DOE F 4600.2
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U.S. Department of Energy
FEDERAL ASSISTANCE REPORTING CHECKLIST AND INSTRUCTIONS FOR RD&D PROJECTS

1. Identification Number: **DE-FE0006821**	2. Program/Project Title: **Small Scale Field Test Demonstration CO2 Sequestration**	
3. Recipient: **University of Kansas Center for Research, Inc.**		
4. Reporting Requirements:	**Frequency**	**Addressees**
A. MANAGEMENT REPORTING		
☒ Research Performance Progress Report (RPPR)	Q	FITS@NETL.DOE.GOV
☒ Special Status Report	A	FITS@NETL.DOE.GOV
B. SCIENTIFIC/TECHNICAL REPORTING		
(Reports/Products must be submitted with appropriate DOE F 241. The 241 forms are available at www.osti.gov/elink)		
Report/Product — Form		
☒ Final Scientific/Technical Report — DOE F 241.3	FG	http://www.osti.gov/elink-2413
☒ Conference papers/proceedings* — DOE F 241.3	A	http://www.osti.gov/elink-2413
☐ Software/Manual — DOE F 241.4		
☐ Other (see special instructions) — DOE F 241.3		
** Scientific and technical conferences only*		
C. FINANCIAL REPORTING		
☒ SF-425 Federal Financial Report	Q, FG	FITS@NETL.DOE.GOV
D. CLOSEOUT REPORTING		
☒ Patent Certification	FC	FITS@NETL.DOE.GOV
☒ SF-428 & 428B Final Property Report	FC	FITS@NETL.DOE.GOV
☐ Other		
E. OTHER REPORTING		
☒ Annual Indirect Cost Proposal	O	See block 5 below for instructions.
☐ Audit of For-Profit Recipients		
☒ SF-428 Tangible Personal Property Report Forms Family	A	FITS@NETL.DOE.GOV
☒ Other – see block 5 below	A	FITS@NETL.DOE.GOV

FREQUENCY CODES AND DUE DATES:

- A - Within 5 calendar days after events or as specified.
- FG- Final; 90 calendar days after the project period ends.
- FC- Final; End of Effort.
- Y - Yearly; 90 calendar days after the end of the reporting period.
- S - Semiannually; within 30 calendar days after end of project year and project half-year.
- Q - Quarterly; within 30 days after end of the reporting period.
- Y180 – Yearly; 180 days after the end of the recipient's fiscal year
- O - Other; See instructions for further details.

5. Special Instructions:

Annual Indirect Cost Proposal – If DOE is the Cognizant Federal Agency, then the proposal should be sent to FITS@NETL.DOE.GOV . Otherwise, it should be sent to the Cognizant Federal Agency.

Other – The Recipient shall provide all deliverables as contained in Section D of Attachment 2 Statement of Project Objectives.

QUARTERLY PROGRESS REPORT
To
DOE-NETL
Brian Dressel, Program Manager
Award Number: DE-FE0006821

SMALL SCALE FIELD TEST DEMONSTRATING CO_2 SEQUESTRATION IN ARBUCKLE SALINE AQUIFER AND BY CO_2-EOR AT WELLINGTON FIELD, SUMNER COUNTY, KANSAS

Project Director/Principal Investigator:
W. Lynn Watney
Senior Scientific Fellow
Kansas Geological Survey

Ph: 785-864-2184, Fax: 785-864-5317
lwatney@kgs.ku.edu

Joint Principal Investigator:
Jason Rush

Date of Report: November 1, 2012
Revised 11-11-12

DUNS Number: 076248616

Recipient: University of Kansas Center for Research &
Kansas Geological Survey
1930 Constant Avenue
Lawrence, KS 66047

Project/Grant Period: 10/1/2011 through 9/30/2015

Fourth Quarterly Report

Period Covered by the Report: July 1, 2012 through September 30, 2012

Signature of Submitting Official:

Willard Lynn Watney
Digitally signed by Willard Lynn Watney
DN: cn=Willard Lynn Watney, o=The University of Kansas, ou=Kansas Geological Survey, email=lwatney@kgs.ku.edu, c=US
Date: 2012.11.11 14:01:15 -06'00'

EXECUTIVE SUMMARY

Project Objectives

The objectives of this project are: (1) inject under supercritical conditions approximately 40,000 metric tons of CO_2 into the Arbuckle saline aquifer; (2) demonstrate the application of state-of-the-art MVA (monitoring, verification, and accounting) tools and techniques to monitor and visualize the injected CO_2 plume; (3) develop a robust Arbuckle geomodel by integrating data collected from the proposed study area, and a multi-component 3D seismic survey; (4) conduct reservoir simulation studies to map CO_2 plume dispersal and estimate tonnage of CO_2 sequestered in solution, as residual gas and by mineralization; (5) integrate MVA data and analysis with reservoir modeling studies to detect CO_2 leakage and to validate the simulation model; (6) develop a rapid-response mitigation plan to minimize CO_2 leakage and a comprehensive risk management strategy; and (7) establish best practice methodologies for MVA and closure. Additionally, approximately 30,000 metric tons of CO_2 shall be injected into the overlying Mississippian to evaluate miscible CO_2-EOR potential in a 5-spot pilot pattern. The CO_2 shall be supplied from the Abengoa Bioenergy ethanol plant at Colwich, Kansas who has operated the facility since 1982 demonstrating reliability and capability to provide an adequate stream and quality of CO_2. The project shall install compression, chilling, and transport facilities at the ethanol plant for truck transport to the injection site.

Project Goals

The proposed small scale injection will advance the science and practice of carbon sequestration in the Midcontinent by refining characterization and modeling, evaluating best practices for MVA tailored to the geologic setting, optimize methods for remediation and risk management, and provide technical information and training to enable additional projects and facilitate discussions on issues of liability and risk management for operators, regulators, and policy makers.

The data gathered as part of this research effort and pilot study will be shared with the Southwest Sequestration Partnership (SWP) and integrated into the National Carbon Sequestration Database and Geographic Information System (NATCARB) and the 6th Edition of the Carbon Sequestration Atlas of the United States and Canada.

Project Deliverables by Task

1.5 Well Drilling and Installation Plan (Can be Appendix to PMP or Quarterly Report)
1.6 MVA Plan (Can be Appendix to PMP or Quarterly Report)
1.7 Public Outreach Plan (Can be Appendix to PMP)
1.8 Arbuckle Injection Permit Application Review go/no go Memo
1.9 Mississippian Injection Permit Application Review go/no go Memo
1.10 Site Development, Operations, and Closure Plan (Can be Appendix to PMP)

2.0 Suitable geology for Injection Arbuckle go/no go Memo
3.0 Suitable geology for Injection Mississippian go/no go Memo
11.2 Capture and Compression Design and Cost Evaluation go/no go Memo
19 Updated Site Characterization/Conceptual Models (Can be Appendix to Quarterly Report)
21 Commercialization Plan (Can be Appendix to Quarterly Report).
30 Best Practices Plan (Can be Appendix to Quarterly or Final Report)

ACCOMPLISHMENTS

1. **Completed Milestone 1 (Task 2)** -- Site Characterization of Arbuckle Saline Aquifer System - Wellington Field.
2. **Significant progress and nearing completion of Milestone 2 (Task 3) --** Site characterization of Mississippian Reservoir for CO2 EOR - Wellington Field
3. **Subtask 1.8 Arbuckle Injection Permit Application –** An update on the status of the Class VI application is attached. We solidified the geomodel for the simulation and basic input for the simulation. We have a well define plume by CO2 saturation and pressure and accordingly, have a stabilized AOR. Pressures and size of CO2 plume are nominal/minor. Class VI injection application will be submitted for internal review followed by official submittal to EPA to obtain the permit during the 5th quarter.

Milestone Status Report

Task	Budget Period	Number	Milestone Description
Task 2.	1	1	Site Characterization of Arbuckle Saline Aquifer System - Wellington Field
Task 3.	1	2	Site characterization of Mississippian Reservoir for CO2 EOR - Wellington Field
Task 10.	2	3	Pre-injection MVA - establish background (baseline) readings
Task 13.	2	4	Retrofit Arbuckle Injection Well (#1-28) for MVA Tool Installation
Task 18.	3-yr1	5	Compare Simulation Results with MVA Data and Analysis and Submit Update of Site Characterization, Modeling, and Monitoring Plan
Task 22.	3-yr1	6	Recondition Mississippian Boreholes Around Mississippian CO2-EOR injector
Task 27.	3-yr2	7	Evaluate CO2 Sequestration Potential of CO2-EOR Pilot
Task 28.	3-yr2	8	Evaluate Potential of Incremental Oil Recovery and CO2 Sequestration by CO2-EOR - Wellington field

Project Schedule

Abengoa Biofuels informed us in mid August 2012 that the Colwich Ethanol Facility would be shut down for one year because of the severe drought in the Midwest. The dry weather severely impacted their dryland feedstock base (mainly milo and sorghum) and the resulting high grain prices. The facility will remains closed until the next harvest. Abengoa, DOE, and partners agreed that the plant reopening will be revisited on October 1, 2013 after the next harvest cycle to determine if they will reopen. During DOE site visit in September 2012, Abengoa official gave us a tour of the ethanol plant and relayed that every effort is being taken to keep the plant in a condition so that it can be reopened next year.

A request was made and DOE extended Budget Period 1 for an additional year at no cost until October 1, 2013. The project will make every effort to evaluate alternative sources, but as yet the economics are not close to meeting the arrangements made with Abengoa and the Colwich ethanol facility. Both Abengoa and Berexco, the oil field industry partner, are committed to working with each other to link the ethanol-based CO2 with oil field operations in the area.

Geologic CO2 will not be part with the Kansas market due to demand along existing pipelines in Texas, New Mexico, Colorado, and Wyoming. Anthropogenic is the only viable source to provide the CO2 needed for CO2-EOR. Both Abengoa and Berexco are keenly interested in the saline aquifer storage in order to obtain enhanced prices for ethanol, obtain deposal fees, and with the case at Wellington, the income generated by carbon trading through Biorecro in Sweden.

A condensed version of the Gantt Chart tracks tasks based on the one year no cost extension of Budget Period 1 (Figure 1).

Activities of Lawrence Berkeley National Lab

No work has been completed or funds expended during this quarter by LBNL.

ONGOING ACTIVITIES –

TASK 1. PROJECT MANAGEMENT AND REPORTING

Permit Status and Activities

Continued progress was made on the Class VI application permit. With the Petrel geomodel and accompanying CMG based dynamic simulation expected to be completed in Q1 2013, we are on track to submit the permit in the present quarter. The sections of the Class VI permit application and the associated percent completion is presented in Table 1.

