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2. AREA OF REVIEW AND CORRECTIVE ACTION PLAN 40 CFR 146.84(b)

HEARTLAND GREENWAY STORAGE PROJECT

Facility Information

Facility name:	Heartland Greenway Storage Site (HGSS)
Facility contact:	David Giles 2626 Cole Ave., Dallas, Texas, USA 75204 Phone: (210) 880-6000; Email: dgiles@navco2.com
Well location:	Taylorville, Christian County, Illinois

2.1. Computational Modeling Approach

Pursuant to 40 CFR 146.84 (b), Heartland Greenway Carbon Storage, LLC (HGCS) performed computational modeling to predict the lateral and vertical movement of CO_2 injected into the Mt. Simon sandstone. The computational model factored in the physical flow and trapping processes associated with CO_2 injection into subsurface reservoirs. The 3D geo-cellular model for this activity was generated in Schlumberger's Petrel using available seismic, geologic, and hydrologic data. The model was then exported to Computer Modeling Group (CMG)'s General Equation of State Model (GEM), a fully implicit multiphase flow simulator, that modeled the injection of supercritical CO_2 into the lower Mt. Simon reservoir unit at the rate of 6 million metric tons (MMT) per year. Subsequent sections of this document elaborate on the details of computational modeling and consequent AoR results.

2.1.1. Model Background

CMG-GEM, as previously mentioned, is a fully implicit multiphase fluid flow modeling package that uses an equation of state (EoS) to model multiphase behavior. GEM is a widely accepted reservoir simulator that has been referenced in over 4450 technical papers (CMG, 2021). CO_2 injection into a saline reservoir is a complex process that involves phases changes as they relate to temperature and pressure distribution in tight pore spaces where Darcy flow may not be applicable. Consequently, a robust simulator, such as GEM, is required to fully predict density changes of the injected fluid as well as mass transfer and transport in diffusive and advective conditions. GEM also factors in multiple trapping mechanisms such as structural, residual, and solubility trapping of CO_2, all of which play a crucial role in containing the injected CO_2 in the storage reservoir. Therefore, the choice was made to employ GEM as the reservoir simulator of choice for all computational modeling activities in this project. Additional details on the code and dataset used will be provided to the U.S. EPA Region V UIC Program Director and any independent third-party Reviewers upon request. The computational model was set up to include brine and CO_2 as the only components since there was no evidence of in-situ oil or gas in the Mt.

Simon sandstone or overlying formations in the project area. A trace methane component (~ 1% by volume) was used to initialize the reservoir to avoid numerical instability.

Table 2-1 lists the processes that were modeled to estimate the movement of CO_2 within the subsurface and predict the associated pressure changes in the storage system.

Table 2-1. Key fluid behavior models implemented in CMG-GEM for HGSS.

Process	Method
Phase behavior (CO_2 and water)	Peng-Robinson (1976) Two-Parameter EoS[1]
CO_2 dissolution in brine	Henry's solubility model which uses a constant determined by pressure, temperature, and salinity as published by Harvey (1996)[2]. The fugacity/partition coefficients for soluble CO_2 in aqueous phase were calculated using Li & Ngheim (1986)[3] method.
Brine viscosity	Kestin, Khalifa, & Correira (1981)[4]
Brine density	Rowe-Chou (1970)[5]
CO_2 trapping hysteresis	Land (1968)[6]

The methods and correlations mentioned were implemented to accurately model phase properties such as brine density due to CO_2 dissolution, brine solubility, and CO_2 trapping due to hysteresis. Dissolution and solubility processes were included in the simulation model because they are play a major role in immobilizing the CO_2 plume in addition to stratigraphic/structural trapping mechanisms. Multiphase flow (gas/water) and buoyancy/gravity processes are modeled to estimate lateral and vertical migration of the injectant. Mineralization of the injected CO_2 is not currently considered in the model due to the absence of information on different mineral distribution in the injection formations. If mineral distribution of the geologic formations becomes available and is deemed to be significant, the simulation model will be updated, and the

[1] Peng, D.Y. and Robinson, D.B., "A New Two-Constant Equation of State", Ind. Eng. Chem. Fundamen., Vol. 15, (1976), pp. 59-64.

[2] Harvey, A.H., "Semiempirical Correlation for Henry's Constants over Large Temperature Ranges", AIChE Journal, Vol. 42, (May 1996), pp. 1491-1494.

[3] Li, Y.-K. and Nghiem, L.X., "Phase Equilibria of Oil, Gas and Water/Brine Mixtures from a Cubic Equation of State and Henry's Law", Can. J. Chem. Eng., (June 1986) pp. 486-496.

[4] Kestin, J., Khalifa, H.E. and Correia, R.J., "Tables of the Dynamic and Kinematic Viscosity of Aqueous NaCl Solutions in the Temperature Range 20-150 °C and Pressure Range 0.1-35 MPa", J. Phys. Chem. Ref. Data, Vol. 10, (1981) pp. 71-87.

[5] Rowe, A.M. and Chou, J.C.S., "Pressure-Volume-Temperature-Concentration Relation of Aqueous NaCl Solutions", J. Chem. Eng. Data, Vol. 15, (1970), pp. 61-66.

[6] Land, C.E., "Calculation of Imbibition Relative Permeability for Two- and Three-Phase Flow from Rock Properties", SPEJ, Vol. 8, (June 1968), pp. 149-156.

resulting CO_2 plume will be compared with the previous modeling work to see the effect of mineralization. However, small to negligible effect from mineralization on CO_2 plume migration is expected within the timeframe that concerns this project.

The Area of Review (AoR) is created to encompass the entire region surrounding HGSS where USDWs may be endangered by injection activity. The AoR is delineated by the lateral and vertical migration extent of the CO_2 plume, formation fluids and pressure front in the subsurface. The threshold of the pressure front is determined by the minimum pressure sufficient to cause movement of injected fluids or formation fluids into a USDW. The lateral and vertical migration extent of the CO_2 plume, formation fluids, and the pressure front was determined by site characterization and computational modeling initially. After injection commences, monitoring and operational data will be added to ongoing modeling to continue to reevaluate and validate the AoR.

In its current state, the AoR model does not factor in geochemical effects of CO_2 injection. Balashov *et* al (2013)[7] discuss the importance of mineral trapping wherein they indicate such effects play a dominant role after 200 years post-injection. Therefore, such effects do not lie within the scope of this project's operations. While the presence of CO_2 in pore space is expected to alter pH of the formation fluid and thereby result in a kinetic and reactive transfer of minerals between the in-situ fluid and reservoir matrix, such effects are expected to occur beyond the project period. Short-term (< 100 year) geochemical reactions are dependent on the presence and composition of carbonates while quartz dissolution dominates long-term (> 100 year) reactions and consequent geochemical effects such as mineral trapping and permeability alteration[8]. Since the reservoir of interest is a sandstone, whose mineralogy is dominated by quartz and clays with traces of calcite[9], a decision was made not to include geochemical impacts of CO_2 injection in our current AoR model. However, fluid samples from the reservoir will be collected as outlined in the *Pre-Operational Testing Plan* which will be used to conduct a compatibility assessment with cores obtained from the well construction phase. If any geochemical alterations are identified during these studies that might impact modeling and estimation of the CO_2 plume as AoR, such findings will be promptly included into the computational model and AoR will be re-evaluated.

