ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

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Well location: Union Island Gas Field, San Joaquin County, CA
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Document Version history

Version	Submission Date	File Name	Description of Change
1	5/3/2022	Att B – AoR_CA CTV II	Original submission as part of CTV II storage project
2	8/4/2022	Att B – AoR_CA CTV II V2	Updated submission to address EPA Administrative review request for additional information dated 6/9/2022.
3	12/14/2022	Att B – AoR_CA CTV II V3	Updated submission to address EPA Administrative review request for additional information dated 9/21/2022, and for project expansion from two to five injectors
4	2/2/23	Att B – AoR_CA CTV II V3.1	Updated to address EPA request
5	2/13/23	Att B – AoR_CA CTV II V3.2	Updated to address EPA request

3.0 AoR and Corrective Action Plan

3.1 Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid, which also includes seismic information to understand faults and flow barriers. Attributes of the grid include porosity, permeability and facies distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault Holdings LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase

- Liquid and gas relative permeability
- Capillary pressure data
- Proposed injection well completions, injection rates and injection pressure over the life of the project
- Field pressure history
- Fluid geochemical analysis
- Rock and fluid compressibility

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the CTV II Storage project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous) plus a buffer zone, and this provides confidence that the corrective action well review and potential impact to the USDW is conservative and has been appropriately evaluated. Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

3.1.1 Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State and the solubility of CO_2 in water is modeled by Henry's Law. The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual gas in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, permeability and seismic interpretation.
2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al
2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

3.1.2 Site Geology and Hydrology

The Union Island Gas Field is a northeast-southwest trending faulted anticlinal structure located at the southern end of the Sacramento Basin of California. Historical and current gas production is sourced from the Late Cretaceous Winters Formation in the footwall along a regional reverse fault, the Stockton Arch fault. As described in the Narrative, the Winters Formation is the proposed Injection Zone. Different gas-water-contacts observed at the time of the field's discovery indicate a flow barrier exists within the Injection zone, between the northern and southern halves of the field. The reservoir sands were deposited as a series of coalesced channels at the base of the slope on the upper channelized portion of a sandy suprafan. The Injection zone reservoir is present across the entire project area and is offset by the Stockton Arch Fault, as shown in **Figure 3.1**.

The Injection zone is bound above by the Starkey-Sawtooth Shale and below by the Delta Shale. The Delta Shale Formation serves as the lower confining zone, which consists of approximately a 157 feet shale barrier. This shale has an average permeability of 0.04 md and porosity of 14.7%. The Starkey-Sawtooth Shale has an average gross thickness of over 2,200 feet and a very low matrix permeability which makes it a competent Upper Confining Zone in preventing the upward migration of fluids.

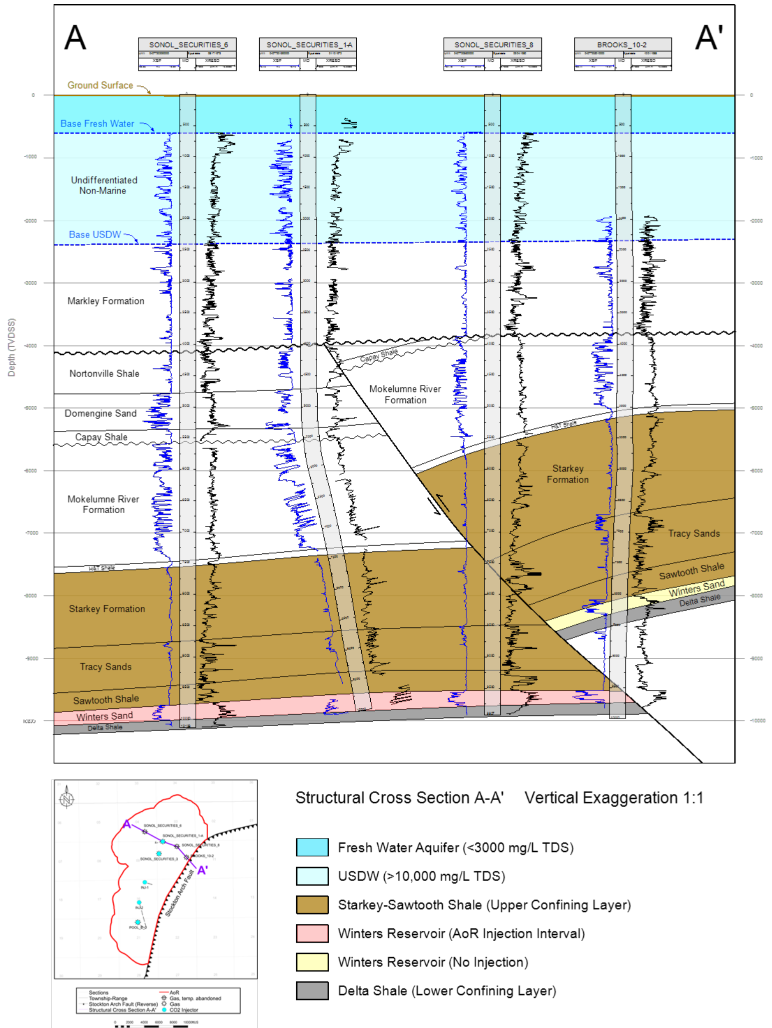


Figure 3.1. Dip cross section showing stratigraphy and lateral continuity of major formations across the project area. Section is representative of formations and sand continuity at all five CO2 injector locations.

The Injection zone reservoir was discovered in the 1970's and has been developed with primary production (Table 3.1 Production volumes). Over 50 years, reservoir pressure has declined from 5,040 PSI to 1,200 PSI, indicating a closed reservoir with limited water influx and/or connection to an aquifer.

Table 3.1: Production volumes for the proposed Injection zone at the Union Island Gas field

Process	Phase	Volume
Production	Gas	292 billion cubic feet
	Water	3.4 million barrels

Well data, open-hole well logs and core (Figure 3.2), define the subsurface geological characteristics of stratigraphy, lithology and rock properties. Reservoir performance information (production rates and volumes, reservoir and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

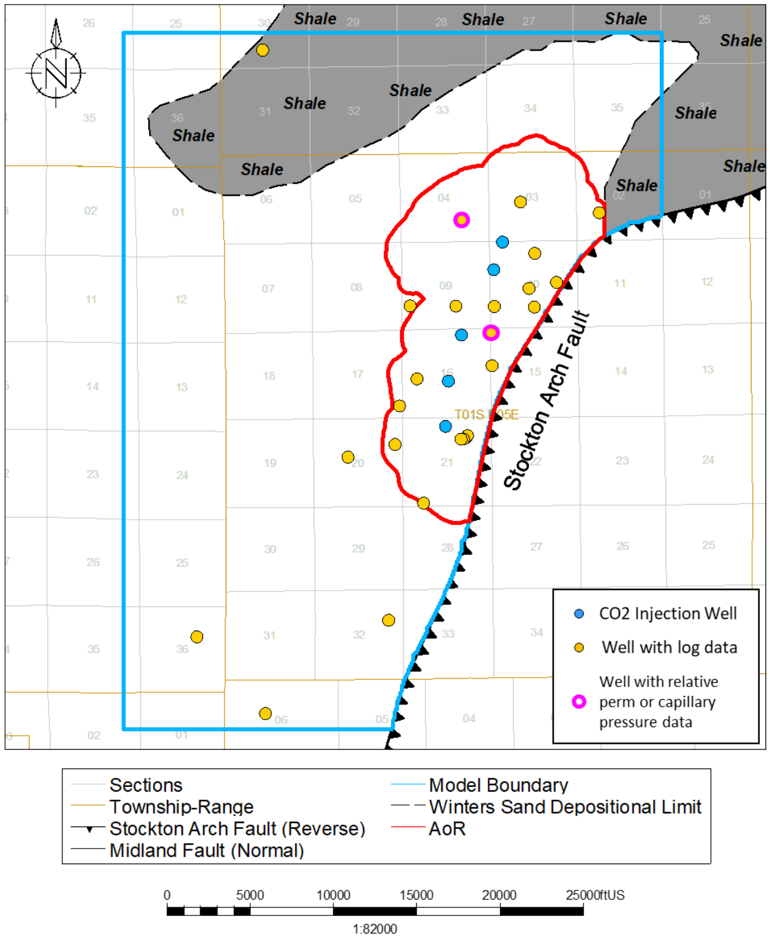


Figure 3.2. Location of wells with open-hole log data and injection zone relative permeability or capillary pressure data used to develop the static and computational models.

3.1.3 Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in **Table 3.2**.

Table 3.2: Model domain information.

Coordinate System	California State Plane		
Horizontal Datum	North American Datum (NAD) 27		
Coordinate System Units	Feet		
Zone	Zone 2		
FIPSZONE	0402	**ADSZONE**	3301
Coordinate of X min	2,145,400.00	**Coordinate of X max**	2,177,700.00
Coordinate of Y min	44,800.00	**Coordinate of Y max**	86,700.00
Elevation of bottom of domain	-10,375	**Elevation of top of domain**	-9,492

The geo-cellular grid was initially built with uniformly spaced 100 feet x 100 feet cells throughout the 36.9 square mile model area (**Figure 3.3**). This was then upscaled to 200 feet x 200 feet for the dynamic modeling. These grid dimensions allow for adequate resolution of plume development. Finer resolution for the grid will prevent the simulation from running efficiently and a coarser grid will not adequately simulate plume movement. The model grid is aligned north to south and reservoir properties were distributed in a northeast-southwest direction (40-degree rotation) parallel to the depositional trend of the proposed Injection zone.

Model boundaries were defined to include the entire footwall portion of the Injection zone's anticlinal structure that is bound to the east by the Stockton Arch fault (**Figure 3.3**). To the north, the depositional limit of the Injection zone is considered a closed boundary (**Figure 3.2**). The flow barrier identified at discovery is modeled as a no-flow boundary and partially separates the northern and southern portions of the field.

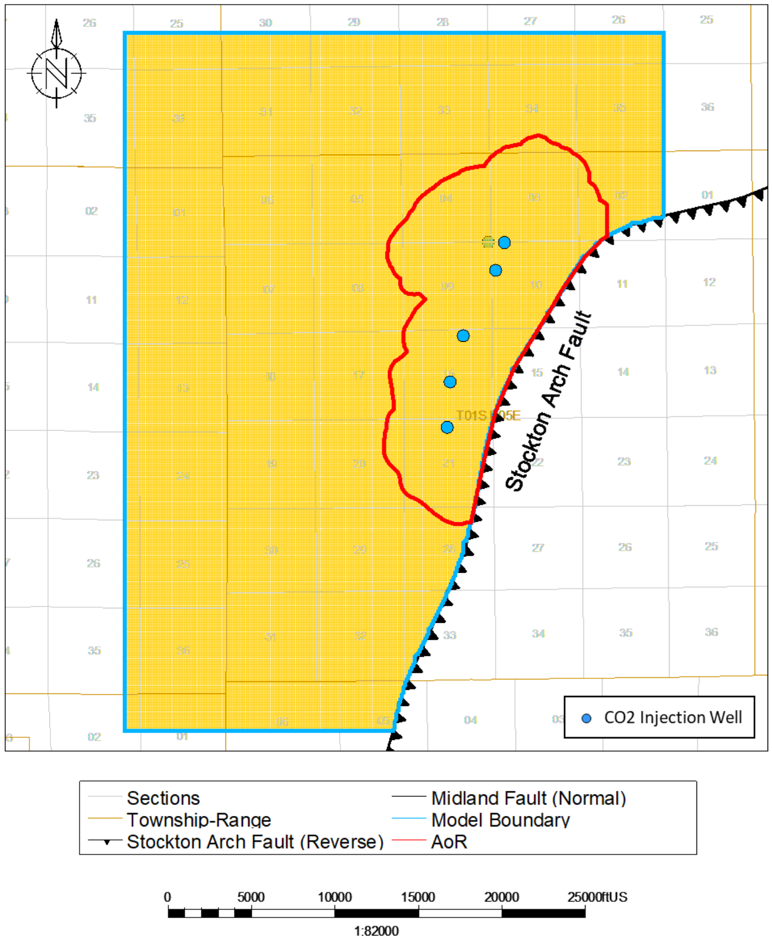


Figure 3.3. Plan view of the model boundary and geo-cellular grid used to define the project AoR.

A constant vertical cell height of 5 feet was utilized initially over the model domain to generate grid layers within the geomodel as shown in **Figure 3.4**. The 5-foot cell height provides the vertical resolution necessary to capture significant lithologic heterogeneity (sand versus shale) which helps to ensure accurate upscaling of log data and distribution of reservoir properties in the static model. To optimize run times and make the dynamic model run more efficiently, some upscaling was done for the dynamic flow model such that vertical thickness within the model depends on the vertical proportion of each sandy body. The average grid thickness for the flow model is 9 feet. **Figure 3.5** shows a comparison of open-hole log data and the associated upscaled logs for a well within the AoR.

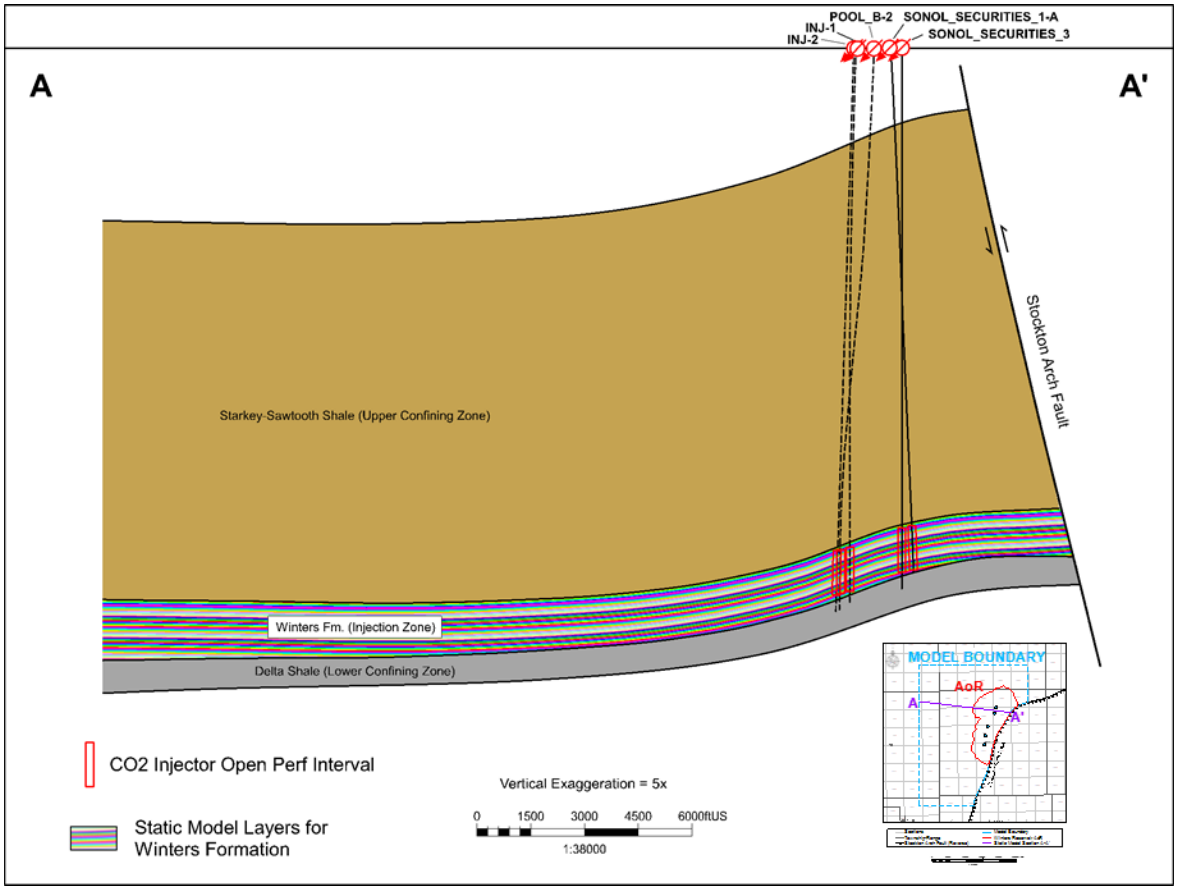


Figure 3.4. Dip section showing static model layering for the injection zone with all injectors projected onto section to show relative depth in reservoir structure. Section is representative of all injector locations

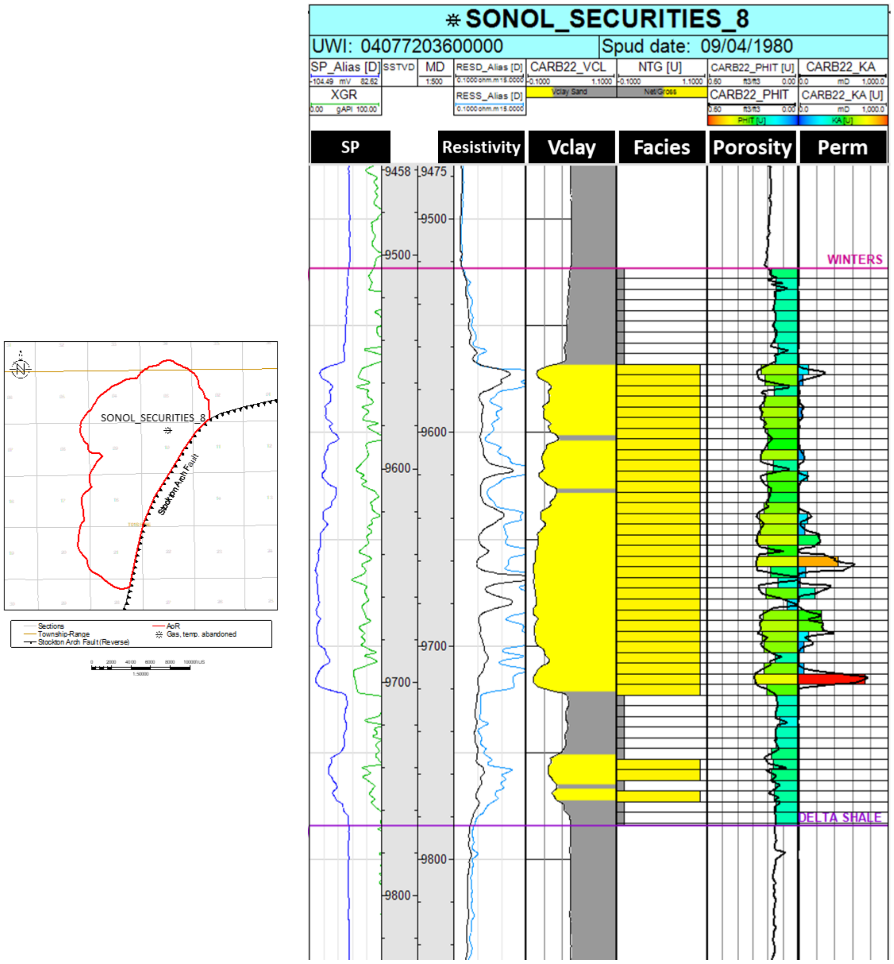


Figure 3.5. Well "Sonol Securities 8" upscaled logs versus open-hole logs.

3.1.4 Porosity and Permeability

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, compressional sonic, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined one of two ways: from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using 55.5 µsec/ft matrix slowness and the Raymer-Hunt equation.

Volume of clay is determined by spontaneous potential and is calibrated to core data.

Log-derived permeability is determined by applying a core-based transform that utilizes capillary pressure porosity and permeability along with clay values from XRD or FTIR. Core data from two wells with 13 data points was used to develop a permeability transform (**Figure 3.6**). An example of the transform from core data is illustrated in **Figure 3.7**.