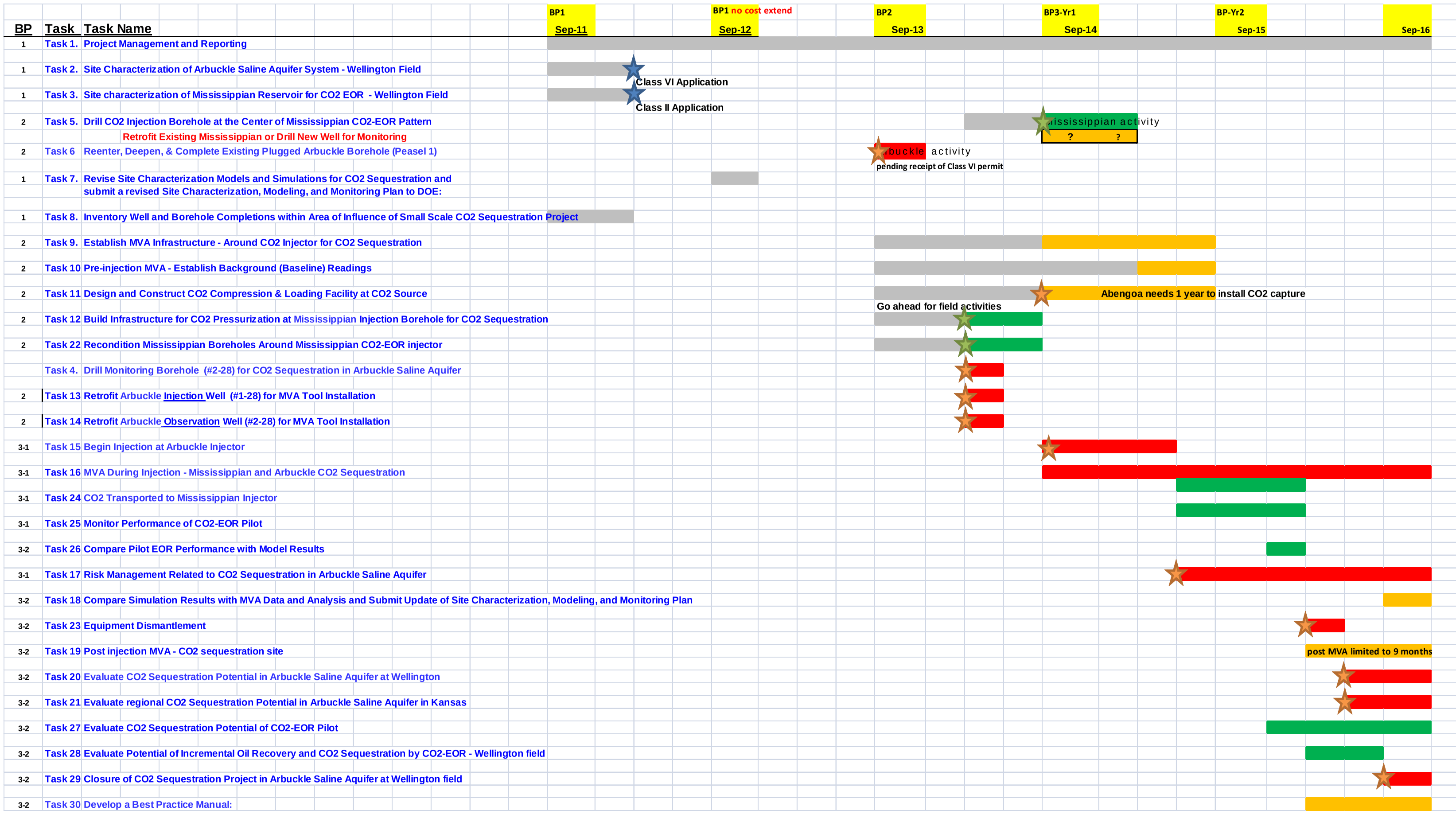

BP1
Sep-11
BP1 no cost extend
Sep-12
BP2
Sep-13
BP3-Yr1
Sep-14
BP-Yr2
Sep-15
Sep-16
BP
Task
Task Name
1 Task 1. Project Management and Reporting
1 Task 2. Site Characterization of Arbuckle Saline Aquifer System - Wellington Field
Class VI Application
1 Task 3. Site characterization of Mississippian Reservoir for CO2 EOR - Wellington Field
Class II Application
2 Task 5. Drill CO2 Injection Borehole at the Center of Mississippian CO2-EOR Pattern
Mississippian activity
Retrofit Existing Mississippian or Drill New Well for Monitoring
? ?
2 Task 6 Reenter, Deepen, & Complete Existing Plugged Arbuckle Borehole (Peasel 1)
Arbuckle activity
pending receipt of Class VI permit
1 Task 7. Revise Site Characterization Models and Simulations for CO2 Sequestration and submit a revised Site Characterization, Modeling, and Monitoring Plan to DOE:
1 Task 8. Inventory Well and Borehole Completions within Area of Influence of Small Scale CO2 Sequestration Project
2 Task 9. Establish MVA Infrastructure - Around CO2 Injector for CO2 Sequestration
2 Task 10 Pre-injection MVA - Establish Background (Baseline) Readings
2 Task 11 Design and Construct CO2 Compression & Loading Facility at CO2 Source
Abengoa needs 1 year to install CO2 capture
Go ahead for field activities
2 Task 12 Build Infrastructure for CO2 Pressurization at Mississippian Injection Borehole for CO2 Sequestration
2 Task 22 Recondition Mississippian Boreholes Around Mississippian CO2-EOR injector
Task 4. Drill Monitoring Borehole (#2-28) for CO2 Sequestration in Arbuckle Saline Aquifer
2 Task 13 Retrofit Arbuckle Injection Well (#1-28) for MVA Tool Installation
2 Task 14 Retrofit Arbuckle Observation Well (#2-28) for MVA Tool Installation
3-1 Task 15 Begin Injection at Arbuckle Injector
3-1 Task 16 MVA During Injection - Mississippian and Arbuckle CO2 Sequestration
3-1 Task 24 CO2 Transported to Mississippian Injector
3-1 Task 25 Monitor Performance of CO2-EOR Pilot
3-2 Task 26 Compare Pilot EOR Performance with Model Results
3-1 Task 17 Risk Management Related to CO2 Sequestration in Arbuckle Saline Aquifer
3-2 Task 18 Compare Simulation Results with MVA Data and Analysis and Submit Update of Site Characterization, Modeling, and Monitoring Plan
3-2 Task 23 Equipment Dismantlement
3-2 Task 19 Post injection MVA - CO2 sequestration site
post MVA limited to 9 months
3-2 Task 20 Evaluate CO2 Sequestration Potential in Arbuckle Saline Aquifer at Wellington
3-2 Task 21 Evaluate regional CO2 Sequestration Potential in Arbuckle Saline Aquifer in Kansas
3-2 Task 27 Evaluate CO2 Sequestration Potential of CO2-EOR Pilot
3-2 Task 28 Evaluate Potential of Incremental Oil Recovery and CO2 Sequestration by CO2-EOR - Wellington field
3-2 Task 29 Closure of CO2 Sequestration Project in Arbuckle Saline Aquifer at Wellington field
3-2 Task 30 Develop a Best Practice Manual:

Figure 1. Condensed version of the project Gantt Chart.

Table 1. Status of the Class VI permit application.

Section	Percent Complete
Project Overview	**90%**
Geologic Sequestration of Carbon Dioxide	**90%**
Regional Scale Geologic and Hydrogeologic Background	**75%**
Local Scale Geologic and Hydrolgeologic Background	**40%**
Flow and Transport Model Simulations and AOR Delineation	**60%**
Potential Capture in Depleted Mississippian Formation	**60%**
Geomechanical Stability Investigations	**50%**
Injection Well Design	**60%**
Monitoring Well Design	**60%**
Site Operations	**20%**
Monitoring Verification and Accounting Activities	**65%**
Post Injection Site Care	**50%**
Site Closure	**50%**
Risk Management and Mitigation Plan	**20%**
Financial Assurances	**40%**

A brief discussion of some of the activities conducted in Q4 2012 in support of the Class VI permit application is provided below.

Based on the literature review and the theoretical basis governing fault failure, a technical approach was developed to evaluate the potential for fault failure should such features be present in the study area. It should be noted that the EPA does not require a geomechanical analysis, and it is up to the discretion of the local director to request a stability analysis. Some efforts were however expanded in Q4 to develop the analytical approach to preempt any concern by the EPA based on their interpretation of the seismic data, and thereby minimize the potential for delays.

The EPA Class VI rule was carefully reviewed to ensure that material and construction requirements were met during construction of the project injection and monitoring wells (1-28 and 1-32 respectively). Specifications governing testing of mechanical integrity were also identified and are to be finalized with Berexco prior to inclusion in the permit application.

Conversations were held with Joesph Tiaggo and Bruce Kobelski of US EPA regarding financial requirements. The wellfield operator, Berexco was informed of the findings and the consensus is that Berexco will be able to meet the financial requirements.

The default EPA post injection monitoring period is 50 years. The Post Injection Site Care and the Site Closure sections are being carefully crafted in order to provide a strong justification for early site closure (preferably coinciding with the end of the DOE funding period). We are hopeful that the EPA may grant this waiver subject to field validation of the extent of plume migration and pressure dissipation.

The monitoring, verification, and accounting (MVA) aspects are key components of the Wellington project. During the planning stage, various MVA activities were identified but described only in general terms without design details as the anticipated plume and pressure impacts were not available due to the absence of a reservoir model based on integration of the various geophysical data collected at the site. With the preliminary impacts now available, key investigators at the Kansas State University, Kansas University, Kansas Geological Survey, and Lawrence Berkley and Sandia laboratories, have been contacted in order to finalize the MVA design and data sampling plans. For example, the anticipated vertical displacement at the surface is expected to be in the sub-mm scale and Mike Taylor at KU has been notified of the projections. He is currently developing plans in order to capture such minor displacements using ultra sensitive remote sensing techniques.

During Q4, contact was also made with Susan Collins at LBNL to make a presentation on the risk profile methodology being developed for quantifying risk potential at underground carbon storage sites in support of large-scale CCUS projects. The following set of questions were identified by the KGS group and forwarded to Susan for addressing during her visit:

- How are uncertainties in well penetrations/construction to be handled
- How are uncertainties in faults characterization to be handled
- What technical approach is to be implemented to evaluate and assign risk factors (what stochastic framework is to be applied for the overall analyses)
- What will the simulation system consist of – both software and hardware
- What are the lateral and vertical extent and continuity of the subsurface flow systems that are to be modeled
- What simulations approaches are to be implemented to efficiently handle the problem of dual scales of interest (large scale pressure propagation and the relatively small scale plume migration)
- What level of information (and source) is to be used to characterize the subsurface formations in Kansas
- What uncertainty techniques are to be used for both capacity estimation (if that is to be attempted) and geomechanical stability
- How are uncertainties in regional stress fields to be addressed/evaluated in estimating risks of geomechanical failure
- What activities have been completed so far and what are the findings.

- How can we assist in their efforts since we plan on conducting regional simulations as well.

The step rate test conducted at KGS 1-32 (with monitoring at KGS #1-28) was analyzed by three different participants on the project; Ken Cooper, Gene Williams, and Tiraz Birdie. Working independently, all three came to the same conclusions that the Arbuckle is not a homogenous aquifer because the observations at the injection and monitor well could not be matched with the same set of hydrogeologic parameters (for example, see Figure 2).