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[7] Victor N. Balashov, George D. Guthrie, J. Alexandra Hakala, Christina L. Lopano, J. Donald Rimstidt, Susan L. Brantley, 2013. Predictive modeling of CO_2 sequestration in saline sandstone reservoirs: Impacts of geochemical kinetics. Appl. Geochem., Volume 30 (2013), p 41-56.

[8] Rathnaweera, T., Ranjith, P. & Perera, 2016. M. Experimental investigation of geochemical and mineralogical effects of CO_2 sequestration on flow characteristics of reservoir rock in deep saline aquifers. Sci Rep 6, 19362 (2016). https://doi.org/10.1038/srep19362

[9] Leeper, N., 2012. Characterization of the Mt. Simon Sandstone in Southwest Ohio for CO_2 Sequestration. The Ohio State University.

From a geomechanical standpoint, the model assumes a fracture pressure gradient of 0.7 psi/ft consistent with the regional geology. This assumption will also be verified using flow and pressure tests as noted in the *Pre-Operational Testing Plan*. The HGSS model also possesses the ability to couple advanced geomechanical processes if required. A robust monitoring program will be implemented to track induced seismicity (see *Testing and Monitoring Plan*). If the project team identifies unexpected seismic events, a geomechanical model will be developed to couple with existing multiphase fluid flow model to match injection and pressure history and predict subsequent geomechanical effects. In such an event, the AoR and monitoring plans will be re-evaluated to reflects the results from any updates to the computational model.

2.1.2. Site Geology and Hydrology

Please see the *Geologic Evaluation Report* for details on HGSS geology, hydrogeology, geomechanics, geochemistry petrophysical properties, and seismic history.

2.1.3. Static Earth Modeling Details

The Static Earth Model (SEM) for HGSS was generated in Schlumberger's Petrel*. The purpose of the model is to represent the petrophysical properties (porosity and permeability) of Eau Claire shale (caprock) and Mt. Simon Sandstone (reservoir). The framework for the HGSS SEM is based on regional geologic elevation maps that have been updated with well control points from the FutureGen2 site[10], the Illinois Basin Decatur Project (IBDP)[11], and the TR McMillen 2 well directed by the Illinois State Geological Survey (ISGS)[12] (**Figure 2-1**). The TR McMillen 2 well provides analog well data and serves as the basis for the 35-mile by 35-mile HGSS SEM (**Figure 2-2**).

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[10] Gilmore T., et al, 2016, Characterization and design of the FutureGen 2.0 carbon storage site, International Journal of Greenhouse Gas Control, Vol 53, pp.1-10, https://www.sciencedirect.com/science/article/abs/pii/S1750583616303851

[11] Bauer, R.A., Will, R., Greenberg, S.E., and Whittaker S.G., 2019, Illinois Basin–Decatur Project, Geophysics and Geosequestration, (Chapter 19) from Part III - Case Studies, pp. 339 – 370, https://doi.org/10.1017/9781316480724.020

[12] Whittaker, S. et al., 2019, CarbonSAFE Illinois–Macon County, Addressing the Nation's Energy Needs Through Technology Innovation, ISGS, DE-FE0029381, CarbonSafe, DOE Review Meeting Pittsburgh

Figure 2-1. Illinois Basin map showing HGSS location and closest wells that penetrate the Mt. Simon. Red box represents Static Earth Model footprint.

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Figure 2-2. SEM footprint for the HGSS. Six proposed injection wells are positioned northeast of Taylorville, Illinois, and are central to the SEM's 35x35 mile tartan grid.

2.1.3.1. Model Domain

The HGSS SEM spanned 35x35 miles as shown in **Figure 2-2**. The coordinates and model domain information are summarized in **Table 2-2**. A preliminary "regular grid" model framework had cell dimensions of 500 x 500 feet with varying cell thicknesses dependent on the proportional layering summarized in Table 2. The SEM was partitioned to capture the prevailing Mt. Simon zones broadly. These zones are based on TR McMillen 2 well log signatures and interpretations. For Dynamic Reservoir Modeling (DRM), the SEM's grid was upscaled to a tartan grid with varying horizontal cell sizes ranging from 500ft to 10,000ft (**Table 2-3**) and preserved the original layering scheme as detailed in **Table 2-4**.

Well tops from FutureGen 2, the IBDP CCS#1, and the TR McMillen 2 well were used to update key regional model surfaces, including the Maquoketa Shale, Eau Claire, Mt. Simon, and the Precambrian top. The model framework was further developed by inserting zones between these surfaces with the goal of representing the Eau Claire Formation (caprock), Mt. Simon Sandstone (reservoir), the thin underlying Argenta Formation, and the upper 100 feet of basement rock. **Figure 2-3** shows an oblique view of the SEM area, nearby Mt. Simon wells, and proposed HGSS injection wells within the context of the regional Mt. Simon surface.

Table 2-2. Model domain information.

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Figure 2-3. Oblique view of 35x35 mile SEM footprint for the HGSS. Proposed CO_2 injection wells for the HGSS are arranged south to north.

Table 2-3. Tartan grid scaling in x and y-directions.

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Table 2-4. SEM layering showing all model zones used the proportional layering method. The layering scheme was preserved for all petrophysical modeling zones.

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A total of 6 proposed injection wells are planned for the HGSS. Wells NCV-1 through NCV-5 are placed from south to north, with well NCV-6 offset to the west between NCV-3 and -4 (**Figure 2-2**). The coordinates and estimated Kelly Bushings (KB) are summarized in **Table 2-5**.

Table 2-5. Proposed injection well placement. msl: mean sea level.

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The SEM also includes the Ironton formation, which overlies the Eau Claire confinement zone. Based on well log response from the TR McMillen 2 well, the Ironton is believed to be the first saline reservoir that overlies the caprock. It has been included in the SEM and DRM work to gauge whether flow simulations can reveal any fluid migration from the underlying seal, the Eau Claire. The Ironton and all deeper sedimentary zones plus the upper 100 feet of crystalline basement rock have been included in the SEM framework, **Table 2-4**. Depth, thickness, and the layering scheme of all petrophysical model zones are summarized in **Table 2-6**.

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Figure 2-4. Oblique view of the 3D framework featuring tartan grid, proposed injection wells, and model zones dipping southeast. 25x vertical exaggeration.

