallon glycol, per million standard cubic feet, and at no time shall glycol be present in a liquid state at temperature and pressure conditions of the pipeline.

(k) **Carbon Monoxide** Product shall not contain more than 4,250 parts per million, carbon monoxide, by weight.

(l) **NOx** Product shall not contain more than one (1) part per million, NO_x, by weight.

(m) **SOx** Product shall not contain more than one (1) part per million, SO_x, by weight.

(n) **Particulates** Product shall not contain more than one (1) part per million, particulates, by weight.

(o) **Amines** Product shall not contain more than one (1) part per million, amines, by weight.

(p) **Hydrogen** Product shall not contain more than one per cent (1%) hydrogen, by mole fraction.

(q) **Mercury** Product shall not contain more than five (5) nano grams per liter (ng/l) mercury.

(r) **Ammonia** Product shall not contain more than fifty (50) parts per million, ammonia, by weight.

(s) **Argon** Product shall not contain more than one volume percent (1% by volume) argon.

(t) **Liquids** Product shall be free of liquids at delivery conditions and shall not produce condensed liquids in the pipeline at pipeline pressure and temperature.

(u) **Compressor Lube Oil Carry Over** Compressor lube oil carry over in the product shall not exceed fifty (50) parts per million, by weight, and shall not cause fouling of pipeline, pipeline equipment downstream systems or reservoirs.

(v) **Impurities Deleterious to Pipeline, Equipment, Downstream Systems or Reservoirs** In addition to compositional limits listed above, product shall not contain impurities deleterious to pipeline, equipment, downstream systems or reservoirs.

APPENDIX C – PIPELINE SAFETY PLAN

Kinder Morgan CO_2 pipelines are monitored 24 hours a day, 7 days a week by personnel in control centers using a SCADA computer system. This electronic surveillance system gathers pipeline pressures, volume and flow rates and the status of pumping equipment and valves. Whenever operating conditions change, an alarm warns the operator on duty and the condition is investigated. Both automated and manual valves are strategically placed along the pipeline system to enable the pipeline to be shut down immediately and sections to be isolated quickly, if necessary. Visual inspections of the pipeline right-of-way, a narrow strip of land reserved for the pipeline, are conducted by air and ground on a regular basis.

