DOE F 4600.2
(03/11)
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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

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Brett Blazer, Dana Wreath, Christa Jackson, Katie Graham, Brock Norwood

Date of Report: August 10, 2016
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 9/30/2016
Eighteenth Quarterly Report
Period Covered by the Report: May 1, 2016 through August 1, 2016
Signature of Submitting Official:

W. Lynn Watney

Digitally signed by W. Lynn Watney
DN: cn=W. Lynn Watney, o=The University of Kansas, ou=Kansas Geological Survey, email=lwatney@kgs.ku.edu, c=US
Date: 2016.08.10 07:35:52 -05'00'

EXECUTIVE SUMMARY

PROJECT OBJECTIVES

The objectives of this project are to understand the processes that occur when a maximum of 70,000 metric tonnes of CO_2 are injected into two different formations to evaluate the response in different lithofacies and depositional environments. The evaluation will be accomplished through the use of both *in situ* and indirect MVA (monitoring, verification, and accounting) technologies. The project will optimize for carbon storage accounting for 99% of the CO_2 using lab and field testing and comprehensive characterization and modeling techniques.

CO_2 will be injected under supercritical conditions to demonstrate state-of-the-art MVA tools and techniques to monitor and visualize the injected CO_2 plume and to refine geomodels developed using nearly continuous core, exhaustive wireline logs, and well tests and a multi-component 3D seismic survey. Reservoir simulation studies will map the injected CO_2 plume and estimate tonnage of CO_2 stored in solution, as residual gas, and by mineralization and integrate MVA results and reservoir models shall be used to evaluate CO_2 leakage. A rapid-response mitigation plan will be developed to minimize CO_2 leakage and provide comprehensive risk management strategy. A documentation of best practice methodologies for MVA and application for closure of the carbon storage test will complete the project. The CO_2 shall be supplied from a reliable facility and have an adequate delivery and quality of CO_2.

SCOPE OF WORK

Budget Period 1 includes updating reservoirs models at Wellington Field and filing Class II and Class VI injection permit application. Static 3D geocellular models of the Mississippian and Arbuckle shall integrate petrophysical information from core, wireline logs, and well tests with spatial and attribute information from their respective 3D seismic volumes. Dynamic models (composition simulations) of these reservoirs shall incorporate this information with laboratory data obtained from rock and fluid analyses to predict the properties of the CO_2 plume through time. The results will be used as the basis to establish the MVA and as a basis to compare with actual CO_2 injection. The small scale field test shall evaluate the accuracy of the models as a means to refine them in order to improve the predictions of the behavior and fate of CO_2 and optimizing carbon storage.

Budget Period 2 includes completing a Class II underground injection control permit; drilling and equipping a new borehole into the Mississippian reservoir for use in the first phase of CO_2 injection; establishing MVA infrastructure and acquiring baseline data; establishing source of CO_2 and transportation to the injection site; building injection facilities in the oil field; and injecting CO_2 into the Mississippian-age spiculitic cherty dolomitic open marine carbonate reservoir as part of the small scale carbon storage project.

In Budget Period 3, contingent on securing a Class VI injection permit, the drilling and completion of an observation well will be done to monitor injection of CO_2 under supercritical conditions into the Lower Ordovician Arbuckle shallow (peritidal) marine dolomitic reservoir.

Monitoring during pre-injection, during injection, and post injection will be accomplished with MVA tools and techniques to visualize CO_2 plume movement and will be used to reconcile simulation results. Necessary documentation will be submitted for closure of the small scale carbon storage project.

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.

<u>Project Deliverables by Task</u>

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

CO2-EOR

1. Completed injection of 1,101 truckloads, 21,784 US tons, 19,803 metric tons, approximately 374,000 MCF of CO2 on June 21, 2016. Total expenditures for purchasing CO2 were $1,964,000. Our overall price for CO2 was $90.16 per US ton from Linde Group.
2. Injected completed in 165 days or approximately 5 months with an average of 120 tonnes per day of CO2 injected.

3. Linde Group was able to provide nearly continuous CO_2 supply to the site outside of a five day of interruption in April 2016.
4. Successful monitoring of CO_2 injection, prior to and during injection, and post-injection -
   a. Recorded volumes of CO_2 injected and CO_2, oil, and brine recovered,
   b. Sampled fluids via on-site and lab-based geochemistry from 17 wells,
   c. Reduced well based monitoring to seven wells after CO_2 ended and continuous water injection began,
   d. Operated Wellington seismometer array installing two accelerometers outside of field to improve location and magnitude of events,
   e. Since mid-April 2016 have recorded continuous (1-sec) baseline pressure measurements of the perforated lower Arbuckle zone in shut-in Class VI injection.
   f. Confirmed that SAR satellite images obtained to date have useful images for InSAR and moving to new ERS satellite with new radar with improved coherency of response in humid temperate climate. Also, frequency of scenes has been reduced from every 20 days to 8 days.
5. The primary CO_2 plume has been managed by pressure maintenance including use of two nearby injection wells and varying fluid withdrawal in eight surrounding wells. Also, fluid flow barriers and baffles with lower permeability lie south and east and downdip of the injection well, which have apparently limited CO_2 migration beyond those areas. The CO_2 injection thus far has verified the geomodel based on the well and seismic interpretations.
6. The simulation used to forecast the design of pressure maintenance and injection of CO_2 and to forecast the oil response has demonstrated its usefulness. Simulation forecasts are again being confirmed during the initial stages of waterflooding where oil production has reached a new well, #45, to the north of the injection well and one well location out from the inner ring of producing wells.
7. The CO_2 plume remains within the nearby producing wells that surround the injection well indicating conformance of this flood, demonstrating the matrix controlled permeability vs. fractures.
8. Since the CO_2 injection stopped in June 21st and continuous water injection began and this phase of injection is viewed upon as a success due to
   a) high level of sweep efficiency,
   b) lack of notable CO_2 fingering beyond the plume,
   c) evidence for a bank of oil recognized by well production with notable increase incremental oil, but lack of significant CO_2 production
9. Cumulative ratio of produced/purchased CO_2 is only 11% (as of July 25). No notable changes occurred until CO_2 injection ceased and water injection was increased from 50 to 750 barrels on July 14^{th} when the daily CO_2 produced has begun falling from ~450 MCFD to half that rate on July 25th.

10. A rate of 50 BWDP following CO2 injection was maintained to keep the plume stable until a 2D seismic profile could be acquired passing through the injection well. Producing wells were shut-in during the actual seismic survey.
11. Acquisition of the 2D seismic was designed to have sufficient offset to allow optimized AVO (Amplitude vs. Offset) to evaluate this approach for detection of the CO2 plume during the Arbuckle injection.
12. The new 2D seismic survey was acquired and will be processed in the same manner as the original 3D seismic survey. Moreover, 3D survey will be reprocessed to bring it to date with current methods offered by Fairfield-Nodal.

Class VI – USEPA Geosequestration Permit

The KGS/Berexco team has successfully addressed all of the remaining requests for information from EPA pertaining to our Class VI permit including discussions and resolution of the financial assurance required by EPA for plugging and site restoration of the injection well, addressed through insurance, and anticipated mitigation of leakage of CO2 through the use of a bond by Berexco, LLC, the signatory of the permit.

An important question from EPA pertained to the conversion the Petrel geomodel so that it could be imported into and run in EPA's STOMP simulator. This conversion has been demonstrated and results have been shown to be consistent with the original model by our own demonstration. We anticipate using our monitoring information to keep models evergreen including STOMP, so that we can successfully achieve closure of the CO2 injection by certifying the location and stabilization of the CO2 plume.

The KGS/Berexco team is pleased with the results of the 20,000 ton CO2 injection into the overlying Mississippian oil reservoir with CO2 injection completed on June 21st. The team has carried out the injection safely, effectively, and economically, and the information is being analyzed to understand the amount of CO2 that will eventually be stored. Thus far, the CO2 plume behavior and oil recovery are consistent with model forecasts and indicate an economic success for CO2-EOR, if carried out on a full-field basis. These results are vitally important to support the first basis of the Kansas model of combining an oil field with a saline aquifer. Together they will to serve as the basis to provide the 50 million ton capacity threshold set by DOE. We hope to carry out the test injection in in the Arbuckle and further demonstrate how another carbonate reservoir responds to CO2 and how it can be successfully monitored and managed to meet both the EPA and DOE criteria for CCS.

The monitoring accomplished during the Mississippian injection has proven effective and new monitoring reserved for the Arbuckle injection have been revisited in the past few months from both a budget perspective and from current best practices so that the monitoring is best suited for success, effective detection, and tracking of the CO_2. You will note in the discussion of the Class VI permit application that the team has responded to every inquiry from EPA including ensuring that we will have a safe and effective injection in the Arbuckle, a vitally important outcome for CCS.

Benefits of the Wellington Project and the Class VI permit to DOE-NETL

1. **Vast storage capacity of the Arbuckle carbonate saline aquifer established in DE-FE0002056 has not been verified** -- Many sites in Kansas resemble Wellington Field, with stacked reservoirs including the large underlying Arbuckle saline aquifer proven by decades of commercial brine disposal. Commercialization requires metrics obtained from such an injection test, with demonstration of the usefulness of our simulations to establish how geosequestration can be accomplished utilizing the viable petroleum industry infrastructure. The path has been long and arduous, but we believe a successful test will pay for itself many times over with the remaining incremental investment of time and financial resources needed to finish the injection. The KGS/Berexco team is ready; now with CO_2 injection experience, a CO_2 supply, and soon to receive a draft Class VI permit.
2. **The pilot injection will address the latest safety and environmental considerations based on implementation in a highly controlled and monitored environment**. Land surrounding the Wellington site is almost exclusively used as farmland, and EPA has confirmed absence of a USDW within the Area of Review. This significant determination is unprecedented in UIC permit history by EPA Region 7.
3. **A *rapid-response mitigation plan* has been developed to minimize CO_2 leakage or seismicity and provide a comprehensive risk management strategy.** Ongoing development of best practice methodologies for MVA and the anticipated application for closure of the carbon storage test could easily be included in the NRAP portfolio to address risk in injection into carbonate reservoirs, particularly those with concerns about the potential for induced seismicity.
4. **Wellington Field is a viable field laboratory, providing expansion into numerous research opportunities**
   i. Wellington Project has reached its first major goal of proving the viability of the oil field above a large saline aquifer for safe and effective CCUS.
   ii. Excellent site and infrastructure to test new MVA technologies in the Arbuckle.
   iii. Build on ongoing discussions with collaborators to update the MVA infrastructure for the Class VI CO_2 injection.
   iv. Expand the MVA suited for optimally addressing any risk and uncertainty for implementation of CCS, while continuing to engage in a constructive dialog with EPA. We believe the experience in working with EPA through the implementation of the Class VI process is rare, yet essential to conveying to DOE and other stakeholders in expediting future permitting requests.
5. **Advanced Monitoring Technologies will be tested and evaluated for best practice using volume of CO_2 suited to detect and characterize the CO_2 plume.**
   i. Geophysics teams at Berkeley, with possible contributions for an EPRI based project, will deploy highly advanced downhole monitoring equipment in the Arbuckle to evaluate performance of CASSM, crosswell or VSP (pending

simulations of each), acoustic fiber-VSP with fiber installed between casing and borehole wall in cement. The newly proven installation will greatly refine seismic resolution under both active and passive seismic acquisition at a site that is uniquely well suited for both.