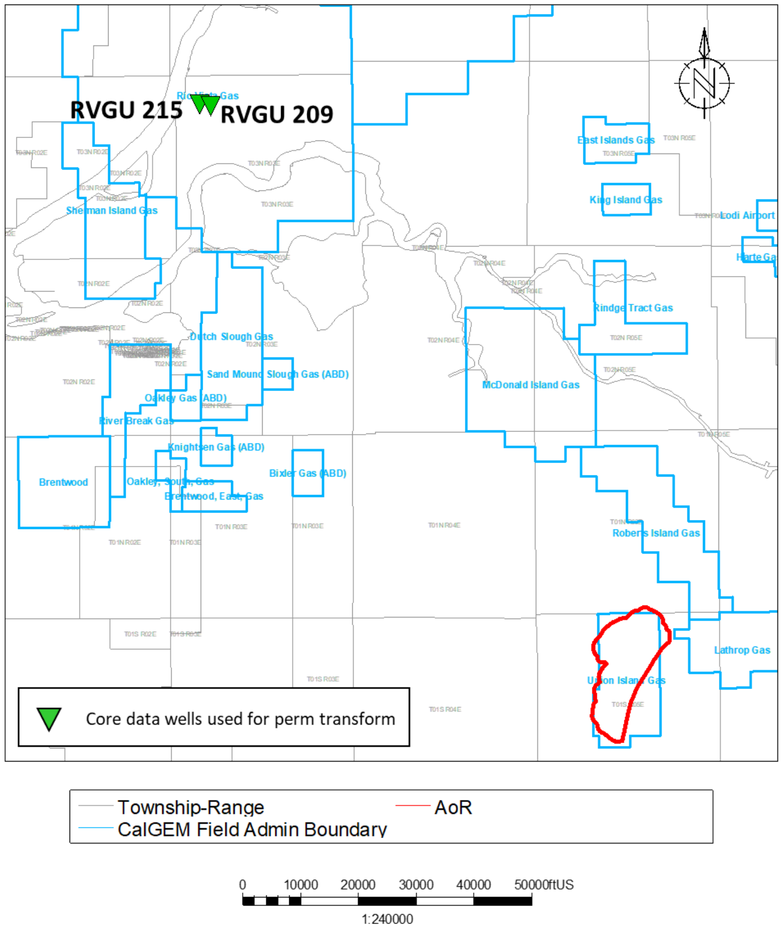


Figure 3.6. Location of wells with core data used for permeability transform.

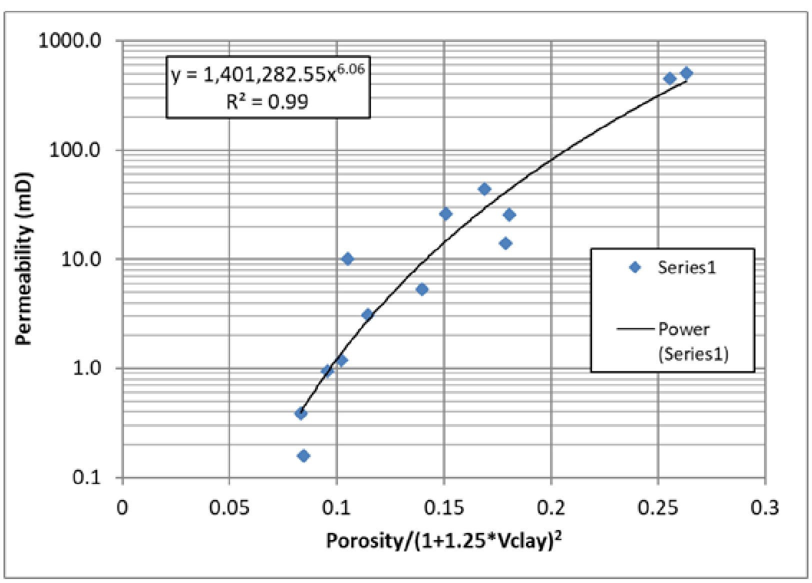


Figure 3.7. Porosity and permeability data from capillary pressure analysis for Injection zone sand. A permeability transform calculates permeability from log-based porosity.

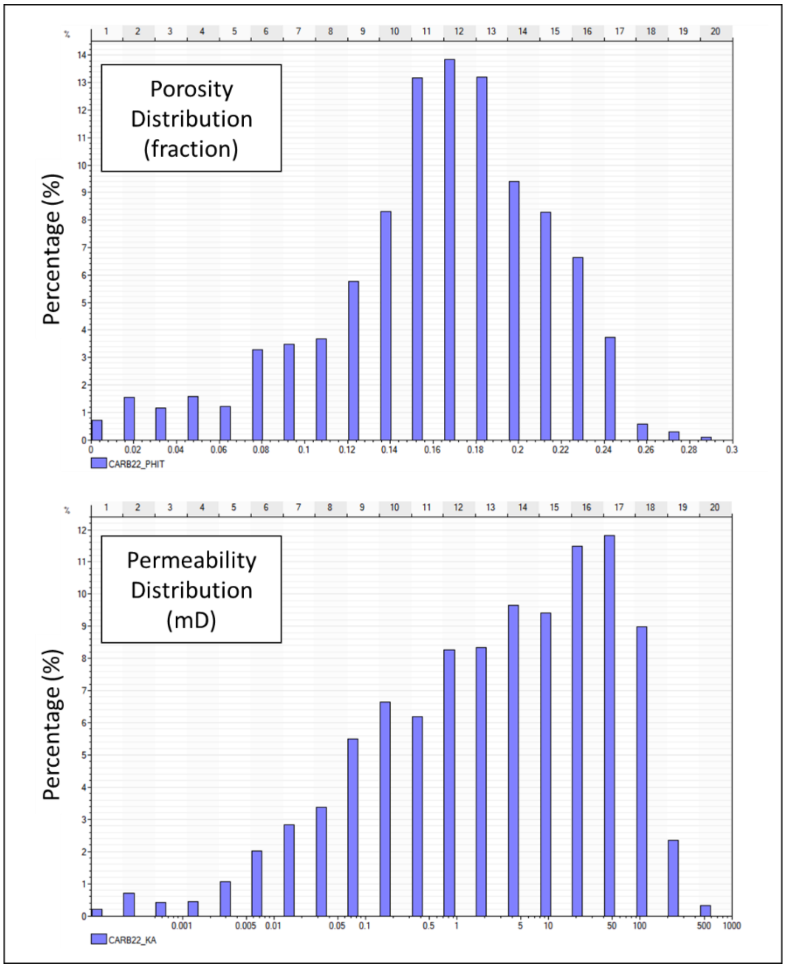
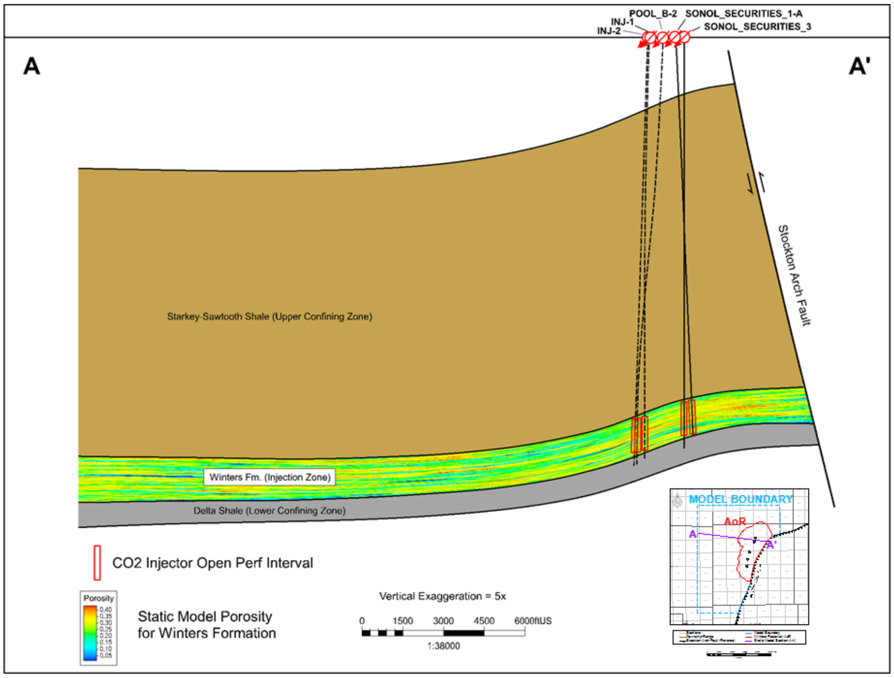


Figure 3.8. Injection Zone porosity and permeability distribution in the static model.

Figure 3.8 shows porosity and permeability histograms for the Injection zone. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. **Figure 3.9** shows the distribution of permeability and porosity using Sequential Gaussian simulation (kriging) within the static model. Reservoir quality is the highest at the top of the faulted anticline.



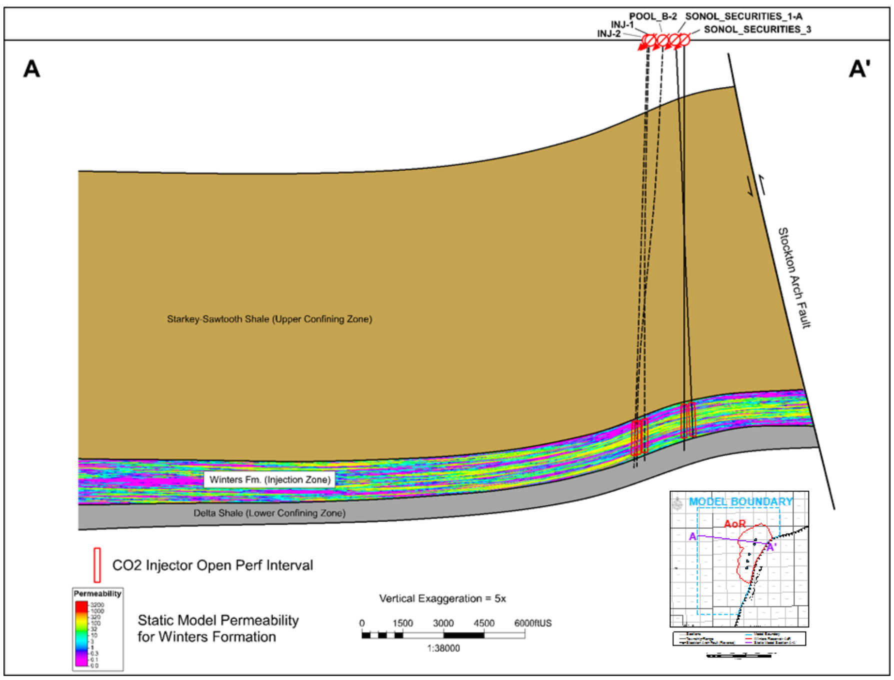


Figure 3.9. Dip section through the static grid showing the distribution of porosity and permeability in the reservoir with all injectors projected onto section to show relative depth in reservoir structure.

3.1.5 Constitutive Relationships and Other Rock Properties

The proposed Injection zone reservoir has a gas cap underlain by a basal water zone. Contacts for gas and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study for the regions above and below the Gas-Water contact at the Start of CO_2 injection. **Table 3.3** shows the reservoir contacts and saturations used in the computational model.

Table 3.3: Gas and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.

	North	South	Water Zone
Contact (depth sub-sea)	Gas - Water 9,600	Gas - Water 9,800	
Saturation (fraction)	Water: 0.34 Gas: 0.66	Water: 0.34 Gas: 0.66	Water: 1.0

With only gas and water present in the reservoir, one set of two-phase relative permeability relationships is needed to determine the flow characteristics of each component and/or phase, where Krw (water relative permeability) and Krg (gas relative permeability) is a function of gas saturation. Relative permeability data was acquired from core flood of samples from well Sonol Securities 6. Two samples results were used for normalizing, averaging and denormalizing process. Corey correlation were used to smooth the final curves. Capillary pressure data acquired from well Sonol Securities 5 measured by centrifuge method, was converted to reservoir condition. **Figure 3.10** shows the relative permeability curves and **Figure 3.11** shows the capillary pressure curve used in the computational model.

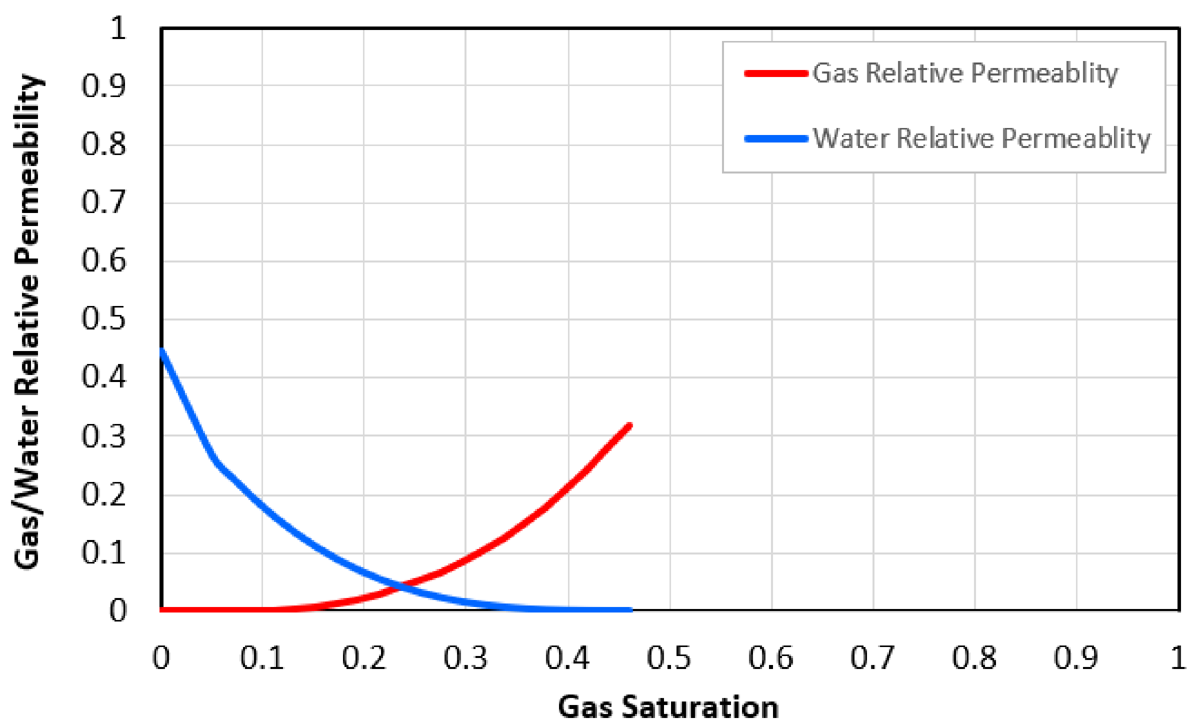


Figure 3.10. Relative permeability curves for Gas-Water System.

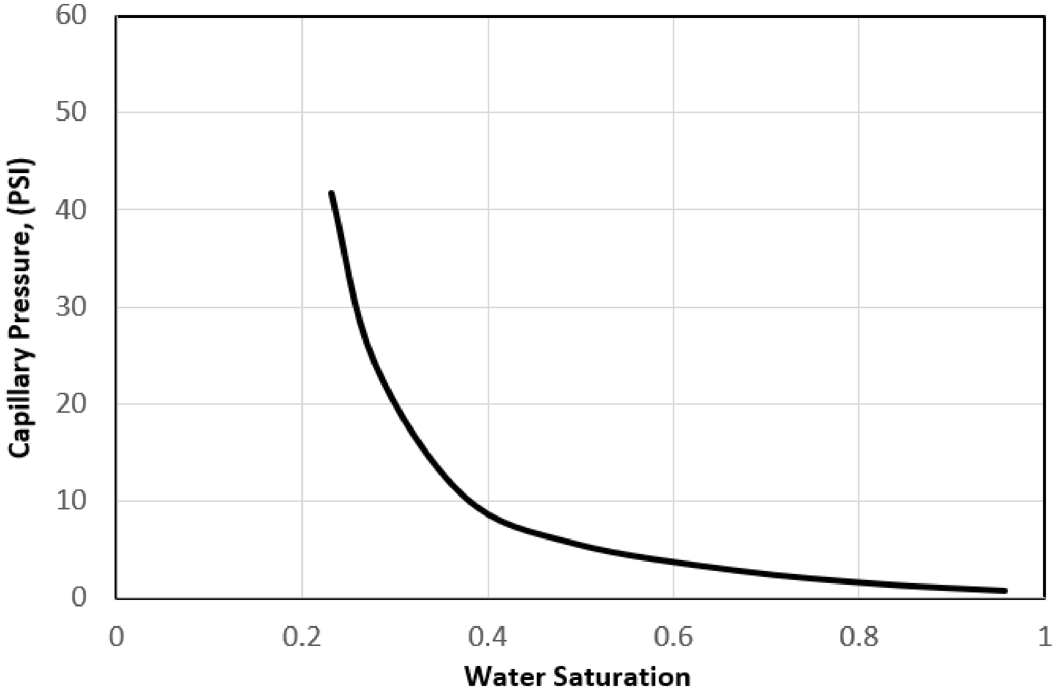


Figure 3.11. Capillary Pressure Curve.

3.1.6 Mineralization

Previous studies into reactive transport modeling and geochemical reaction in CCS have shown that the amount of CO_2 trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage, prepared by Working Group III of the Intergovernmental Panel on Climate Change) for sandstone reservoirs. For the sake of computational efficiency and the minor expected effect on the AoR, reactive transport was not included as a part of the compositional simulation modeling.

Potential geochemical reactions of the Injection zone, Confining zone and formation fluids with the injectate streams being considered were modeled using PHREEQC (ph-REdox-Equilibrium), the USGS geochemical modeling software. Details on the modeling procedure and results are provided in the Section 2.8.3 of the Narrative, and in Appendix 3: CTV II Geochemical modeling. The modeling indicates as expected, that as the formations are stable quartz dominated mineralogy, the effect of geochemical reactions with the injectate will be minor, with a predicted net molar mass increase (precipitation) of 1.5-2%, which is not expected to have a major impact on porosity or permeability in the injection zone or upper confining zone.

3.1.7 Boundary Conditions

No-flow boundary conditions were applied to the edges of reservoir in the computational flow modeling. These conditions were based on the following:

1. The Upper Confining Zone is continuous through the area, has a low permeability (0.04 mD) and has confined oil and gas operations.

2. Performance data from operating the field indicates limited active aquifer.

   i. Historical production data (**Figure 3.12**) shows limited water production,

   ii. Pressure in the reservoir is currently at 1,200 PSI from a discovery pressure of 5,040psi, demonstrating limited aquifer influx

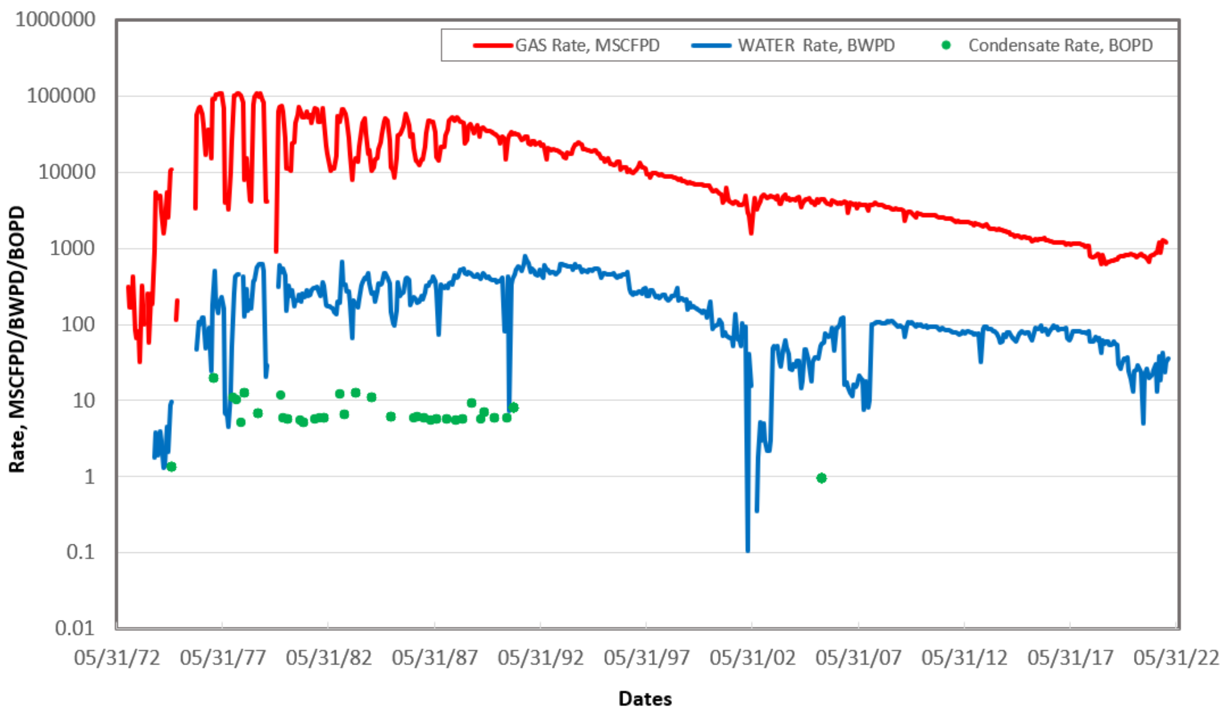


Figure 3.12. Field production graph.