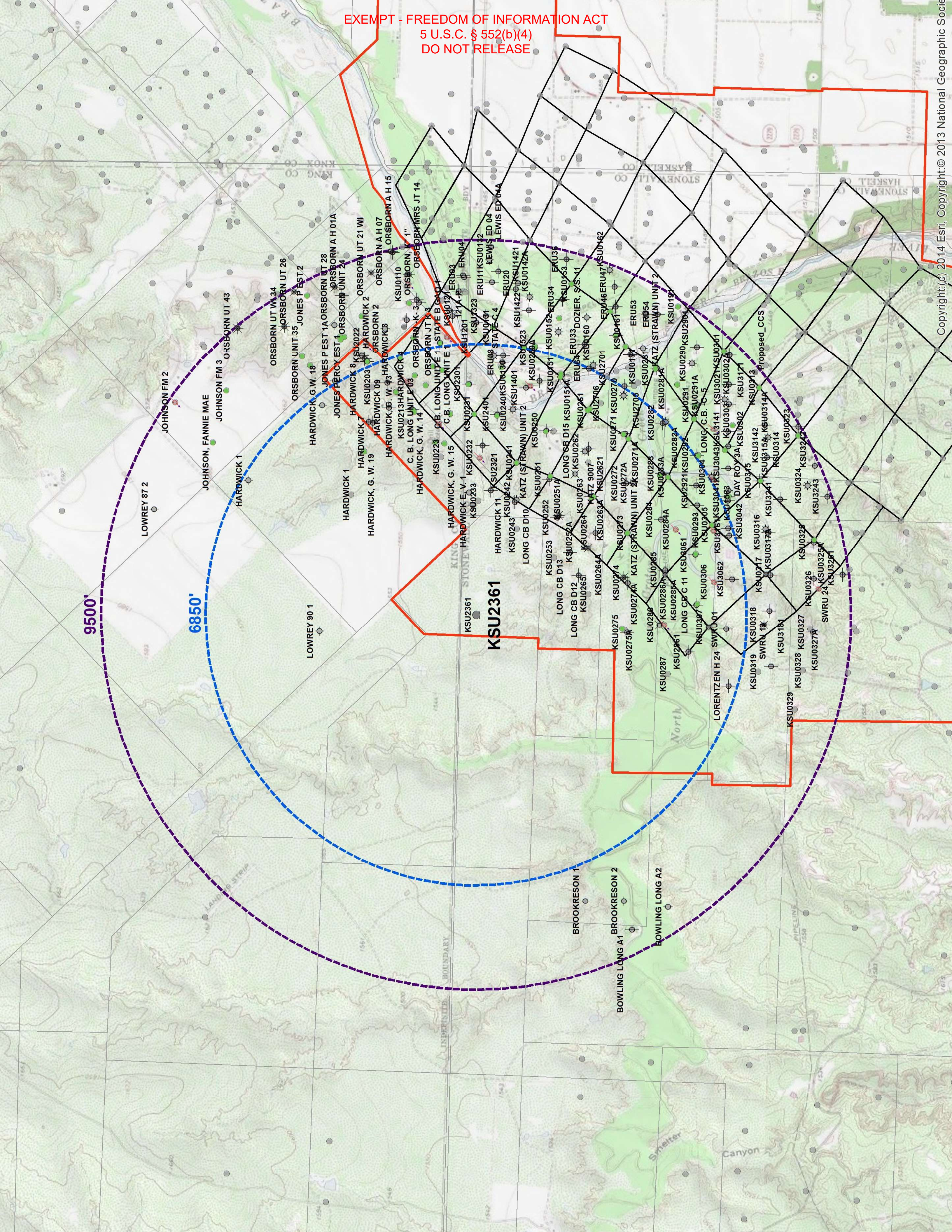
In the event of a CO_2 pipeline rupture, the Kinder Morgan CO_2 Supervisory Control and Data Acquisition (SCADA) computer system will shut down the pipeline and isolate the impacted section with automated valves. Kinder Morgan will notify the appropriate public safety answering point (i.e., 9-1-1 emergency call center) and initiate the internal Emergency Response Line to alert the operations team. An emergency response plan would be initiated with implementation of an incident command system, and Kinder Morgan will work with local emergency responders to isolate the impacted area.