ii. An 18-seismometer array operating since April 2014 has resulted in a refined earthquake catalog containing ever improving information on earthquake magnitudes and depths, now extending into focal mechanisms and obtaining advanced properties about the basement rocks in the vicinity of Wellington Field.

iii. Downhole passive seismic monitoring will augment the surface seismometer array to provide resolution of seismicity down to -2 to -3 magnitudes suitable to locate nuances of CO2 plume movement, particularly along faults or factures, and well below the 2.5 M seismicity threshold that requires notification of EPA.

iv. U-Tube fluid sampling and continuous pressure and temperature monitoring will further enhance the MVA technology that is utilized by what has become a very experienced, highly functioning, interdisciplinary team. The group expects to provide optimal conditions to run the experiment to demonstrate some of the most advanced technologies for monitoring CO2.

v. Continuous (1-second) pressure monitoring temporarily installed in our Class VI Arbuckle injection well in April 2016 is being processed in house to resolve pressure anomalies down to 0.01 psi. This uncommon dataset provides a valuable comparison for possible co-seismic or induced pressure changes from high volume brine disposal wells. Pressure monitoring software will be added to our web-based virtual monitoring "dashboard" to convey information as it is being received.

The following table lists MVA activities by injection schedule as included in the EPA permit application.

Table 1. Listing of monitoring activities to be conducted at the Wellington.

Table 10.1—Listing of monitoring activities to be conducted at the Wellington, Kansas, CO_2 storage site.

Monitoring Activity	Pre-Injection	Injection	Post-Injection
CO_2 Fluid Chemical Analysis	x	x	-
CO_2 Injection Rate and Volume[1]	-	x	-
CO_2 Injection Pressure at Wellhead[1]	-	x	-
CO_2 Injection Pressure at Well Bottom[1]	x	x	x
Internal MIT (Anulus Pressure Test)	x	-	-
External MIT (Temperature Log)	x	x	x
Continuous Annular Pressure	-	x	-
Corrosion	-	x	x
Pressure Fall Off Test	x	-	-
Pressure in Arbuckle Monitoring Well (Direct Arbuckle Monitoring)	x	x	x
INSAR (Indirect Arbuckle Pressure Monitoring)	x	x	x
USDW Geochemistry	x	x	x
Mississippian Geochemistry	x	x	x
U-Tube (Direct Arbuckle Geochemistry Monitoring)	x	x	x
CASSM (Indirect Arbuckle Plume-Front Monitoring)	x	x	x[2]
Crosswell Seismic (Indirect Arbuckle Plume-Front Monitoring)	x	x	-
3D Seismic Survey (Indirect Arbuckle Plume-Front Monitoring)	x	-	x

[1] Monitored continuously

[2] If CO_2 plume is detected at KGS 2-28 during the injection phase, then CASSM will not be conducted during the post-injection phase.

6. **Monitoring both Mississippian and Arbuckle injections with seismometers, 2D seismic, InSAR will provide critical results that will translate to understanding stress-strain and interest in increased seismicity occurring in the OK-KS region.** Keen awareness crosses state, federal, academic, and industry borders. A proactive response by KGS team is being taken to use seismometer deployments (including Wellington) to understand mechanisms of seismic events.
7. **Interest expressed by Kansas Governor in CCUS development in Kansas --** The interest in EOR and CCUS expressed by industry (notably during October's regional AAPG meeting in Wichita) has been shared with and gained the interest of the Governor of Kansas. Plans underway for a future meeting that would showcase this DOE project.
8. **Linde Group, a leader in CO2 capture and supply, an excellent partner for this project --** Linde Group has expressed a strong interest to participate in the commercialization opportunities in the CCUS field, and are prepared to make the necessary investments to achieve this goal.

Considerations for moving forward to BP3 budget

1. **Our cost of CO2 from the Linde Group at $90.16 per US ton**, so our budget number for ~26,000 tons of CO2 in the Arbuckle is $2,550,000. Reducing the CO2 to 20,000 tons (~23%) would lower the cost to $1,803,200 and result in a savings of $746,800. If these savings support for the first two years in BP3, the funding request from DOE declines from $2.13 million to $1.38 million. Provided we have only a one-year duration of the PISC and closure, a request under $1.5 million should provide a palatable number for DOE to carry out one of the nation's first, and notoriously costly Class VI projects.
2. **A carefully constructed budget to extend the Wellington project into BP3 and beyond September 30, 2016** includes an anticipated 1-year injection (BP3yr1) and 1-year post injection site care (PISC) (BP3y2). Please refer to Table 2.
3. **After careful consideration, reducing the amount of CO2 from 26,000 tons to 20,000 tons is not advised by engineers or geophysicists on the team.** Very refined simulations have been set at 26,000 tons that will be incorporated in the Class VI permit. CO2 saturations cover sufficient area for detection by surface seismic, but forecasted CO2 saturations within the plume in this dolomite aquifer are highly variable both in areal and vertical extent. While we are confident that we can resolve the plume, we wish to maintain injection rate at 26,000 tons as models show that the reduced volume of CO2 will not change the areal distribution of CO2, but lower the saturation which may decrease the seismic resolution of locations with lower CO2 saturation. The 26,000 ton simulation is also incorporated in the Class VI permit and is running in EPA's STOMP simulation software. Changes to the volume will delay the time of actual injection. In any case, we believe the injection can be securely closed through indications that plume will stabilize according to the simulations.
4. **Berexco has carried out the Class II CO2 injection cost-effectively with a field operating cost of ~$45,000 per month**. They have delivered superior engineering and logistical support to carry out project objectives and the KGS and DOE-NETL team.
5. **The KGS/Berexco team has clearly demonstrated its capability and determination** to satisfy the obligations of the DOE-NETL contract.
6. **KGS/Berexco is positioned to continue the post-injection operation of the Mississippian** cost-effectively and realize further gains in understanding CO2 sequestration and oil recovery from this reservoir.

7. **Highly skilled and talented group scientists and engineers including students have participated in many successes** including the Class VI permit application addressing utmost details about this geologic system**,** and persevered through the uncertainty brought on by delays in CO_2 supply, budget constraints, and accepting and realizing the burden of the new Class VI permit. We hope to attain a successful test with necessary support for full staffing of all phases of this work to reach the expectations of DOE, EPA, and our stakeholders, as was promised in 2011.

PROJECT SCHEDULE

Schedule for the CO2-EOR

The CO2 injection in the Mississippian was completed on June 21, 2016. A total of 1,101 truckloads, 21,784 US tons, 19,803 metric tons, approximately 374,000 MCF of CO2 were injected into Berexco Wellington KGS #2-32. Total expenditures for purchasing CO2 were $1,964,000. Our overall price for CO2 was $90.16 per US ton from Linde Group. The Injection was completed in 165 days or approximately 5 months with an average of 120 tonnes per day of CO2 injected. Linde Group was able to provide nearly continuous CO2 supply to the site outside of a five day of interruption in April 2016.

Schedule and costs for Arbuckle CO2 injection --

Wellington project currently is scheduled to end on September 30, 2016. The information for the Determinations and Findings (D&F) was submitted on August 7, 2016 requesting an extension of 1 year for fabrication and Arbuckle CO2 injection beginning as BP3 year 1 on January 1, 2017 followed by BP3 year 2 starting January 1, 2018 for post injection site care (PISC) to comply with anticipated determination from EPA as a requirement before the Class VI permitted well can be closed **(Figure 1**). Based on a go no-go decision, Berexco requests that an additional two years of monitoring be included if EPA requests additional monitoring.

The completion date anticipated for the Arbuckle CO2 injection is anticipated to be the end of July 2017. The one year post injection site care as proposed to EPA would begin in August 2017 and continue through August 2018 (**Figure 1**).