Table 2-6. Model framework statistics. The asterisk marks statistics that occur at injection well location of NCV-1; MD: Measured depth from well Kelly Bushing; Z: elevation depth below mean sea level.

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2.1.3.2. Property Modeling (Porosity and Permeability)

Currently, there are no deep wells at the HGSS to supply site-specific data for the confining zone and reservoir. The closest analog well is the TR McMillen 2 well that was drilled down to Precambrian basement rock (**Figure 2-2**). Data from this well, including well logs and core samples, were used to determine the porosity and permeability of the injection and confining zones for the HGSS. Thus, this data serves as proxy or analog data in developing the SEM for the HGSS (**Figure 2-5**). Due to differences in formation thickness and depth between the TR McMillen 2 well and the HGSS, the following four-step method was used to synthesize well logs for the HGSS:

1) Regional surfaces, including the Eau Claire, Mt. Simon, and Precambrian Basement, served to define coarse model zones. A precursory one-foot proportional layering framework model was prepared within these zones between the TR McMillen 2 well and the HGSS.
2) TR McMillen 2 well logs, including gamma ray (GR), porosity, and permeability, were sampled into this high-resolution layering. Each layer received a homogeneous log value which was migrated to the HGSS wells.
3) At the HGSS, each proposed injection well was used to sample the finely layered property models at a 1-foot vertical resolution to synthesize logs.
4) These synthesized logs, like porosity and permeability, were saved for each of the six HGSS wells and were then available to serve as input to the subsequent petrophysical modeling.

Log preparation also involved calibrating the TR McMillen 2 permeability log to core points. For the lower Mt. Simon sections, in this case, model zones Mt. Simon A-lower, A-upper, and B, adjustments were made to the permeability log. Permeability data based on laboratory core data measurements for the TR McMillen 2 well showed that preliminary permeability logs underestimated permeability data from the lower Mt. Simon. While there was reasonable agreement between porosity logs and core-derived porosity data, an adjustment to the permeability log was deemed necessary. The core data appears to be representative of heightened permeability for the lower Mt. Simon, which is consistent with subsurface measures acquired in support of the IBDP and ICCS projects in Decatur[13]. Thus, a positive gain (adjustment) was applied to the permeability log for the Mt. Simon A and B zones, as depicted in **Figure 2-6**. The revised permeability log was labeled *KSDRadj* and used in the SEM for the HGSS.

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[13] Leetaru, H.E., and Freiburg, J.T., 2014, Decatur Litho-facies and reservoir characterization of the Mt Simon Sandstone at the Illinois Basin – Decatur Project, Greenhouse Gases, https://onlinelibrary.wiley.com/doi/full/10.1002/ghg.1453

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Figure 2-5. TR McMillen 2 well logs were adapted to HGSS using proportional layering, approximating differences in stratigraphic depth and formation thickness. TR McMillen 2 well logs serve as proxy logs for the proposed injection wells at the HGSS site. The red region features core data used to correct or adjust the permeability log.

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Figure 2-6. TR McMillen 2 well logs and core point data for the lower Mt. Simon. The porosity log was consistent with the porosity core data. The preliminary permeability log, KSDR, was adjusted to better align with core data points and is labeled KSDRadj. The gray arrow highlights the applied gain to the permeability log for Mt. Simon zones A and B.

The synthesized porosity and permeability well logs at the HGSS were upscaled along their well trajectories into the Tartan grid model cells and were distributed layer cake style, meaning that each model layer is homogeneous and isotropic. The layer cake modeling was conducted for the Ironton zone down through the top 100 feet of the Precambrian basement, as shown in **Figure 2-7** and **Figure 2-8**. Model cross-sections through the HGSS further reveal the layer cake modeling of the petrophysical properties (**Figure 2-9**). Using the SEM, the average porosity and permeability were computed for each model zone and are reported in **Table 2-7**. Histograms of porosity and permeability for the Eau Claire confining zone and the entire Mt. Simon section reveals the contrast between these two geologic units (**Figure 2-10**).

Table 2-7. Average porosity and permeability values by model zone.

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Figure 2-7. Oblique view of the 3D layer cake porosity model. Model zones dip to the southeast.

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Figure 2-8. Oblique view of the 3D layer cake permeability model. Model zones dip to the southeast.

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Figure 2-9. Model cross-sections. a) Model zones for petrophysical modeling. b) Layer cake porosity model. c) Layer cake permeability model.

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Figure 2-10. Histograms depicting porosity and permeability model distributions. Histograms are filtered by model zones, with the Eau Claire representing the confining interval and the Mt. Simon zones consisting of Mt. Simon E zone down through Mt. Simon A Lower.

2.1.3.3. SEM Updates Using Pre-Injection Data

HGCS plans to collect porosity and permeability of the Eau Claire and Mt. Simon to validate the current modeling assumptions through a series of logging and core collection activities prior to injection well construction. These tasks are described in the *Pre-Operational Testing Program*. Specific logs that will aid this process include:

- Elemental capture spectroscopy (to understand the mineral and pore space composition)

- Full-bore micro imagery (to image bedding planes, reservoir textures, and fractures (open, healed, and drilling-induced))
- Nuclear magnetic logging (to gauge pore size distribution for identifying the highly porous zones from tight zones.

Additional activities in the *Pre-Operational Testing Program* provide updated inputs for the HGCS SEM include:

- Sonic logging to prepare a synthetic seismic well tie and velocity model for use with the three existing 2D seismic lines
- Reservoir fluid sampling to understand formation water composition and to measure total dissolved solids
- Core sampling in the Eau Claire and in Mt. Simon zones A and B to obtain lab measurements of porosity and permeability; the core will also serve subsurface interpretation through visual inspection and description and will be paired with thin sections, which will reveal rock composition, grain size and sorting, cementation, and the distribution of pore space among the mineral grains.