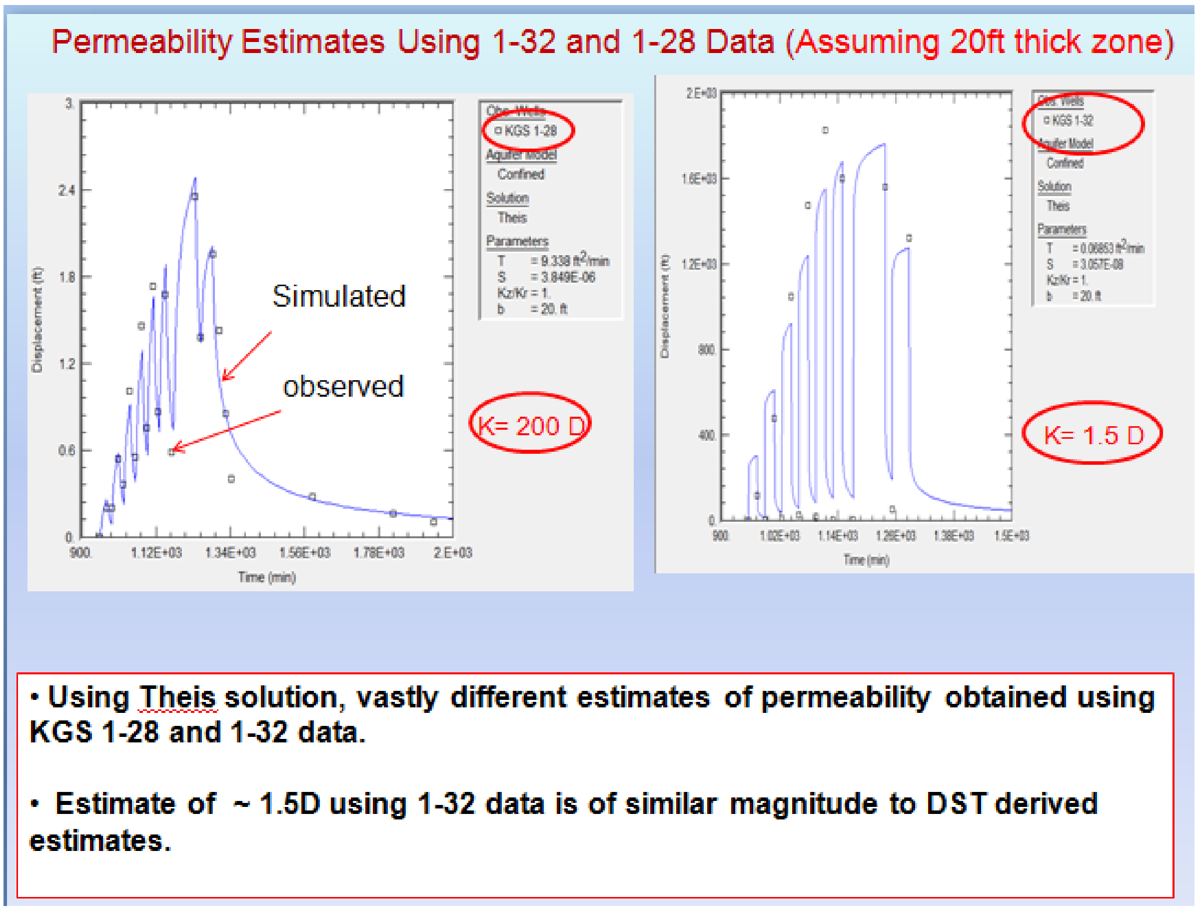
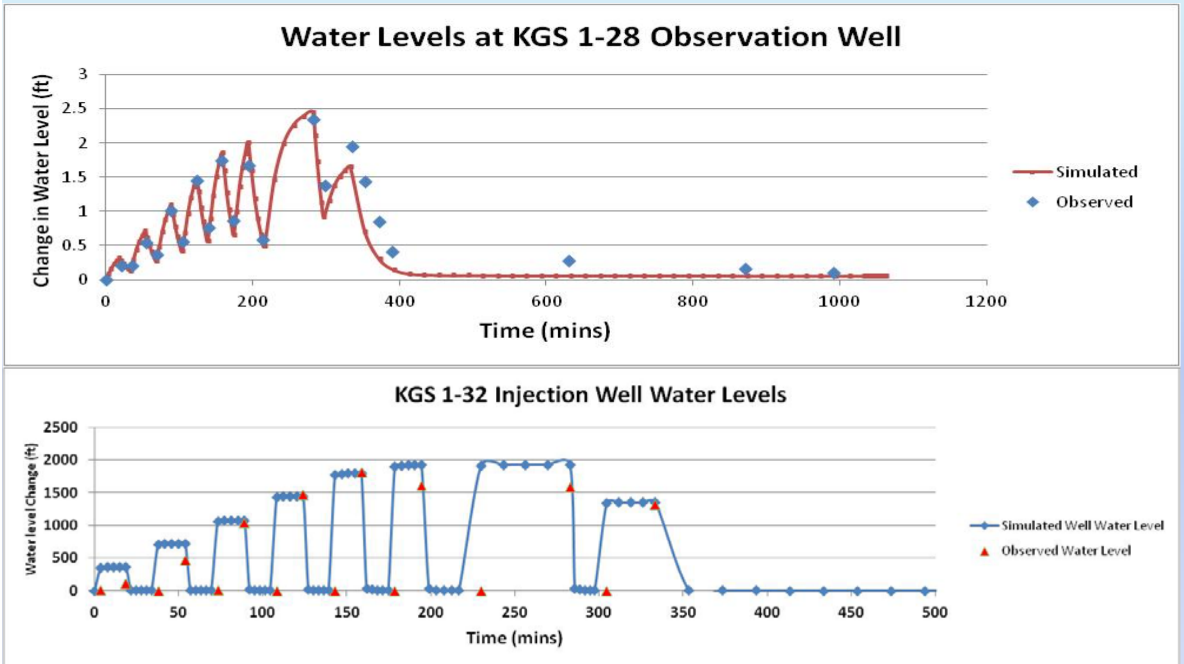


Figure 2. Calibrated hydrogeologic parameters derived from the step rate test at injection well 1-32 and observation well 1-28.

Using the USGS modeling code MODFLOW, it was later demonstrated that observed pressures at KGS 1-32 and 1-28 during the step rate test could be simultaneously reproduced with the same matrix petrophysical properties by incorporating baffle like features between 1-28 and 1-32 (Figure 3). This information may be recalled in the future during live calibration of the reservoir model as CO2 is injected.

Obtained Simultaneous Match at 1-28 and 1-32



Permeability (Darcy)					
Injection Zone (layer 5)	intermediate Confining Layers	Core	Top of Arbuckle (layer 1)	Damage Zone	Specific Storage
1	0.01	0.001	2.5	2	1.00E-10

- Permeabilities in various aquifer zones on left.
- Required low specific storage (highly compressed water).

Figure 3. MOFLOW calibrated observed and simulated water levels at KGS 1-28 and 1-32.

Subtask 1.6. Monitoring Verification and Accounting (MVA) and Mitigation Plan

The MVA and mitigation plans will be completed as part of the Class VI application and submitted as a separate report. MVA plan will now include equipping same technologies and methodologies for the Mississippian CO2 injection ahead of the Arbuckle. This will require adapting the MVA to the CO2-EOR to establish 99% sequestration of the CO2.

Subtask 1.7. Public Outreach Plan:

The Public Outreach Plan will also be submitted as part of the Class VI application. The DOE document will describe workshops, presentations, and publications in technical and trade journals to be used to transfer lessons learned best practices, geomodels, simulation results, MVA data and observations to the public, regulators, legislators, and local industry. The PI is actively discussing the project with stakeholders.

Subtask 1.8. (Go-No Go Decision for CO_2 saline formation sequestration) Arbuckle Injection Permit Application

Effort during the fourth quarter was focused on the Class VI injection permit including revision the geomodel and running simulations. The following is a review of the geomodeling and simulation activities as they pertain to the Class VI application.

Dynamic Simulation Model

On completion of the Petrel based geomodel in September 2012, the heterogeneous flow and transport properties from the geomodel were imported into the CMG dynamic model and simulations conducted in order to estimate the pressure and plume extent resulting from injecting 40 KT of CO_2 for a period of nine months. The geomodel incorporates the injection interval, the middle transitional zone, the upper high permeability and porosity interval, and a portion of the sealing unit (Simpson Shale). It is developed using a complex combination of well logs, core data, seismic surveys, literature information, depositional analogs, and statistics. Due to availability of log data at only two sites (KGS 1-28 and KGS 1-32), the model also relied on seismic data, SRT, and DST information.

Reservoir properties (porosity and permeability) were distributed in the CMG simulation model by upscaling via arithmetic mean methods. Initial reservoir conditions were specified using known information about the pressure and temperature distribution. Fluid saturations were distributed using the sequential Gaussian simulation algorithm. The Carter-Tracer aquifer boundary conditions were specified along the lateral extent of the simulation model. Although observations suggest that the flow in Arbuckle reservoir is controlled by a combination of matrix and fractures, this initial set of model run considers flow only in the formation matrix.

The effective porosity derived in the geomodel (Figure 4) was deemed to be quite representative of the formation due to the extensive set of processing and synthesis conducted for this property by the KGS team led by John Doveton. The effective hydraulic conductivity (Figure 5) on the other is not directly derived from logs and therefore uncertainties in this parameter was explored by conducting three scenarios in which the base case model permeability was varied from the Petrel derived distribution of this property.

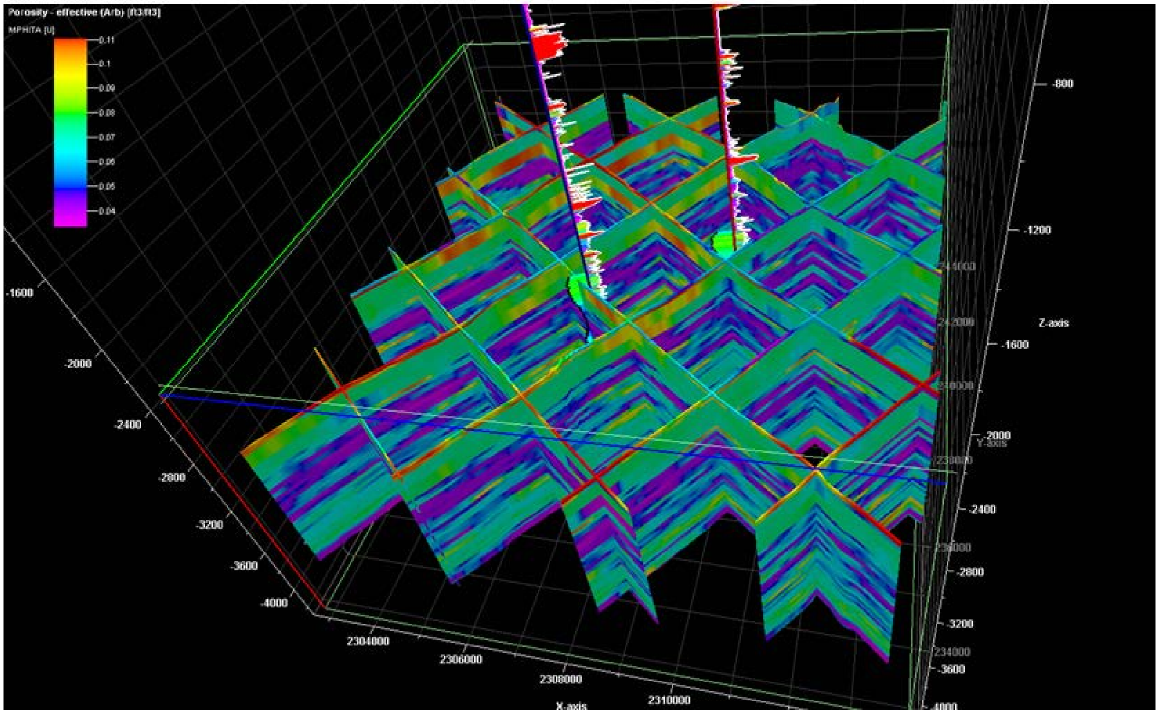


Figure 4. Petrel model based distribution of effective porosity in the Arbuckle aquifer

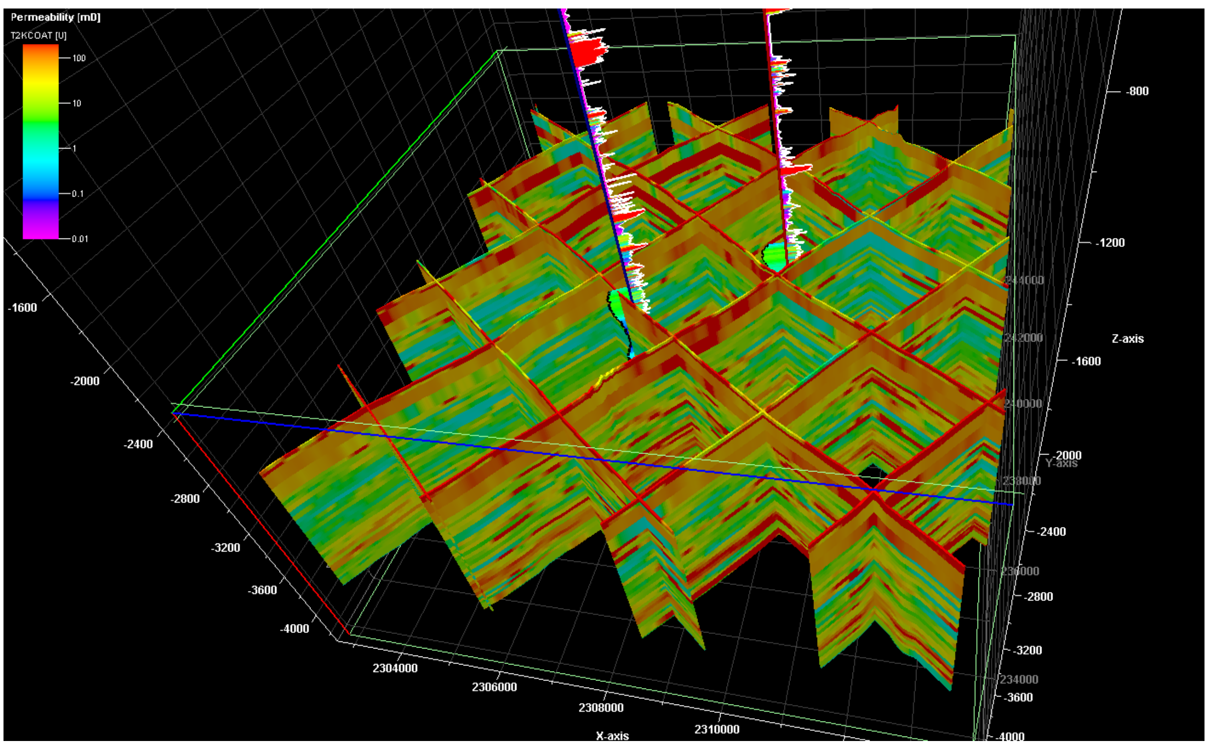


Figure 5. Petrel model based distribution of hydraulic permeability of the Arbuckle aquifer

The simulations were conducted by also assuming two different conditions in the mid Arbuckle: a no-flow barrier, and a finite but low permeability matrix in this zone. The reservoir medium was assumed to be porous; without fractures. Sequestration of CO2 was primarily by dilution due to dispersion/diffusion and residual trapping. This is expected to provide conservative results as solubility and geochemical trappings are not considered. These processes will be considered in the next round of simulations.