3.1.8 Initial Conditions

Initial model conditions (start of CO2 injection) of the Injection zone have been established and verified over time as the reservoir has been developed for gas production. Initial conditions for the model are given in Table 3.4.

Table 3.4: Initial conditions (start of CO2 Injection).

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	218	Fahrenheit	9,600	Fluid Analysis
Formation pressure	1,200	Pounds per square inch	9,600	Pressure Test
Fluid density	61	Pounds per cubic foot	9,600	Water analysis
Salinity	15,000	Parts per million	9,600	Water analysis

3.1.9 Operational Information

Details on the injection operation are presented in **Table 3.5**.

Table 3.5: Operating details.

Operating Information	SONOL SECURITIES 1-A	SONOL SECURITIES 3	POOL B-2	UI_INJ_1	UI_INJ_2
Location (global coordinates) LAT LONG	37.86861 -121.418	37.86405 -121.419	37.8383 -121.4297	37.8533 -121.4262	37.8457 -121.4288
Model coordinates (ft) X Y	2168172.00 74088.43	2167639.00 72424.55	2164738.00 63009.3	2165702.95 68502.85	2164946.41 65731.55
Perforated interval (ft MD | TVD | MSL) Z top Z bottom	9720 | 9592 | 9580 9960 | 9827 | 9815	9,620 | 9620 | 9607 9,910 | 9920 | 9897	10033 | 9807 | 9792 10387 | 10147 | 10132	9905 | 9782 | 9760 10173 | 10049 | 10027	10465 | 9755 | 9732 10845 | 10103 | 10080
Wellbore diameter (in.)	6	6.75	8.5	8.75	8.75
Planned injection period Start End	2025 2048	2025 2048	2025 2048	2025 2048	2025 2048
Injection duration (years)	24	24	24	24	24
Injection rate (t/day)*	530-794	530-794	530-794	530-794	530-794

3.1.10 Fracture Pressure and Fracture Gradient

In the past, produced water from the field had been injected into the Mokelumne formation by well GALLI 1. The Class II permit approved maximum operating pressure gradient for that zone was 0.80 psi/foot. A 0.7 Psi/foot fracture gradient is assumed for the Injection zone at present. CTV will conduct a step rate test in the injection zone as part of the pre-operational testing plan to confirm this fracture pressure gradient.

At this time, no fracture gradient information has been found for the Upper Confining Zone. CTV will conduct a step rate test for the Upper Confining zone as per the pre-operational testing plan.

The Maximum Injection pressures for the injection wells, calculated at the top perforation using a 0.7psi/foot fracture gradient and a 10% safety factor as per EPA guidance, are shown in **Table 3.6**. The average operating conditions of the injectors are also shown and CTV will ensure the wells never cross the maximum injection pressures. Further details can be found in the "Appendix 4: Operational Procedures" document.

Table 3.6: Injection pressure details.

Injection Pressure Details	**SONOL SECURITIES 1-A**	**SONOL SECURITIES 3**	**POOL B-2**	**UI_INJ_1**	**UI_INJ_2**
Fracture gradient (psi/ft)	0.70	0.70	0.70	0.70	0.70
Maximum bottomhole injection pressure (90% of fracture pressure) (psi)	6043	6061	6178	6163	6146
Elevation corresponding to maximum injection pressure (ft TVD)	9592	9620	9807	9782	9755
Elevation at the top of the perforated interval (ft TVD)	9592	9620	9807	9782	9755
Average bottom hole injection pressure at top of perforations (psi)	3388	3372	3065	2960	3005
Average bottom hole injection gradient at top of perforations (psi/foot)	0.35	0.35	0.31	0.30	0.31

3.2 Computational Modeling Results

3.2.1 Predictions of System Behavior

Computational modeling cases were run using 2 injectate streams representing potential injectate compositions from different sources. Details of the injectate composition are covered in Section 7.2 of the Narrative document.

The following maps (**Figure 3.13**) and cross-sections (**Figure 3.14)** show the computational modeling results and development of the CO_2 plume at different time-steps for the 2 injectate scenarios. The boundaries of the AoR have been defined with a 0.1 CO_2 global mole fraction cutoff plus a buffer zone.

As shown in **Figure 3.13** and **Figure 3.14**, the CO_2 extent is largely defined by the end of injection (Year 23). By Year 30 after the end of injection, for both Injectate 1 and Injectate 2, the plume is largely stabilized with very little further movement seen in comparison to the 100 year post end of injection plume extent.

For both injectates, the majority of the CO_2 injectate remains as super-critical CO_2 (88%) with the remaining portion of the CO_2 dissolving in the formation brine over the simulated 100 years post injection. **Figure 3.15** shows the cumulative storage for each of the mechanisms for Injectate 1 and Injectate 2.

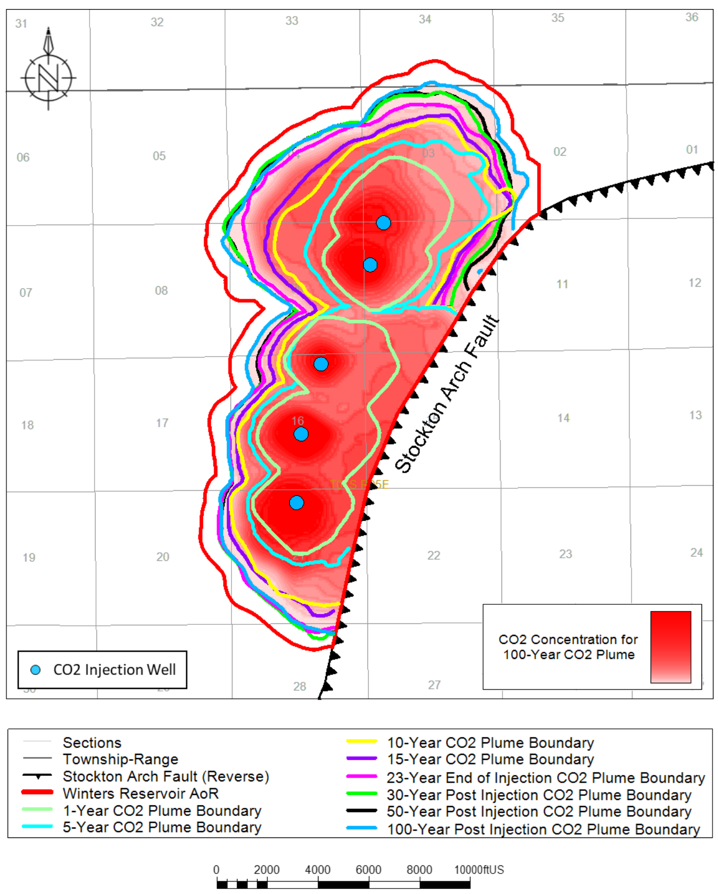


Figure 3.13A. Injectate 1 Plume development through time: 1-year, 5-year, 10-year, 15-year, 23-year (end of injection), 30-year post injection, 50-year post injection, and 100-year post injection.

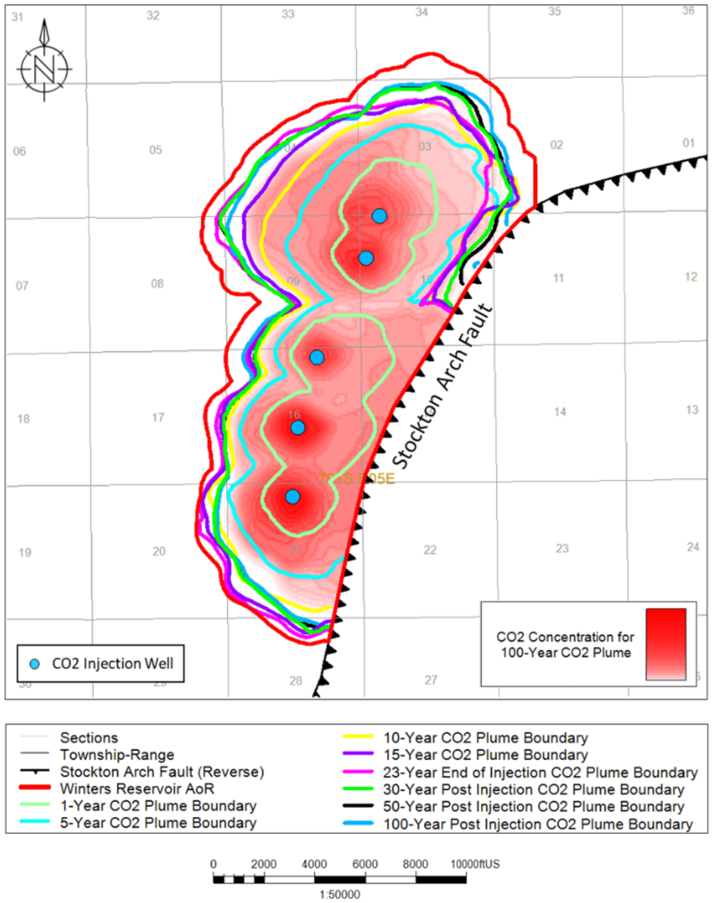


Figure 3.13B. Injectate 2 Plume development through time: 1-year, 5-year, 10-year, 15-year, 20-year, 23-year (end of injection), 32-year post injection, and 100-year post injection.

Multiple mixing scenarios were also run, where the two injectates were mixed in different proportions to test the effect on the plume and AoR shape. As would be expected, since the resulting mixtures were still high purity CO2 streams with impurity concentrations in between those of Injecate 1 and 2, the results of these mixing scenarios fell within the envelope represented by the end point compositions - Injectate 1 and 2.

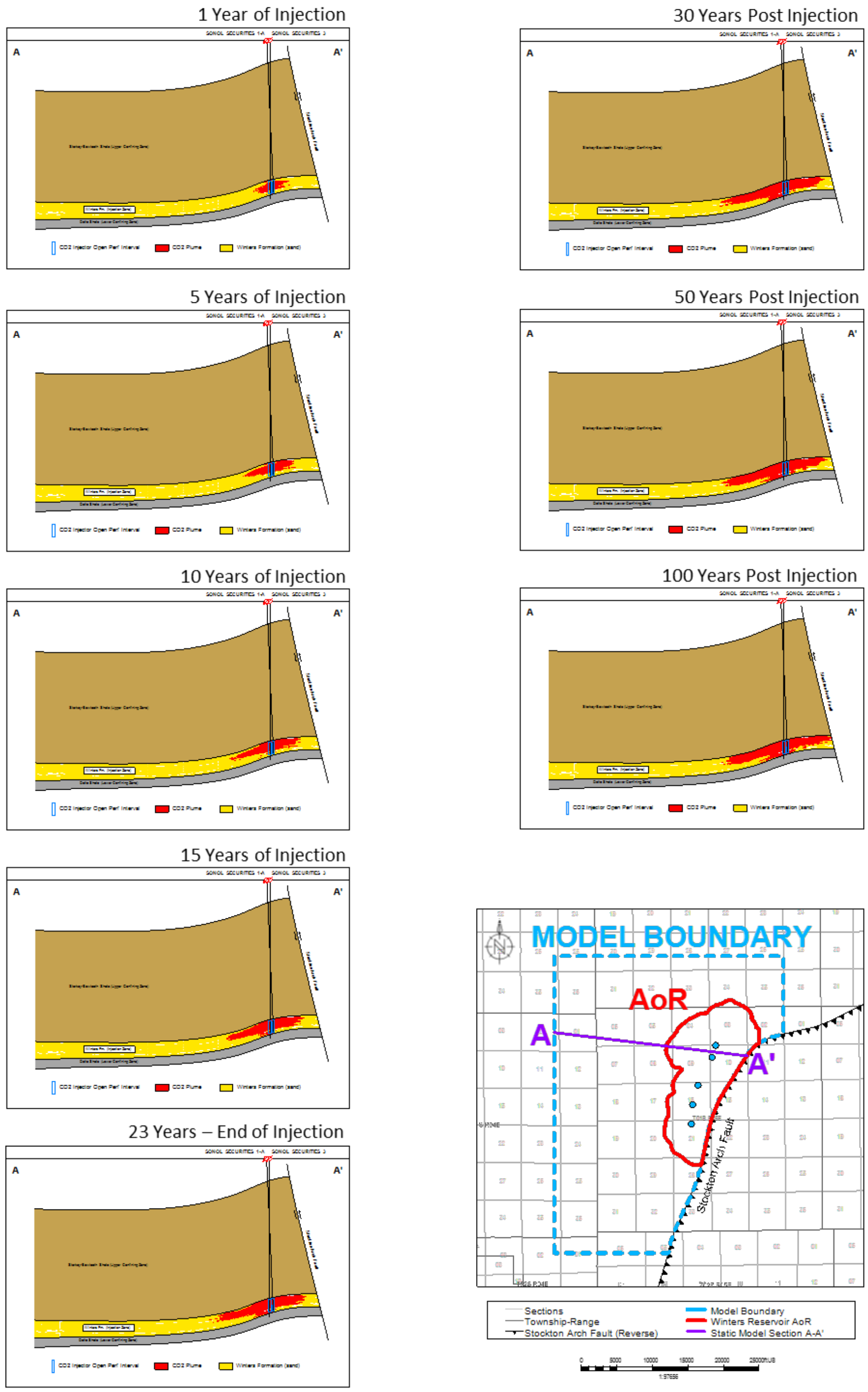


Figure 3.14A. Section showing proximity of CO2 (Injectate 1) to the Stockton Arch Fault and lateral dispersion of CO2 throughout time and confinement under the overlying Starkey-Sawtooth through time for the five injector modeled Base scenario. As the sections show, plume growth over time is driven by the reservoir anticlinal structure, and is thus representative of the plume growth at all injector locations.

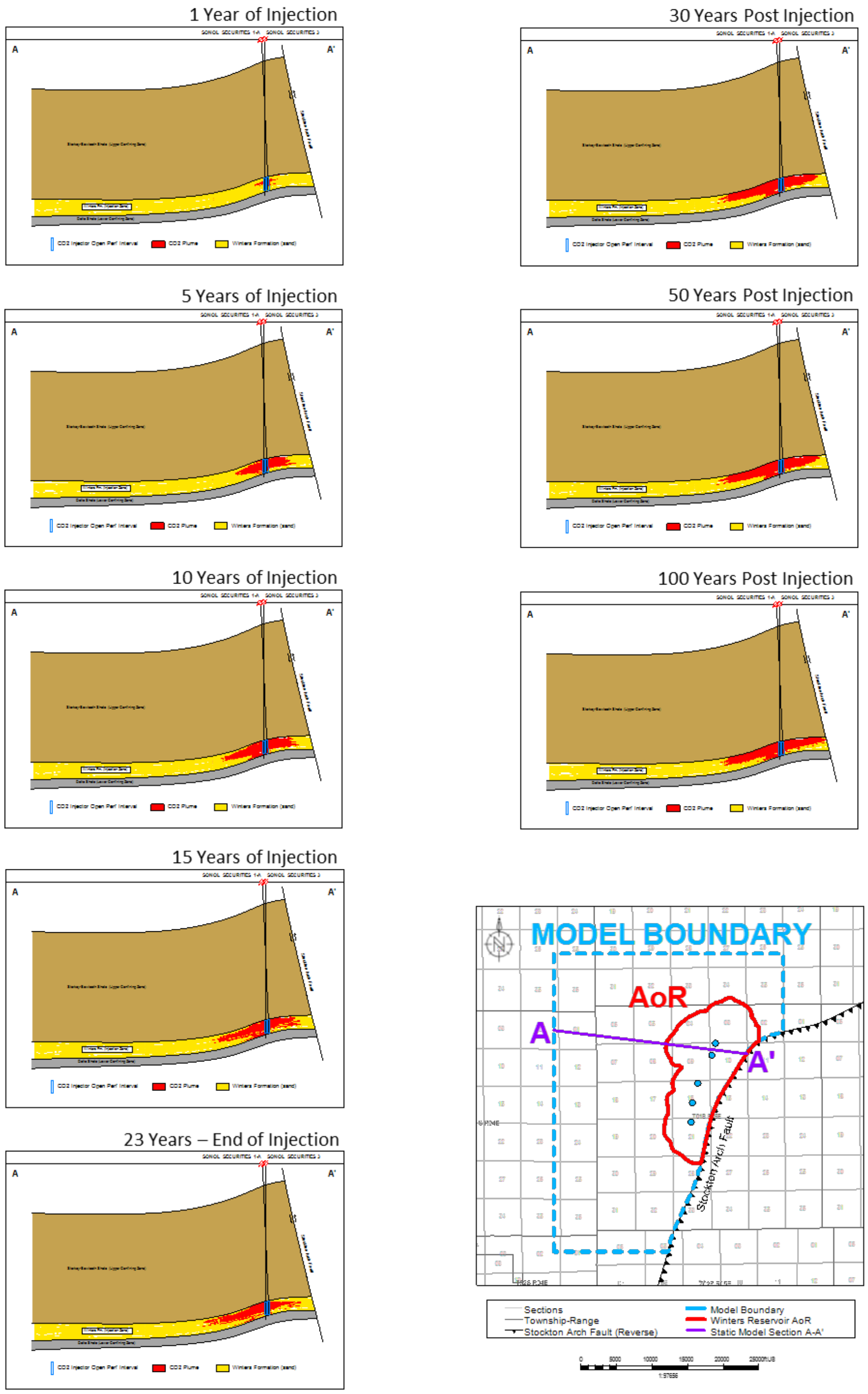


Figure 3.14B. Section showing proximity of CO2 (Injectate 2) to the Stockton Arch Fault and lateral dispersion of CO2 throughout time and confinement under the overlying Starkey-Sawtooth through time for the five injector modeled Base scenario. As the sections show, plume growth over time is driven by the reservoir anticlinal structure, and is thus representative of the plume growth at all injector locations.