2.1.4. Constitutive Relationships and Other Rock Properties

Rock-fluid flow behavior was modeled using two-phase relative permeability curves for a CO_2-brine system. There were no available core analyses for this specific project location which resulted in the use of analogous data from nearby wells and literature. Two separate sets of relative permeability curves were used, one for the porous sand zones and another for confining shale layer. The two sets of relative permeability curves were:

- **Set Number 1:** CO_2-water drainage curve for Mt. Simon sandstone published by Krevor *et al.* (2011)[14] based on samples from a well in Macon County, IL; samples were taken at 5,400 ft. depth and subjected to coreflooding experiments with brine and CO_2. Experimental data was further fit using Brooks-Corey correlations to extrapolate to saturation end points. **Figure 2-11** shows the drainage curve used for this study. Additional data on this curve is presented in the *Computational Modeling Details* attachment to this plan.
- **Set Number 2**: CO_2-water drainage curve for a shale confining layer with nominal pore sizes distribution comparable to that of the Eau Claire shale published by Bennion and Bachu (2007)[15]. Data for the Calmar shale was used as an analog since the median pore

[14] Krevor, S.C M., Pini, R., Zuo, L., and Benson, S.M., 2012. Relative permeability and trapping of CO2 and water in sandstone rocks at reservoir conditions. *Water Resources Research* Vol. 48, doi: 10.1029/2011WR010859

[15] Bennion, D.B., and Bachu, S., 2007. Permeability and Relative Permeability Measurements at Reservoir Conditions for CO_2-Water Systems in Ultra Low Permeability Confining Caprocks. SPE Paper # 106995 presented at the SPE Europec/EAGE Annual Conference and

size for this formation was 0.006 µm, which is comparable to Eau Claire nominal pore distribution of 0.002-0.01 µm. **Figure 2-12** shows the CO_2-brine drainage curve for the tighter (< 1 mD) units in the model that includes the Eau Claire shale. Additional data on this curve is presented in the *Computational Modeling Details* attachment to this plan. **Table 2-8** lists the relative permeability curves assigned to model zones.

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Figure 2-11. CO_2-brine drainage curve for Mt. Simon sandstone (Krevor *et al*., 2011)

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Figure 2-12. CO_2-brine drainage curve for Eau Claire shale (adapted from Bennion and Bachu, 2007)

Exhibition, London, United Kingdom, 11–14 June.

Table 2-8. Relative permeability set allocations for the storage model in CMG-GEM.

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Gas relative permeability hysteresis was modeled using the HYSKRG parameter in the GEM. Land correlation was used as the modeling method with a maximum residual gas saturation of 0.4. This value, although an initial estimate obtained from Bachu (2005), will be verified by obtaining actual core samples from the injection site and conducting two-phase relative permeability measurements as outlined in the *Pre-Operational Testing Program*.

2.1.5. Rock Compressibility

Any porosity changes in the model resulting from fluid injection were modeled by introducing a pressure dependent compressibility coefficient. Sensitive, Confidential, or Privileged Information [redacted] This porosity value was obtained by examining the property distribution across the injection interval which is a combination of Mt. Simon B and the upper part of Mt. Simon A.

2.1.6. Boundary Conditions

Current model assumes open boundary conditions at the model boundary. There are no known geological barriers to fluid flow in the model area. This assumption will be verified using the injectivity and pressure transient tests that will be performed on HGSS injection wells as outlined in the *Pre-Operational Testing Program*. In its current form, the GEM model's open boundary condition was designed by providing volume multipliers of 10,000 to the cells at the grid

[16] Newman, G.H., 1973. Pore-Volume Compressibility of Consolidated, Friable, and Unconsolidated Reservoir Rocks Under Hydrostatic Loading. *J Pet Technol* 25 (02): 129–134.

boundary in the i-j direction. There were no flow boundaries imposed in the vertical direction with low permeability of the Eau Claire shale and the pre-Cambrian basement acting as natural barriers to fluid flow.

2.1.7. Initial Conditions

Initial conditions for the model are given in **Table 2-9**. Additional details on model initialization are presented in the *Computational Modeling Details* document.

Table 2-9. Initial conditions at an example reference depth of the top of Mt. Simon B.

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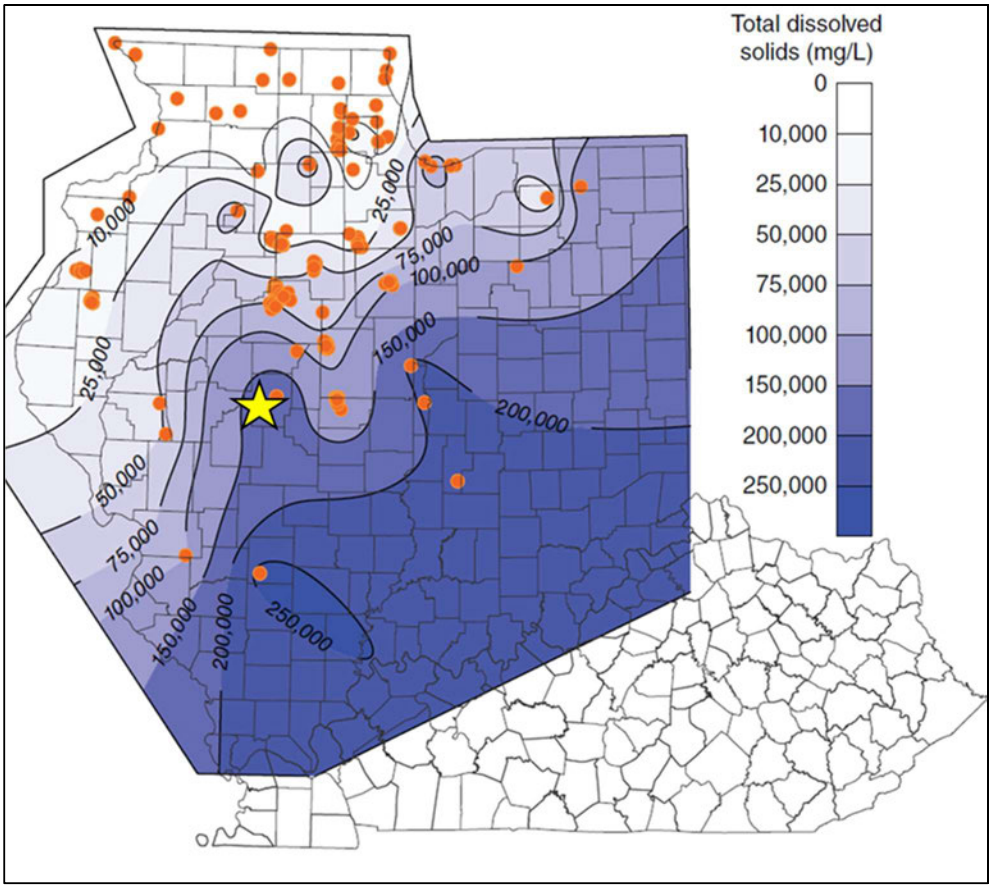

Figure 2-13. Mt. Simon salinity map for Illinois basin (Illinois State Geological Survey, 2014)

Initial conditions assumed in the reservoir model will be verified during the pre-injection testing phase wherein flow tests will be used to verify reservoir pressure and the consequent hydrostatic pressure gradient (see *Pre-Operational Testing Program*). Reservoir brine properties such as density, salinity, and ionic composition will be verified by collecting a baseline fluid sample from the reservoir zone as outlined in the *Baseline Testing and Monitoring Plan*. Additionally, fluid sampling outlined in the Testing and Monitoring Plan will seek to validate and confirm fluid salinity and density values through the course of injection and post injection (see *Testing and Monitoring Plan*).