The vertical migration of CO2 within a cross section through the injection well (1-28) is presented in Figure 6a and 6b for the case with a permeable mid Arbuckle. By the end of the injection period of 9 months, the CO2 plume is contained within the lower Arbuckle and is approximately 500 feet wide with a saturation of about 40%. The plume extent remains fairly stable up to 5 years. By the 10^{th} year the CO2 concentration in the plume starts to reduce, and by year 30 the CO2 saturation further reduces, but the plume has extended into the mid Arbuckle. By the 100^{th} year, the plume has CO2 saturation of less than 20% and has stabilized with minor amounts trapped at the top of the upper Arbuckle under the Simpson Shale. The maximal horizontal extent of the plume at 5, 10, and 100 years is presented in Figure 7. The plume has the widest extent (of 600 feet) in the lower Arbuckle in the 5^{th} and 10^{th} year. By the 100^{th} year, the plume has migrated into the upper Arbuckle and the widest extent is underneath the Simpson Shale.

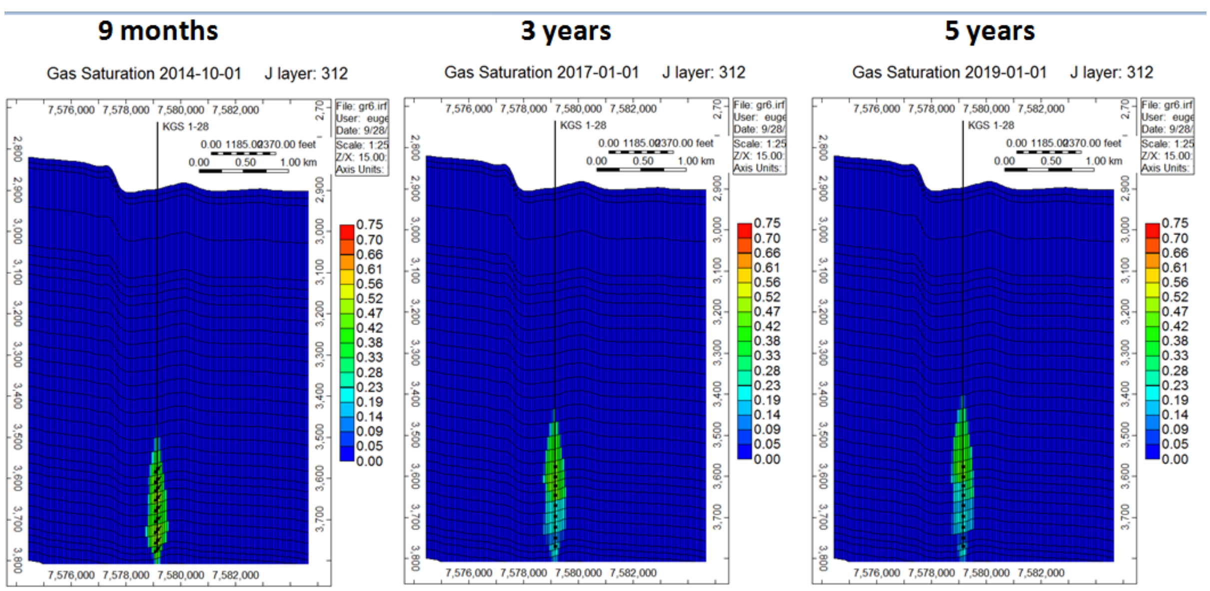


Figure 6a. CO2 saturation at 9 months, 3 and 5 years for the case with permeable mid Arbuckle.

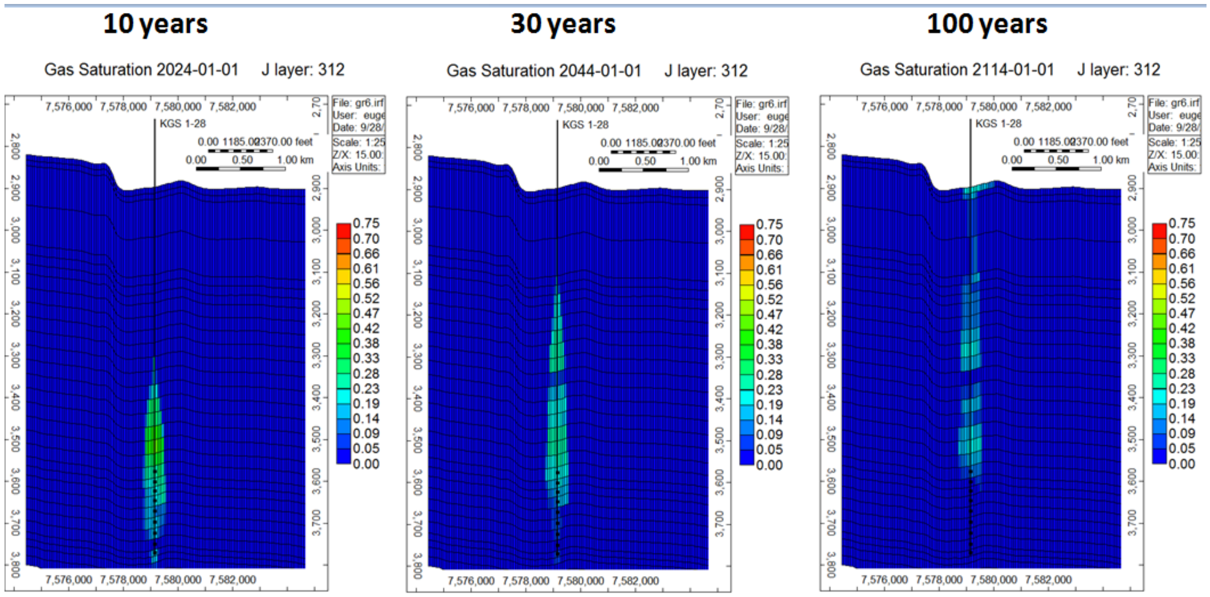


Figure 6b. CO2 saturation at 10, 30, and 100 years for the case with permeable mid Arbuckle.

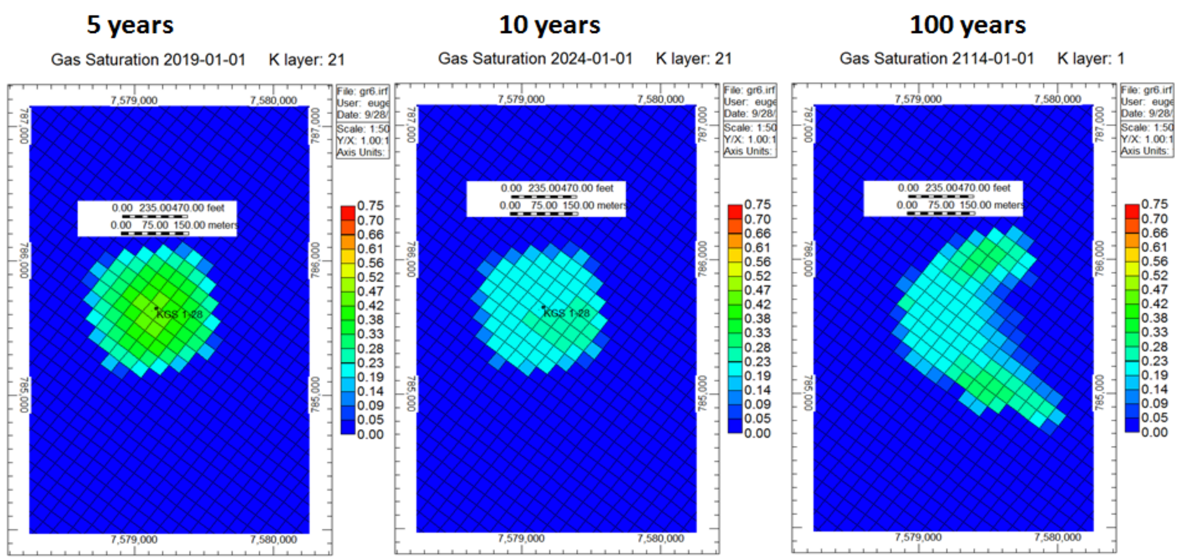


Figure 7. Maximal horizontal extent of CO2 plume at 5, 10, and 100 years for the case with permeable mid Arbuckle.

The vertical migration of the CO2 plume for the case in which the mid Arbuckle is a barrier is presented in Figures 8a and 8b. The saturation in the center of the plume is approximately 50% at the end of the injection period. By the end 5th and 10th years, the plume extent increases only slightly but the concentration in the lower Arbuckle has reduced slightly. The plume extent and saturations at the end of 30, 70, and 100 years are presented in Figure 8b from which a stable plume can be inferred as the solubility aspects are not presently active in the model. The maximal extent of the CO_2 plume after 9 months and at the end of years 3 and 5 is approximately the same at about 600 feet with a saturation of approximately 50% in the center of the plume (Figure 10a). By the end of 100 years, the plume extent has grown to over 1,000 feet but the saturations have dropped to 40% (Figure 10b).

The bottomhole pressures for the various permeability cases are presented in Figure 11. For all cases, the pressure initially increases substantially due to capillary effects prior to stabilizing at a lower level. The largest pressure increase is for the low permeability (base) case, but even for this case the pressure increase is under 100 psi; which is lower than the approximately 200 psi threshold for defining the EPA (pressure based) Area of Review. On cessation of injection, the pressure drops very rapidly to pre-injection levels. The vertical distribution of the pressure prior to and following injection is presented in Figure 12. A pressure increase of about 100 psi can be noted at the injection well at the end of 10 months. By the end of the first year, pressures have dropped to pre-injection levels. The maximal pressure response corresponding to an alternate low permeability case in which the injection pressures are nearly 2400 psi is presented in Figure 13 for illustrative purposes.

With the preliminary dynamic model under operation, simulations were conducted at a commercial level injection rate of 14 MT for a period of 15 years. The vertical extent of the plume for this case increases is presented in Figure 14a and 14b. The plume is approximately 0.5 mile wide by 9 months, and increases to 1 mile by the end of 5 years. By the end of 30, 70, and 100 years, the plume extent does not grow significantly but saturation levels have started to lower. The maximal horizontal plume extent is presented in Figures 14c and 14d. The plume grows from about 0.5 mile width at the end of 9 months to well over 2 miles wide at the end of 100 years. The highest saturation in the plume remains at 50% during this entire period. It should be noted that the CO_2 concentrations will be lower in future simulations as solubility and geochemical trapping mechanisms are activated. The well bottom hole pressures are presented in Figure 15 from which a fairly high (pressure) build up of approximately 4,100 psi can be noted. The background pressure does not revert to pre-injection levels yet as the model requires some additional “tweaking”. The maximal pressure response at the end of the injection period is presented in Figure 16.

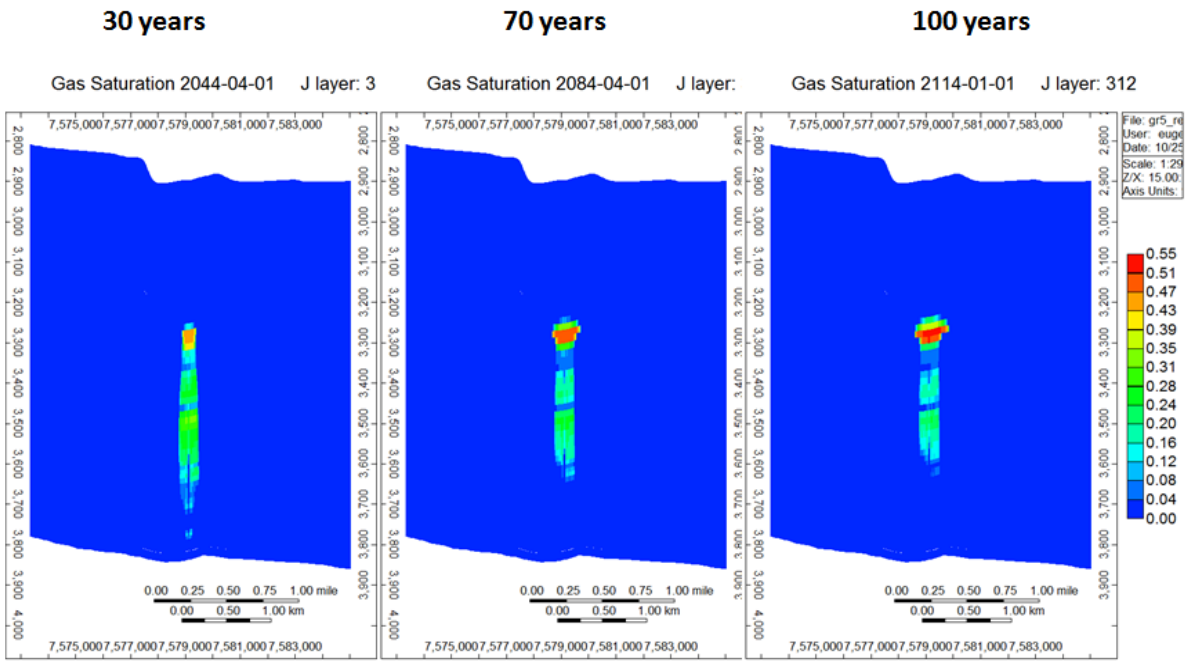


Figure 8a. CO2 saturation in the Arbuckle at 9 months, 3 years, and 5 years for the case with the mid Arbuckle as a barrier.