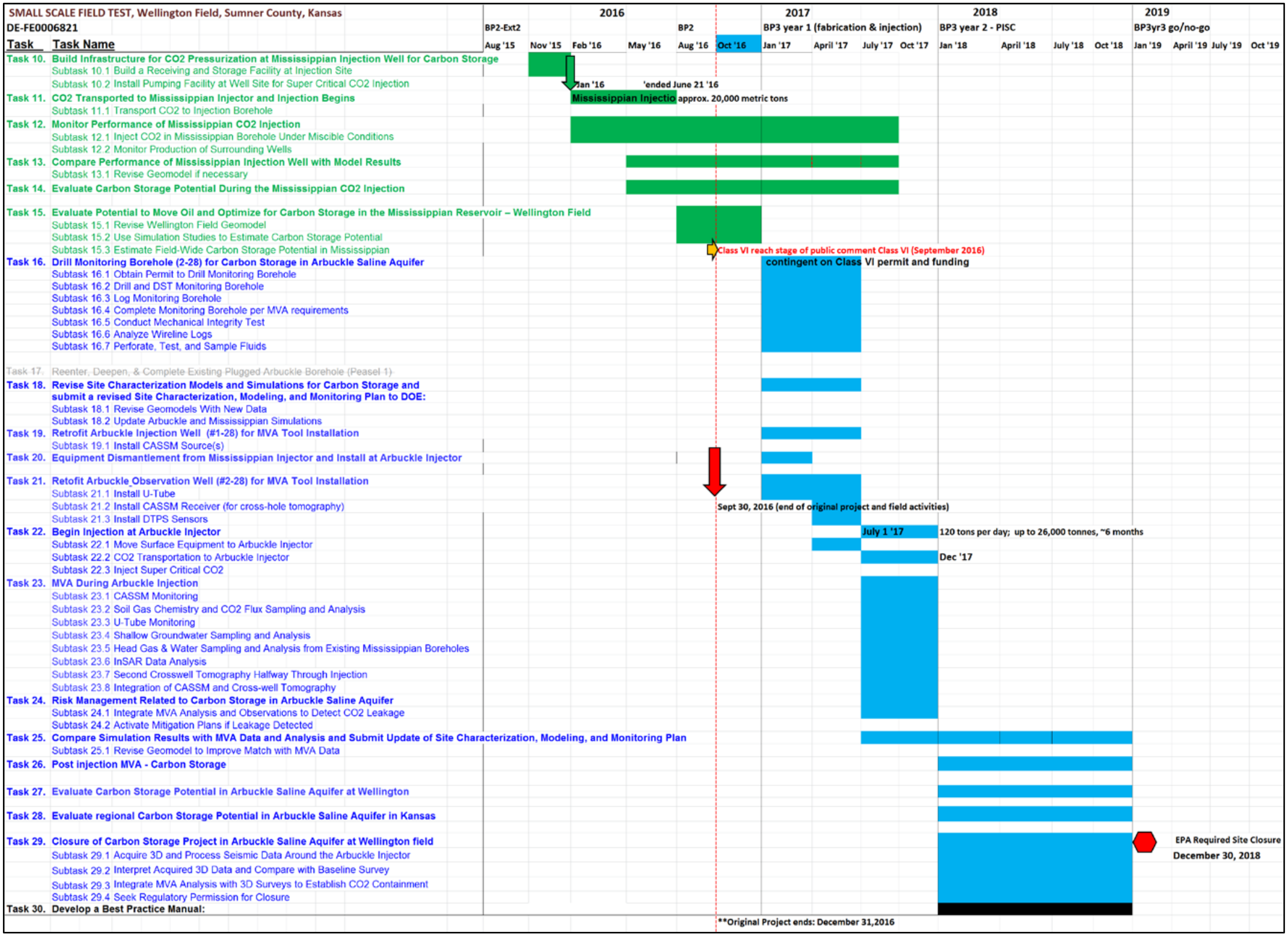
SMALL SCALE FIELD TEST, Wellington Field, Sumner County, Kansas
DE-FE0006821
2016
2017
2018
2019
BP2-Ext2
BP2
BP3 year 1 (fabrication & injection)
BP3 year 2 - PISC
BP3yr3 go/no-go
Aug '15
Nov '15
Feb '16
May '16
Aug '16
Oct '16
Jan '17
April '17
July '17
Oct '17
Jan '18
April '18
July '18
Oct '18
Jan '19
April '19
July '19
Oct '19
Task
Task Name
Task 10. Build Infrastructure for CO2 Pressurization at Mississippian Injection Well for Carbon Storage
Subtask 10.1 Build a Receiving and Storage Facility at Injection Site
Subtask 10.2 Install Pumping Facility at Well Site for Super Critical CO2 Injection
Task 11. CO2 Transported to Mississippian Injector and Injection Begins
Subtask 11.1 Transport CO2 to Injection Borehole
Task 12. Monitor Performance of Mississippian CO2 Injection
Subtask 12.1 Inject CO2 in Mississippian Borehole Under Miscible Conditions
Subtask 12.2 Monitor Production of Surrounding Wells
Task 13. Compare Performance of Mississippian Injection Well with Model Results
Subtask 13.1 Revise Geomodel if necessary
Task 14. Evaluate Carbon Storage Potential During the Mississippian CO2 Injection
Task 15. Evaluate Potential to Move Oil and Optimize for Carbon Storage in the Mississippian Reservoir – Wellington Field
Subtask 15.1 Revise Wellington Field Geomodel
Subtask 15.2 Use Simulation Studies to Estimate Carbon Storage Potential
Subtask 15.3 Estimate Field-Wide Carbon Storage Potential in Mississippian
Task 16. Drill Monitoring Borehole (2-28) for Carbon Storage in Arbuckle Saline Aquifer
Subtask 16.1 Obtain Permit to Drill Monitoring Borehole
Subtask 16.2 Drill and DST Monitoring Borehole
Subtask 16.3 Log Monitoring Borehole
Subtask 16.4 Complete Monitoring Borehole per MVA requirements
Subtask 16.5 Conduct Mechanical Integrity Test
Subtask 16.6 Analyze Wireline Logs
Subtask 16.7 Perforate, Test, and Sample Fluids
Task 17. ~~Reenter, Deepen, & Complete Existing Plugged Arbuckle Borehole (Peasel 1)~~
Task 18. Revise Site Characterization Models and Simulations for Carbon Storage and submit a revised Site Characterization, Modeling, and Monitoring Plan to DOE:
Subtask 18.1 Revise Geomodels With New Data
Subtask 18.2 Update Arbuckle and Mississippian Simulations
Task 19. Retrofit Arbuckle Injection Well (#1-28) for MVA Tool Installation
Subtask 19.1 Install CASSM Source(s)
Task 20. Equipment Dismantlement from Mississippian Injector and Install at Arbuckle Injector
Task 21. Retofit Arbuckle Observation Well (#2-28) for MVA Tool Installation
Subtask 21.1 Install U-Tube
Subtask 21.2 Install CASSM Receiver (for cross-hole tomography)
Subtask 21.3 Install DTPS Sensors
Task 22. Begin Injection at Arbuckle Injector
Subtask 22.1 Move Surface Equipment to Arbuckle Injector
Subtask 22.2 CO2 Transportation to Arbuckle Injector
Subtask 22.3 Inject Super Critical CO2
Task 23. MVA During Arbuckle Injection
Subtask 23.1 CASSM Monitoring
Subtask 23.2 Soil Gas Chemistry and CO2 Flux Sampling and Analysis
Subtask 23.3 U-Tube Monitoring
Subtask 23.4 Shallow Groundwater Sampling and Analysis
Subtask 23.5 Head Gas & Water Sampling and Analysis from Existing Mississippian Boreholes
Subtask 23.6 InSAR Data Analysis
Subtask 23.7 Second Crosswell Tomography Halfway Through Injection
Subtask 23.8 Integration of CASSM and Cross-well Tomography
Task 24. Risk Management Related to Carbon Storage in Arbuckle Saline Aquifer
Subtask 24.1 Integrate MVA Analysis and Observations to Detect CO2 Leakage
Subtask 24.2 Activate Mitigation Plans if Leakage Detected
Task 25. Compare Simulation Results with MVA Data and Analysis and Submit Update of Site Characterization, Modeling, and Monitoring Plan
Subtask 25.1 Revise Geomodel to Improve Match with MVA Data
Task 26. Post injection MVA - Carbon Storage
Task 27. Evaluate Carbon Storage Potential in Arbuckle Saline Aquifer at Wellington
Task 28. Evaluate regional Carbon Storage Potential in Arbuckle Saline Aquifer in Kansas
Task 29. Closure of Carbon Storage Project in Arbuckle Saline Aquifer at Wellington field
Subtask 29.1 Acquire 3D and Process Seismic Data Around the Arbuckle Injector
Subtask 29.2 Interpret Acquired 3D Data and Compare with Baseline Survey
Subtask 29.3 Integrate MVA Analysis with 3D Surveys to Establish CO2 Containment
Subtask 29.4 Seek Regulatory Permission for Closure
Task 30. Develop a Best Practice Manual:
Jan '16
'ended June 21 '16
Mississippian Injectio
approx. 20,000 metric tons
Class VI reach stage of public comment Class VI (September 2016)
contingent on Class VI permit and funding
Sept 30, 2016 (end of original project and field activities)
July 1 '17
120 tons per day; up to 26,000 tonnes, ~6 months
Dec '17
EPA Required Site Closure
December 30, 2018
**Original Project ends: December 31,2016

Figure 1. Updated Gantt Chart of Wellington Project with revised schedule for proposed BP3 Arbuckle injection.

ONGOING ACTIVITIES

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

Task 2. Site Characterization of Arbuckle Saline Aquifer System – Wellington Field

Summary and Status of the Class VI Permit Application

1. **Class VI Geosequestration permit (See timeline, Figure 2) -- Summary**
   i. Project was initiated as a Class V permit on Oct. 1, 2011. Class VI permit regulations became effective in September 2011. Region 7 EPA confirmed that October that the project would require a Class VI permit.
   ii. Initial draft of permit reviewed internally in January 2013.
   iii. Continued characterization in 2013 with updates to Petrel and CMG models in February 2014 with "final" 1468 page permit application submitted.
   iv. Application reformatted and submitted via EPA's newly released Geosequestration (GS) Data Upload Tool in April 2014.
   v. EPA requested eleven formal RFIs (requests for information) and seven RFI tables of questions, but NO notices of deficiencies. Of the nine attachments to the permit, seven are confirmed with EPA to be in the final drafts stage. **ALL RFIs have been responded to and formally submitted to EPA as of August 5, 2016.**
   vi. EPA has had not made an adverse determination on USDW and Induced Seismicity to-date which is reflected in RFIs and subsequent discussions.
   vii. Confirmed with DOE HQ on July 11, 2016 that financial responsibility (FR) is main issue remaining and that EPA is close to determination on issuing a draft permit. FR was addressed between discussions with EPA, DOE, and Berexco and is incorporated in the revised BP3 budget ($40,000/yr estimated for insurance and bond).
   viii. KGS' participation in *Kansas' Induced Seismicity (IS) Task Force* (including Bidgoli, Holubnyak, Newell, and Watney on this team, all led by Rex Buchanan,

interim KGS Director) relied heavily on characterizations and simulations from DE-FE0002056. Previous work from Wellington Field and the surrounding region experiencing seismicity became increasingly important in the permitting process to minimize EPA concerns about induced seismicity. Additional efforts included:

1. Addressing RFI related to nearby induced seismicity from very large brine disposal in south-central Kansas and north-central Oklahoma,
2. Wellington faulting and seismicity addressed by KGS/Berexco's proactive approach and careful response plan based on latest structural characterizations and simulation, including discrete fracture network modeling, geomechanical analysis, establishing reliability of Wellington's 18-seismometer array with weekly updates of event catalog and online viewing features, refining hypocenters and providing earthquake focal mechanisms, and (soon to be shared) use of continuous downhole pressure monitoring in our existing Class VI well to validate the forecast of a regional pressure field based on regional simulation. The Wellington project is an integral part of the solution to an important CCS issue.