2.1.8. Operational Information

Details on the injection operation are presented in **Table 2-10**. Additional details on the well model are presented in the *Computational Details* document.

Table 2-10. Operating details.

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Figure 2-14 shows the proposed well locations at the project site. Five injection wells are placed along the existing N-S seismic line, line # 101. The sixth well, NCV-6, is placed between NCV-3 and NCV-4 and 1.75 miles to the west of seismic line # 101 and on seismic line # 301 as shown in the figure. Well placement was primarily dictated by seismic line orientation and land availability.

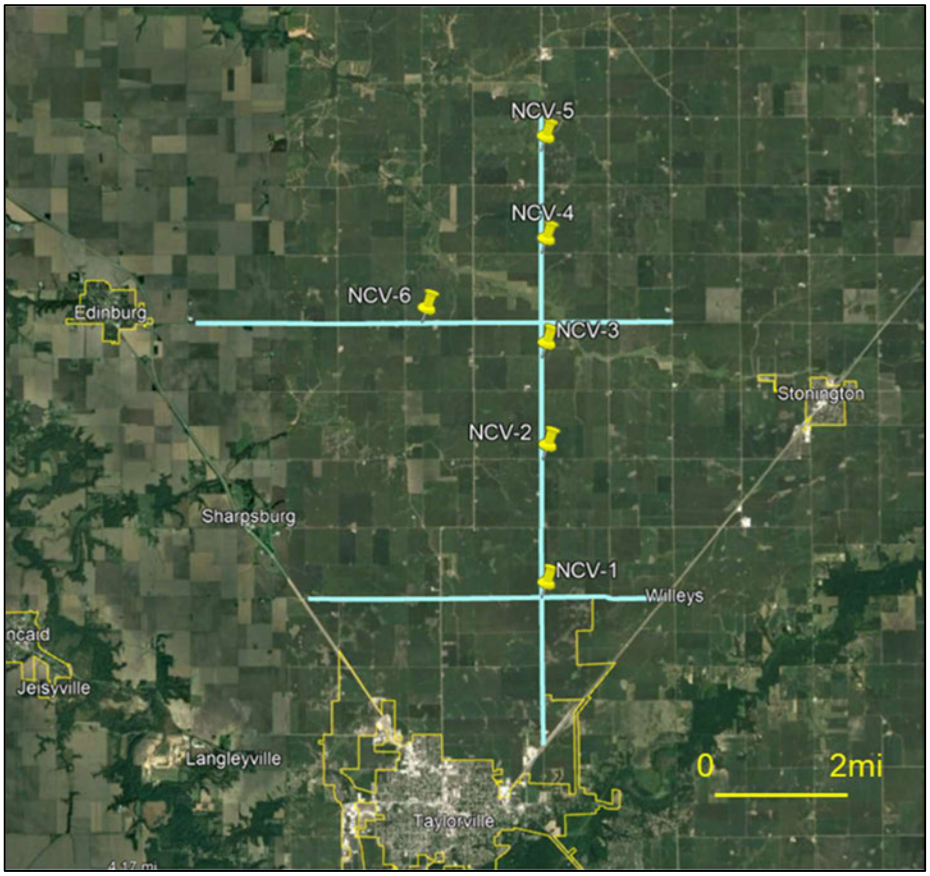

Figure 2-14. Proposed well locations at HGSS.

2.1.9. Gridding and Numerical Conditions

As shown in **Figure 2-2**, a tartan grid was implemented laterally with the smallest grid cells in the nearby vicinity of the injection wells. Cell block sizes are listed in **Table 2-3**. The grid cell size was increased with increased distance from the wells and as the model boundary was approached. The cells block sizes at the corners of the well model boundary were approximately 15,000 feet by 12,000 feet where there is no anticipated fluid communication.

The vertical gridding scheme included cell block thickness ranging from a minimum of 5 feet at the wells to 36 feet at the model periphery and in shallower formations where no fluid communication is anticipated. These values were listed previously in **Table 2-6**. The vertical gridding scheme in the dynamic model is visually illustrated in **Figure 2-15**.

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Figure 2-15. Vertical gridding scheme for HGSS reservoir model.

Timesteps in the simulations varied between 1E-08 days to 365 days. The simulator had the flexibility to pick a time step based on convergence of material balance and finite changes of block pressure and saturation. Each timestep had one iteration of material balance. However, the maximum timestep size was adapted to each phase of model run with maximum timestep size limited to 3 days during injection, and 31 days post-injection since changes in the system are less pronounced in the post-injection stage compared to injection. Please see the *Computational Modeling Details* for more information on the numerical solvers implemented in the HGSS model.

2.1.10. Fracture Pressure and Fracture Gradient

Calculated fracture gradient and maximum injection pressure values are given in Table 6.
The fracture pressure gradient for modeling purposes was assumed to be 0.7 psi/ft. This value was taken from the Area of Review and Corrective Action Plan attachment for CCS #1 well (permit number IL-115-6A-002) as published by the U.S. EPA. A step rate test was conducted at CCS#1 was conducted to estimate the fracture pressure of the Mt Simon injection zone. Although CCS #1 well is located 30 miles northeast of the project site, geomechanical properties of the Mt Simon formation are assumed to be homogenous in the Illinois basin. Consequently, in the absence of well-specific data for this project, a starting point of 0.7 psi/ft is assumed to be a realistic assumption.

Current model is designed to constrain injection well bottomhole pressure (BHP) at 80% of the fracture pressure of Mt Simon sandstone at top perforation depth. These values are listed in **Table 2-11**. As an additional safety constraint, the reference depth for calculating BHP constraint is assumed to be the top of the grid block (~20 ft above the grid center) corresponding to the top perforation at each well.

HGCS will verify fracture pressure assumption by testing the parting pressure of the confining zone and the reservoir by conducting a step-rate test or an equivalent technique, prior to injection. This is further explained in the *Pre-Operational Testing Program*. Test results from fracture tests during drilling and characterization and prior to injection will be compared to model assumption of 0.7 psi/ft and the model will be adjusted accordingly to update AoR delineation.

Table 2-11. Injection pressure details.

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2.2. <u>Computational Modeling Results</u>

2.2.1. Predictions of System Behavior

All the injection wells injected at an average annual rate of 1 MMT/year. The injection was rate constrained since and the well BHP for all the six injection wells always remained below their individual BHP constraints as shown in **Figure 2-16**.

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Figure 2-16. Predicted injector BHP profiles and corresponding constraints at top perforations.

Reservoir simulation results for CO_2 plume propagation and pressure buildup are illustrated in **Figure 2-17** through **Figure 2-20**. Due to lateral contiguity of the reservoir model, the results appear isotropic. Consequently, plume and pressure propagation are predictable in space and time. It is also crucial to note that the pressure built up during injection quicks starts to dissipate upon cessation of injection. This is a result of the reservoir quality and the lack of any known flow barriers that would impede fluid and pressure propagation. HGCS used these predictions to develop a monitoring strategy that will help confirm model predictions.