APPENDIX D – MMA/AMA REVIEW MAPS

APPENDIX D-1: OIL AND GAS WELLS WITHIN THE MMA MAP

APPENDIX D-2: OIL AND GAS WELLS WITHIN THE MMA LIST

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE



Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332238	BOWLING-LONG A	2	P & A	5,815	WILDCAT	4/20/1987	5/7/1987
4243332229	BROOKRESON	1	P & A	5,730	WILDCAT	3/7/1987	5/14/1987
4243332319	BROOKRESON	2	P & A	5,745	WILDCAT	12/2/1987	12/13/1987
4226932003	C. B. LONG UNIT	E 03	P & A	5,300	KATZ	--	--
4243300422	C.B. LONG UNIT	C 11	P & A	5,127	KATZ	7/11/1989	5/15/2009
4243332388	C.B. LONG UNIT	C 16	P & A	5,200	KATZ	11/18/1989	12/8/2010
4243300585	C.B. LONG UNIT	D 10	P & A	5,197	KATZ	6/30/1989	1/13/2009
4243332465	C.B. LONG UNIT	D 13	P & A	5,201	KATZ	12/27/1989	9/23/2005
4243301965	C.B. LONG UNIT	D 4	P & A	5,188	KATZ		11/30/2010
4226900122	C.B. LONG UNIT	E 1	P & A	5,165	KATZ		9/15/2009
4226932006	C.B. LONG UNIT	E 2	P & A	5,200	KATZ	10/11/1990	2/24/2011
4243332116	DOZIER, S.S.	11	P & A	5,950	WILDCAT	6/12/1986	06/23/1986
4226900308	EAST RIVER UNIT	4	INACTIVE	4,931	KATZ		02/21/1995
4243332303	EAST RIVER UNIT	8	P & A	5,200	KATZ	11/17/1987	06/24/2009
4243332302	EAST RIVER UNIT	11	P & A	5,200	KATZ	11/26/1987	3/18/2004
4243300796	EAST RIVER UNIT	18	ACTIVE	5,300	KATZ	7/26/1951	--
4243300802	EAST RIVER UNIT	20	P & A	5,184	KATZ	8/22/1988	7/6/2009
4243300798	EAST RIVER UNIT	21	P & A	4,957	KATZ		12/5/1989
4243300787	EAST RIVER UNIT	33	P & A	5,155	KATZ		10/21/2009
4243300781	EAST RIVER UNIT	34	P & A	5,120	KATZ		10/30/2009
4243332306	EAST RIVER UNIT	36	P & A	5,200	KATZ	12/15/1987	2/28/2006
4243300849	EAST RIVER UNIT	45	P & A	5,167	KATZ		12/7/2010
4243300848	EAST RIVER UNIT	46	INACTIVE	4,875	KATZ		2/15/1990
4243332308	EAST RIVER UNIT	47	P & A	5,200	KATZ	12/5/1987	10/13/2009
4243300780	EAST RIVER UNIT	53	P & A	4,918	KATZ		2/14/1995
4243300788	EAST RIVER UNIT	54	P & A	5,211	KATZ		2/11/2009
4243332417	EAST RIVER UNIT	64	P & A	5,245	KATZ	8/8/1988	1/23/2009
4243333510	EAST RIVER UNIT	105	ACTIVE	5,325	KATZ	11/3/2009	--
4243333368	EAST RIVER UNIT	73H	P & A	4,750	KATZ	8/8/2007	9/3/2007
4243381146	EDD LEWIS		P & A	4,967	KATZ		10/14/2005
4226932269	HARDWICK	1	P & A	5,820	WILDCAT	6/19/1997	7/1/1997
4226900006	HARDWICK	2	P & A	5,147	KATZ		5/15/1975
4226900007	HARDWICK	3	P & A	5,168	KATZ		7/27/1970
4226900008	HARDWICK	4	P & A	5,146	KATZ		1/26/1984
4226900011	HARDWICK	6	P & A	5,152	KATZ		7/24/1970
4226900009	HARDWICK	7	P & A	5,150	KATZ		8/19/1967
4226900010	HARDWICK	8	P & A	5,152	KATZ		6/18/1976
4226980016	HARDWICK	9	P & A	2,171	KATZ		1/27/1984