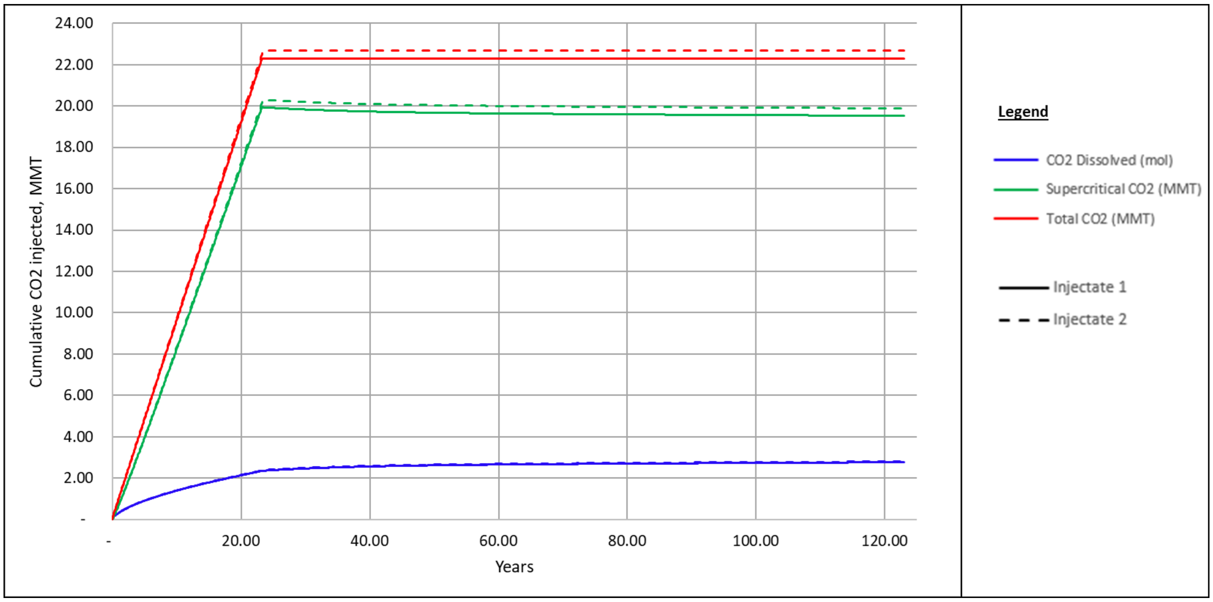


Figure 3.15. CO_2 storage mechanisms in the reservoir. Results shown for Base cases with Injectate 1 (solid lines) and Injectate 2 (dashed lines)

3.2.2 Model Calibration and Validation

The Union Island Gas field was discovered in 1972, and has been produced from the Winters Formation for around 50 years. This operational experience provides insight into the reservoir continuity. The plume model results were compared against the area of the reservoir that has been depleted by gas production and against initial gas contacts.

Additionally, the scenarios listed in the **Table 3.7** were run varying major inputs to the simulation to see whether it had any significant impact on the AoR boundary. All cases were run with injection being ceased once the depleted reservoir had been pressured back up to 90% of discovery pressure. The results from the different scenarios were reviewed and showed varying final CO_2 storage amount but minimal impact to the AoR boundary.

Table 3.7: Simulation sensitivity scenarios.

Scenario	CO_2 plume & AoR impact
Porosity: 10% reduction from base case	Minimal Impact
Porosity: 10% increase from base case	Minimal Impact
Permeability: 10% reduction from base case	Minimal Impact
Permeability: 10% increase from base case	Minimal Impact

These scenarios demonstrate that the AoR, as defined by the maximum extent of CO_2 injectate plus a buffer, is consistent for a range of scenarios. This provides confidence that the corrective action well review and potential impact to the USDW is conservative and has been appropriately evaluated.

3.2.3 AoR Delineation

The Critical threshold pressure calculation and results are discussed in Appendix 10. As the injection is in a depleted reservoir being re-pressured to below the discovery conditions, the largest CO2 plume extent plus a buffer zone was used to determine the AoR. For both injectate scenarios, CO2 was injected into the depleted Injection zone until the reservoir pressure reached 90% of the discovery pressure of 5,040 PSI.

Figure 3.16 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the Pressure and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

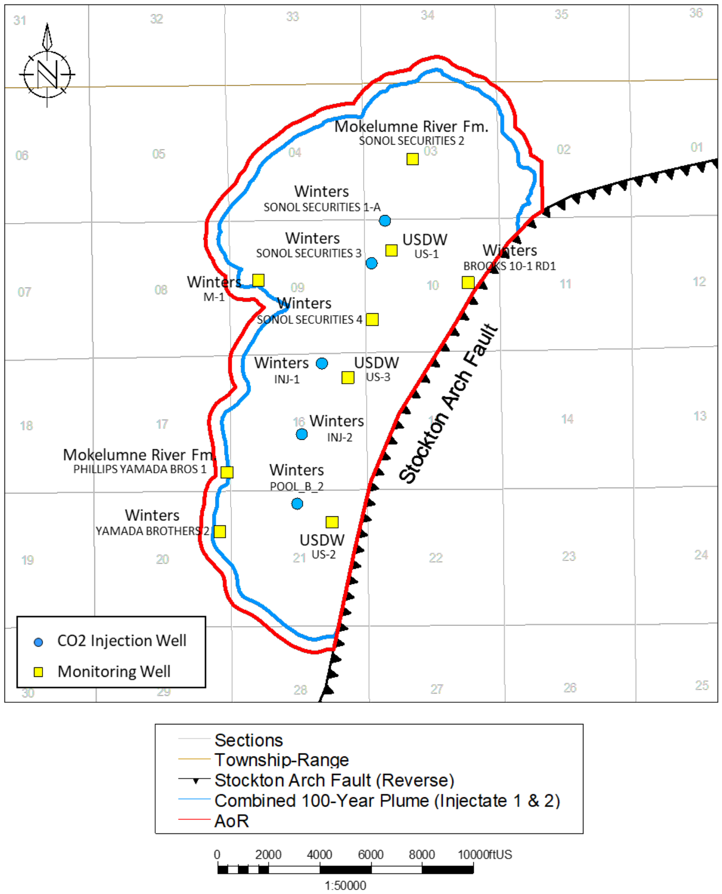


Figure 3.16. Map showing the location of injection wells and plume monitoring wells.

3.3 Corrective Action

3.3.1 Tabulation of Wells within the AoR

Wells within the AoR are associated with exploration and development of the Winters Formation for gas production from 1972 onwards. As such, there are sufficient records for wells drilled in the study area. There have been no undocumented historical wells found in the AoR.

CTV accessed internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR (Sources: https://wellstar.conservation.ca.gov , https://maps.conservation.ca.gov/doggr/wellfinder).

Tables 3.8 and 3.9 provide counts of the AoR wellbores with a description that includes status and type, for each wellbore with a unique API-12 identifier. **Appendix 7** provides a complete list of all API-12 wellbores within the AoR. As required by 40 CFR 146.84(c)(2), the well table in **Appendix 7** describes each well's type, construction, date drilled, location, measured depth, true vertical depth, completion record relative to the Injection zone, record of plugging, and requirement for corrective action, if necessary. CTV also identifies well work to be completed during the pre-operational testing phase.

Table 3.8. Wellbores in the AoR by status.

Status	Count
Active Producer	5
Idle Producer	15
Plugged and Abandoned Producer	9
Total	**29**

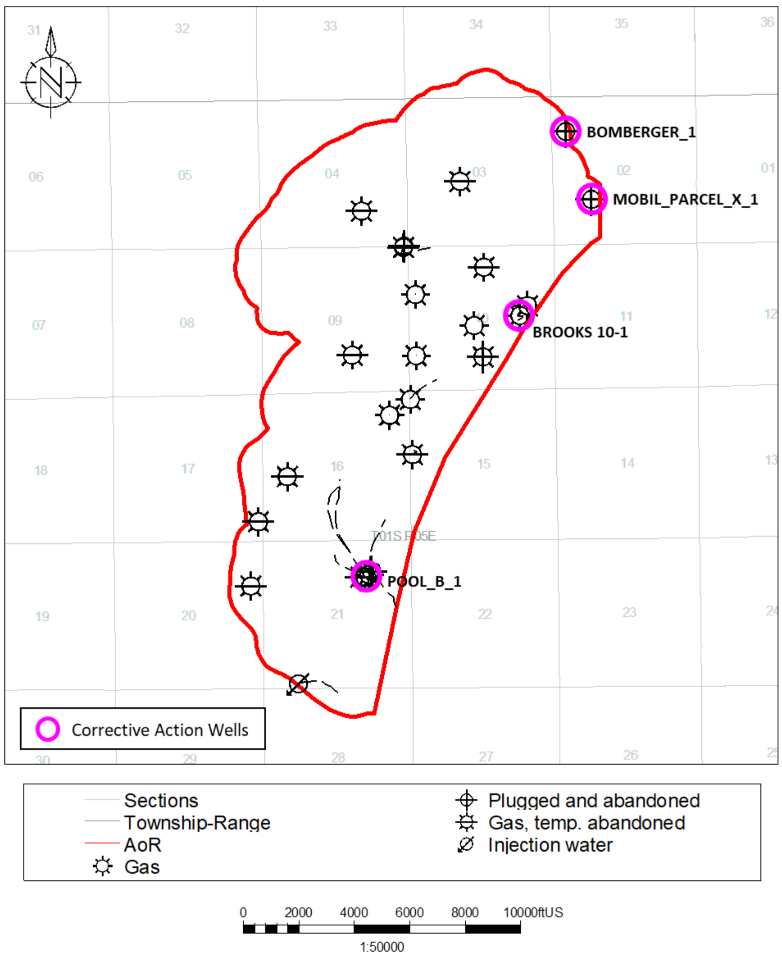


Figure 3.17. Wells penetrating the upper confining layer and the injection zone reviewed for corrective action. The wells requiring corrective action prior to injection are identified by a magenta circle.

3.3.2 Protection of USDW

For the CTV II Storage Project, CTV assessed the USDW protection by evaluating all wellbores that penetrate the Upper Confining Zone. All wells within the AoR meet the criteria below, ensuring the protection of the USDW.

1. Surface or intermediate casing over the USDW

2. If well is abandoned, cement plug across base of USDW

3. Cement in the annulus:

    a. Intermediate casing – cement above the surface casing shoe.

    b. Adequate annular cement within the confining Upper Confining Zone.

3.3.3 Wells Penetrating the Confining Zone

The depth of the confining zone in each of the wells penetrating the Upper Confining Zone was determined through open-hole well logs utilizing the deviation survey. All wells in the AoR penetrate the Upper Confining zone.

3.3.4 Injection Zone Isolation

Wells that will not be repurposed for the storage project that penetrate and are currently open in the Injection zone will be abandoned prior to injecting CO_2. These wells have not been deemed deficient. The abandonment of these wells shown in **Figure 3.18** is considered to be normal operating procedures to manage and minimize liabilities. Wellbores that meet these criteria are identified for abandonment in **Appendix 7**.

Appendix 8 provides the plugging procedure that will be used to abandon these wells along with well-specific plugging plan tables that identify the number of plugs, placement method, cement type, density, and volume for the wells to be abandoned during pre-operational testing. Additionally, the procedures achieve all requirements of CalGEM regulations for proper abandonment of oil and gas wells.

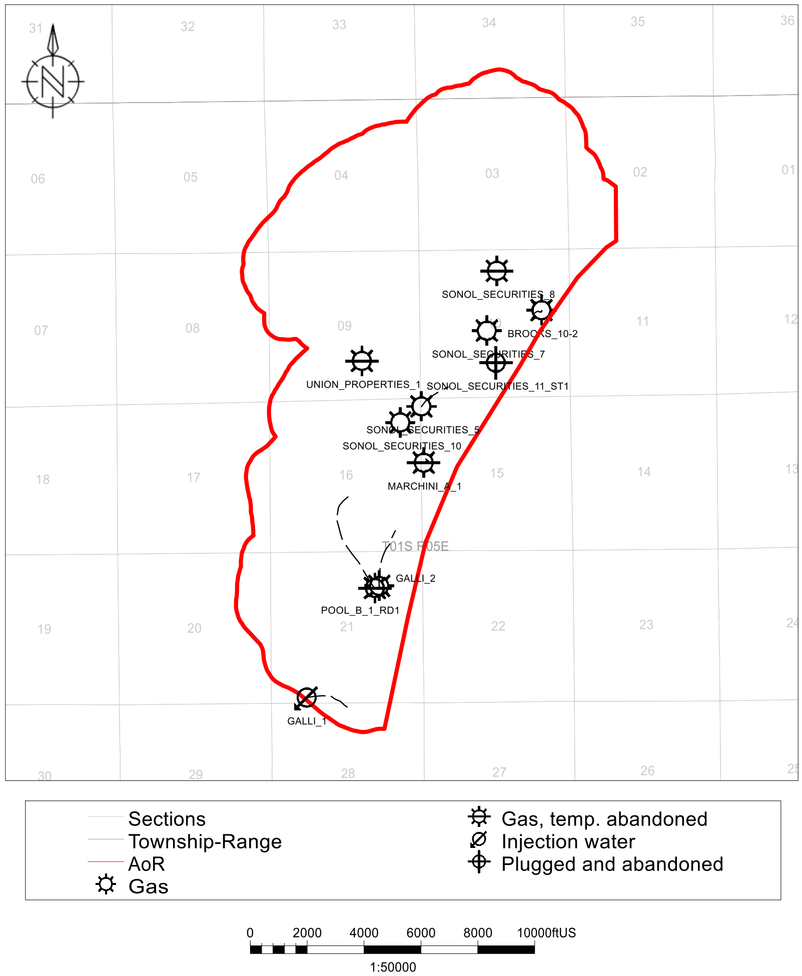


Figure 3.18. Wells to be abandoned prior to injection.

3.3.5 Corrective Action Assessment of Wells in AoR

The corrective action assessment included the generation of detailed casing diagrams for each wellbore, review of all perforations, assessment of well architecture (casing depths, annular cement, etc.), and determination of cement plug depths relative to key storage complex formation tops.

The Brooks 10-1-RD1 is a sidetrack of the Brooks 10-1 original hole, and the Brooks 10-1 RD1 well is being repurposed as a monitoring well. The original hole was sidetracked by setting a cement plug from 5648' – 6246' MD, and the well was suspended with drilling mud below the plug. CTV will re-abandon the well and ensure isolation of the injection zone. CTV plans to re-enter the section of the well beneath the plug from ~5700' – 6500' MD, clean out the original openhole as deep as possible, and fill the well with Class G cement plugs to ensure isolation.

The Pool B-1 RD1 is the idle sidetrack of Pool B-1, a wellbore within the AoR that will require corrective action. Originally sidetracked due to a drillpipe fish, there is no cement across the confining layer in this wellbore. CTV plans to re-abandon the portion of the well below the fish by re-entering the wellbore and filling the well with Class G cement plugs to ensure isolation.

Bomberger 1 and Mobil Parcel X 1 are both dry hole abandonment wells outside of the Union Island gas field boundary. With no gas shows during the drilling process, these wells were abandoned with casing set above the confining layer and openhole drilled through the injection zone. Abandonment plugs were set within the casing, but no cement was laid across the confining layer. CTV plans to drill out abandonment plugs and re-enter the openhole portion of the abandoned wellbore, filling the well with Class G Portland cement plugs to re-establish the confining layer and ensure isolation.

All corrective action wells are highlighted in **Figure 3.17**. Appendix 9 shows diagrams for the current well configurations and proposed corrective action on all four wells.

3.3.6 Plan for Site Access

CTV has obtained surface access rights for the duration of the project.

3.3.7 Corrective Action Schedule

Corrective action for all wells within the AoR will be completed before CO_2 is injected in the reservoir. This will ensure that CO_2 is confined to the injection zone for the entire AoR, protecting the overlying USDW and ensuring confinement.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

3.4 Reevaluation Schedule and Criteria

3.4.1 AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data forthe review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO_2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the reulsts are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

3.4.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Injection zone that are not related to well integrity.

    b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results with a variance >±10% from the Base Case Simulation.

    c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

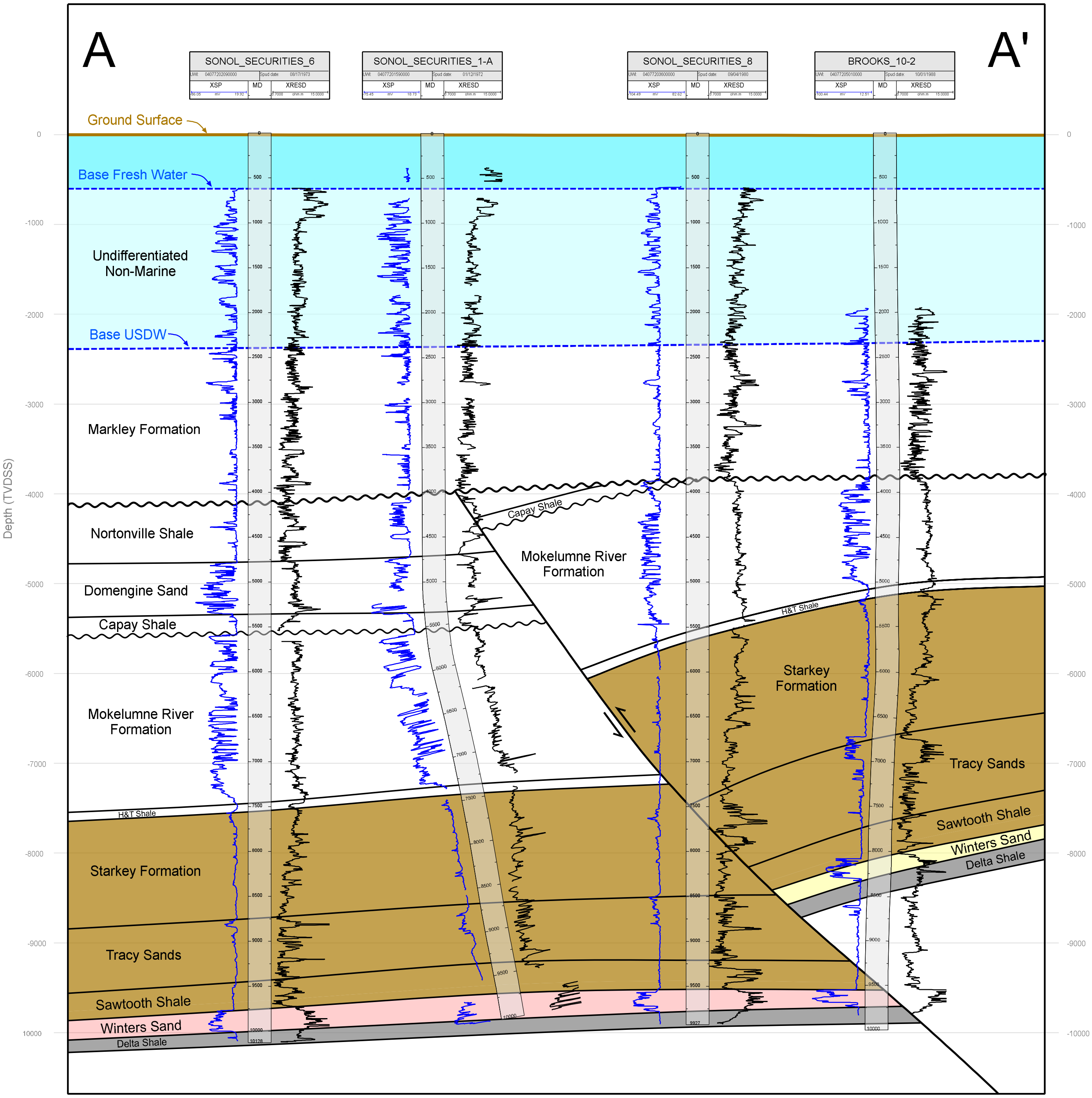
a. The presence of faults near the confining zone that indicates propagation into the confining zone.

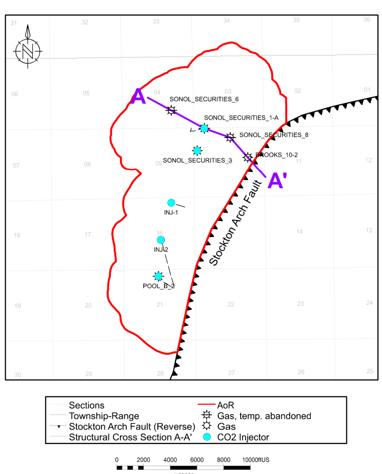
b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.
3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).
4. Initiation of competing injection projects within the same injection formation within a 1- mile radius of the injection well (including when additional CTV injection wells come online);
5. A significant change in injection operations, as measured by wellhead monitoring;
6. Significant land-use changes that would impact site access; and
7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event

AREA OF REVIEW AND CORRECTIVE ACTION - FIGURES





Structural Cross Section A-A'   Vertical Exaggeration 1:1

- Fresh Water Aquifer (<3000 mg/L TDS)
- USDW (>10,000 mg/L TDS)
- Starkey-Sawtooth Shale (Upper Confining Layer)
- Winters Reservoir (AoR Injection Interval)
- Winters Reservoir (No Injection)
- Delta Shale (Lower Confining Layer)

Figure 3.1. Dip cross section showing stratigraphy and lateral continuity of major formations across the project area. Section is representative of formations and sand continuity at all five CO2 injector locations.