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Figure 2-17. Lateral development of the CO_2 plume at HGSS with top pointing north; time slices are from layer 61 of the model corresponding to Mt. Simon B where plume is the most laterally extensive.

The key takeaway from **Figure 2-17** is that once injection stops, the gas plume continues to redistribute before stabilizing after 5 years. There is no noticeable change in lateral plume geometry after 5 years from injection.

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Figure 2-18. Vertical development of the CO_2 plume at HGSS; time slices are along seismic line #101 with S-N direction being left to right.

Like **Figure 2-17**, **Figure 2-18** also indicated the gas plume stabilizes between the 5–10-year period post-injection. After injection stops, the CO_2 plume migrates vertically although this vertical migration is not pronounced. However, the plume is still confined to Mt. Simon B with very little to no interaction with Mt. Simon C, which is a less permeable layer compared to B.

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Figure 2-19. Lateral development of the pressure buildup plume at HGSS with top pointing north; time slices are from layer 77 of the model corresponding to Mt. Simon A where pressure plume is the most laterally extensive; black line indicated the outline of threshold pressure (135 psi).

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Figure 2-20. Vertical development of the pressure buildup plume at HGSS; time slices are along seismic line #101 with S-N direction being left to right; black line indicated the outline of threshold pressure (135 psi).

Figure 2-19 and **Figure 2-20** indicate that the lateral and vertical migration of the pressure buildup plume in response to injection. As expected from an isotropic model, the pressure buildup plume propagates radially outward from the injection area. Injecting in the Mt. Simon B and upper part of Mt. Simon A is also anticipated to increase pressure in the geological layers below the injection zone namely Mt. Simon A lower, Argenta, and the Pre-Cambrian Basement. HGCS will monitor the geomechanical impacts of these pressure increases as outlined in the geophysical monitoring section of the *Testing and Monitoring Plan*. The figures also depict an outline of the expected pressure buildup component of the AoR computed using a threshold pressure of 135 psi (please see the critical pressure calculations section below). Noticeably, the pressure buildup falls rapidly after injection stops which is a result of the lateral continuity of the reservoir as well as the absence of any flow/pressure barriers in the project area. These assumptions will be further validated during the initial phases of pre-injection testing by means of injectivity and pressure fall-off tests (see *Pre-Operational Testing Program*).

Figure 2-21 and **Figure 2-22** are contour maps that show CO_2 plume and pressure buildup plume migration respectively. CO_2 plume migration in the post-injection phase appears to be predictable and well-contained. The plume after 100 years post-injection is slightly larger than that right after injection thought he overall increase area is less than 10% of the original area of 26 mi^2. The pressure buildup plume area is 102 mi^2 right after injection, which is when it is the most laterally extensive. This area falls rapidly after injection halts and completely diminishes within the first 5 years of post-injection period. Details on pressure threshold calculation used for mapping the pressure buildup plume are presented in later sections of this document.

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Figure 2-21. Plume contours for plume progression during injection (left) and post-injection (right).

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Figure 2-22. Plume contours that signify pressure buildup plume progression during injection (left) and post-injection (right). The threshold pressure used for delineation was 135 psi calculated based on the approach suggested by Birzkohler *et al.* (2011).

2.2.1.1. *Monitoring Well Data Predictions*

Monitoring well locations were picked based on a risk-based strategy that considered the migration of injected CO_2. **Figure 2-23** shows the locations of in-zone monitoring wells.

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Figure 2-23. In-zone (Mt. Simon) monitoring well locations at HGSS.

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Figure 2-24. In-zone monitoring well predictions for CO_2 saturation and bottomhole pressure.

Figure 2-24 is a composite plot of bottomhole pressure and gas saturation profiles for the six in-zone monitoring wells that assumes injection starts in the year 2026. Gas saturation values correspond to Mt. Simon B (layer 61) where areal extent of the plume is at a maximum while pressure values are from upper part of Mt. Simon A (layer 77) where pressure buildup plume is the most laterally extensive. Some wells notice an arrival of the gas plume earlier than others while some wells never interact with the plume based on their spatial location. Also noticeable is the pressure increase while immediately starts to dissipate upon the halt of injection. **Table 2-12** summarizes gas and pressure plume observations at the six in-zone monitoring well locations.

Table 2-12. CO_2 plume and pressure fall-off predictions for in-zone monitoring wells.

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2.2.2. Model Calibration and Validation

Currently, the geologic model is calibrated to the petrophysical data obtained from ADM CCS#1 well and the TR McMillen #2 well which was drilled by the Illinois State Geological Survey (ISGS). Additional calibration to field conditions will be performed upon obtaining pre-injection testing data outlined in the *Pre-Operational Testing Plan*.

2.3. <u>Storage Complex Delineation</u>

2.3.1. Critical Pressure Calculations

The determination of pressure front is based on existing standard practices for other well classes in the UIC Program and involves calculation of a threshold reservoir pressure as described in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*[17]. The value of the threshold reservoir pressure that defines the pressure front may be calculated based on static pressure within the injection zone and the lowermost USDW, as well as the elevations of both zones by determining the pressure within the injection zone that is great enough to force fluids from the injection zone through a hypothetical open conduit into any overlying USDW.

[17] U.S. EPA, 2013. Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance. Document EPA 816-R-13-005 published May 2013.

The pressure-based AoR is defined by the pore pressure ($P_{i,f}$) isoline of the following magnitude within which it can cause vertical flow from the injection zone into the USDW (Birzkohler *et al.*, 2011)[18].

$$P_{i,f} = P_u \frac{\rho_i}{\rho_u} + \rho_i g (z_u - z_i)$$

Where,

- $P_{i,f}$ = minimum pressure within the injection zone necessary to cause vertical flow from the injection interval into the USDW
- P_u = pressure within the lowermost USDW
- ρ_u = fluid density within the USDW
- ρ_i = fluid density in the injection zone
- z_i = injection depth
- z_u = depth of the lowermost USDW

The lowermost USDW is assumed to be the St. Peter formation. The lowermost depth, salinity, and corresponding pressure calculations based on our assumptions are listed in **Table 2-13**.

Table 2-13. Threshold pressure calculation inputs and output.