4243301905	HARDWICK	11	P & A	5,152	KATZ		7/22/1970
4226900005	HARDWICK E. V.	1	P & A	5,960	KATZ		7/14/1951
4226931776	HARDWICK, G. W.	12	P & A	5,200	KATZ	3/10/1988	11/6/2009
4226931777	HARDWICK, G. W.	13	P & A	5,200	KATZ	3/11/1988	11/19/2009
4226931775	HARDWICK, G. W.	14	P & A	5,200	KATZ	5/29/1988	11/16/2009
4226931771	HARDWICK, G. W.	15	P & A	5,200	KATZ	3/15/1988	11/12/2009
4226931774	HARDWICK, G. W.	16	P & A	5,200	KATZ	3/8/1988	5/13/2004
4226931772	HARDWICK, G. W.	17	P & A	5,250	KATZ	3/9/1988	11/10/2009
4226932431	HARDWICK, G.W.	18	P & A	5,300	KATZ	8/13/2001	8/24/2001
4226932178	JOHNSON, FANNIE MAE	1	P & A	5,840	KATZ	4/11/1995	2/2/2016
4226932197	JOHNSON, FANNIE MAE	2	P & A	5,825	KATZ	10/5/1995	2/3/2016
4226932236	JOHNSON, FANNIE MAE	3	P & A	5,830	KATZ	11/2/1996	2/1/2016
4226900420	JONES PERCY EST	1	P & A	5,200	KATZ		1/1/1962
4226900428	JONES PERCY ESTATE	3	P & A	4,940	KATZ		7/1/1958
4226932805	KATZ (STRAWN) UNIT	110	ACTIVE	5,312	KATZ	3/13/2011	--
4226931666	KATZ (STRAWN) UNIT	121	P & A	4,879	KATZ	2/9/1987	10/24/2019
4243300797	KATZ (STRAWN) UNIT	131	ACTIVE	5,200	KATZ	9/24/1951	--
4243333513	KATZ (STRAWN) UNIT	132	ACTIVE	5,320	KATZ	12/2/2009	--
4243332296	KATZ (STRAWN) UNIT	143	P & A	5,200	KATZ	12/13/1987	7/30/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4243332304	KATZ (STRAWN) UNIT	151	P & A	5,200	KATZ	11/20/1987	7/20/2010
4243300779	KATZ (STRAWN) UNIT	152	ACTIVE	5,255	KATZ		--
4243300783	KATZ (STRAWN) UNIT	153	ACTIVE	5,299	KATZ	4/25/1952	--
4243333511	KATZ (STRAWN) UNIT	160	ACTIVE	5,302	KATZ	11/20/2009	--
4243333518	KATZ (STRAWN) UNIT	161	ACTIVE	5,308	KATZ	1/22/2010	--
4243333512	KATZ (STRAWN) UNIT	162	ACTIVE	5,328	KATZ	12/30/2009	--
4243333521	KATZ (STRAWN) UNIT	171	ACTIVE	5,334	KATZ	2/2/2010	--
4243333580	KATZ (STRAWN) UNIT	180	ACTIVE	5,327	KATZ	6/29/2010	--
4243333665	KATZ (STRAWN) UNIT	191	ACTIVE	5,423	KATZ	5/2/2011	--
4226932789	KATZ (STRAWN) UNIT	211	ACTIVE	5,316	KATZ	11/7/2010	--
4226932795	KATZ (STRAWN) UNIT	212	P & A	5,294	KATZ	8/21/2010	6/8/2022
4226932783	KATZ (STRAWN) UNIT	220	ACTIVE	5,308	KATZ	3/9/2010	--
4226932788	KATZ (STRAWN) UNIT	221	ACTIVE	4,863	KATZ	6/6/2010	--
4226932793	KATZ (STRAWN) UNIT	222	ACTIVE	5,308	KATZ	6/18/2010	--
4243333534	KATZ (STRAWN) UNIT	231	ACTIVE	5,315	KATZ	4/23/2010	--
4243333592	KATZ (STRAWN) UNIT	232	ACTIVE	5,340	KATZ	8/10/2010	--
4243333523	KATZ (STRAWN) UNIT	240	ACTIVE	5,309	KATZ	3/18/2010	--
4243300584	KATZ (STRAWN) UNIT	241	ACTIVE	5,250	KATZ	6/8/1957	--
4243333615	KATZ (STRAWN) UNIT	242	ACTIVE	5,297	KATZ	11/30/2010	--