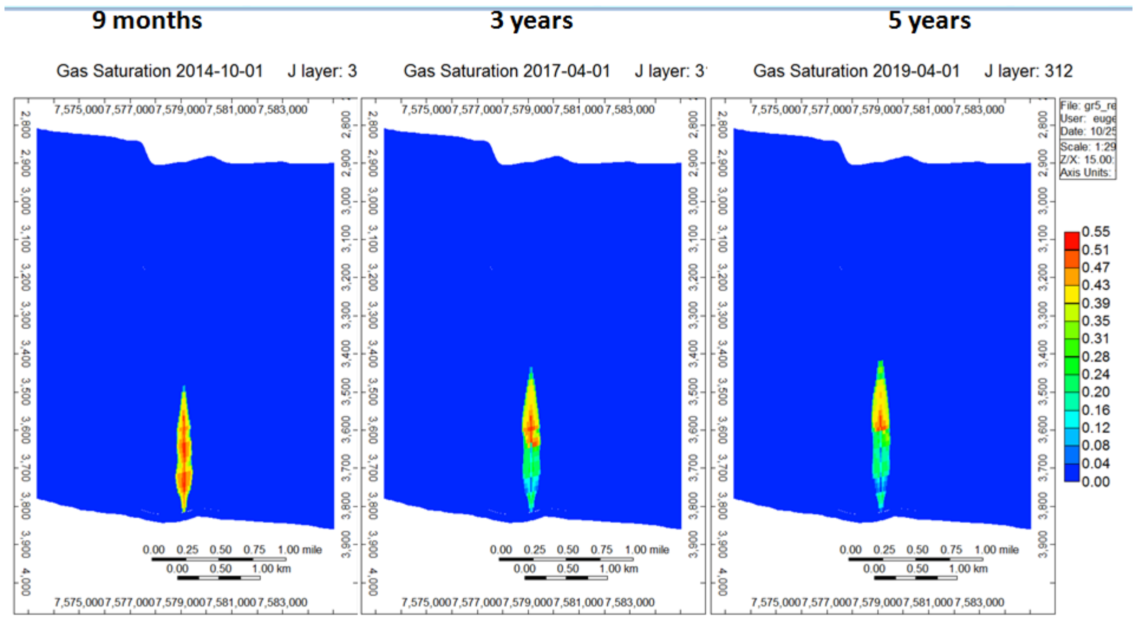


Figure 8b. CO2 saturation in the Arbuckle at 30, 70, and 100 years for the case with the mid Arbuckle as a barrier.

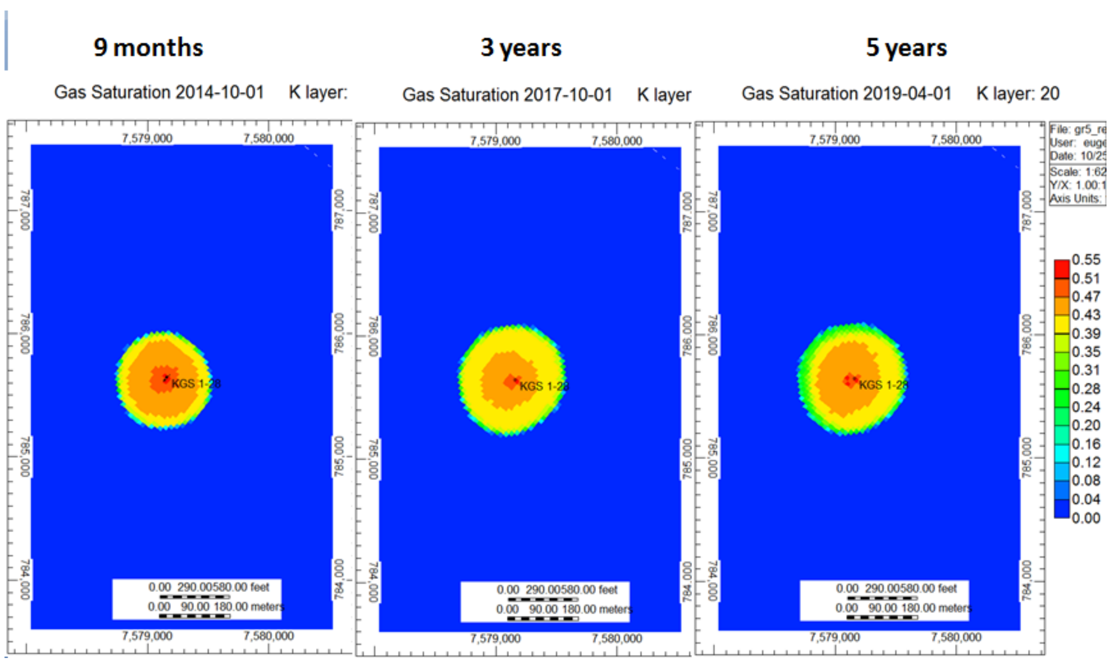


Figure 9a. Maximal horizontal extent of CO2 plume at 9 months, 3 years, and 5 years for the case with mid Arbuckle as a barrier.

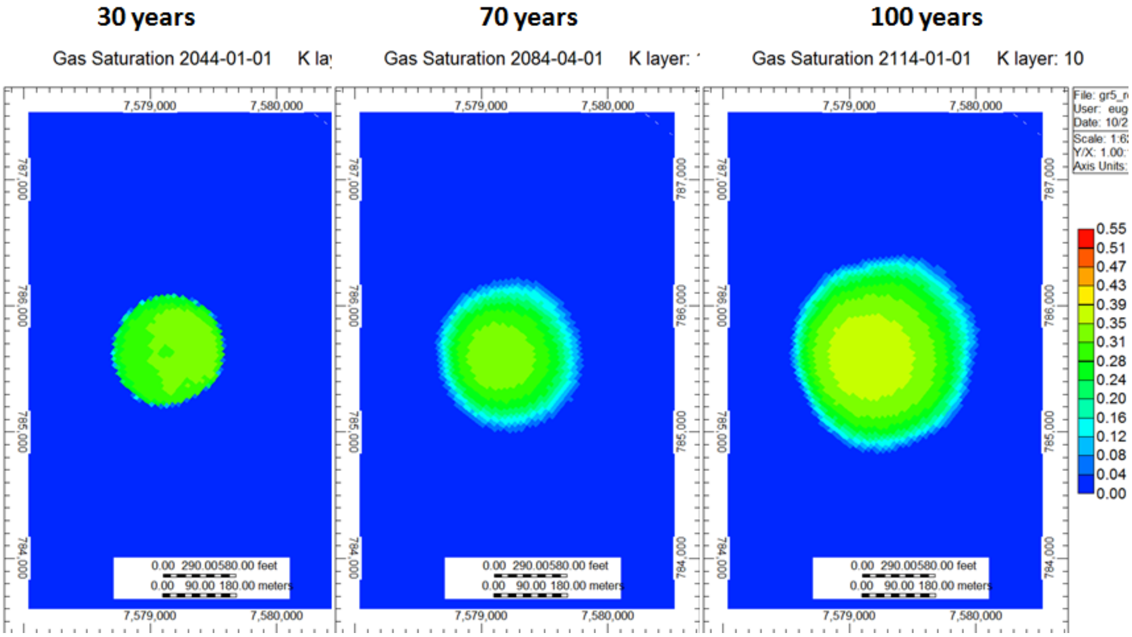


Figure 9b. Maximal horizontal extent of CO2 plume at 30 years, 70 years, and 100 years for the case with mid Arbuckle as a barrier.

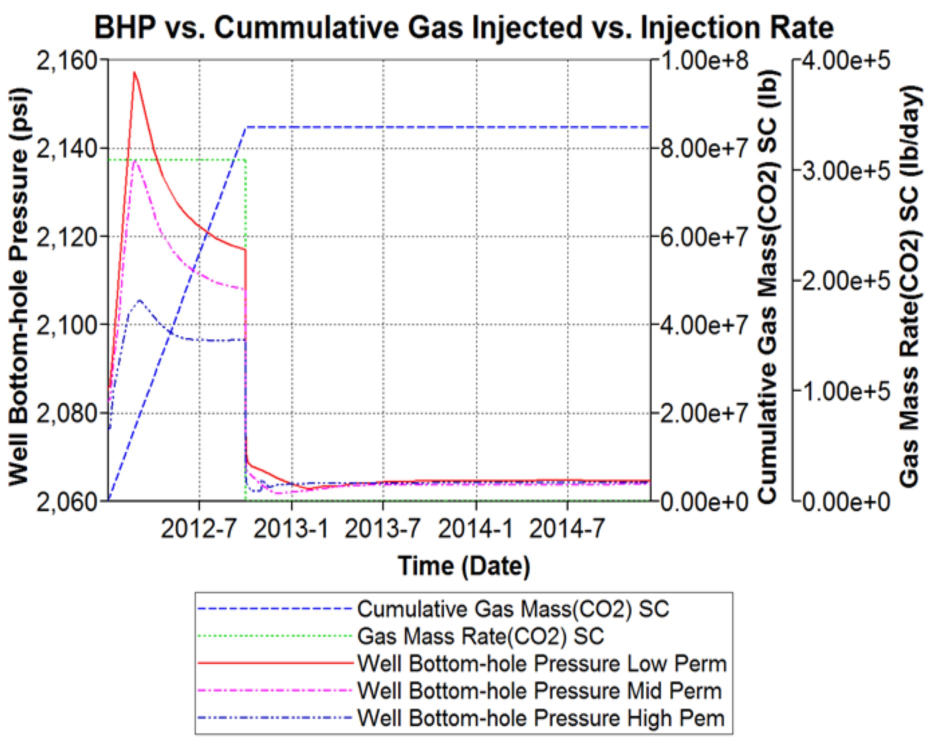


Figure 10. Well bottom-hole pressures for the low, medium, and high permeability cases.