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2.3.2. Storage Complex Delineation

AoR at HGSS Site in Illinois has been determined as a composite of the maximum areal movement of injected CO_2 and the pressure buildup at or above the threshold value of 135 psi as

[18] Birzkohler, J.T., Nicot, J.P., Odenburg, Zhou, Q., Kraemer, S., and Bandilla, K., 2011. Brine flow up a well caused by pressure perturbation from geologic carbon sequestratoin: Static and dynamic evaluations. International Journal of Greenhouse Gas Control (5), pp. 850-861

[19] McCutcheon, S.C., Martin, J.L, Barnwell, T.O. Jr. 1993. Water Quality in Maidment, D.R. (Editor). Handbood of Hydrology, McGraw-Hill, New York, NY (p. 11.3).

calculated in **Table 2-13**. The pressure buildup profile was plotted right after injection, which is when it is anticipated to be the most laterally extensive and compared with CO_2 plume movement after injection. It was determined that the pressure buildup plume covered a much larger area compared to the CO_2 plume. Therefore, the pressure buildup plume at and above the 135-psi threshold right after injection is assumed to be the AoR at HGSS. The total areal extent of the AoR is 102 mi^2. The gas plume area is 27 mi^2. These areas are illustrated in **Figure 2-25** where the dotted line also represents HGSS AoR. The map also indicates locations of the observation wells namely in-zone (Mt. Simon and Eau Claire), above-zone (Ironton), and shallow groundwater wells. CO_2 plume movement, as delineated by computational modeling presented here, was used to pick in-zone well locations which above-zone wells are located close to the injection wells where the risk of leakage to the above-zone is the highest.

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Figure 2-25. HGSS AoR map generated using computational modeling; the dotted line, which is the pressure after 30 years of injection, is the AoR since it is the larger of two plumes (CO_2 and pressure buildup); the map also indicates locations of in-zone Mt. Simon (MS), above-zone Ironton (I), and shallow groundwater (SG) wells.

2.3.3. Plume Stabilization and Post-Injection Monitoring Period

Based on the results obtained from computational modeling of the storage complex using best practices as mentioned in this document, HGCS has determined a 15-year post-injection site care (PISC) period is appropriate in adequately describing the containment of the gas plume as well as stabilization of reservoir pressure in the injection system. As noted earlier, CO_2 plume movement post-injection is predictable and constrained with minor increase in plume area from the end of injection through a 100-year post-injection period. There is minor vertical migration of the plume within the injection system and there is no communication with shallower strata of the Mt. Simon that overlie the injection zone, much less so with the Eau Claire caprock (see **Figure 2-18**). This confirms there is negligible risk of CO_2 leaking out of the storage system from a computational modeling perspective. From a pressure standpoint, the pressure buildup in the project area resulting from injection starts to drop immediately after injection. As noted by the black line contours in **Figure 2-19** and **Figure 2-20**, the pressure required to force any fluids out of the reservoir and into the USDW through an open wellbore is not existent after 10 years of post-injection. **Figure 2-26** is a pressure buildup versus time plot for the six injection wells. The pressure buildup in each of the wells falls rapidly after injection and completely dissipates eventually. Most notably, the pressure buildup falls below the calculated threshold pressure of 135 psi approximately 3 years into post-injection. Consequently, at the end of the proposed 15-year period, the pressure in the reservoir is lower than the required amount to force any fluid migration out of zone and endanger UDSWs. Therefore, a 15-year PISC period is expected to cover a post-injection timeframe wherein the gas plume and pressure buildup stabilize sufficiently and predictably to not endanger natural resources, public safety, or local environment.

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Figure 2-26. Predicted pressure buildup at the six injection wells (topmost perf used as reference)

HGCS understands that the PISC period will also depend on the actual response of the storage system to CO_2 injection and therefore has developed a robust geophysical monitoring strategy to gather real-time injection data and compare them with reservoir modeling predictions noted in this document. If model predictions do not align with actual data, HGCS will recalibrate reservoir models and re-forecast simulation results to either confirm or adjust the 15-year PISC timeframe. Additional details of plume reevaluation process are listed in subsequent sections of this document. Contingent on actual modeling data and its agreement with computational modeling results, HGCS will submit evidence to the UIC Program Director that plume stabilization has occurred. Such evidence will include

- Updated modeling using operational and post-injection monitoring measurements
- Measured CO_2 and pressure buildup plume migration rates
- Anticipated plume migration over a 100-year period and its inferences on CO_2 leakage out of the storage system area

Additional details on this process are available in the *Post-Injection Site Care and Site Closure Plan*.

2.3.4. Sensitivity Analysis

As mentioned earlier in the SEM section of this document, the geologic model is calibrated to the petrophysical data obtained from ADM CCS#1 well, the FutureGen well and the TR McMillen 2 well, all of which are located with 50 miles from HGSS. Specifically, the TR McMillen 2 well is the closest well (~10 miles from NCV-5 towards northeast). Consequently, there is a good handle on the petrophysical properties of the reservoir and the caprock given the availability of data from analog wells in Christian County. However, site and location specific data will be required to calibrate the reservoir models and accurately forecast fluid movement. There is some uncertainty in site-specific geomechanical data as well as in-situ reservoir fluid properties and relative permeability. Therefore, HGCS has identified specific parameters for running a sensitivity analysis to understand their impact on model predictions of gas plume area, pressure buildup, overall AoR, and a timeframe for post-injection site care (PISC). These parameters and sensitivity cases listed in **Table 2-14**.

Table 2-14. Sensitivity analysis parameters and their variation from base value

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As a primary observation from all cases, the following conditions were satisfied regardless of the parameter being sensitized:

- There is no vertical migration of the CO_2 into the confining layer (Eau Claire)
- Overall reservoir pressure in the model area was stable and unchanged

- Pressure buildup in the model started dropping instantly after the injection was stopped

Additionally, the proposed PISC period of 15 years appears to be a conservative estimate as all cases indicated the pressure buildup reduced and fell below the threshold value of 135 psi anywhere between two and eight years of PISC (**Figure 2-27**).

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Figure 2-27. Time required for pressure buildup to fall below threshold pressure; pressure buildup behavior at topmost perf at NCV-3 used as reference.

Upon validating the overall model behavior was unchanged, analysis was directed toward studying the impact of aforementioned test parameters on

- Gas plume area
- Overall AoR

These results are summarized in **Figure 2-28** and **Figure 2-29**.

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Figure 2-28. Sensitivity of CO_2 plume area to test parameters

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Figure 2-29. Sensitivity of project AoR to test parameters

The results for CO_2 plume area and overall project AoR were identical. Both these attributes appear to be most sensitive to fluid salinity and vertical permeability anisotropy. The gas plume and AoR results were particularly sensitive to fluid salinity as expected. Currently, the model estimates majority (> 95% by mass) of the CO_2 is trapped via solubility into formation brine. Increasing brine salinity decreases CO_2 solubility and consequently, the area contacted by the gas increases to accommodate the same amount of mass as the base case to account for reduced solubility per unit area. The converse if true for a lower salinity case compared to the base case.