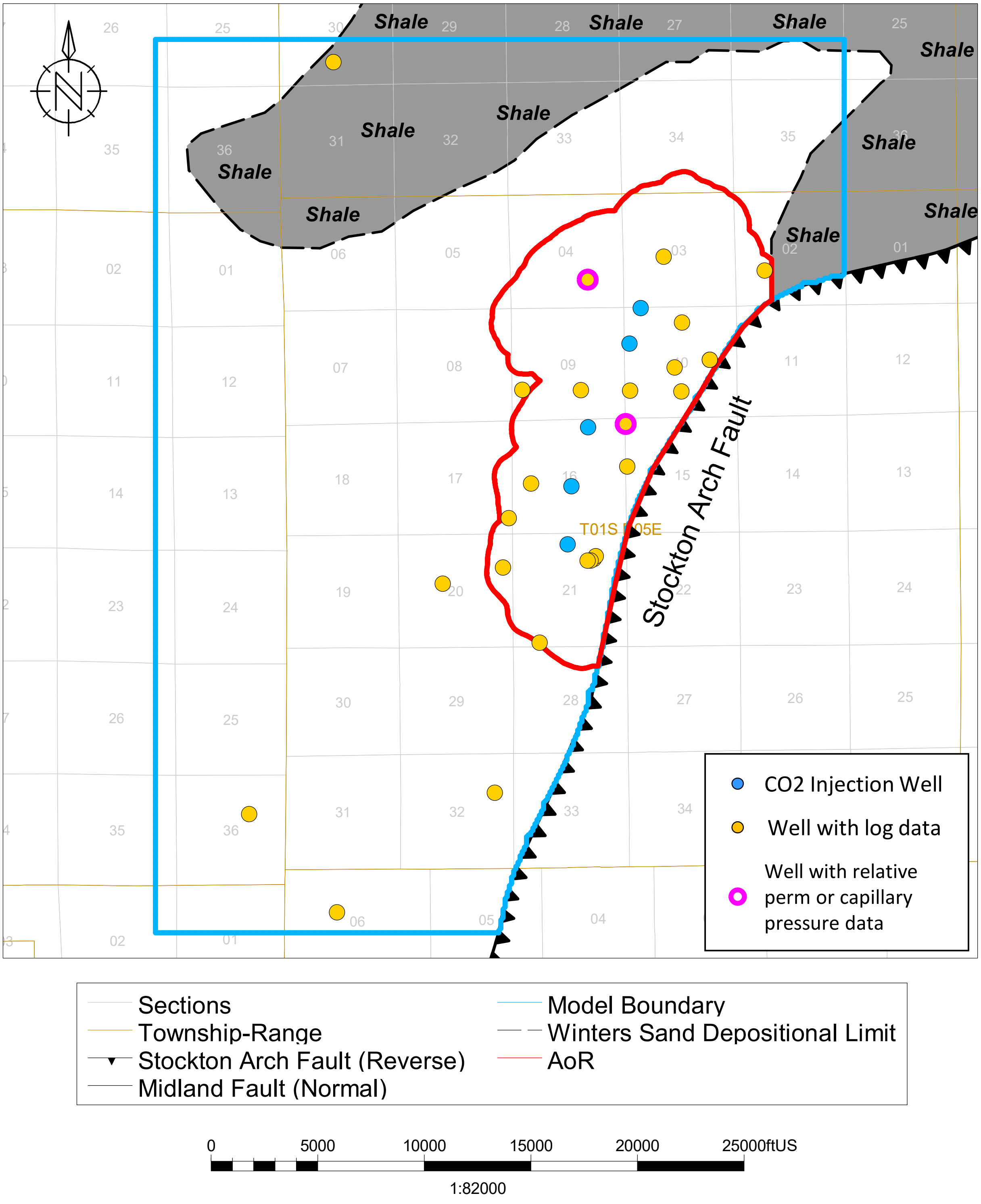


Figure 3.2. Location of wells with open-hole log data and injection zone relative permeability or capillary pressure data used to develop the static and computational models.

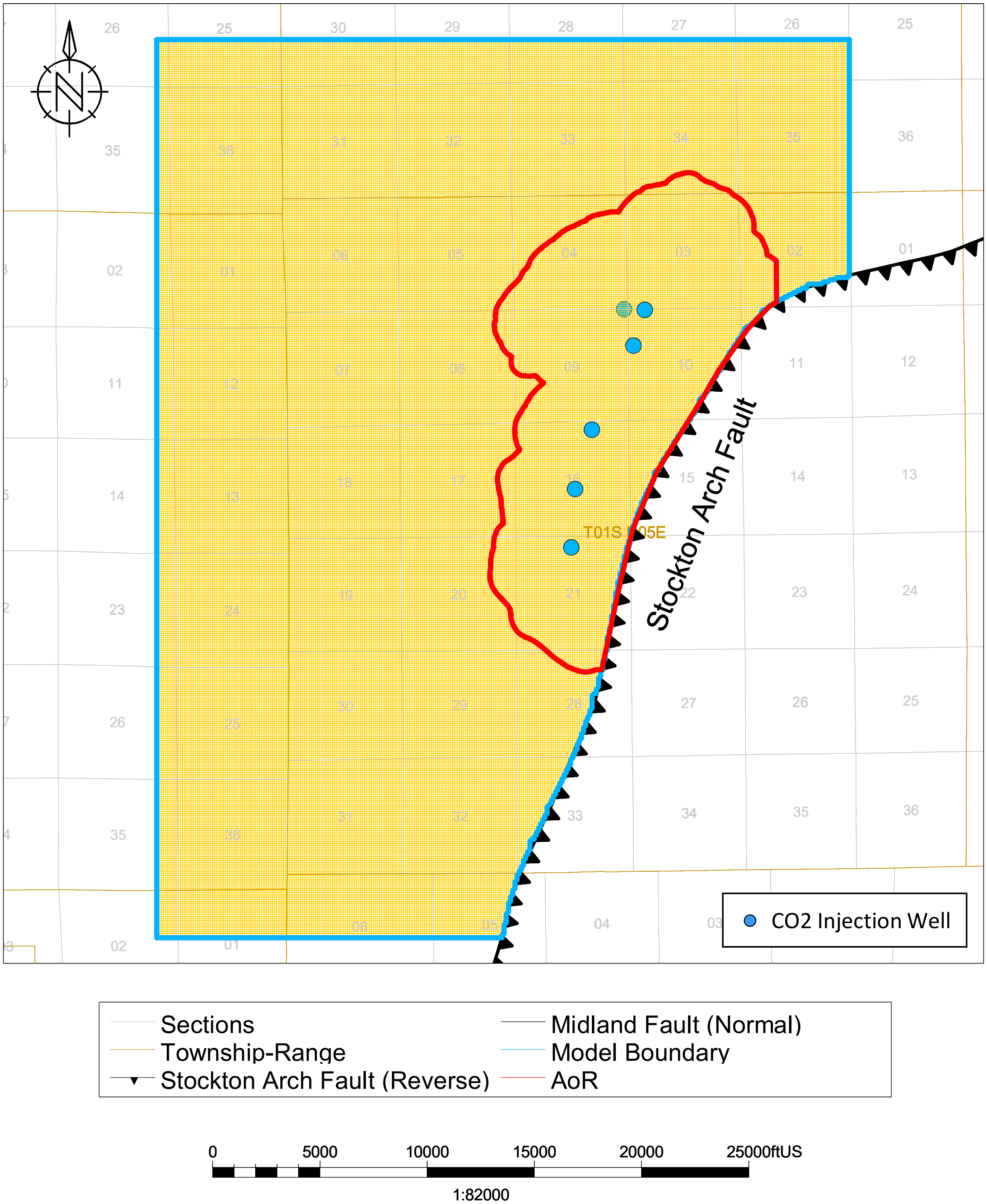


Figure 3.3. Plan view of the model boundary and geo-cellular grid used to define the project AoR.

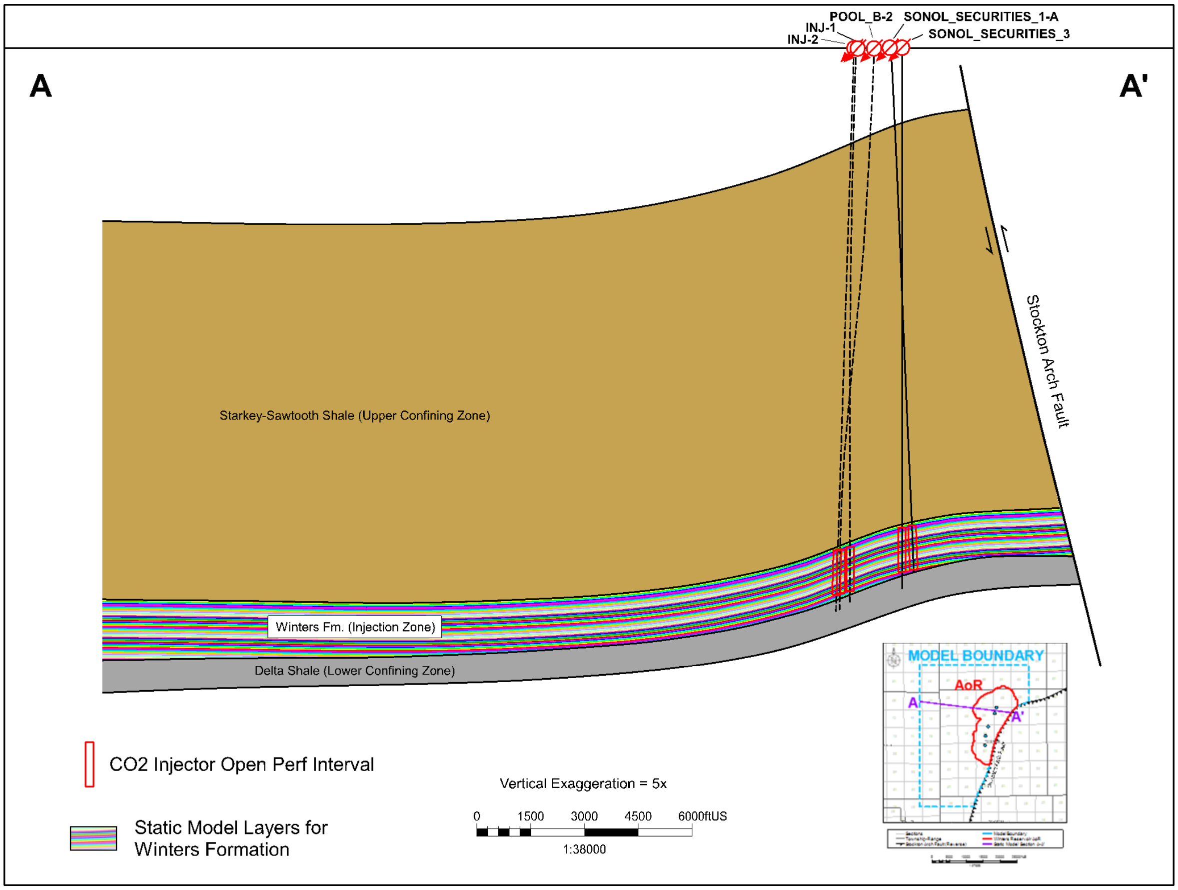


Figure 3.4. Dip section showing static model layering for the injection zone with all injectors projected onto section to show relative depth in reservoir structure. Section is representative of all injector locations.

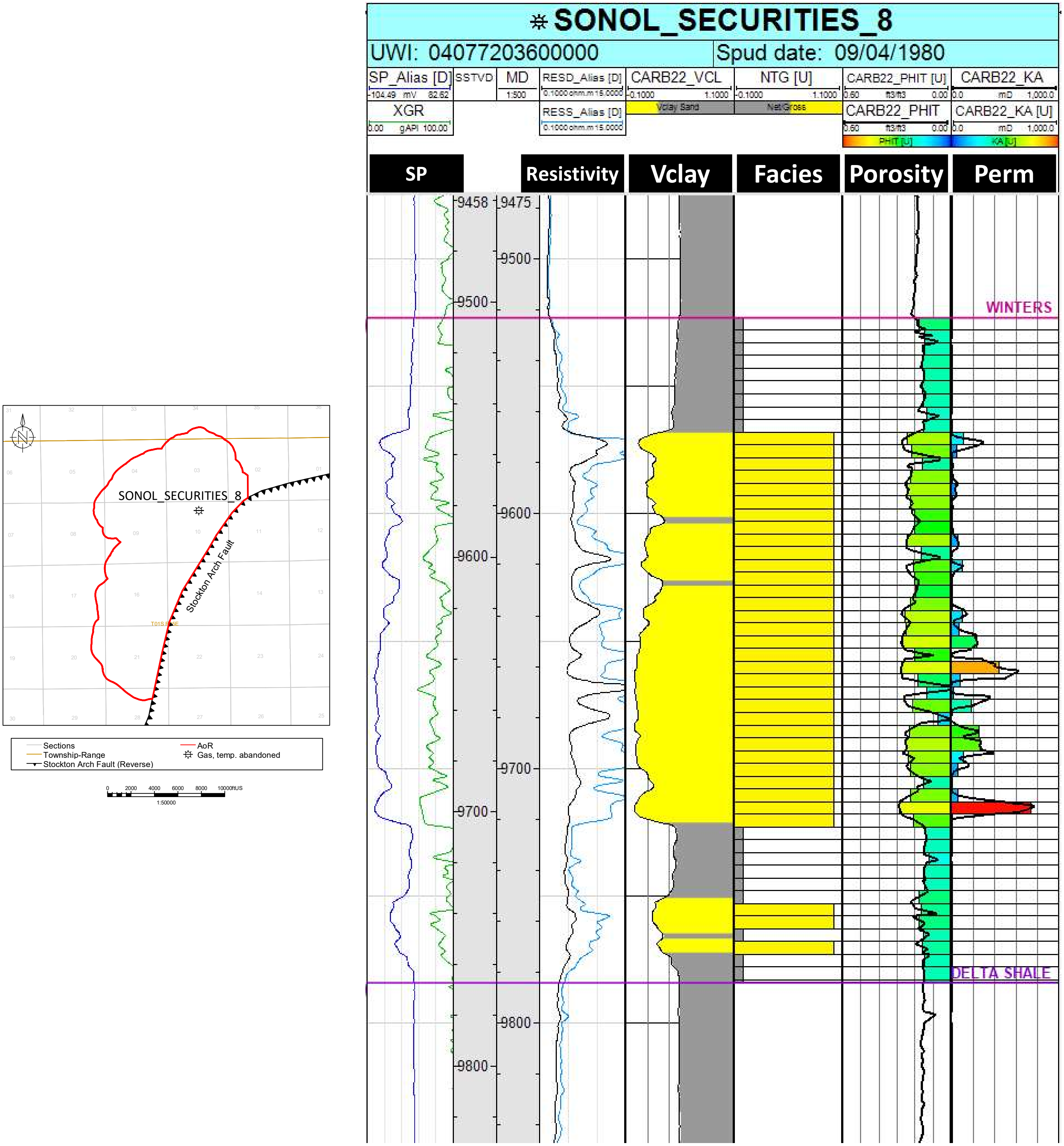


Figure 3.5. Well "Sonol Securities 8" upscaled logs versus open-hole logs.

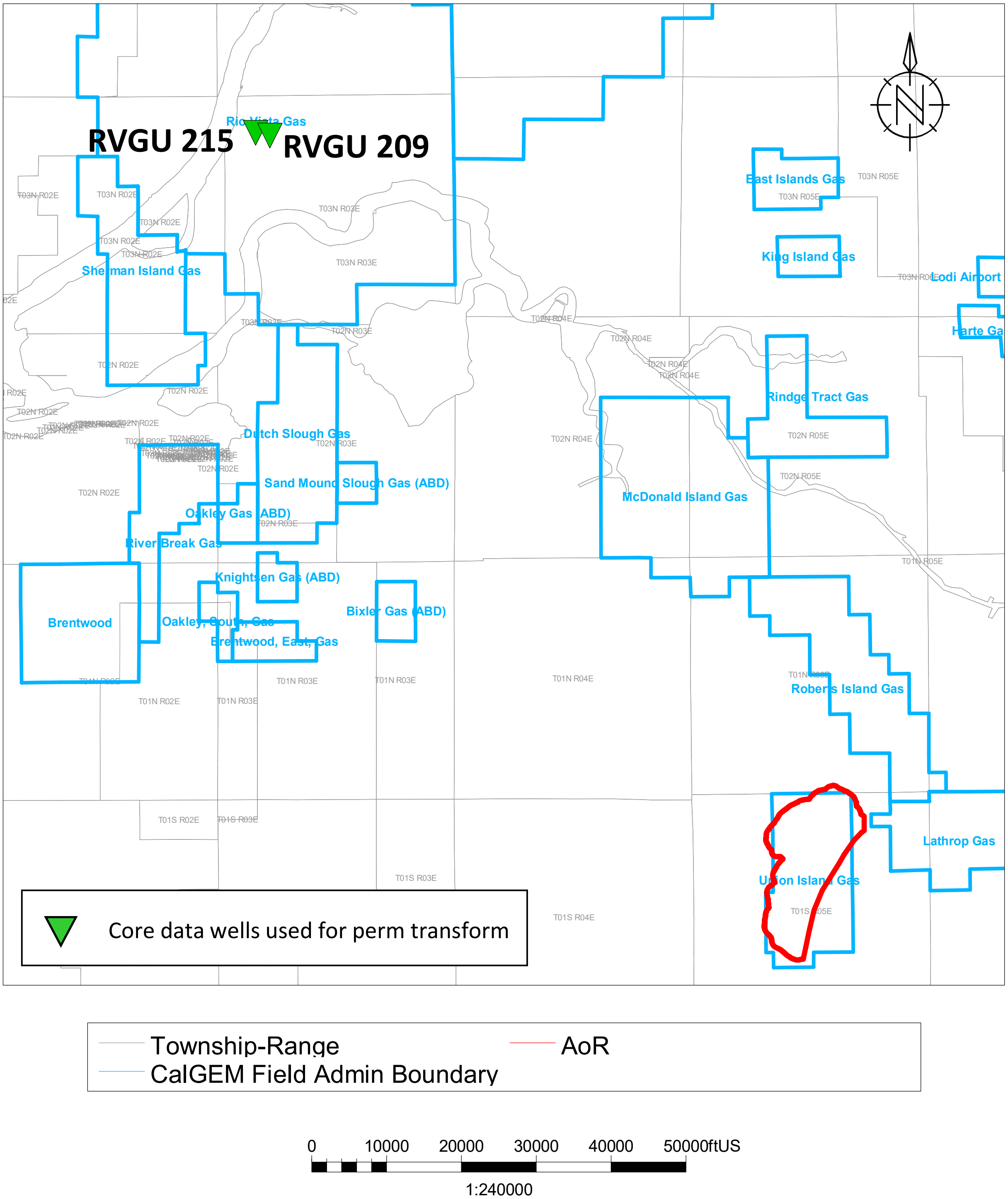


Figure 3.6. Location of wells with core data used for permeability transform.