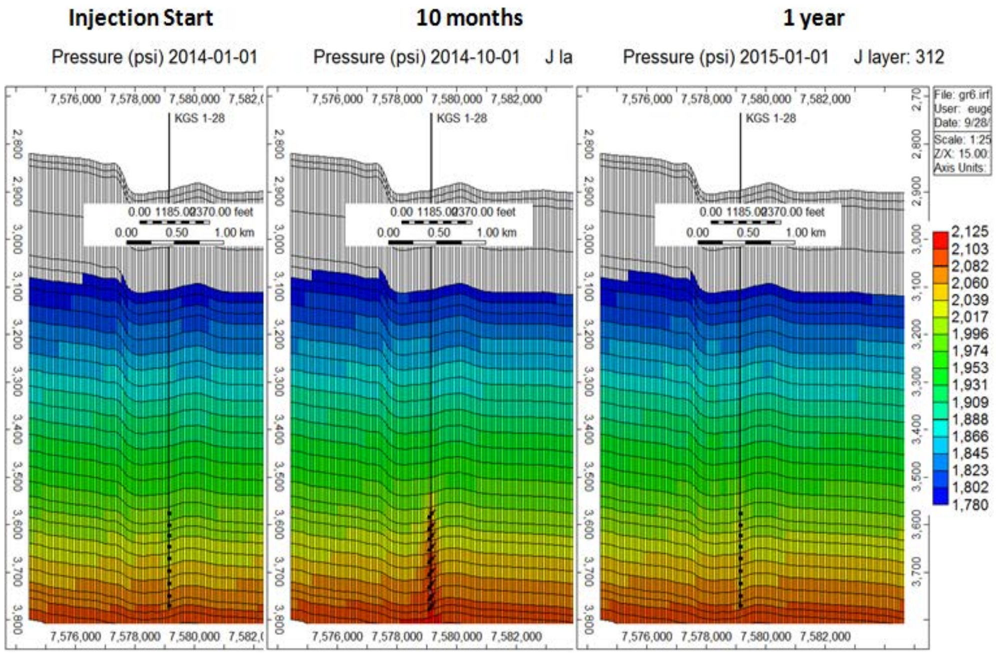


Figure 11. Vertical pressure profile at the start of injection, at 10 and 12 months

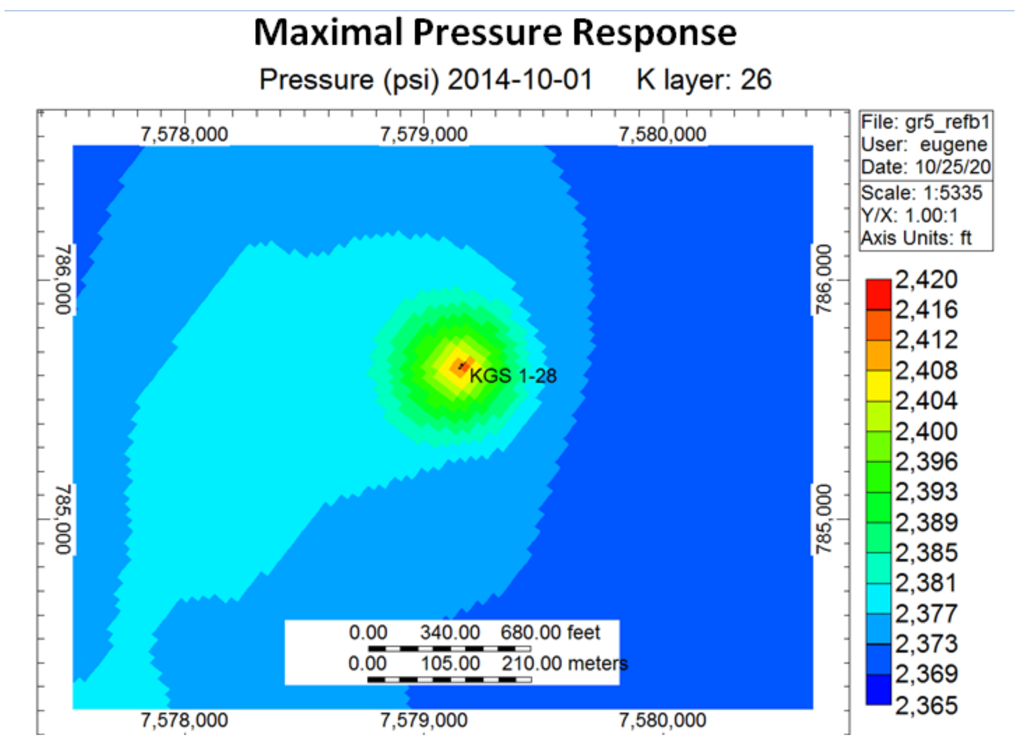


Figure 12. Maximal pressure response in the lower Arbuckle for an alternate case with lower permeability

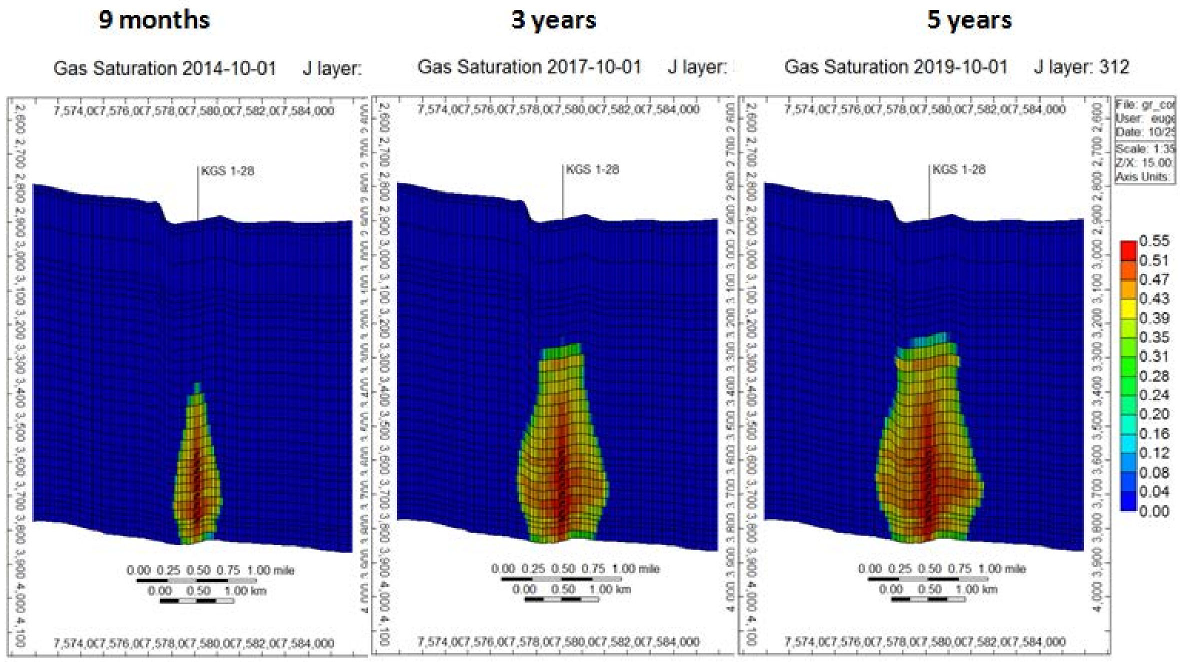


Figure 13a. Vertical distribution of CO2 saturation at 9 months, 3 years, and 5 years with commercial level injection rate of 14 MT over 15 years.

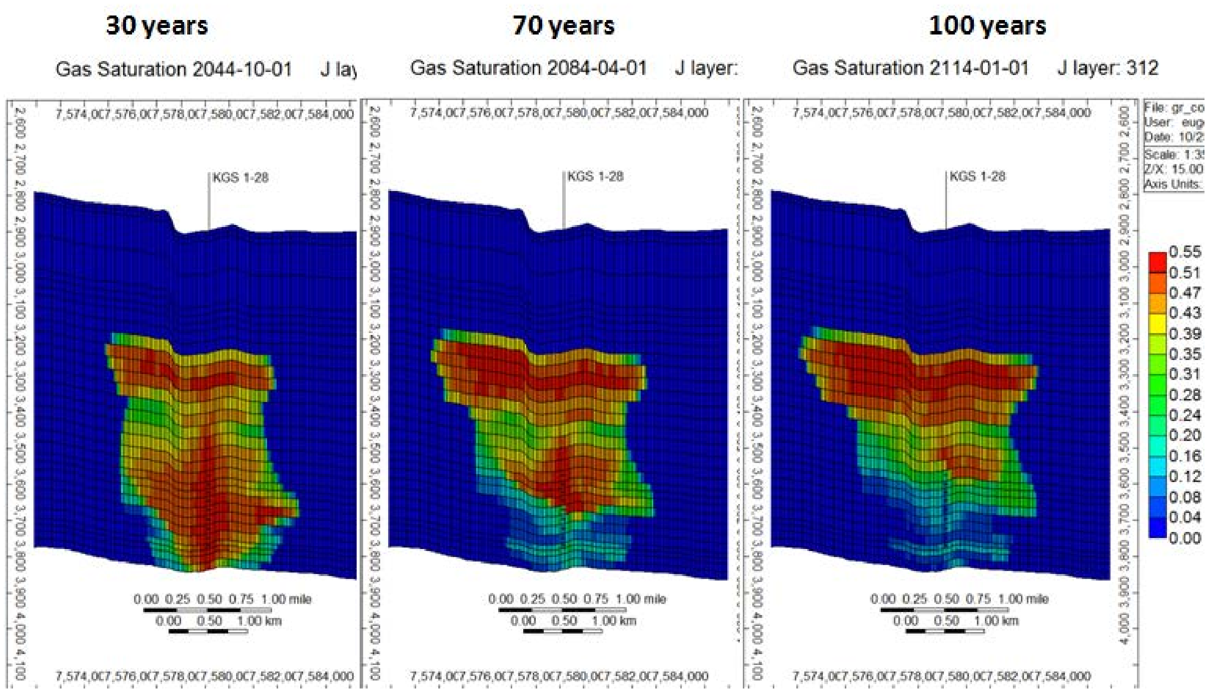


Figure 13b. Vertical distribution of CO2 saturation at 30, 70, and 100 years with commercial level injection rate of 14 MT over 15 years.

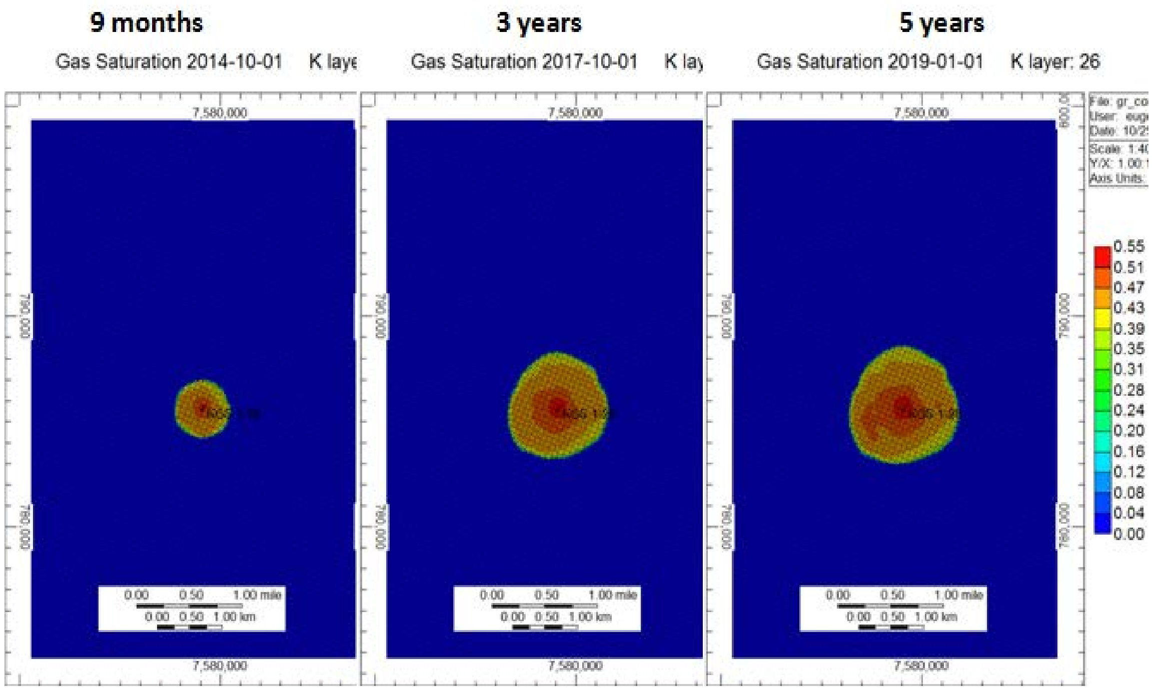


Figure 13c. Horizontal extent of the plume at 9 months, 3 years, and 5 years for the commercial level injection case.