Moreover, fluid salinity also affects the threshold pressure calculation shown in **Table 2-14**. For the low salinity case, the threshold pressure is calculated as 58 psi while for the high salinity case, the threshold pressure value is 218 psi. This impacts AoR delineation.

2.4. <u>Corrective Action</u>

2.4.1. Tabulation of Wells within the Storage Complex AoR

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Figure 2-30 displays the ISGS Oil and Gas Resources database wells within the AoR boundary while **Figure 2-31** shows water wells in the project AoR.

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Figure 2-30. ISGS Oil and Gas Wells in HGSS AoR; deepest well reaches a total depth of 3,218 feet.

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Figure 2-31. ISGS Water Wells in HGSS AoR; deepest well reached a total depth of 2,020 feet.

Despite the presence of numerous oil and water wells in the area, none are deep enough to penetrate the confining zone.

2.4.1.1. Wells Penetrating the Confining Zone

There are only two water wells that were drilled deeper than 1,000 feet from surface. The deepest they go is 2,020 feet. Of all the oil and gas wells, only two wells were drilled to reach depths greater than 3,000 feet, none of which penetrate the HGSS storage system. None of the existing wells go as deep as the Ironton, which is the above zone formation overlying our storage complex. The deepest existing well is a dry and abandoned well drilled and plugged by the Illini Development Company (API 120210225400) that reached a total depth of 3,218 feet from surface. For reference, the shallowest depth of the Ironton in the model area is 3,951 feet from surface. However, if the project team identifies any new or existing wells, except the planned HGSS wells, that penetrate the above zone or the storage system, HGCS will obtain appropriate public records for pertinent wells to assess their completions and interaction with the storage system. HGCS plans to utilize a combination of monitoring techniques such as satellite imagery, and surface/atmospheric leak detection as well as site reconnaissance during and after injection to monitor for any wells that act as conduits for leakage of CO_2 or brine. Should HGCS identify any wells that require corrective action, HGCS will develop a fit-for-purpose strategy and communicate this with the UIC Program Director prior to obtaining site access and implementing corrective action. HGCS will also update the permit materials accordingly.

2.4.2. Plan for Site Access

HGCS plans to secure options for rights to surface access across the entire project AoR. If corrective action is required for legacy wells that exist in the AoR that were not identified at the time of this writing, HGCS shall exercise the options agreement to access, enter, and implement corrective action on faulty wellbores.

2.4.3. Corrective Action Schedule

As indicated earlier, results of our analysis of the wells existing in the project AoR indicate no corrective action is required at this point. However, HGCS will actively monitor for any potential fluid leakage in the AoR through direct and indirect means as detailed in the *Testing and Monitoring Plan*. Upon detection of possible communication of injected or in-situ fluids with existing wellbores, the wells in communication will be examined for integrity issues and corrective action will be scheduled accordingly. Specific parameters that are monitored for this purpose include CO_2 saturation at or near project and legacy wells, shallow groundwater monitoring, and deep groundwater monitoring. Corrective action will depend on the condition of well in communication. If any corrective actions are identified as necessary, HGCS will develop a plan to address them as necessary and provide the details of such plans to the UIC Program Director prior to implementation for approval.

2.5. <u>Plume Extent Reevaluation Schedule and Criteria</u>

2.5.1. AoR Reevaluation Cycle

Pursuant to 40 CFR 146.84 (e), HGCS will reevaluate the above described AoR at least once every 5 years during the injection and post-injection phases, unless any one of the following conditions are met, which would trigger an earlier reevaluation:

- There are significant changes in operations of injection wells or other project wells which may include deviation of permitted injectate compositions, pressure, and flowrates, emergency leaks or spills, and major operational challenges (this does not include short-term routine workovers)
- Significant deviation of operational and monitoring data from modeled and permitted behavior of the storage site compared to its baseline conditions
- Any additional site characterization conducted prior to next scheduled AoR revaluation

AoR reevaluations will address the following:

- Changes to the monitoring and operational data prior to the scheduled 5-year reevaluation date.
- Deviations in monitoring and operational data (e.g., injection rate and pressure); this data will be used to update the geologic model and the computational simulations to inform a reevaluation of the AoR and corrective action plan, including the computational model that was used to determine the AoR, will be updated, and the operational data to be utilized as the basis for that update will be identified.
- Methods of conducting corrective action, if necessary, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AoR.

If it is found that the site conditions or behavior of the plume or pressure front are not consistent with the most recent model's predictions, and that the actual plume or pressure front extend beyond what is modeled HGCS will re-delineate the AoR. Triggers for AoR reevaluation are listed in the section below. If necessary, re-delineation will include the following steps:

- Calibrating the model with new site characterization, operational, or monitoring data (pressures, fluid saturations).
- Performing a new AoR delineation with the same methods described in the Computational Modeling Section of this chapter.
- Identify any new wells that penetrate the confining zone and provide a description of each well's type, construction, date drilled, location, depth and records of plugging and/or completion.

- Performing corrective action on all new wells that penetrate the confining zone and cannot be proven to exist or be abandoned in a way that prevents the movement of CO_2 or other fluids that endanger any USDWs.

If the reevaluation process results in the re-delineation of the AoR, HGCS will prepare a report to be submitted to the UIC Program Director that details the decision to update the AoR delineation, the data evaluated used to make the decision, and any necessary changes to the corrective action plan.

2.5.2. Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

As detailed in the *Testing and Monitoring Plan*, monitoring and operational data are gathered and reviewed frequently. If this data suggests that the actual extent and movement of the plume or pressure font have deviated significantly from the modeled predictions HGCS will initiate a reevaluation of the AoR prior to the next scheduled reevaluation period. The following is a list unexpected changes in quantitative parameters that could trigger reevaluation of the AoR.

- Pressure: Unexpected changes in injection pressure, Mt. Simon (reservoir) or Ironton (above-zone) pressure that are of concern
- Temperature: Unexpected changes in injection temperature, temperature in the Mt. Simon, or Ironton (above zone)
- Fluid Saturations: Unexpected changes in CO_2 saturation that indicate the movement of CO_2 out of the injection formation and above the confining zone. If this change is due to well integrity, no AoR reevaluation will be triggered, and the well integrity issue will be addressed.
- Deep Ground Water and Sampling: Unexpected changes in groundwater geochemical and physical parameters that may indicate movement of CO_2 and formation fluids from the injection zone and into formations above the confining zone.
- Induced Seismicity: Seismic event(s) greater than M3.0 within the AoR

Other events that may trigger an AoR reevaluation include the following:

- The volume of CO_2 injected is larger than what is initially permitted.
- New site characterization data become available that significantly modifies the extent of the plume or pressure front beyond what is predicted by the initial model. This can include the identification of a previously unknown fault or fracture in the confining or injection zones.

HGCS will discuss any such events with the UIC Program Director to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, HGCS will perform the steps described at the beginning of this section of this Plan.