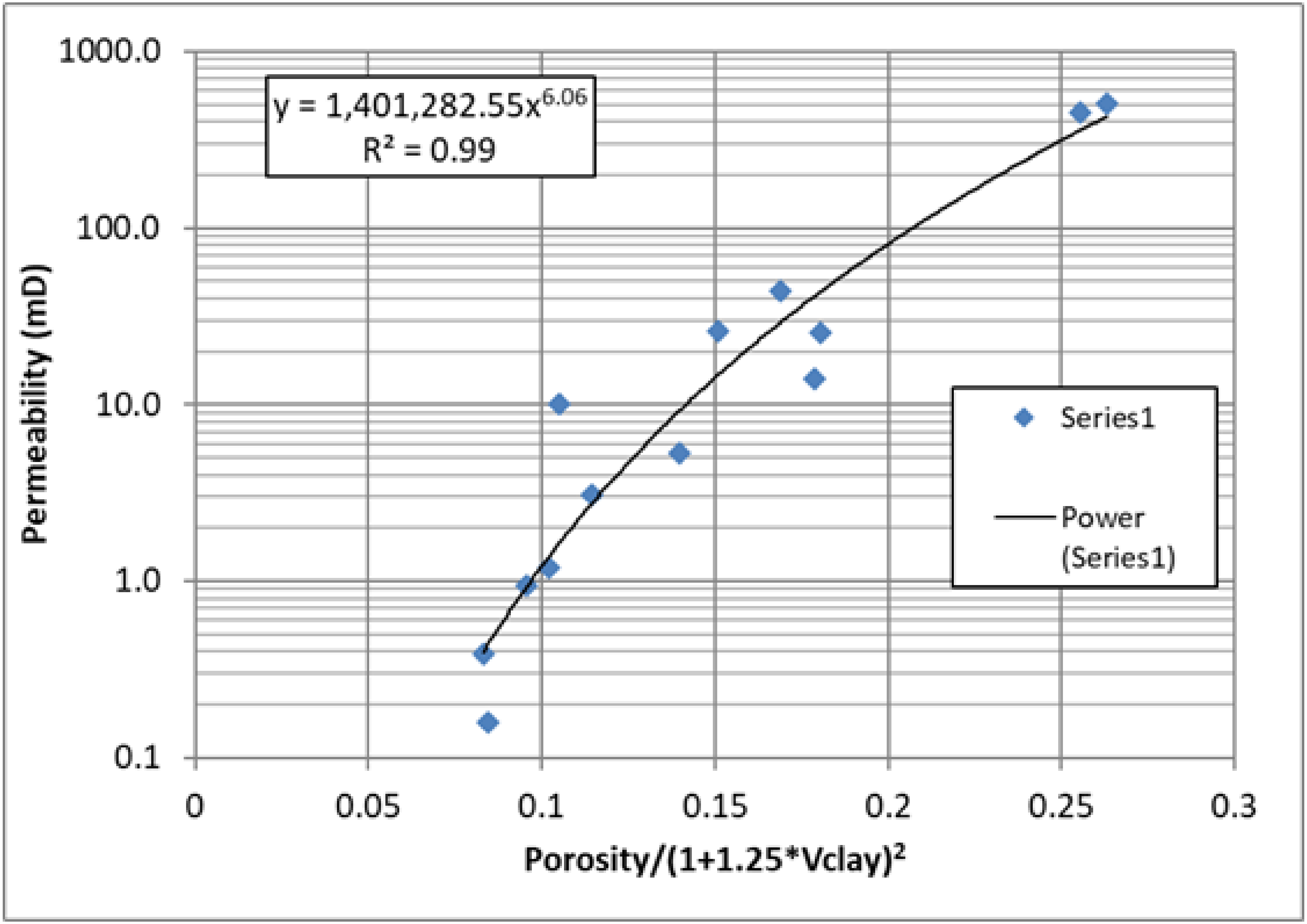


Figure 3.7. Porosity and permeability data from capillary pressure analysis for Injection zone sand. A permeability transform calculates permeability from log-based porosity.

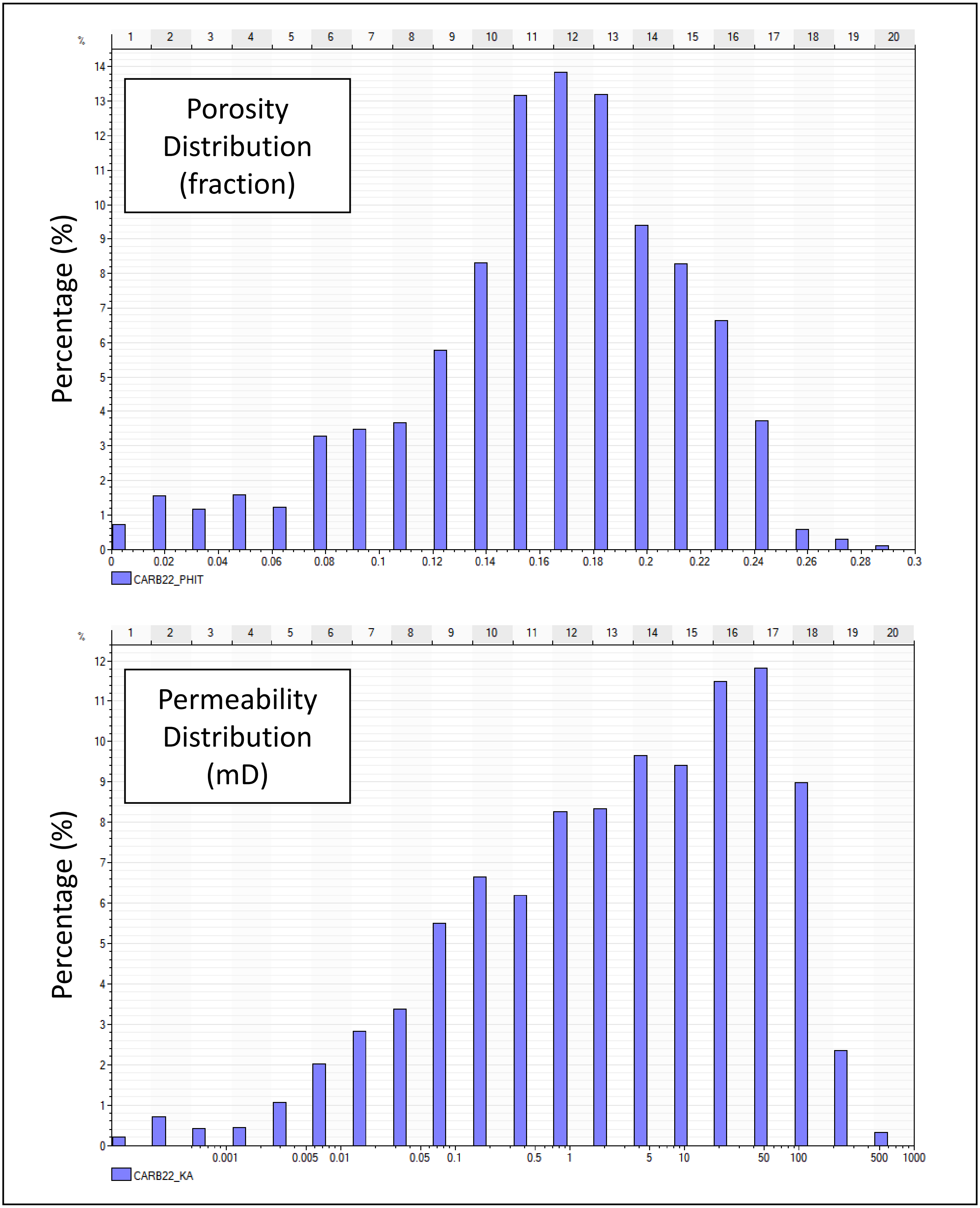
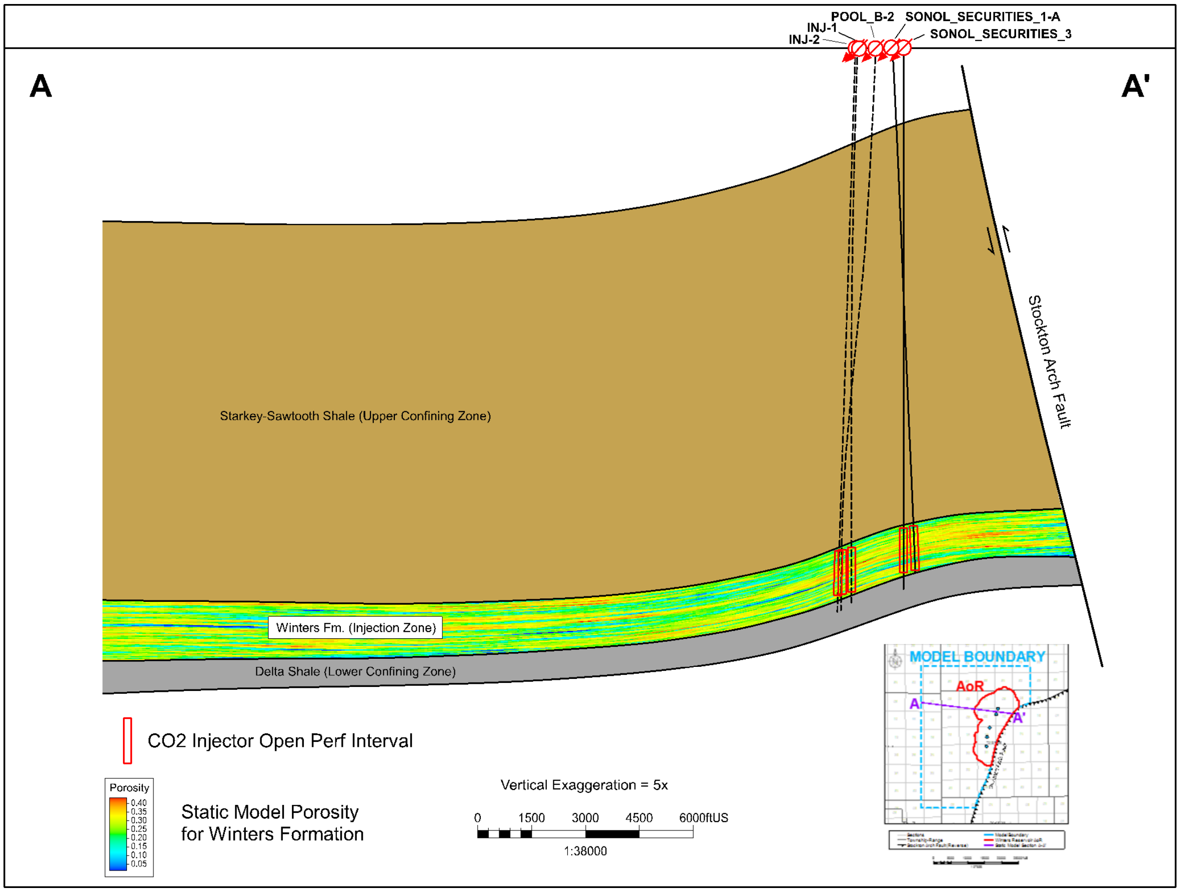


Figure 3.8. Injection zone porosity and permeability distribution in the static model.



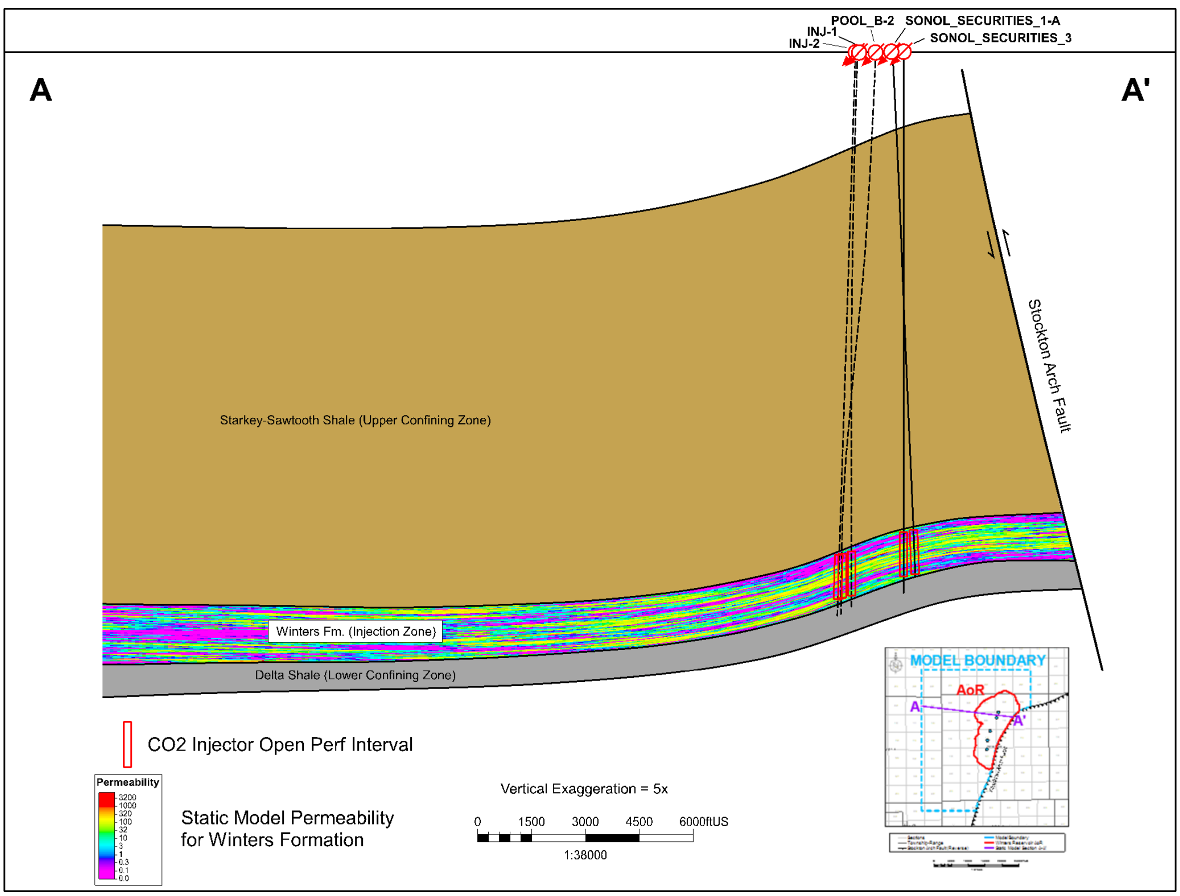


Figure 3.9. Dip section through the static grid showing the distribution of porosity and permeability in the reservoir with all injectors projected onto section to show relative depth in reservoir structure.

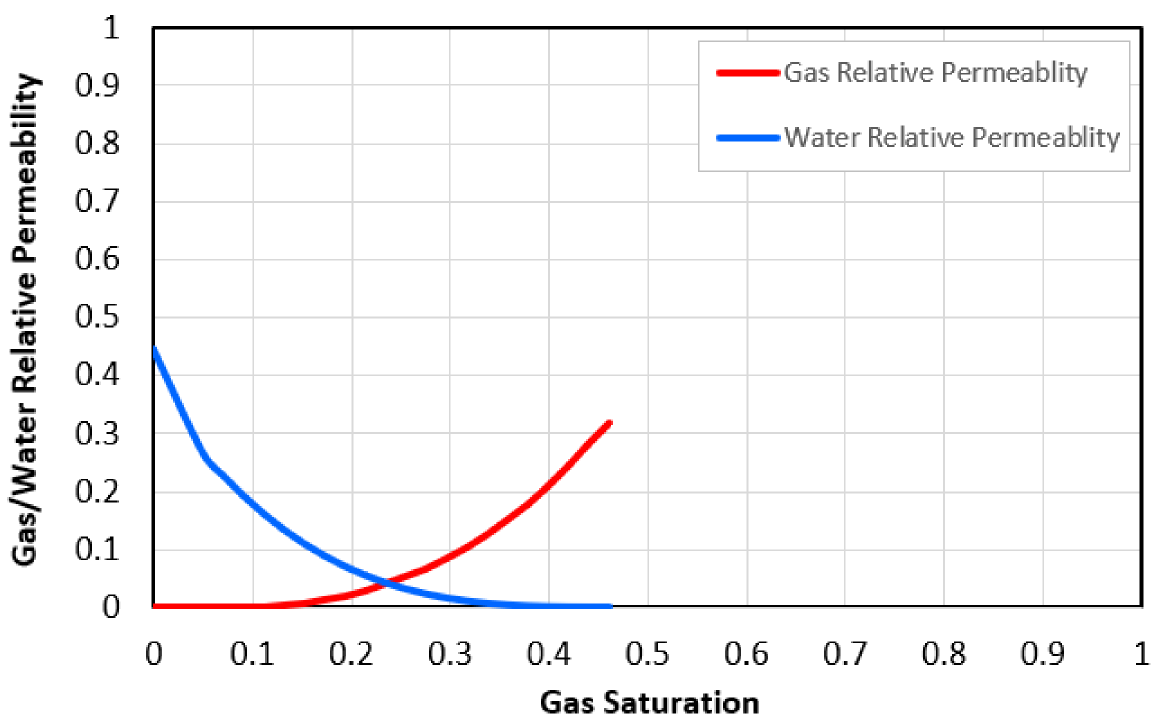


Figure 3.10. Relative permeability curves for Gas-Water System.

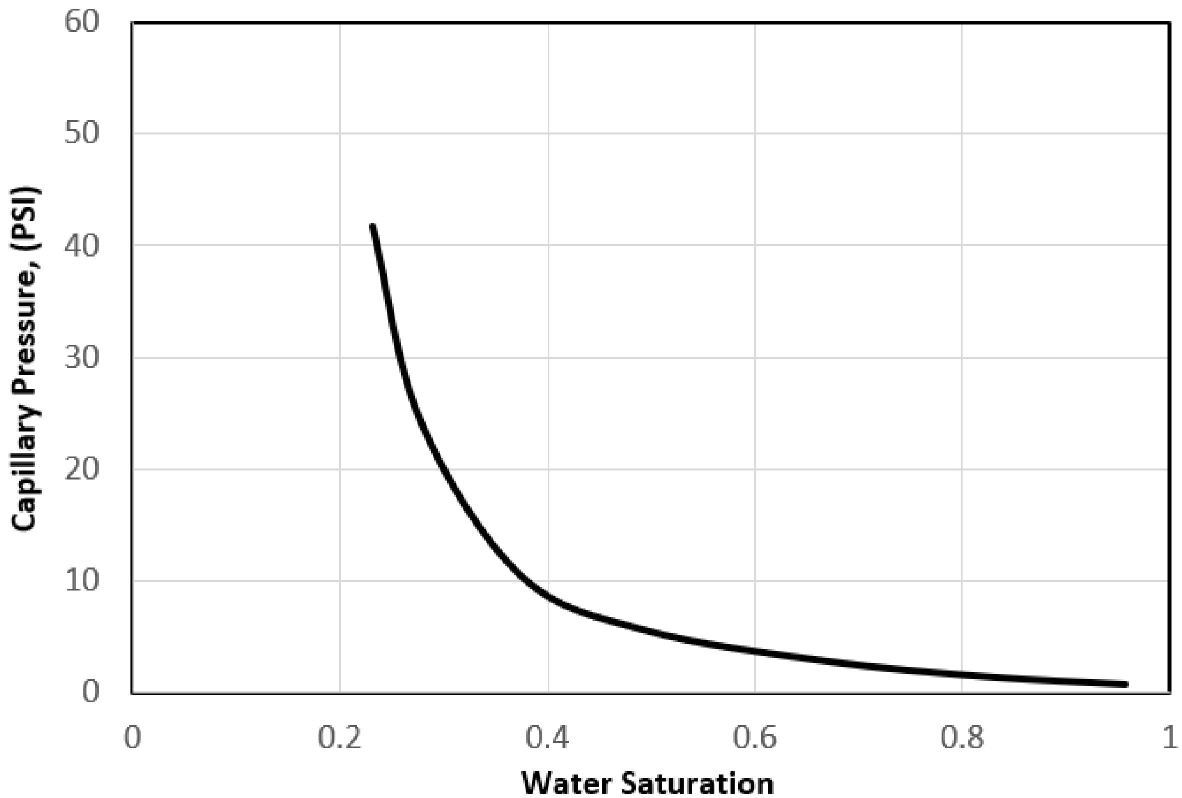


Figure 3.11: Capillary Pressure Curve.