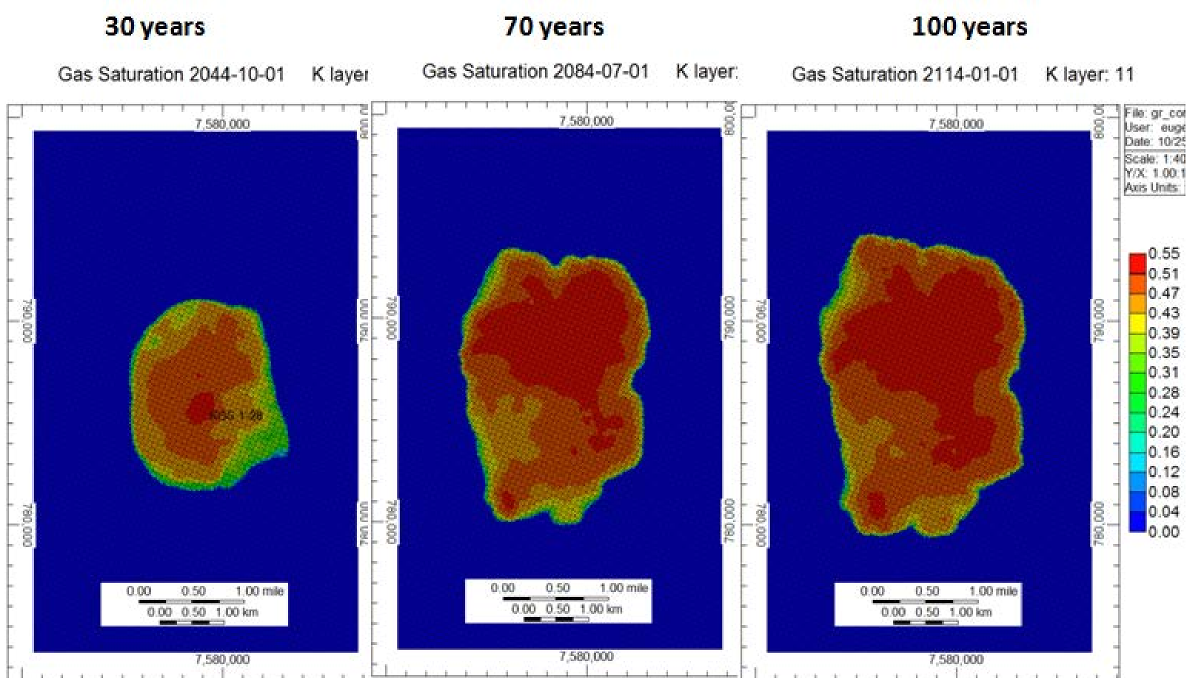


Figure 13d. Horizontal extent of the plume extent at 30, 70, and 100 years for the commercial level injection case.

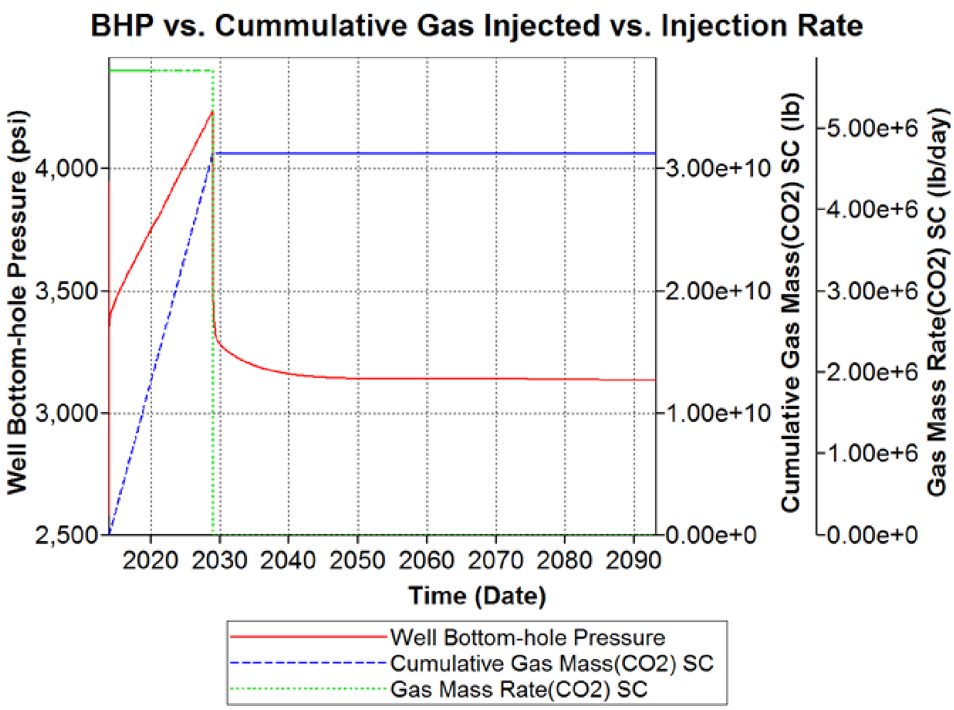


Figure 14. Bottomhole pressures for the commercial scale injection rate of 15 MT over 15 years.

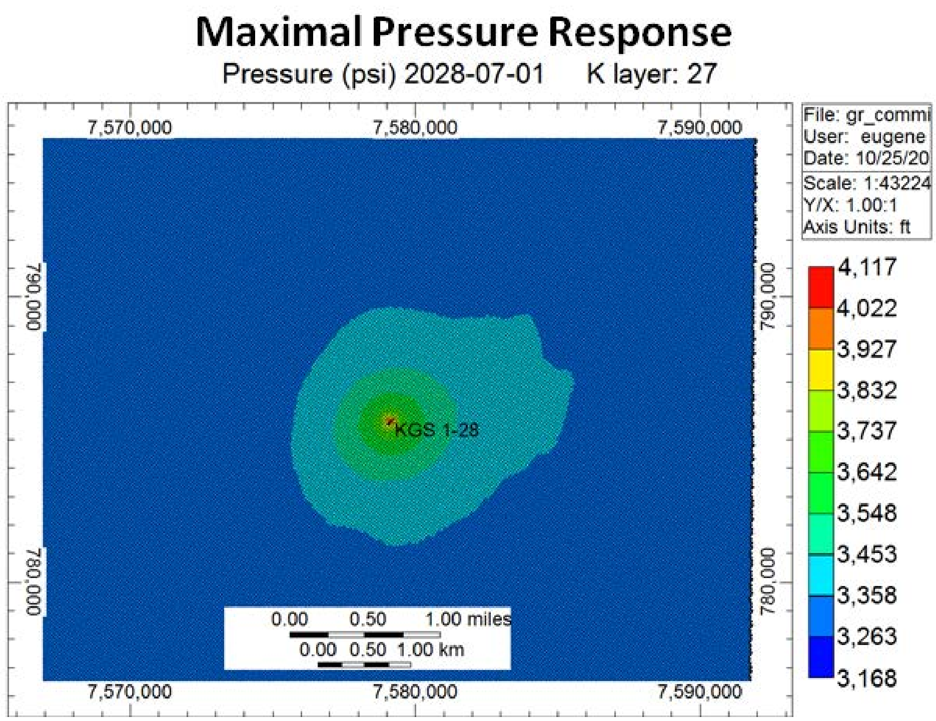


Figure 15. Maximal pressure response for commercial rate injection case

Geomechanical simulations were also conducted with the dynamic model in order to estimate the vertical displacement at the surface due to injection of CO2. The permeability distribution for this run is presented in Figure 15; which on based on the laboratory derived values of the geotechnical properties as shown in Figure 16. The vertical displacement at the end of the injection period is presented in Figure 17. Approximately 4 mm of vertical displacement is projected at the top of the Arbuckle.

The above simulations represent the initial set of runs derived from the Petrel geomodel. The following enhancements to the dynamic model are currently underway which will improve the predictive capabilities of the reservoir model and also strengthen the permit application:

- Develop dual porosity/permeability model
- Implement CO_2 Solubility
- Incorporate temperature effects and more detailed geomechanical modeling which consider scaling effects.

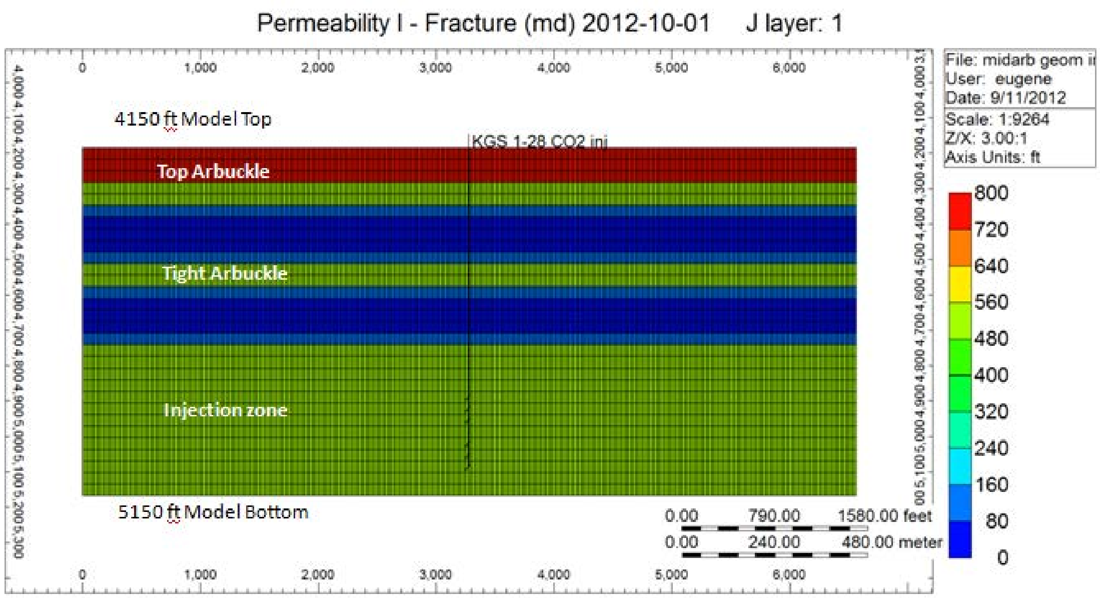


Figure 16. Hydraulic permeability distribution in geomechanical simulation model

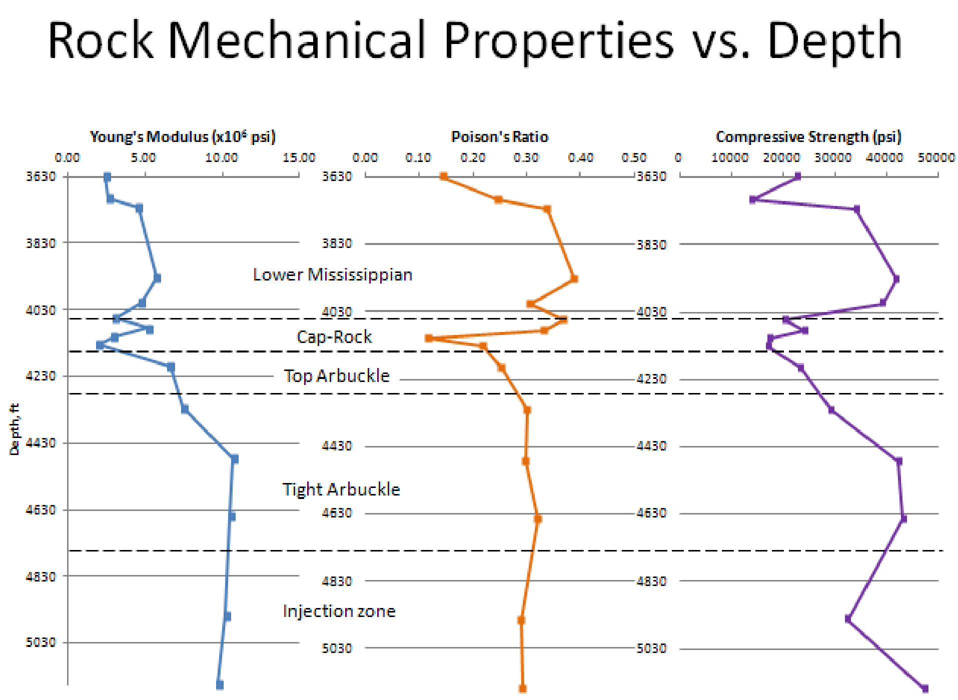


Figure 17. Laboratory derived geotechnical properties derived from core samples.