4243300403	KATZ (STRAWN) UNIT	250	P & A	5,206	KATZ	10/25/1951	12/13/2019
4243300400	KATZ (STRAWN) UNIT	261	ACTIVE	5,150	KATZ		--
4243333573	KATZ (STRAWN) UNIT	262	ACTIVE	5,314	KATZ	5/25/2010	--
4243300583	KATZ (STRAWN) UNIT	264	P & A	5,242	KATZ		4/29/2011
4243333524	KATZ (STRAWN) UNIT	270	ACTIVE	5,300	KATZ	4/13/2010	--
4243300405	KATZ (STRAWN) UNIT	271	P & A	5,150	KATZ		11/4/2010
4243300421	KATZ (STRAWN) UNIT	273	ACTIVE	5,127	KATZ	7/11/1953	--
4243300424	KATZ (STRAWN) UNIT	274	P & A	5,131	KATZ	5/16/1989	12/27/2010
4243301970	KATZ (STRAWN) UNIT	275	P & A	5,185	KATZ		3/14/2011
4243300417	KATZ (STRAWN) UNIT	281	P & A	5,156	KATZ		8/16/2010
4243332387	KATZ (STRAWN) UNIT	282	P & A	5,189	KATZ	11/2/1989	9/20/2010
4243332389	KATZ (STRAWN) UNIT	284	P & A	5,210	KATZ	10/15/1989	1/10/2011
4243332390	KATZ (STRAWN) UNIT	285	P & A	5,219	KATZ		11/3/2010
4243332461	KATZ (STRAWN) UNIT	286	P & A	5,730	KATZ	12/8/1989	4/29/2013
4243333526	KATZ (STRAWN) UNIT	290	ACTIVE	5,315	KATZ	5/6/2010	--
4243333704	KATZ (STRAWN) UNIT	301	ACTIVE	5,365	KATZ	7/27/2011	--
4243301620	KATZ (STRAWN) UNIT	302	P & A	5,138	KATZ	3/28/1953	1/5/2012
4243333738	KATZ (STRAWN) UNIT	304	ACTIVE	5,300	KATZ	12/3/2011	--
4243333778	KATZ (STRAWN) UNIT	305	ACTIVE	5,330	KATZ	4/6/2012	--
4243333569	KATZ (STRAWN) UNIT	306	ACTIVE	5,328	KATZ	5/16/2010	--
4243333813	KATZ (STRAWN) UNIT	307	INACTIVE	5,365	KATZ	6/26/2012	--
4243333746	KATZ (STRAWN) UNIT	313	ACTIVE	5,380	KATZ	11/20/2011	--
4243332561	KATZ (STRAWN) UNIT	314	P & A	5,225	KATZ	12/16/1989	2/7/2012
4243333788	KATZ (STRAWN) UNIT	315	P & A	5,320	KATZ	3/17/2012	7/1/2014
4243332553	KATZ (STRAWN) UNIT	317	P & A	5,200	KATZ	12/11/1989	10/14/2013
4243333822	KATZ (STRAWN) UNIT	318	P & A	5,320	KATZ	7/5/2012	5/24/2021
4243333736	KATZ (STRAWN) UNIT	324	ACTIVE	5,380	KATZ	2/6/2012	--
4243333527	KATZ (STRAWN) UNIT	326	ACTIVE	5,503	KATZ	3/30/2010	--
4243300819	KATZ (STRAWN) UNIT	327	P & A	4,952	KATZ		12/23/2010
4243332509	KATZ (STRAWN) UNIT	1201	P & A	5,295	KATZ	7/1/1989	11/29/2010
4226931752	KATZ (STRAWN) UNIT	1221	P & A	5,200	KATZ	1/23/1988	10/11/2011
4243300800	KATZ (STRAWN) UNIT	1323	P & A	4,930	KATZ		3/23/2010
4243332298	KATZ (STRAWN) UNIT	1401	P & A	5,261	KATZ	1/24/1988	3/19/2010
4243332274	KATZ (STRAWN) UNIT	1422	P & A	5,220	KATZ	9/2/1987	11/16/2009
4243300801	KATZ (STRAWN) UNIT	1523	P & A	5,101	KATZ	5/20/1952	11/24/2009
4243332299	KATZ (STRAWN) UNIT	1801	P & A	4,879	KATZ	2/2/1988	3/31/2011
4226932806	KATZ (STRAWN) UNIT	2022	ACTIVE	5,313	KATZ	3/25/2011	--
4226932345	KATZ (STRAWN) UNIT	2121	P & A	5,800	KATZ	8/8/1999	11/12/2010