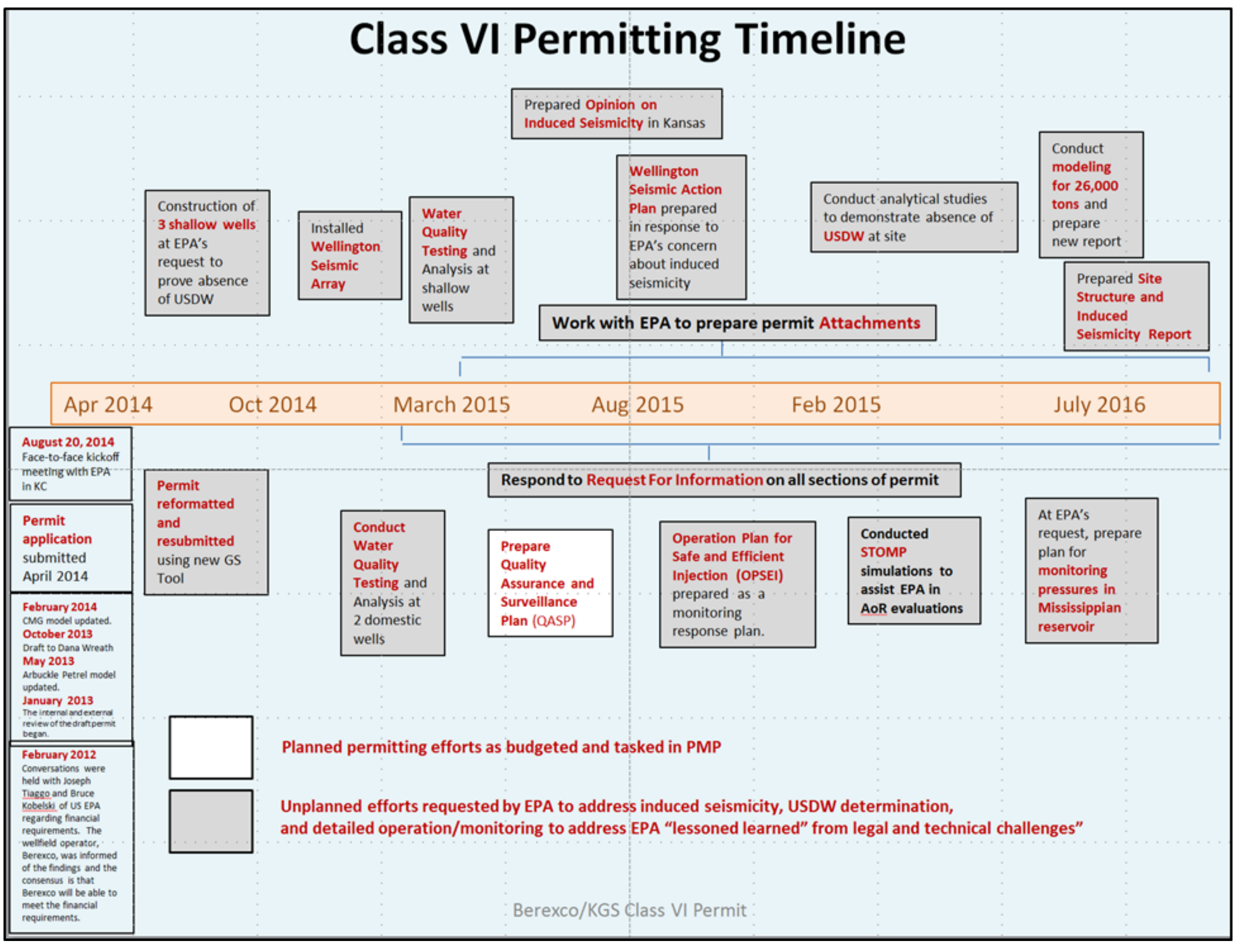

Figure 2. Class VI permitting timeline.

Continuous pressure monitoring in the lower Arbuckle prior to CO2 injection – prepared by Tandis Bidgoli and Lynn Watney

The KGS installed a pressure transducer on April 25, 2016 with the objective to evaluate:

1) if a pressure increase forecasted by modeling occurred since last measurements were made in 2011,
2) if continuous pressure measurements would be able to record longer term pressure change that might be tied to local seismicity,
3) if short-term pressure changes occur as co-seismic events linked to nearby earthquakes by comparing high resolution pressure records with the signals events recorded by the Wellington seismometer array,
4) if pressure transients can be detected from brine injection wells in the area.

KGS continues to underwrite the acquisition and processing costs for this important activity to record both the long term increase in pressure in the lower Arbuckle in Wellington KGS #1-28 in perforations from 5000 to 5020 ft measured depth (**Figure 3**).

This "sounding" in the base of the Arbuckle aquifer is providing a ground truth for our simulations and perhaps has the potential for use in making downhole pressure measurements in areas of seismic concern involving brine disposal to enable comparison of spatial and temporal changes in pressure in relationship with earthquakes (**Figure 4**). Importantly, the pressure information in the context of the existing geophysical and geologic data may help us understand the cause of the earthquakes, help us to assess risk of earthquakes, and, in general, factor in on recommendations for monitoring of injection wells to reduce the risk of felt earthquakes.

Use of existing web-based apps developed in this KGS funded portion of the study is providing a means to analyze and develop a baseline for the Class VI injection allow us to view and filter the pressure data for short or long--term monitoring. This continuous pressure monitoring and rapid interpretation and response is a vital part to realizing a safe and effective CO2 injection at Wellington. Any rapid pressure changes during injection and pauses in injection need to be quickly integrated with the other monitoring data.

The opportunity to have a longer baseline for pressure recording is dually warranted since nearby seismicity was realized in early 2015. This small scale at levels below being felt (2.5 M) and microseismicity below 1 M may be due to both natural and induced causes, but requires closely monitored characterization. We believe pressure monitoring is can provide additional data to potentially relate pressure perturbations in the Arbuckle saline aquifer with seismicity that has been occurring in the area, perhaps distinguishing between natural and brine injection induced events.

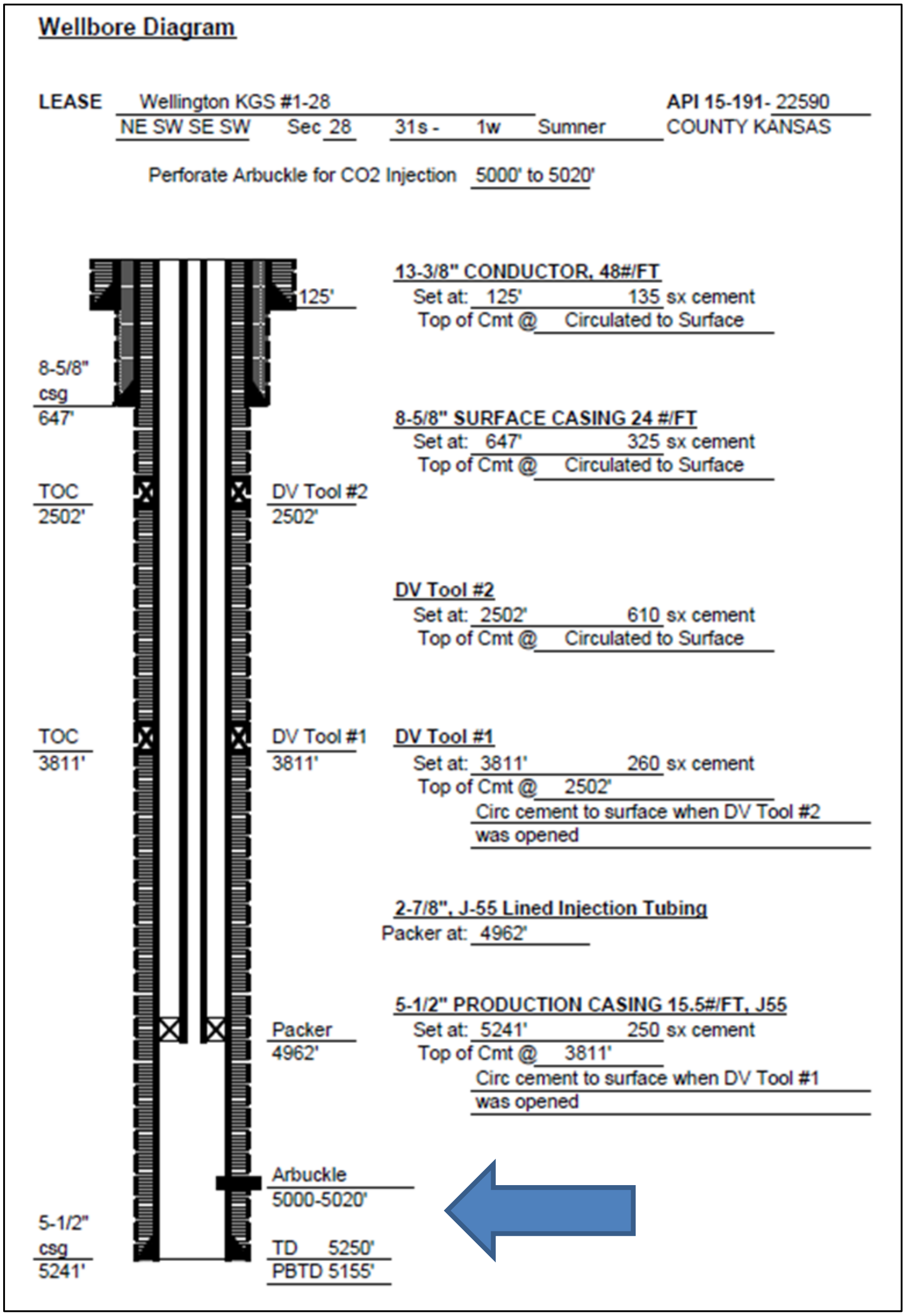

Figure 3. Wellbore schematic of well #1-28 showing perforation at depth of 5000 to 5020 ft.