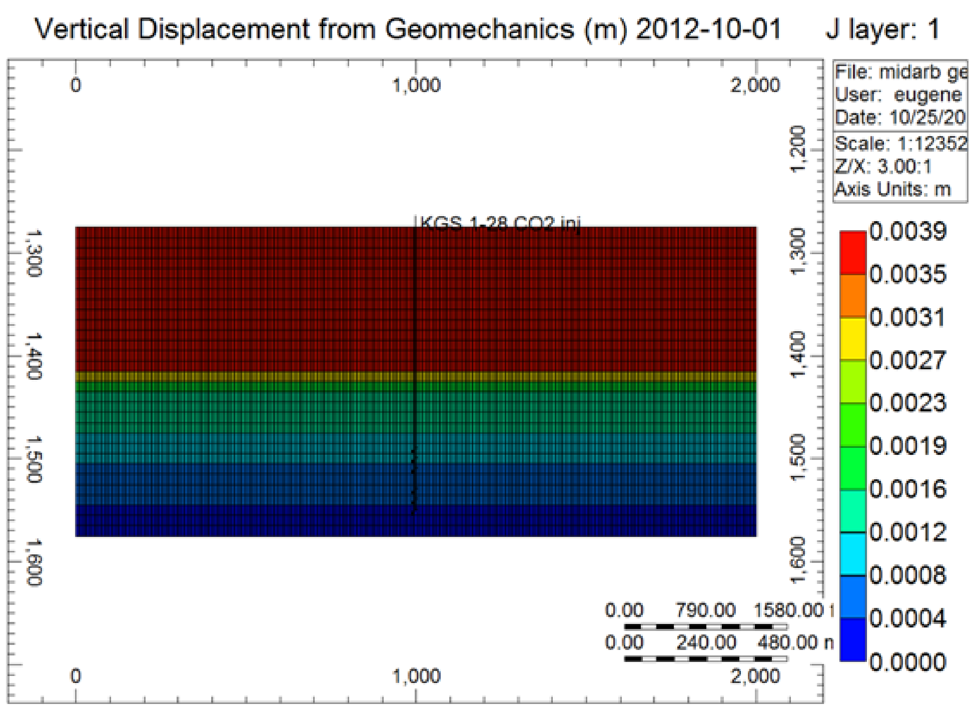


Figure 18. Simulated vertical displacement in the Arbuckle reservoir at the end of the (40 KT) injection period.

Key Findings

1. Significant progress made in compiling information and characterizing site for use in the application for Class VI CO2 injection permit in the Arbuckle.
2. Final revision of the geomodel and penultimate version of the simulation resulting in small CO2 plume footprint and low pressure.
3. Initial geomechanical modeling indicated small mm-scale deformation.

Plans

1. Top priority remains to finalize and submit application for Class VI injection permit to EPA with updated geomodel and simulation of the Arbuckle saline formation so that field activities can begin.

2. Submit updated management plan, well drilling and installation plan, MVA plan, Public Outreach Plan based on material included in Class VI application.

6. Submit Mississippian Injection Permit Application (Class II injection well under Kansas primacy, regulated by Kansas Corporation Commission) using updated geomodel and simulation of the Mississippian oil reservoir.

PRODUCTS

Publications, conference papers, and presentations

Scheffer, A.A., Gulliver, D., Roberts, J.A., Fowle, D., Watney, W.L., Doveton, J., Stotler, R., Whittemore, D., ms. in review, Geochemical, Microbiological, and Permeability Characteristics Indicating Vertical Zonation of the Arbuckle Saline Aquifer, a potential CO2 storage reservoir.

Barker, R., Watney, W., Rush, J., Strazisar, B., Scheffer, A., Bhattacharya, S., Wreath, D., and Datta, S*., in review, GEOCHEMICAL AND MINERALOGICAL CHARACTERIZATION OF THE ARBUCKLE AQUIFER: STUDYING MINERAL REACTIONS AND ITS IMPLICATIONS FOR CO2 SEQUESTRATION, , Chemical Geology.

PARTICIPANTS & OTHER COLLABORATING ORGANIZATIONS:

A project organization chart follows. The work authorized in this budget period includes office tasks related to preparation of reports and application for a Class VI permit to inject CO2 into the Arbuckle saline aquifer. Tasks associated with reservoir characterization and modeling are funded in contract DE-FE0002056.

ORGANIZATION CHART

Name	Project Job Title	Primary Responsibility
Kansas Geological Survey		
Lynn Watney	Project Leader, Joint Principal Investigator	Geology, information synthesis, point of contact
Yevhen Holubnyak	Petroleum Engineer	Reservoir engineer, dynamic modeling, synthesis
Jason Rush	Joint Principal Investigator	Geology, static modeling, data integration, synthesis
John Doveton	Co-Principal Investigator	Log petrophysics, geostatistics
Dave Newell	Co-Principal Investigator	Fluid geochemistry
Rick Miller	Geophysicist	2D seismic acquire & interpretation
		LiDAR/InSAR support, water well drilling/completion
TBN	Geology Technician	Assemble and analyze data, report writing
Tiraz Birdie	President, TBirdie Consulting, Inc.	Hydrogeologic modeling, permitting, MVA, integration
KU Department of Geology		
Michael Taylor	Co-Principal Investigator	Structural Geology, analysis of InSAR, LiDAR, seismometer array
TBN	Graduate Research Assistant	Structural Geology, analysis of InSAR and LiDAR, seismometer array
Kansas State Unversity		
Saugata Datta	Principal Investigator	
TBN	Graduate Research Assistant	Aqueous geochemistry
TBN	3- Undergraduate Research Assistants	
Lawrence Berkeley National Laboratory		
Tom Daley	Co-Principal Investigator	Geophysicist, analysis of crosshole and CASSM data
		Hydrogeology, analysis of soil gas measurements
Barry Freifeld	Co-Principal Investigator	Mechanical Engineer, analysis of U-Tube sampler
Sandia Technologies, Houston		
Dan Collins	Geologist	Manage CASSM and U-Tube operation
David Freeman	Field Engineer	Manage field install of CASSM and U-Tube
Berexco, LLC		
Dana Wreath	VP Berexco, LLC	Engineering, Manager of Wellington Field
Randy Koudele	Reservoir engineer	Engineering
Staff of Wellington Field		Field operations
Beredco Drilling team		Mississippian and Arbuckle drilling operations
Abengoa Bioenergy Corp.		
Christopher Standlee, Danny Alllison		CO2 supply Colwich Ethanol Facility

IMPACT

The project has been discussed in public venues – presentations at professional meetings, legislative committees, and town hall meeting, and has provided information on the project via the website to encourage a dialog on the merits and economies related to carbon management in Kansas. Kansans are realizing the potential for an important collaboration between the two of the largest economies in Kansas – agriculture and related ethanol industry and the petroleum industry to advance energy and contribute to a viable rural economy.

The small scale field test at Wellington Field as designed integrates two petroleum business activities: 1) use of CO_2 for enhanced oil recovery and revitalizing many older mature oil fields and 2) disposal/storage of CO_2 in the underlying saline aquifer for the longer term. It has been conveyed to the local petroleum industry that drilling and oil production infrastructure of an active oil field are important components that could lead to a successful carbon sequestration project including 1) knowledge about the subsurface including injection zones and caprock, 2) knowledge about abandoned wells, 3) access and suitability of land with greater likelihood for participation by landowner, and 4) access to insurance and investors to facilitate economic success.

CHANGES/PROBLEMS

Geomodels and simulations have led to revisions in the CO2 plume and determination of the AOR. The consensus of the team is that we have reached the goal of developing a predictive model to include in the Class VI injection application.

The CO2 source at Colwich Ethanol facility has proven to be susceptible to the exception drought that has gripped the Midcontinent. Although it the opinion of the partners, alternative sources of CO2 will be sought to ensure that BP2 starts on October 1, 2013.

BUDGETARY INFORMATION

Cost Status Report

See next page for the cost status for quarters 1-4.

/14

COST PLAN/STATUS

BP3 Starts 10/1/14 Ends 9/30/16

Baseline Reporting Quarter	Q10	Q11	Q12	Q13	Q14	Q15	Q16	Q17	Q18	Q19	Q20
	14 - 3/31/14	4/1/14 - 6/30/14	7/1/14 - 9/30/14	10/1/14 - 12/31/14	1/1/15 - 3/31/15	4/1/15 - 6/30/15	7/1/15 - 9/30/15	10/1/15 - 12/31/15	1/1/16 - 3/31/16	4/1/16 - 6/30/16	7/1/16 - 9/30/16
Baseline Cost Plan (from SF-424A)											
Federal Share	$447,079.75	$447,079.75	$447,079.75	$650,175.50	$650,175.50	$650,175.50	$650,175.50	$0.00	$0.00	$0.00	$0.00
Non-Federal Share	$258,982.75	$258,982.75	$258,982.75	$184,656.00	$184,656.00	$184,656.00	$184,656.00	$0.00	$0.00	$0.00	$0.00
Total Planned (Federal and Non-Federal)	$706,062.50	$706,062.50	$706,062.50	$834,831.50	$834,831.50	$834,831.50	$834,831.50	$0.00	$0.00	$0.00	$0.00
Cumulative Baseline Cost	$9,232,286.00	$9,938,348.50	$10,644,411.00	$11,479,242.50	$12,314,074.00	$13,148,905.50	$13,983,737.00	$13,983,737.00	$13,983,737.00	$13,983,737.00	$13,983,737.00
Actual Incurred Costs											
Federal Share	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Federal Share	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Incurred Costs-Quarterly (Federal and Non-Federal)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cumulative Incurred Costs	$118,598.76	$118,598.76	$118,598.76	$118,598.76	$118,598.76	$118,598.76	$118,598.76	$118,598.76	$118,598.76	$118,598.76	$118,598.76
Variance											
Federal Share	$447,079.75	$447,079.75	$447,079.75	$650,175.50	$650,175.50	$650,175.50	$650,175.50	$0.00	$0.00	$0.00	$0.00
Non-Federal Share	$258,982.75	$258,982.75	$258,982.75	$184,656.00	$184,656.00	$184,656.00	$184,656.00	$0.00	$0.00	$0.00	$0.00
Total Variance-Quarterly (Federal and Non-Federal)	$706,062.50	$706,062.50	$706,062.50	$834,831.50	$834,831.50	$834,831.50	$834,831.50	$0.00	$0.00	$0.00	$0.00
Cumulative Variance	**$9,107,211.39**	**$9,813,273.89**	**$10,519,336.39**	**$11,354,167.89**	**$12,188,999.89**	**$13,023,830.89**	**$13,858,662.39**	**$13,858,662.39**	**$13,858,662.39**	**$13,858,662.39**	**$13,858,662.39**

BP1 Starts: 10/1/11 Ends: 9/30/13

BP2 Starts 10/1/13 Ends 9/30

(from 424A, Sec. D)	Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9
	10/1/11-12/31/11	1/1/12-3/31/12	4/1/12-6/30/12	7/1/12-9/30/12	10/1/12- 12/31/12	1/1/13 - 3/31/13	4/1/13 - 6/30/13	7/1/13-9/30/13	10/1/13 - 12/31/13
Federal Share	$1,589,619.25	$1,589,619.25	$1,589,619.25	$1,589,619.25	$0.00	$0.00	$0.00	$0.00	$447,079.75
Non-Federal Share	$365,421.00	$365,421.00	$365,421.00	$365,421.00	$0.00	$0.00	$0.00	$0.00	$258,982.75
Total Planned	$1,955,040.25	$1,955,040.25	$1,955,040.25	$1,955,040.25	$0.00	$0.00	$0.00	$0.00	$706,062.50
Cumulative Baseline Cost	$1,955,040.25	$3,910,080.50	$5,865,120.75	$7,820,161.00	$7,820,161.00	$7,820,161.00	$7,820,161.00	$7,820,161.00	$8,526,223.50
Actual Federal Share	$326.84	$17,208.52	$17,282.92	$31,693.50	$0.00	$0.00	$0.00	$0.00	$0.00
Actual Non-Federal Share	$0.00	$6,475.85	$43,028.94	$9,058.04	$0.00	$0.00	$0.00	$0.00	$0.00
Total Incurred Costs-Quarterly	$326.84	$17,208.52	$60,311.86	$40,751.54	$0.00	$0.00	$0.00	$0.00	$0.00
Cumulative Incurred Costs	$326.84	$17,535.36	$77,847.22	$118,598.76	$118,598.76	$118,598.76	$118,598.76	$118,598.76	$118,598.76
Variance Federal Share	$1,589,292.41	$1,572,410.73	$1,572,336.33	$1,557,925.75	$0.00	$0.00	$0.00	$0.00	$447,079.75
Variance Non-Federal Share	$365,421.00	$358,945.15	$322,392.06	$356,362.96	$0.00	$0.00	$0.00	$0.00	$258,982.75
Total Variance-Quarterly	$1,954,713.41	$1,931,355.88	$1,894,728.39	$1,914,288.71	$0.00	$0.00	$0.00	$0.00	$706,062.50
Cumulative Variance	**$1,954,713.41**	**$3,886,069.29**	**$5,780,797.68**	**$7,695,086.39**	**$7,695,086.39**	**$7,695,086.39**	**$7,695,086.39**	**$7,695,086.39**	**$8,401,148.89**