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932002	KATZ (STRAWN) UNIT	2221	P & A	5,200	KATZ	10/25/1990	6/1/2010
4243332753	KATZ (STRAWN) UNIT	2321	P & A	5,200	KATZ	12/10/1991	3/3/2011
4243333712	KATZ (STRAWN) UNIT	2361	ACTIVE	6,625	KATZ	8/23/2012	--
4243300406	KATZ (STRAWN) UNIT	2401	P & A	5,173	KATZ	5/23/1989	12/31/2009
4243332541	KATZ (STRAWN) UNIT	2701	INACTIVE	100	KATZ	9/27/1989	--
4243332565	KATZ (STRAWN) UNIT	2702	INACTIVE	100	KATZ	12/7/1989	--
4243300401	KATZ (STRAWN) UNIT	2705	P & A	5,116	KATZ	5/12/1989	3/2/2010
4243333713	KATZ (STRAWN) UNIT	2706	COMPLETED	7,500	KATZ		--
4243300423	KATZ (STRAWN) UNIT	2861	P & A	5,161	KATZ	7/17/1989	11/21/2013
4243300399	KATZ (STRAWN) UNIT	2901	P & A	5,150	KATZ		2/17/2011
4243333160	KATZ (STRAWN) UNIT	2921	P & A	5,725	KATZ	12/10/1998	1/13/2010
4243380198	KATZ (STRAWN) UNIT	3041	P & A	5,113	KATZ	7/18/2005	6/17/2010
4243301606	KATZ (STRAWN) UNIT	3042	P & A	5,113	KATZ	11/6/1989	3/22/2012
4243300838	KATZ (STRAWN) UNIT	3062	P & A	5,240	KATZ	11/16/1989	7/1/2010
4243301610	KATZ (STRAWN) UNIT	3141	P & A	5,115	KATZ		2/16/2012
4243300837	KATZ (STRAWN) UNIT	3161	P & A	5,190	KATZ	2/13/1990	8/18/2010
4243300842	KATZ (STRAWN) UNIT	3181	P & A	4,961	KATZ		2/16/2011
4243301605	KATZ (STRAWN) UNIT	3241	P & A	5,170	KATZ		4/12/2013
4243332570	KATZ (STRAWN) UNIT	3243	P & A	5,240	KATZ	1/14/1990	2/10/2010
4243332588	KATZ (STRAWN) UNIT	3261	P & A	5,150	KATZ	2/12/1990	3/31/2010
4226932987	KATZ (STRAWN) UNIT	121A	ACTIVE	5,337	KATZ	12/3/2019	--
4243333496	KATZ (STRAWN) UNIT	142A	ACTIVE	5,305	KATZ	10/20/2009	--
4243333595	KATZ (STRAWN) UNIT	151A	ACTIVE	5,317	KATZ	9/7/2010	--
4243334217	KATZ (STRAWN) UNIT	250A	INACTIVE	5,314	KATZ	12/19/2019	--
4243333630	KATZ (STRAWN) UNIT	251A	ACTIVE	5,315	KATZ	12/10/2010	--
4243333598	KATZ (STRAWN) UNIT	252A	TA	5,300	KATZ	10/17/2010	--
4243333599	KATZ (STRAWN) UNIT	263A	ACTIVE	5,315	KATZ	9/29/2010	--