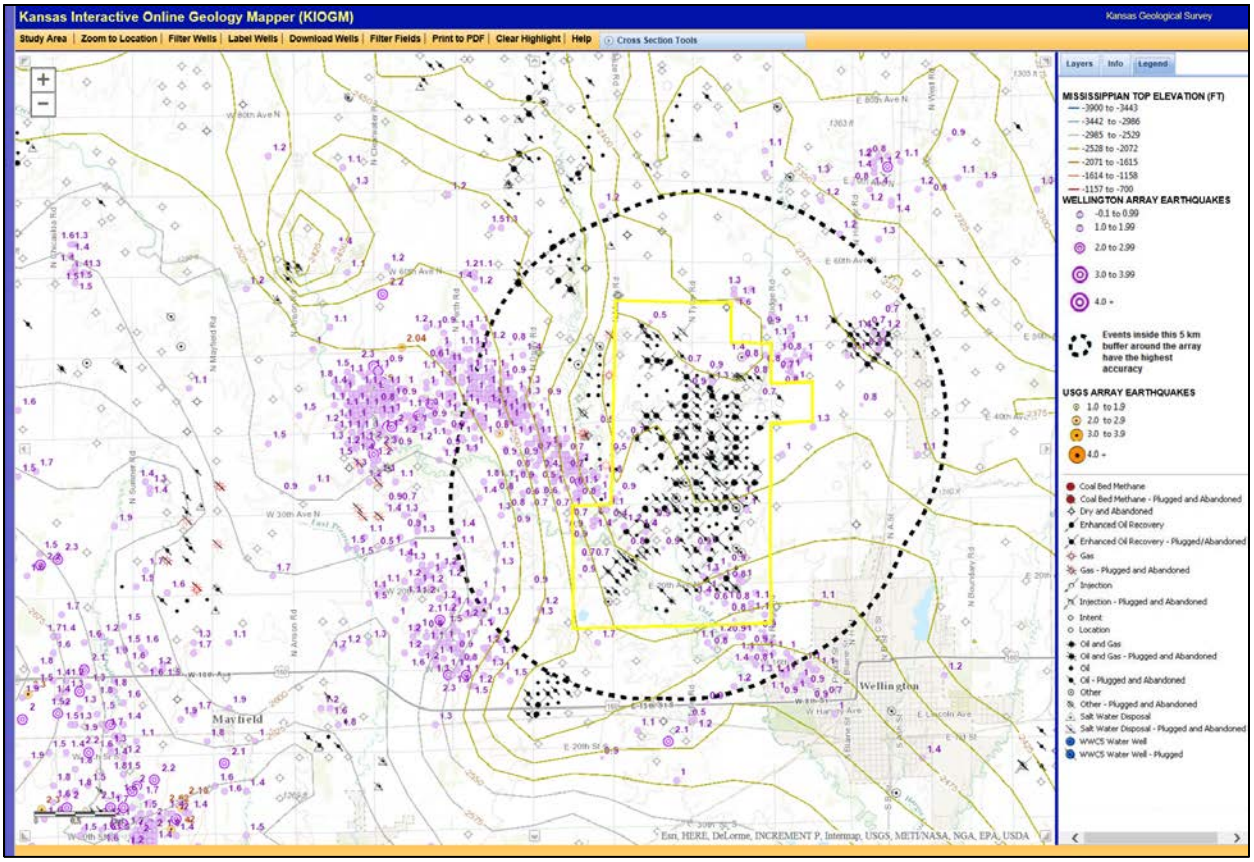

Figure 4. Map of Wellington Field (with yellow outline) and nearby oil fields showing location of earthquakes (pink dots) detected with the Wellington seismometer array. Illustration is from the *Kansas Interactive Online Geology Mapper (KIOGM)* accessed through the KGS on 8/9/16 (http://maps.kgs.ku.edu/co2/). Earthquakes are labeled with magnitudes. Oval area outlined in dashed lines surrounding Wellington Field denotes 5 km radius of reliability of earthquake depths and magnitudes.

Pressure recording continues to be made by Trilobite Testing. As previously noted their company has conducted all of the well testing to date at Wellington and have proven themselves as a very reliable partner.

In addition, pressure data used in conjunction with characterization of earthquakes could help quantify properties of faults and derive stresses needed to reactivate certain faults. These results would also factor in to improving coupled fluid flow and geomechanical models to further quantify what is safe and effective fluid disposal in an area of concern.

The interpretation will be facilitated using an extensive geologic database, much of it which is accessible in the public and pressure data including transient changes in disposal well pressure and rate of injection obtained from the Kansas Corporation Commission. Earthquake waveforms obtained from catalogs of NEIC and Wellington seismometer array are also being compared to the continuous pressure data to evaluate the cause of pressure transients. Currently, the filtering of the pressure data has significantly reduced noise, and accounted for solid earth tidal forces.

Notable pressure pulses (hour long pressures from 5-20 psi) have been recorded. Earthquakes in the range of 3 M and under may not emit pressure signals large enough to be detected without installing a more sensitive pressure transducer at shallower depths in the well, e.g. just below standing water level of ~500 ft in #1-28. The shallow transducers are considerably less expensive to operate, but by themselves cannot be used to obtain absolute values of pressure at depth needed to calibrate simulation, model pressure pulses, or use to establish properties of faults.

A continuously recording pressure transducer in well #1-28 was installed by Trilobite Testing in the middle of perforations (5000 to 5020 ft below ground level) in well #1-28 some 200 ft above the Precambrian granite basement (**Figure 5**). Trilobite's ready access to equipment, expertise in running pressure and fluid tests, over 30 years of experience in Kansas oil and gas wells, and keen interest in contributing to a solution for induced seismicity is a major asset to the quality assurance of this pressure monitoring activity. Trilobite Testing is known throughout the petroleum industry as reliable, efficient, and doing so with integrity. Our well tests in well #1-28 in 2011 were carried out by Trilobite and it was not unexpected for them to look this opportunity enthusiastically as they are interested in contributing to a solution for induced seismicity. If we proceed with the extended pressure monitoring, we can almost guarantee that Trilobite will carry out this task reliably.

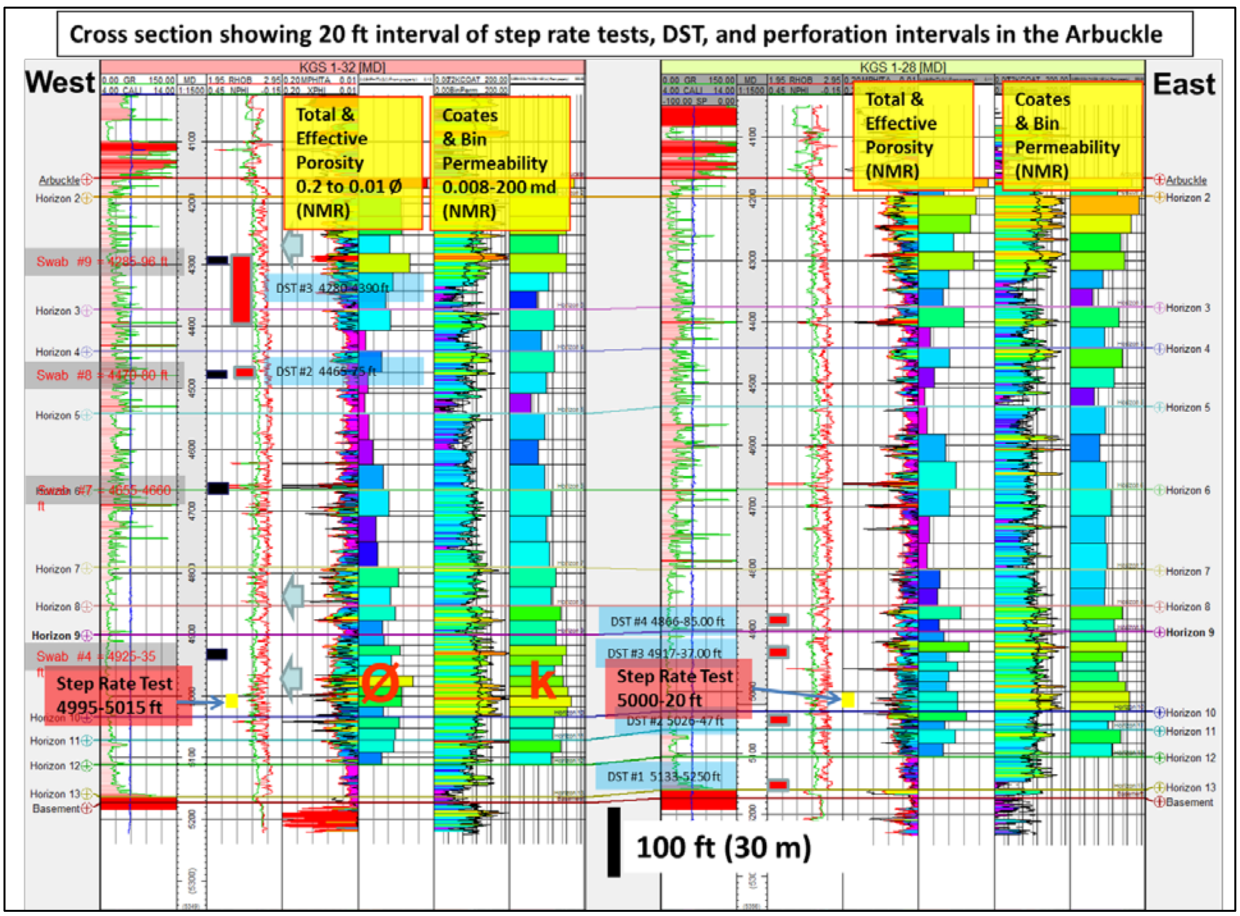

Figure 5. Cross section between wells #1-32 and #1-28 in Wellington field showing profile of porosity and permeability derived from NMR log and locations of DSTs and perforations in well #1-28 besides the location of the step rate test where pressure were

recorded in well #1-28 at a depth of 5000 to 5020 ft. Pressure transducer in current test is located that the perforations at 5000 ft in well #1-28 (lower right).

Trilobite and KGS has established a preliminary methodology to process the pressure data and convey data and results on the web using Java application tools. The process is somewhat involved since the data volume is large, collected at 1 second intervals. The accuracy of the pressures is 0.1psi more than adequate to recognize longer term pressure changes and pressure pulses.

Large rate and high volume brine disposal in the area is believed to be responsible for induced seismicity in south-central Kansas. Simulations by the KGS suggests a regional pressure field (10 to 20 psi) extending 10’s of miles from a core of high pressure in eastern Harper and western Sumner counties has developed in the Arbuckle saline aquifer (Bidgoli et al., 2015). Additional modeling of the pressure faults further suggest that locally faults can become pressurized in the basement where faults are already critically stressed (Bidgoli et al., 2015; Holubnyak, et al., 2015, **Figures 6 and 7**).

A major finding from the Wellington study and the regional mapping of the Arbuckle done conducted under DOE contract DE-FE0002056 is that the Arbuckle is comprised of distinct hydrostratigraphic units in the Wellington Field area including Harper and Sumner counties. Moreover, the major units at Wellington Field are not hydrologic communication based on hydrogeochemical and microbiological evidence (Watney et al, 2015). Thus, brines introduced to the Arbuckle have the potential to at least initially move along these more permeable zones and in the process transmit pressure. As shown by Holubnyak and Watney (2015), the elevated pressure transmitted in hydrostratigraphic units move into an open fault or fractures and potentially direct the pressure into the basement.