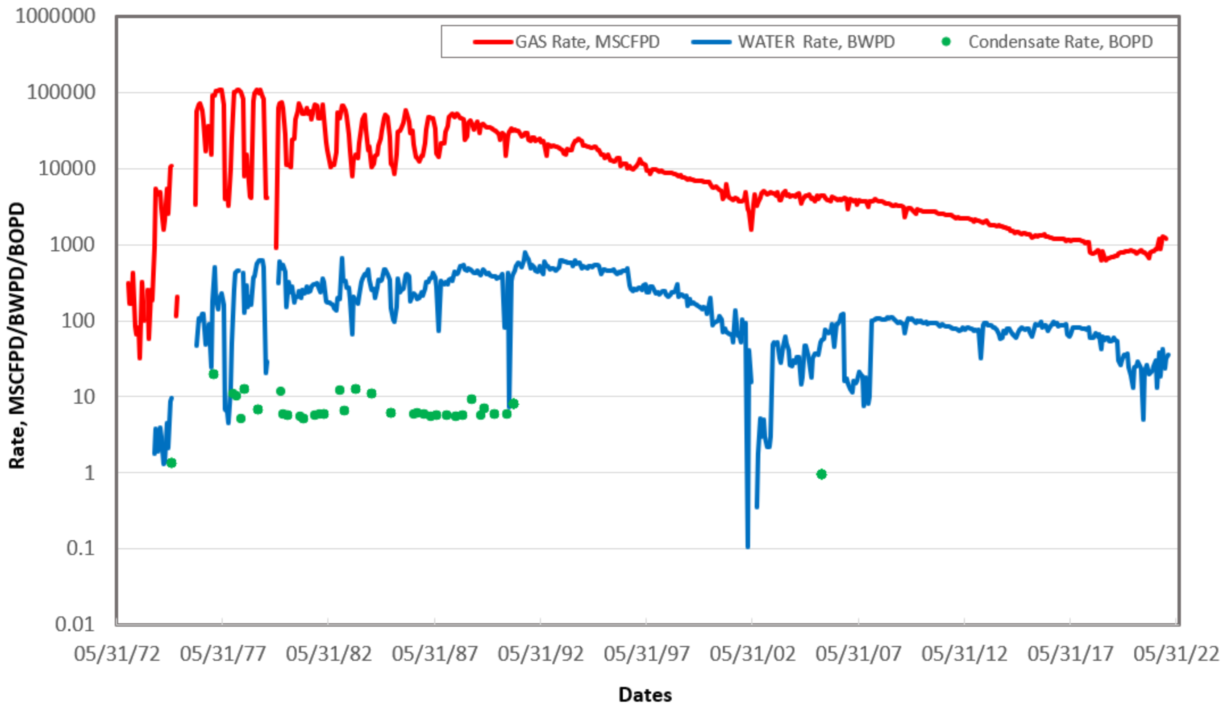


Figure 3.12. Field production graph.

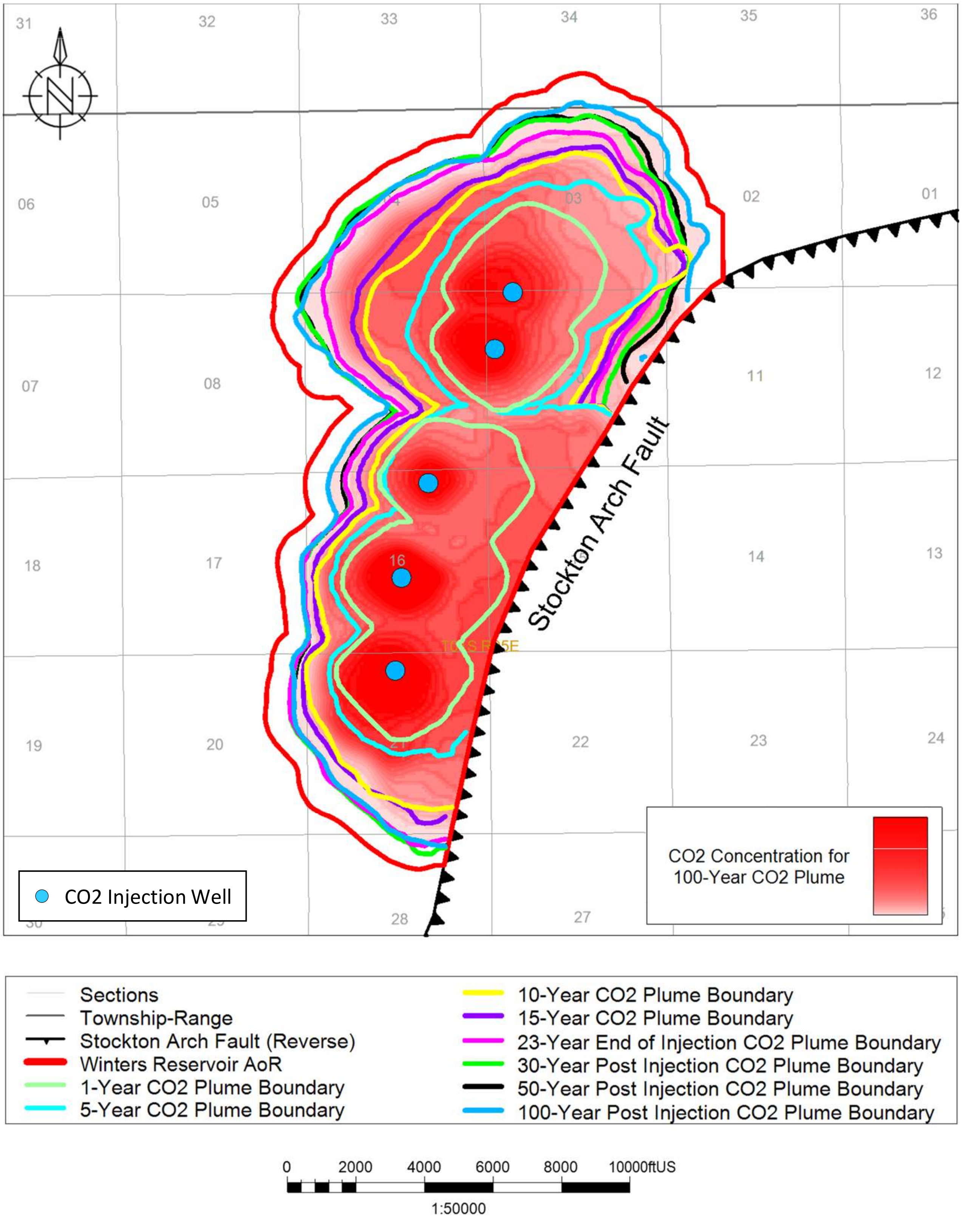


Figure 3.13A. Injectate 1 Plume development through time: 1-year, 5-year, 10-year, 15-year, 23-year (end of injection), 30-year post injection, 50-year post injection, and 100-year post injection.

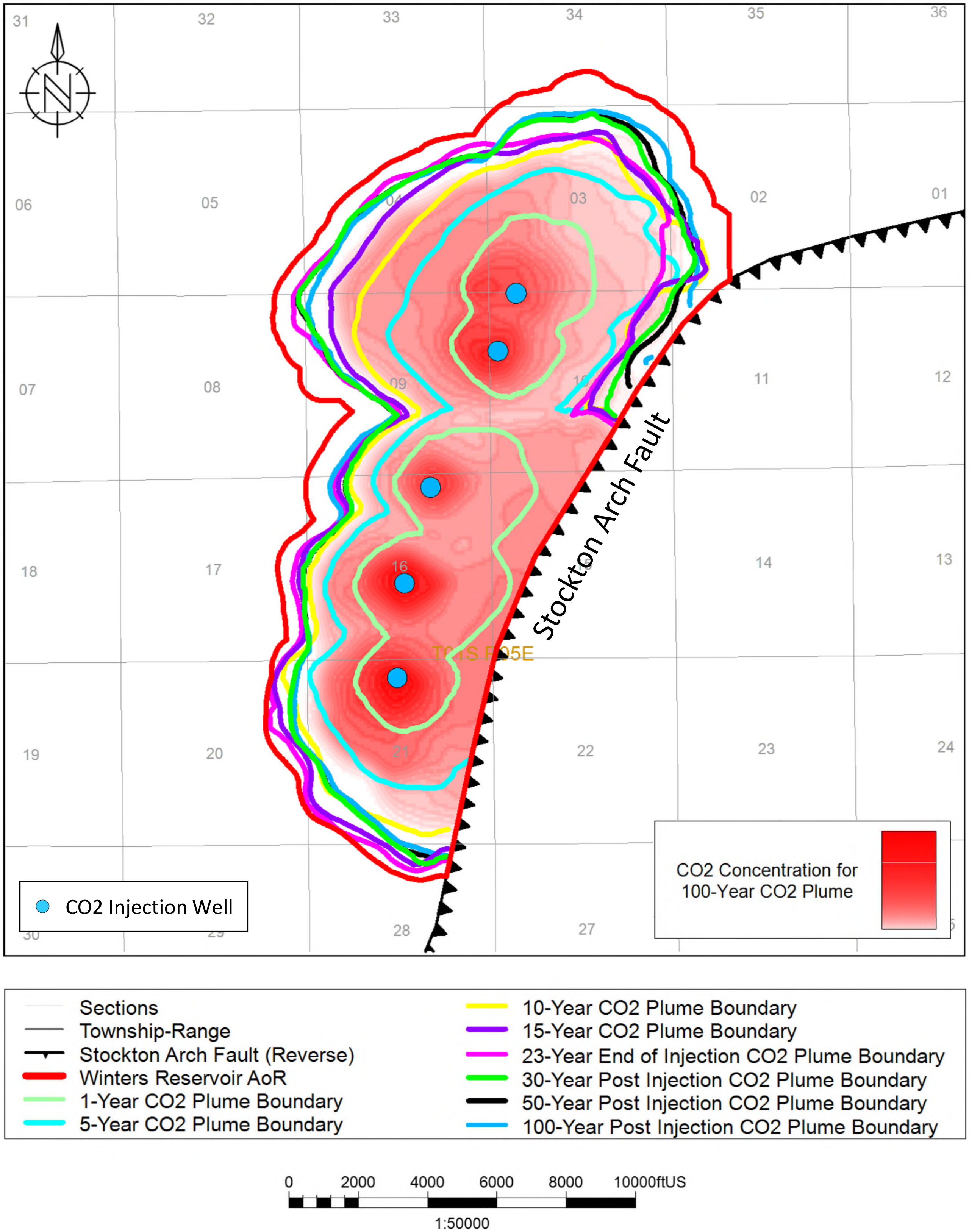
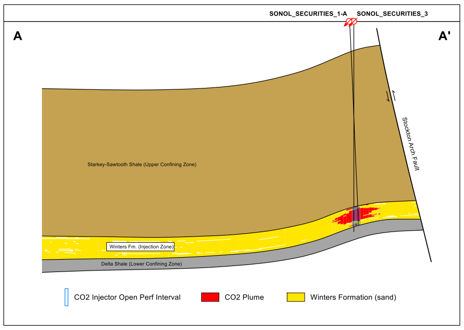
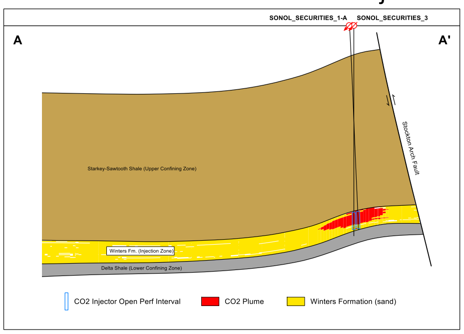


Figure 3.13B. Injectate 2 Plume development through time: 1-year, 5-year, 10-year, 15-year, 20-year, 23-year (end of injection), 32-year post injection, and 100-year post injection.

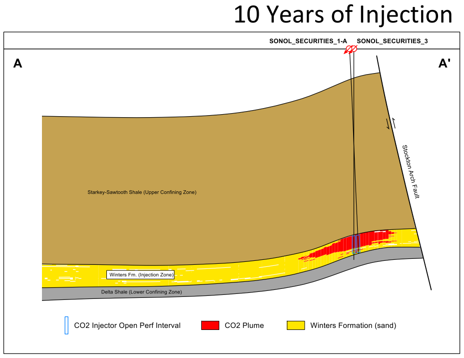
1 Year of Injection



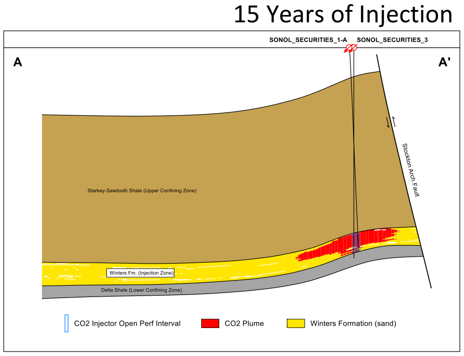
5 Years of Injection



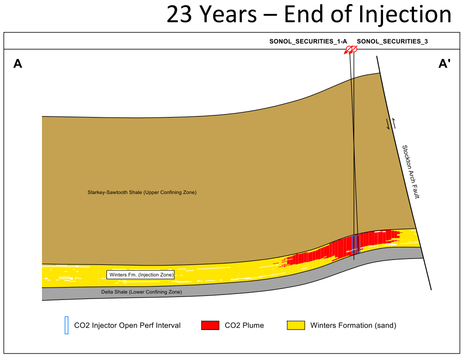
10 Years of Injection



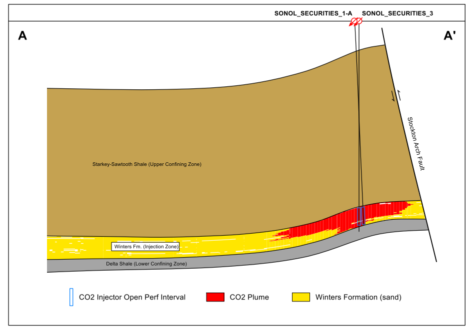
15 Years of Injection



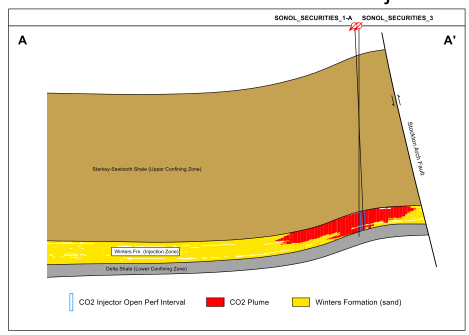
23 Years – End of Injection



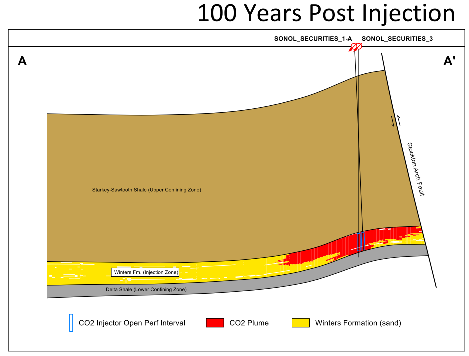
30 Years Post Injection



50 Years Post Injection



100 Years Post Injection



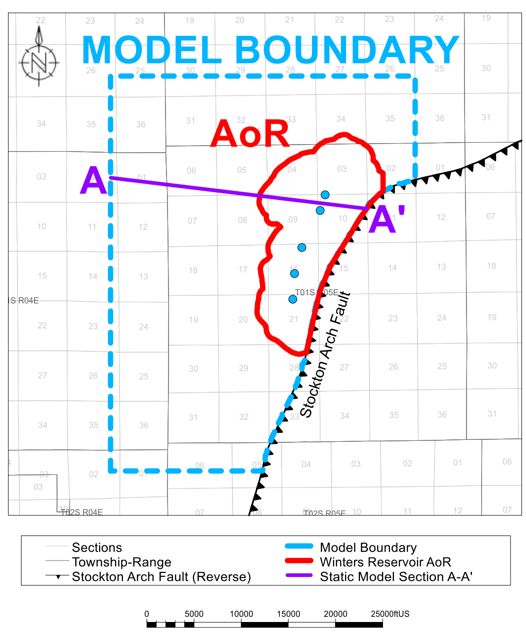


Figure 3.14A. Section showing proximity of CO2 (Injectate 1) to the Stockton Arch Fault and lateral dispersion of CO2 throughout time and confinement under the overlying Starkey-Sawtooth through time for the five injector modeled Base scenario. As the sections show, plume growth over time is driven by the reservoir anticlinal structure, and is thus representative of the plume growth at all injector locations.

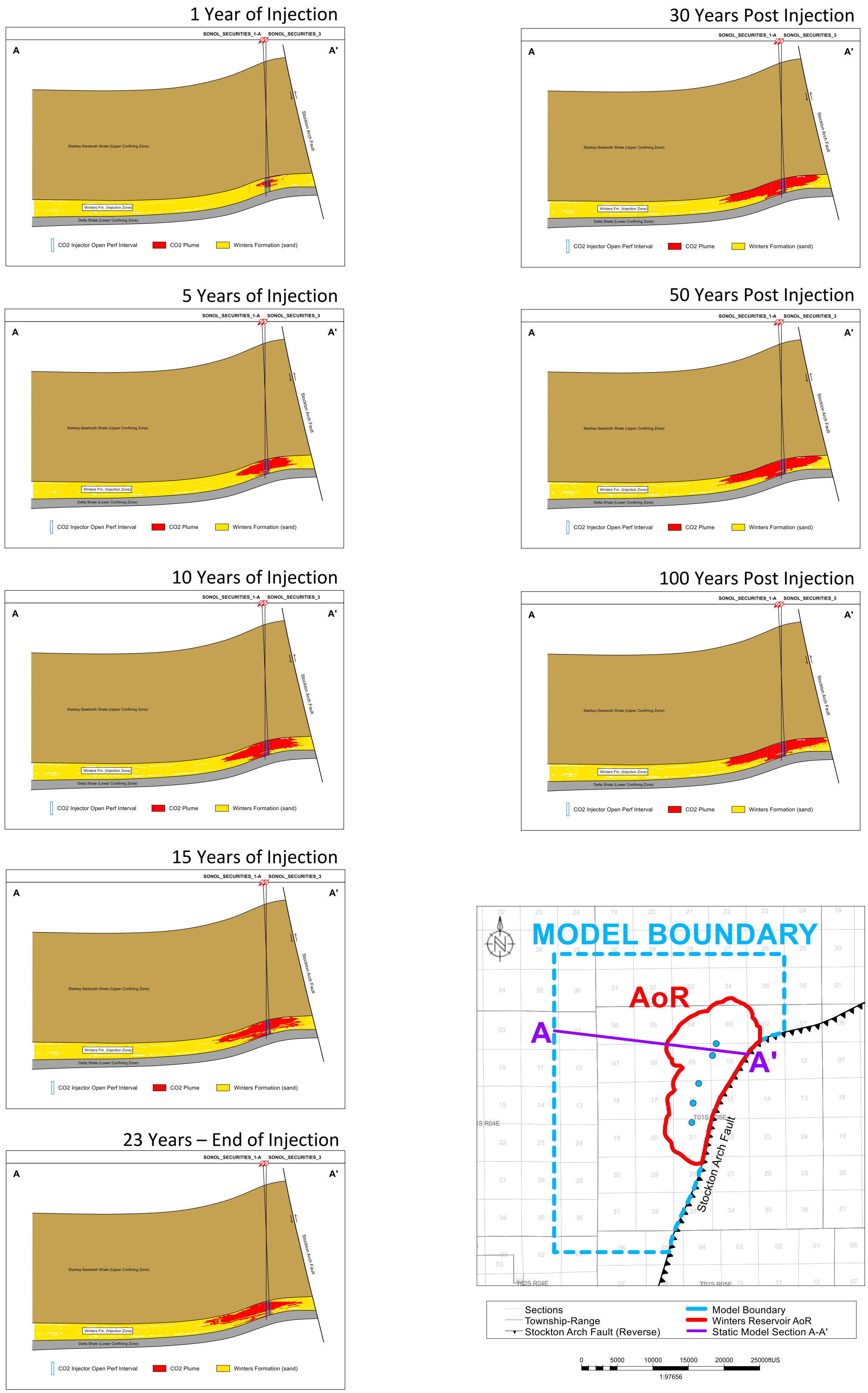


Figure 3.14B. Section showing proximity of CO2 (Injectate 2) to the Stockton Arch Fault and lateral dispersion of CO2 throughout time and confinement under the overlying Starkey-Sawtooth through time for the five injector modeled Base scenario. As the sections show, plume growth over time is driven by the reservoir anticlinal structure, and is thus representative of the plume growth at all injector locations.