4243333639	KATZ (STRAWN) UNIT	264A	P & A	5,333	KATZ	4/5/2011	6/1/2021
4243333627	KATZ (STRAWN) UNIT	271A	ACTIVE	5,302	KATZ	12/20/2010	--
4243333632	KATZ (STRAWN) UNIT	272A	ACTIVE	5,318	KATZ	3/1/2011	--
4243333807	KATZ (STRAWN) UNIT	274A	TA	5,300	KATZ	5/24/2012	7/1/2022
4243333607	KATZ (STRAWN) UNIT	281A	ACTIVE	5,324	KATZ	10/9/2010	--
4243333617	KATZ (STRAWN) UNIT	282A	ACTIVE	5,297	KATZ	11/18/2010	--
4243333735	KATZ (STRAWN) UNIT	283A	ACTIVE	5,380	KATZ	10/7/2011	--
4243333722	KATZ (STRAWN) UNIT	284A	ACTIVE	5,345	KATZ	12/15/2011	--
4243333799	KATZ (STRAWN) UNIT	285A	INACTIVE	5,350	KATZ	4/16/2012	--
4243333927	KATZ (STRAWN) UNIT	286A	TA	5,337	KATZ	3/24/2014	--
4243333730	KATZ (STRAWN) UNIT	291A	ACTIVE	5,364	KATZ	9/24/2011	--
4243333695	KATZ (STRAWN) UNIT	302A	ACTIVE	5,390	KATZ	7/6/2011	--
4243333771	KATZ (STRAWN) UNIT	303A	ACTIVE	5,330	KATZ	2/27/2012	--
4243333753	KATZ (STRAWN) UNIT	314A	ACTIVE	5,375	KATZ	10/27/2011	--
4243334002	KATZ (STRAWN) UNIT	315A	ACTIVE	5,348	KATZ	7/11/2014	--
4243333770	KATZ (STRAWN) UNIT	316A	ACTIVE	5,400	KATZ	1/25/2012	--
4243333820	KATZ (STRAWN) UNIT	317A	INACTIVE	5,336	KATZ	12/29/2013	--
4243333776	KATZ (STRAWN) UNIT	323A	ACTIVE	5,408	KATZ	3/7/2012	--
4243333821	KATZ (STRAWN) UNIT	325A	ACTIVE	5,385	KATZ	12/10/2013	--
4226900309	LEWIS, W. D.	2	P & A	5,090	KATZ		9/29/2008
4243300412	LONG, C. B. -D-	5	P & A	5,165	KATZ		3/12/2010
4243300415	LONG, C. B. -D-	6	P & A	5,188	KATZ		11/8/2010
4243300408	LONG, C.B. -C-	4	P & A	5,214	KATZ		3/9/2011
4243300411	LONG, C.B. -C-	5	P & A	5,165	KATZ		11/30/2010
4243300420	LONG, C.B. -C-	9	INACTIVE	5,163	KATZ		5/13/2010
4243300414	LONG, C.B. -C-	6 T	P & A	5,168	KATZ		11/12/2010
4243300419	LONG, C.B. -C-	8 T	P & A	5,165	KATZ		11/15/2010
4243300418	LONG, C.B. -D-	7	P & A	5,190	KATZ	8/1/1989	8/10/2010
4243300586	LONG, C.B. -D-	11	P & A	5,183	KATZ	6/15/1989	8/30/2010
4243300587	LONG, C.B. -D-	12	P & A	4,896	KATZ		1/13/1986