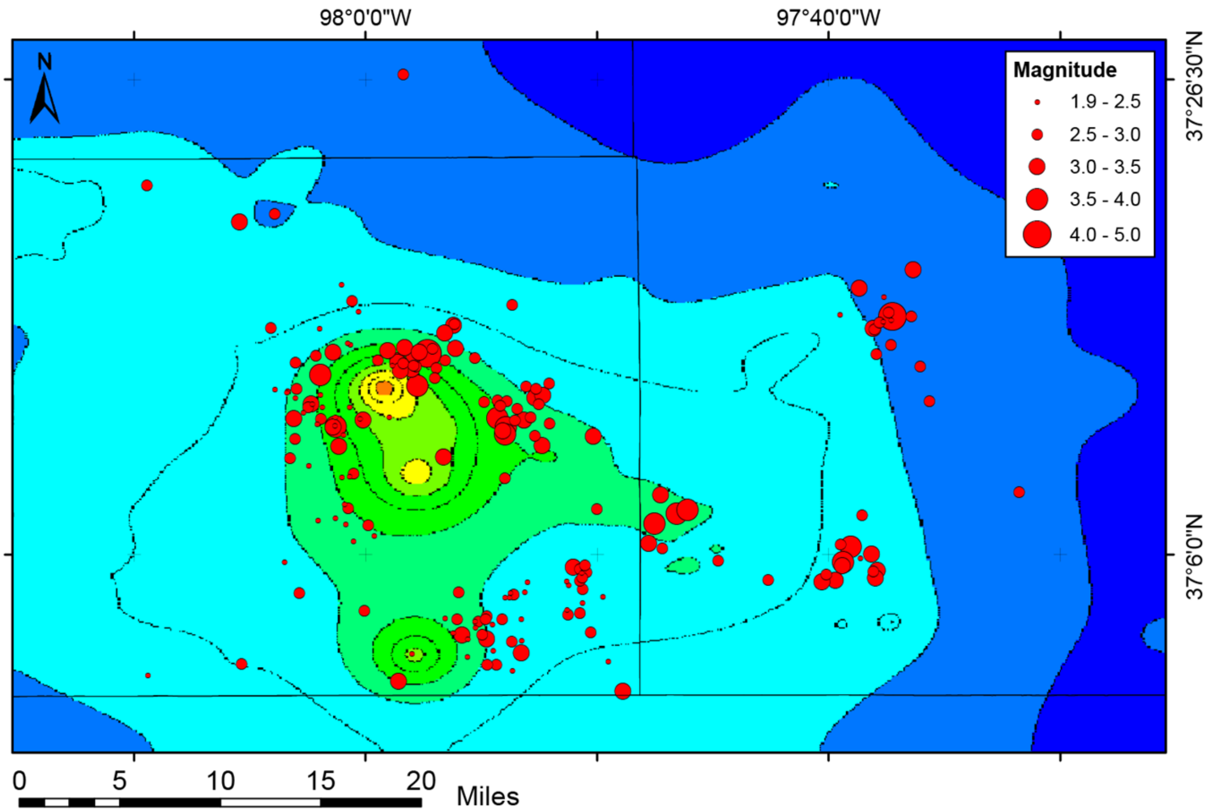

Figure 6, Regional pressure produced in Arbuckle from large volume and rate brine disposal prior to 2014. Higher pressure in inner core of brine disposal (from Bidgoli, Holubnyak, and Fazelalavi, 2015).

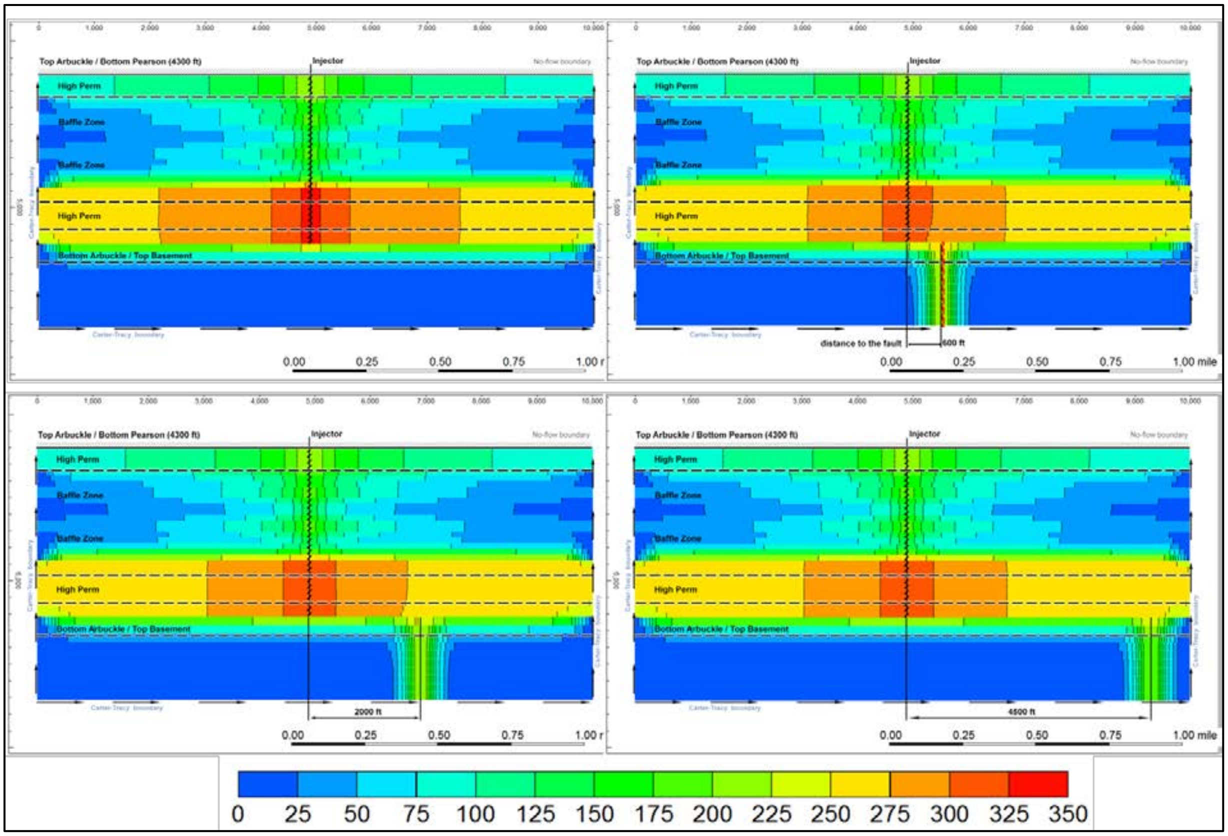

Figure 7. Delta pressure profile introduced by hypothetical brine disposal well completed open hole having a highly permeably hydrostratigraphic (flow) unit in the lower Arbuckle as is often present in the Harper and Sumner county areas. Conservative pressures near the wellbore for large volume wells can exceed <u>the 350 psi modeled here</u> and impose a large pressure differential that can be transmitted large distances beyond the wellbore. Upon reaching a conductive fault, the elevated pressure can potentially move into the basement (Holubnyak et al., 2015).

Intermediate Analysis and Findings – Wellington KGS #1-28 was completed and perforated in the lower Arbuckle in August 2011 and has been shut-in for the past five years. No Arbuckle wells are active or have any disposed of brine in the Arbuckle in Wellington Field during this timeframe. Thus, the well provides an ideal site to test to determine whether a long-term pressure increase occurred in the lower Arbuckle since 2011, a date prior to increased earthquake activity in Kansas.

Wellington Field has undergone extensive characterization including a 3D seismic survey of the field and a fully cored well, #1-32 adjacent to #1-28 and extensive logging and fluid testing of both #1-32 and #1-28 (e.g. **Figure 5**). Well #1-28 was perforated in a highly porous and permeable zone in the lower Arbuckle. This hydrostratigraphic unit is widely correlatable in south-central Kansas including areas in which large volume brine disposal has occurred.

With the 1) expansion of seismicity in general beyond the areas of initial concern (March 19, 2015 KCC order (**Figure 8**) and 2) the recent decision to expand the area of concern to limit brine disposal rates and tubing pressures to include Wellington Field (**Figures 9 and 10**), and 3) recent increase in earthquakes in the area around of Wellington field including several small earthquakes located in the basement in the field proper (**Figure 11)**, it was deemed timely and prudent to establish baseline pressure monitoring to evaluate whether transient pressures were occurring in the Arbuckle saline aquifer at Wellington that might be related to the large volumes of brine disposal in south-central Kansas.

Exhibit A

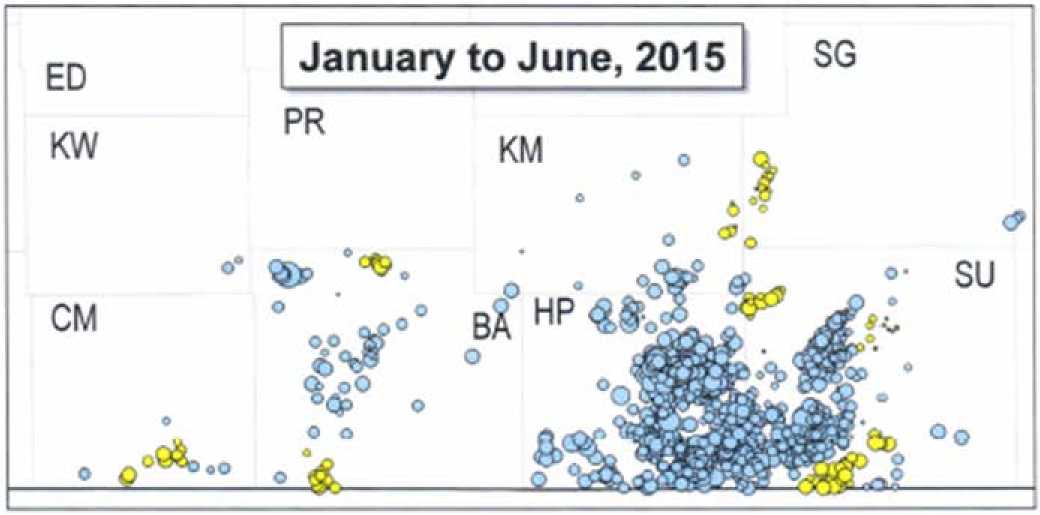

Figure 3. 1690 earthquakes were located by the KCC/KGS network in south-central Kansas from January to June, 2015. Yellow indicates areas with very little activity during the first half of the year that increased significantly during the second half of the year.

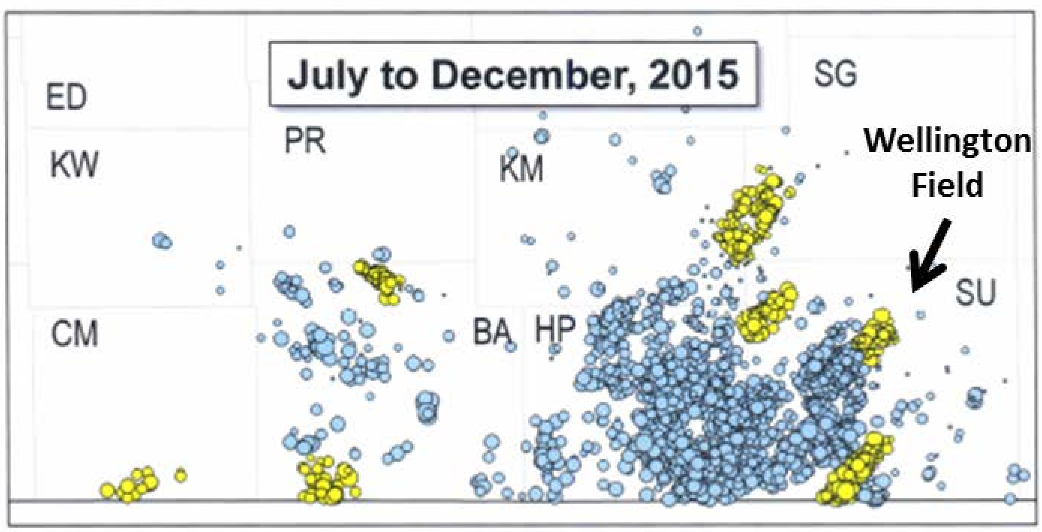

Figure 4. 3085 earthquakes were located by the KCC/KGS network in south-central Kansas from July to December, 2015. Yellow indicates cluster areas with very little activity during the first half of the year that increased significantly during the second half of the year.