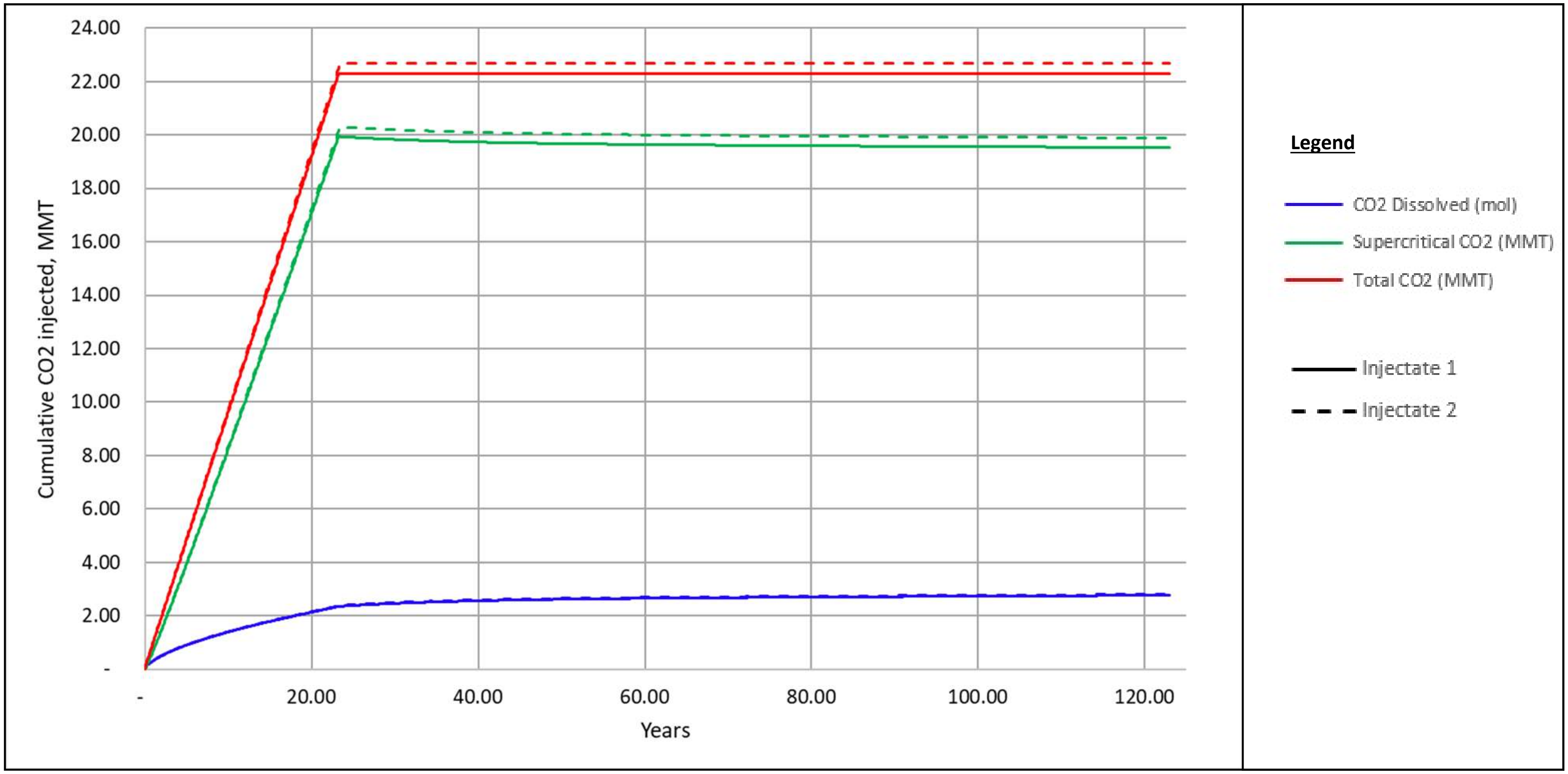


Figure 3.15. CO_2 storage mechanisms in the reservoir. Results shown for Base cases with Injectate 1 (solid lines) and Injectate 2 (dashed lines)

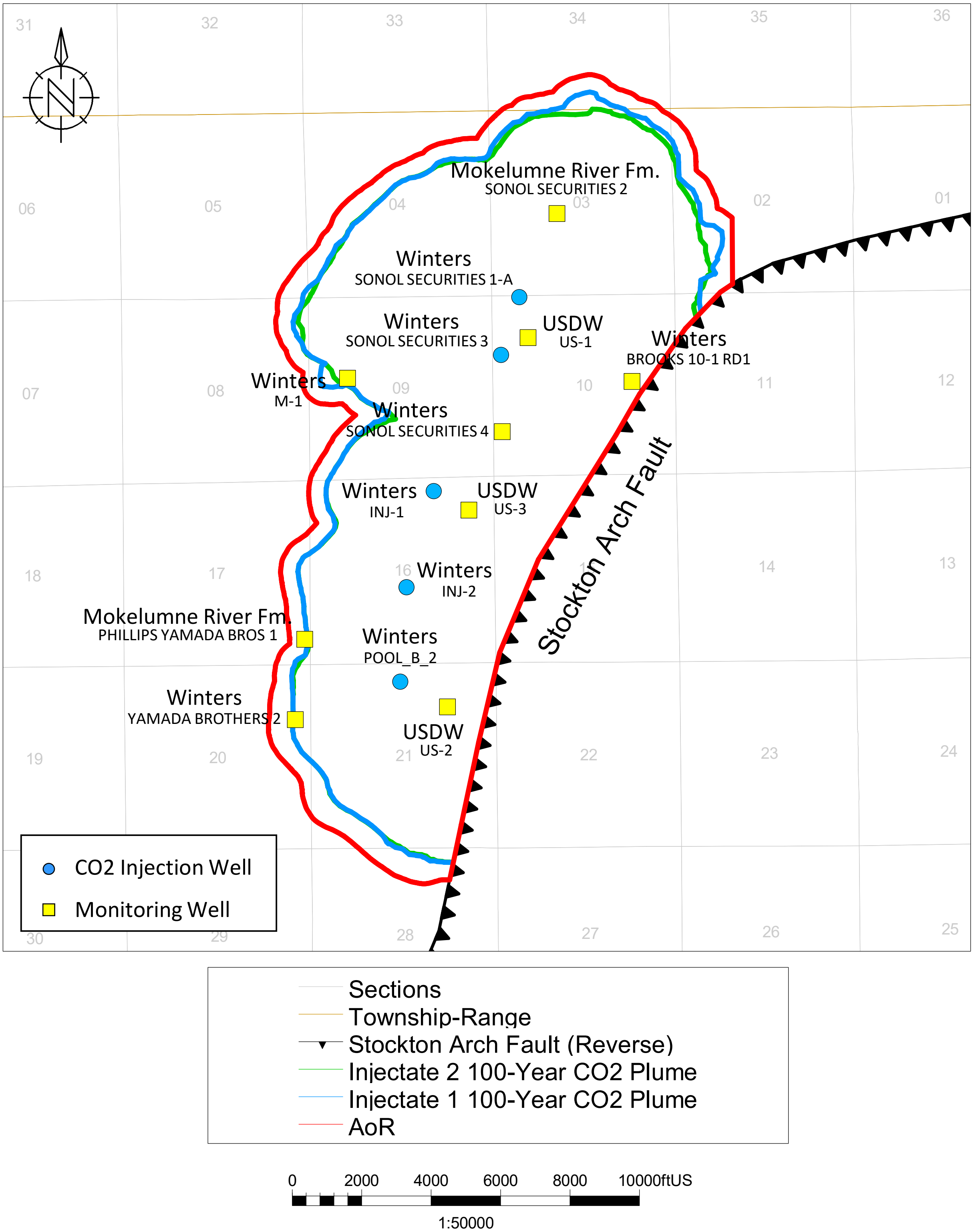


Figure 3.16. Map showing the location of injection wells and monitoring wells.

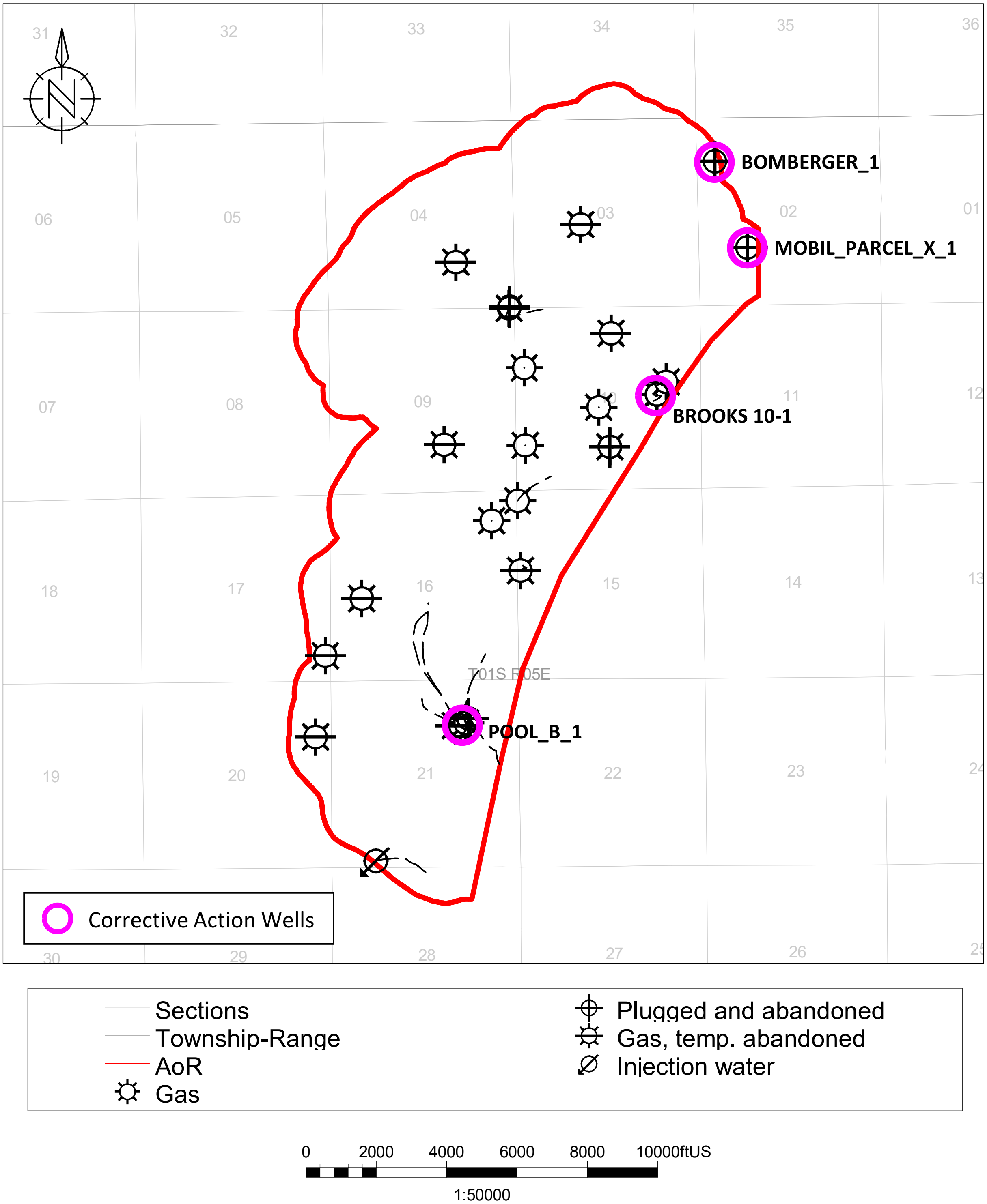


Figure 3.17. Wells penetrating the upper confining layer and the injection zone reviewed for corrective action.

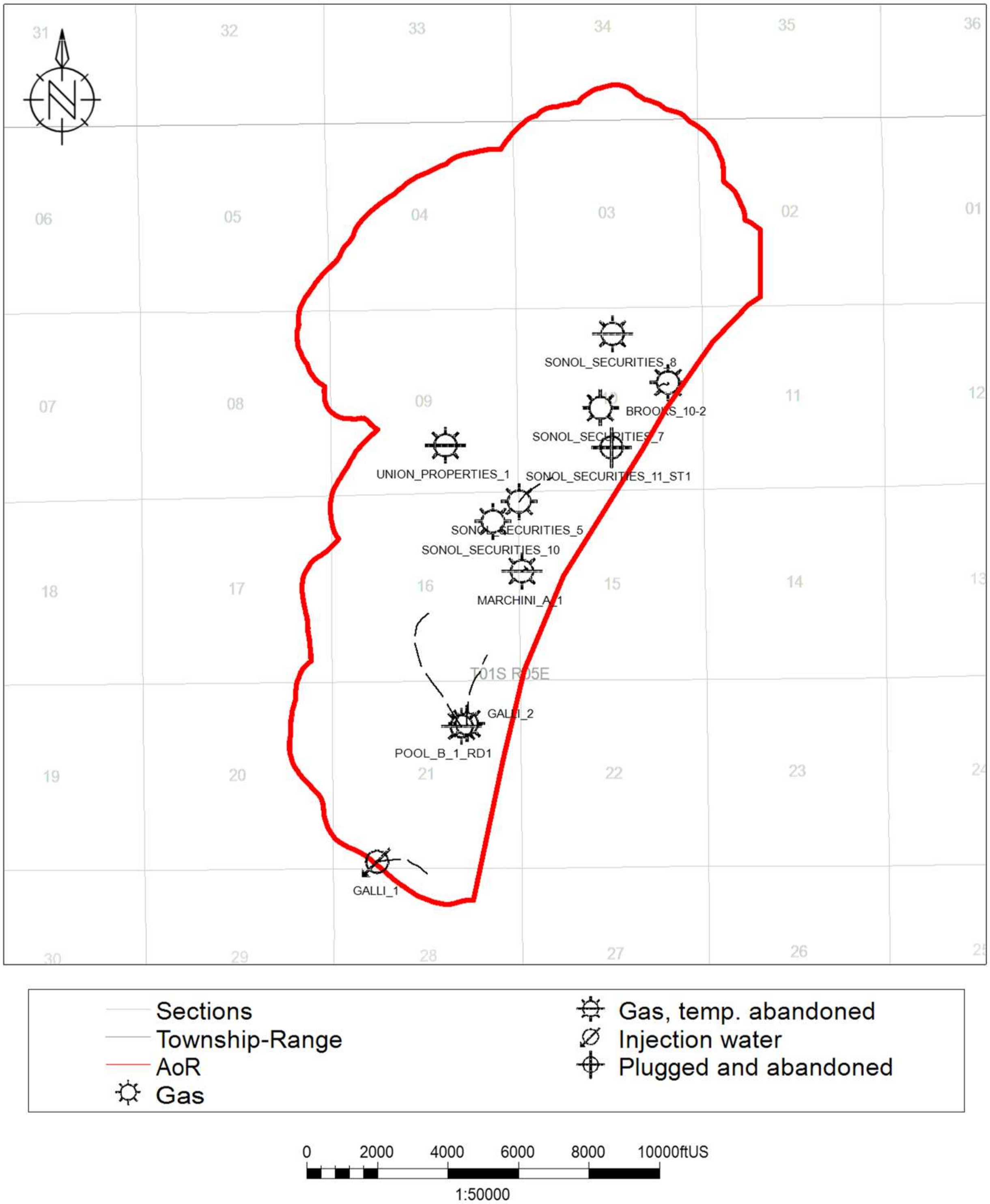


Figure 3.18. Wells to be abandoned prior to injection.

AREA OF REVIEW AND CORRECTIVE ACTION - TABLES

Table 3.1: Production volumes for the proposed Injection zone at the Union Island Gas field

Process	Phase	Volume
Production	Gas	292 billion cubic feet
	Water	3.4 million barrels

Table 3.2: Model domain information.

Coordinate System	California State Plane		
Horizontal Datum	North American Datum (NAD) 27		
Coordinate System Units	Feet		
Zone	Zone 2		
FIPSZONE	0402	**ADSZONE**	3301
Coordinate of X min	2,145,400.00	**Coordinate of X max**	2,177,700.00
Coordinate of Y min	44,800.00	**Coordinate of Y max**	86,700.00
Elevation of bottom of domain	-10,375	**Elevation of top of domain**	-9,492

Table 3.3: Gas and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis

	North	South	Water Zone
Contact (depth sub-sea)	Gas - Water 9,600	Gas - Water 9,800	
Saturation (fraction)	Water: 0.34 Gas: 0.66	Water: 0.34 Gas: 0.66	Water: 1.0

Table 3.4: Initial conditions (start of CO_2 Injection).

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	218	Fahrenheit	9,600	Fluid Analysis
Formation pressure	1,200	Pounds per square inch	9,600	Pressure Test
Fluid density	61	Pounds per cubic foot	9,600	Water analysis
Salinity	15,000	Parts per million	9,600	Water analysis

Table 3.5: Operating details.

Operating Information	**SONOL SECURITIES 1-A**	**SONOL SECURITIES 3**	**POOL B-2**	**UI_INJ_1**	**UI_INJ_2**
Location (global coordinates) LAT LONG	37.86861 -121.418	37.86405 -121.419	37.8383 -121.4297	37.8533 -121.4262	37.8457 -121.4288
Model coordinates (ft) X Y	2168172.00 74088.43	2167639.00 72424.55	2164738.00 63009.3	2165702.95 68502.85	2164946.41 65731.55
Perforated interval (ft MD | TVD | MSL) Z top Z bottom	9720 | 9592 | 9580 9960 | 9827 | 9815	9,620 | 9620 | 9607 9,910 | 9920 | 9897	10033 | 9807 | 9792 10387 | 10147 | 10132	9905 | 9782 | 9760 10173 | 10049 | 10027	10465 | 9755 | 9732 10845 | 10103 | 10080
Wellbore diameter (in.)	6	6.75	8.5	8.75	8.75
Planned injection period Start End	2025 2048	2025 2048	2025 2048	2025 2048	2025 2048
Injection duration (years)	24	24	24	24	24
Injection rate (t/day)*	530-794	530-794	530-794	530-794	530-794

Table 3.6: Injection pressure details.

Injection Pressure Details	**SONOL SECURITIES 1-A**	**SONOL SECURITIES 3**	**POOL B-2**	**UI_INJ_1**	**UI_INJ_2**
Fracture gradient (psi/ft)	0.70	0.70	0.70	0.70	0.70
Maximum bottomhole injection pressure (90% of fracture pressure) (psi)	6043	6061	6178	6163	6146
Elevation corresponding to maximum injection pressure (ft TVD)	9592	9620	9807	9782	9755
Elevation at the top of the perforated interval (ft TVD)	9592	9620	9807	9782	9755
Average bottom hole injection pressure at top of perforations (psi)	3388	3372	3065	2960	3005
Average bottom hole injection gradient at top of perforations (psi/foot)	0.35	0.35	0.31	0.30	0.31

Table 3.7: Simulation sensitivity scenarios.

Scenario	CO2 plume & AoR impact
Porosity: 10% reduction from base case	Minimal Impact
Porosity: 10% increase from base case	Minimal Impact
Permeability: 10% reduction from base case	Minimal Impact
Permeability: 10% increase from base case	Minimal Impact

Table 3.8. Wellbores in the AoR by status.

Status	Count
Active Producer	5
Idle Producer	15
Plugged and Abandoned Producer	9
Total	**29**