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)

EXEMPT - FREEDOM OF INFORMATION ACT
5 U.S.C. § 552(b)(4)
DO NOT RELEASE

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA

API	WELL NAME	WELL NO.	STATUS	TVD (Ft.)	FIELD	DATE DRILLED	DATE PLUGGED
4226932293	LOWERY 87	2	P & A	5,835	WILDCAT	11/11/1997	11/24/1997
4226932268	LOWREY 90	1	P & A	5,800	WILDCAT	5/25/1997	6/4/1997
4226932270	MANGIS	2	P & A	5,770	KAIA	7/10/1997	7/20/1997
4226932325	ORSBORN	2	P & A	5,718	KAIA	10/22/1998	11/4/1998
4226900108	ORSBORN	7	P & A	4,940	KATZ		8/30/2006
4226932955	ORSBORN K	14	INACTIVE	5,235	KATZ	11/5/2015	--
4226900077	ORSBORN -K-	3	P & A	5,091	KATZ		7/19/1993
4226900082	ORSBORN UNIT	1	INACTIVE	5,155	KATZ	8/14/1952	--
4226900081	ORSBORN UNIT	14	P & A	5,077	KATZ		8/30/2018
4226900105	ORSBORN UNIT	15	P & A	5,211	KATZ		8/25/1994
4226910001	ORSBORN UNIT	19	P & A	5,144	KATZ	9/1/1984	9/6/1984
4226931306	ORSBORN UNIT	21	P & A	5,170	KATZ	9/25/1984	11/11/2021
4226931395	ORSBORN UNIT	24	P & A	5,200	KATZ	1/23/1985	3/25/2022
4226931398	ORSBORN UNIT	26	P & A	5,247	KATZ	2/4/1985	5/9/2019
4226931397	ORSBORN UNIT	28	P & A	5,220	KATZ	2/18/1985	3/1/2013
4226931738	ORSBORN UNIT	34	P & A	5,250	KATZ	10/9/1987	8/28/2018
4226932314	ORSBORN UNIT	43	P & A	5,350	KATZ	4/24/1998	4/29/2019
4226932956	ORSBORN UNIT	44	INACTIVE	5,230	KATZ	6/28/2016	--
4226900076	ORSBORN, "K"	1	P & A	5,099	KATZ		7/12/1993
4226900104	ORSBORN, ALMA H.	1	P & A	5,155	KATZ		5/7/1957
4243300841	SOUTHWEST RIVER UNI	1	P & A	4,903	KATZ		7/17/1998
4243301612	SOUTHWEST RIVER UNI	5	P & A	5,115	KATZ		2/20/2012
4243301621	SOUTHWEST RIVER UNI	6	P & A	5,154	KATZ	4/14/1953	1/25/2012
4243301609	SOUTHWEST RIVER UNI	9	P & A	5,150	KATZ		4/13/2011
4243301619	SOUTHWEST RIVER UNI	10	P & A	5,104	KATZ	2/17/1953	12/14/2010
4243300844	SOUTHWEST RIVER UNI	13	P & A	4,987	KATZ		9/18/1995
4243300836	SOUTHWEST RIVER UNI	16	P & A	5,170	KATZ		1/5/2011
4243332587	SOUTHWEST RIVER UNI	18	P & A	5,300	KATZ	2/1/1990	1/27/2010
4243300811	SOUTHWEST RIVER UNI	24	P & A	4,920	KATZ		11/28/2002
4243301444	SOUTHWEST RIVER UNI	28	P & A	4,950	KATZ	8/13/2007	4/13/2011
4243300823	SOUTHWEST RIVER UNI	36	P & A	4,963	KATZ		--
4243300815	SOUTHWEST RIVER UNI	37	P & A	4,972	KATZ		10/15/1991
4243300835	SOUTHWEST RIVER UNI	71	P & A	5,171	KATZ		10/4/1991
4243300809	SOUTHWEST RIVER UNI	25W	P & A	5,230	KATZ		10/22/2013
4243332560	SOUTHWEST RIVER UNI	27W	P & A	5,206	KATZ	1/9/1990	3/12/2013
4226900069	STATE A GAO	1	P & A	5,085	KATZ		4/19/1985
4226900070	STATE B GAO	1	P & A	4,876	KATZ		4/17/1985
4243301761	STATE OF TEXAS -C-	1	P & A	5,296	KATZ		2/11/1983
4243301762	STATE OF TEXAS -C-	2	P & A	5,205	KATZ		12/4/1982
4243301764	STATE OF TEXAS -C-	4	P & A	5,205	KATZ		11/29/1982
4226900012			ACTIVE	5,105			--
4226900016			ACTIVE	5,175			--
4243300005			P & A	3,251			--

Kinder Morgan Katz Strawn Unit #2361 Well
All Oil and Gas Wells Within MMA List
Source: Texas Railroad Commission (2023)