Figure 8. Expansion and clustering of earthquakes including those near Wellington Field comparing Jan-Jun. 2015 (top) with July-December 2015 (bottom) (From Report and recommendation of Commission Staff – February 19, 2016)

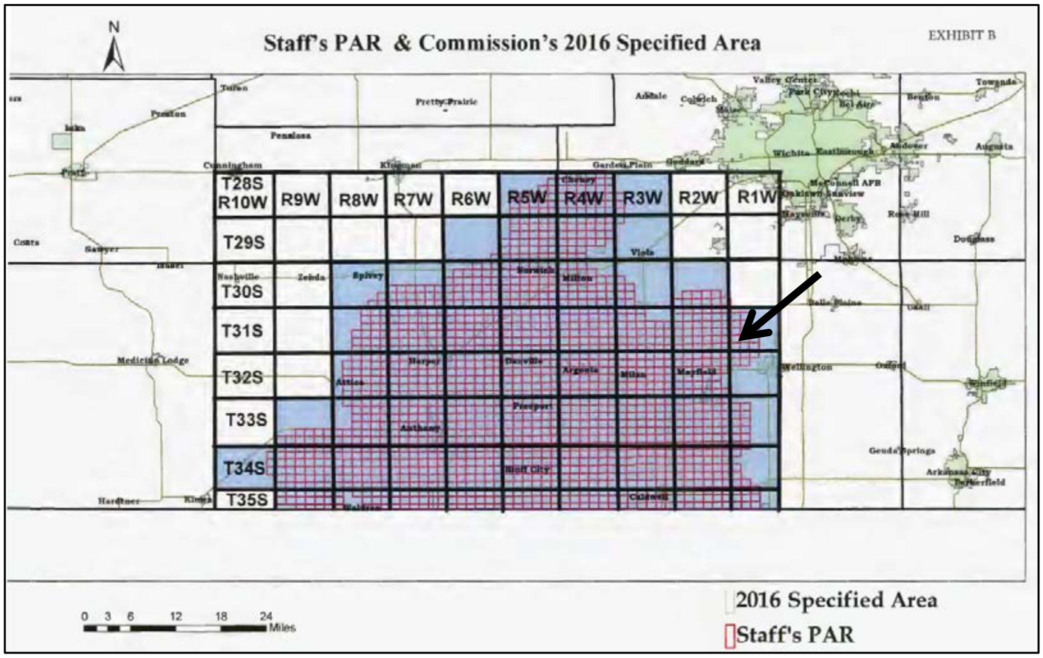

Figure 9. Red squares (1-mile sections) showing location of brine reduction referred to as 2016 Specified Area issued by the Kansas Corporation Commission on August 9, 2016. Illustration from Exhibit B from Second Order Reducing Saltwater Injection Rates, Docket No. 15-CONS-770-CMSC of the Conservation Division). Wellington Field shown with arrow.

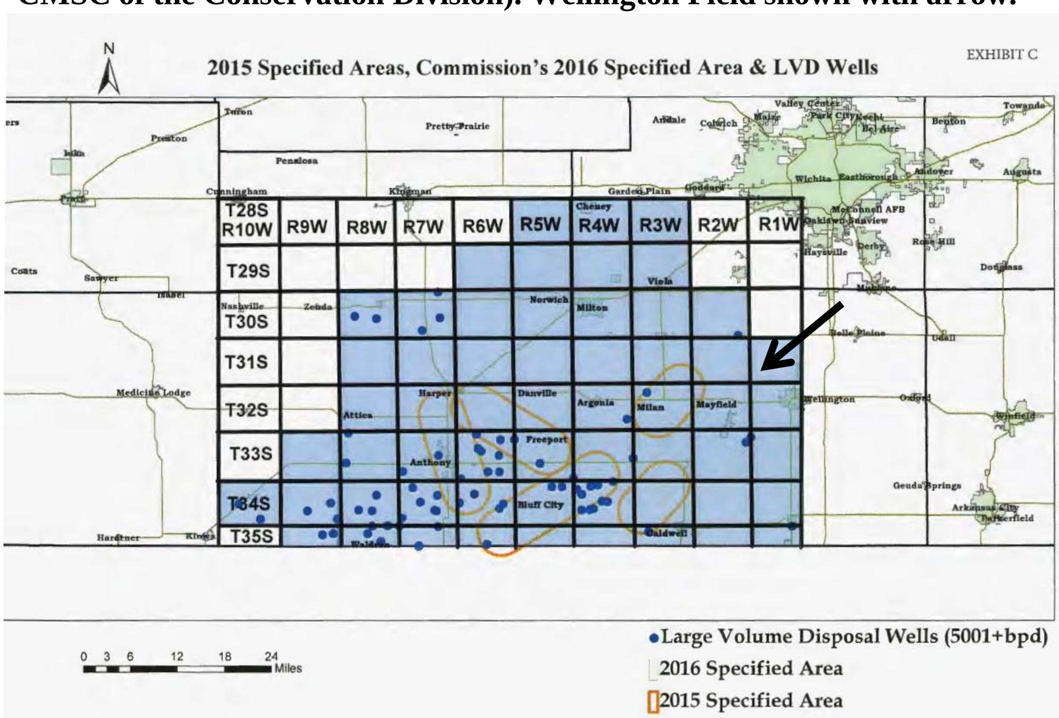

Figure 10. Blue colored townships, 6 miles on a side, identifying location of brine reduction referred to as 2016 Specified Area issued by the Kansas Corporation Commission on August 9, 2016. Illustration from Exhibit B from Second Order Reducing Saltwater

Injection Rates, Docket No. 15-CONS-770-CMSC of the Conservation Division). Wellington Field shown with arrow.

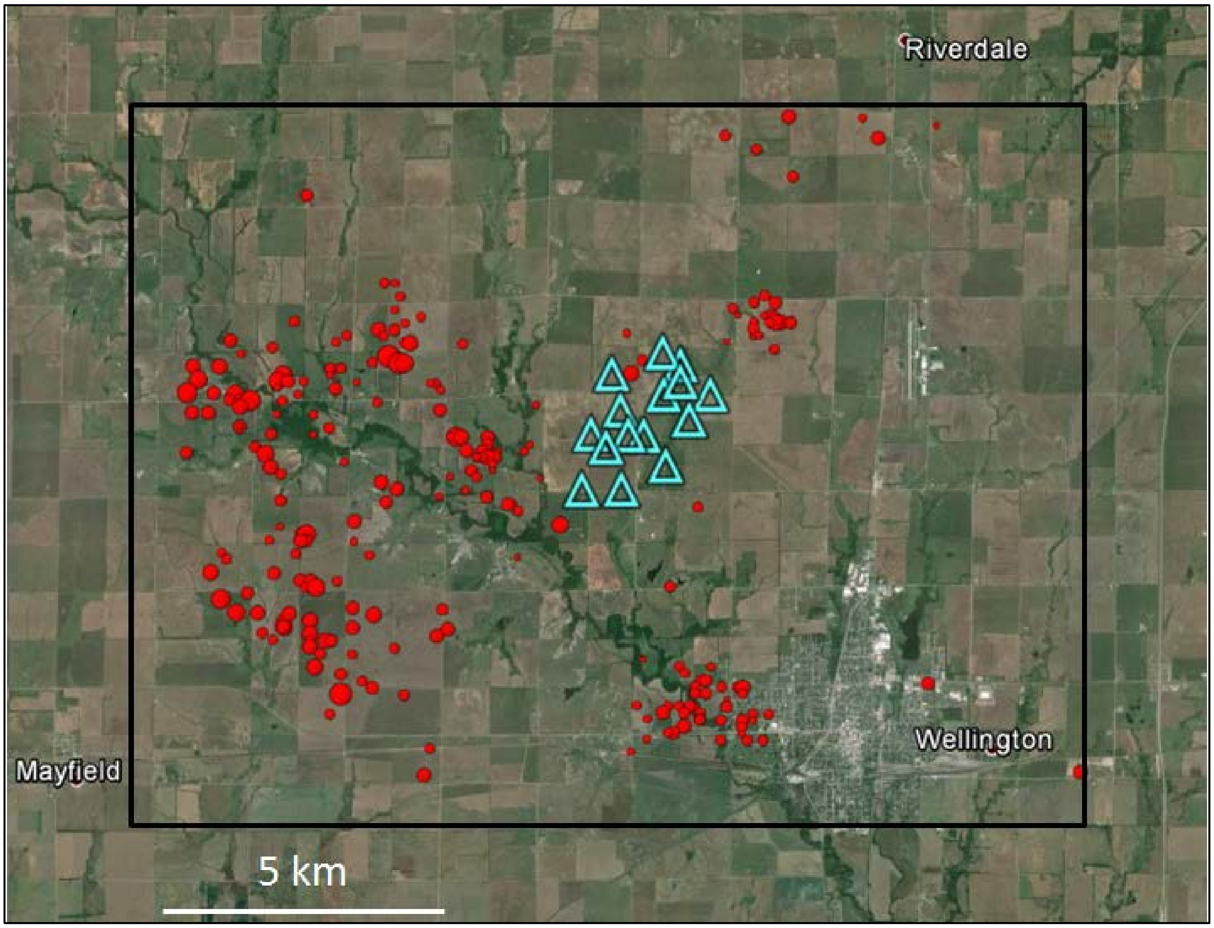

Figure 11. Map showing all events within the Wellington field area. Wellington seismometer stations are the blue triangles and earthquakes are the red circles with diameter proportional to event magnitude. All events in this area were used to calculate a preliminary Magnitude of Completeness (from Nolte et al., 2016).

Long term high-resolution pressure monitoring is optimal in order to test the hypothesis that induced seismicity is, in part, driven by increased regional pore pressure as suggested though simulation (**Figure 6**). The longer term measurements are also needed to identify the solid earth tidal fluctuations due to diurnal and long gravity variations created by the interaction of the earth with the rotation of the moon and the sun. It may also be the base with sharp barometric pressure changes in the atmosphere can change the pressure that is recorded in the cased borehole.

Besides establishing whether a long term pressure increase exists, pulses, oscillations, and pressure steps may also be observed, possibly presenting influence from disposal wells or co-seismic response to larger earthquakes as has been documented in the literature. Information gained regarding communication of the local hydrogeologic system with other wells could provide another useful means for confirming regional transmissivity of the aquifer itself.

The utility of having downhole pressure measurement have been discussed with the Kansas Induced Seismicity Task Force and there has been a general support for it. The confirmation of a pressure increase compared to values obtained five years ago, and the recognition of short term pressure perturbations that have been observed warrant continued monitoring prior to the Arbuckle CO2 to document changes to the pressure regime that the Arbuckle reservoir is apparently being subjected to.

Additional data is needed to observe further changes that can be compared to disposal well activity. The pressure monitoring may be an important tool to assist operators and regulators alike toward establishing guidelines for safe disposal. Increased pressure and short-term pressure pulses could be used as a basis to refine models and to demonstrate lateral communication and interference between wells.

The Arbuckle injection slated for Wellington under a Class VI permit will be introducing a small amount of CO2 (26,000 tonnes) over approximately 6 months at pressures notably lower than in many large volume brine disposal wells (Δp <200 psi). Moreover, the rates of CO2 injection under <900 barrels per day equivalent at more than a magnitude less than the 12,000 barrel per day limit placed on the new brine injection wells in the Wellington area.

Initial Findings from the downhole pressure measurements -- A pressure transducer was installed in just above open perforations in the lower Arbuckle at 5000 to 5020 ft in Berexco Wellington KGS 1-28 (**Figures 3 and 5**). Gauge depths and the static bottomhole pressure in well #1-28 obtained on 8/23/11 were 2090.3 psig at 4997 ft below ground level. The current static bottomhole pressure in #1-28 is 2123.2 psig at a depth of 4997 ft below ground level (**Figure 12**). This depth is the same as the original gauge depth, thus, **the pressure increase over the past five years to when the pressure recording began on April 25, 2016 was +31.4 psig and has continued to rise to +32.9 psi on August 6, 2016 or 1.5 psi in 103 days (0.0147 psi/day or 0.44 psi/mo)**. These pressure increases are similar the (+) ~20 psi estimated from the modeling by Bidgoli et al. (2015) and appears to confirm the simulation suggesting that a cumulative response brine injection as well as an expanding area of seismicity have led to a regional pressure increase from large-scale brine disposal southwest of Wellington.

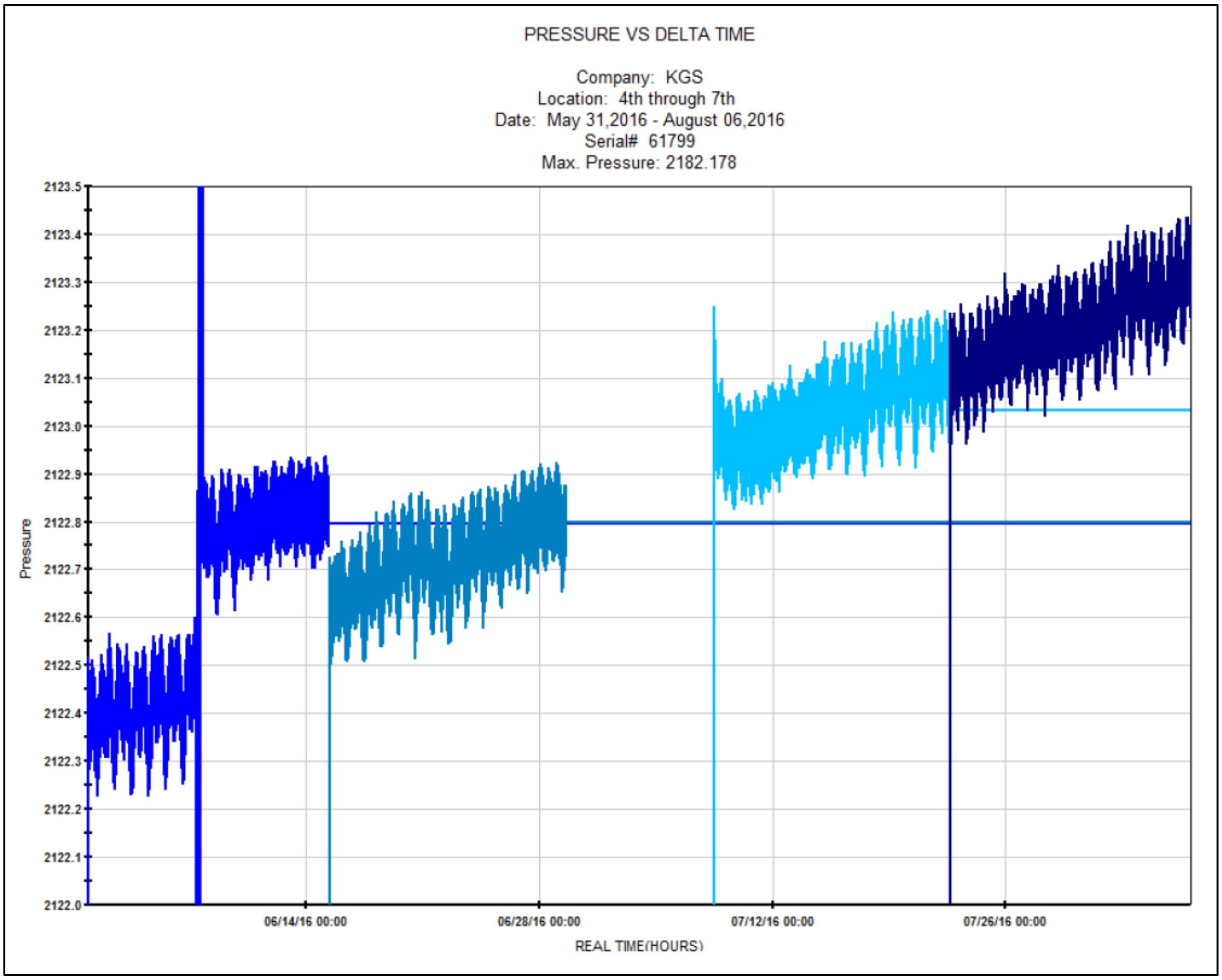

Figure 12. Bottom bottom hole pressure records from Wellington KGS #1-28 have shown steady increases since the pressure recording began in April, 2016. Tool removed and reentered to greater depth in 2nd run shown, but raised to original depth in the third run. Data loss in the 4th segment. Conducted small pressure falloff in 5th (light blue) segment.

The key finding at this point – The bottomhole pressure at #1-28 has increased over 30 psi compared to the same measurement in August 2011. Carefully looking at the new data and the extended pressure measurements in 2011 before induced seismicity appeared in the area leads to a conclusion that the Arbuckle has been pressurized in Wellington Field. While not an indication of earthquakes, the simulation of regional brine disposal would suggest that the area has a greater potentially for seismicity due to the elevated pressures, it the pressures are indeed transmitted into basement faults. The added presence of short time transient pressure changes is of additional concern especially if and where the Arbuckle is in pressure communication with the basement (**Figures 13-15**).

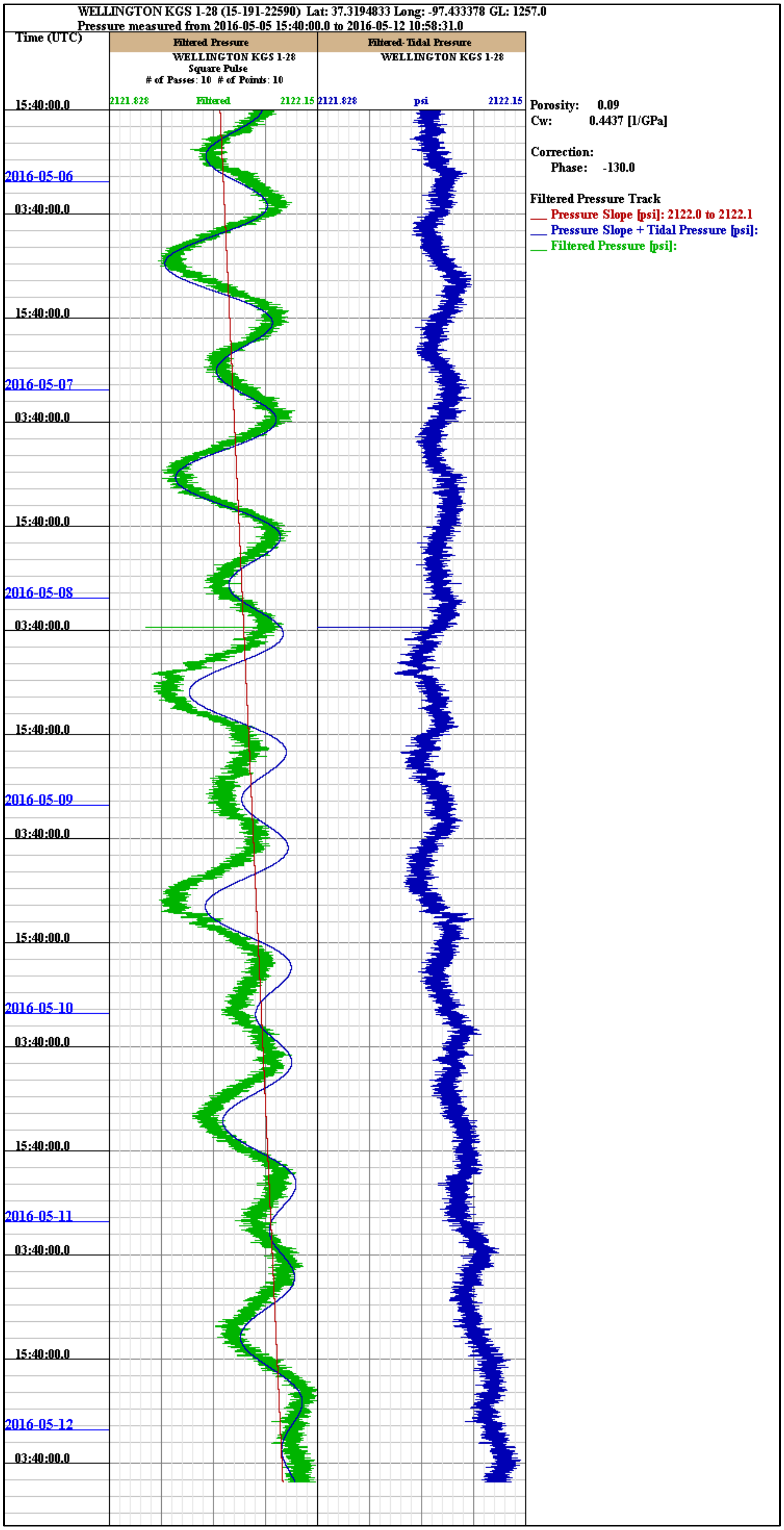

Figure 13. Filtered pressure data including a filter for the solid earth tidal effects shown as blue line representing the tidal (gravitational) effects and the resulting residual. This pressure interval was documented as part of a pressure catalog of anomalies, in this case a slightly negative pressure lasting 2.5 days in the mid portion of the chart.

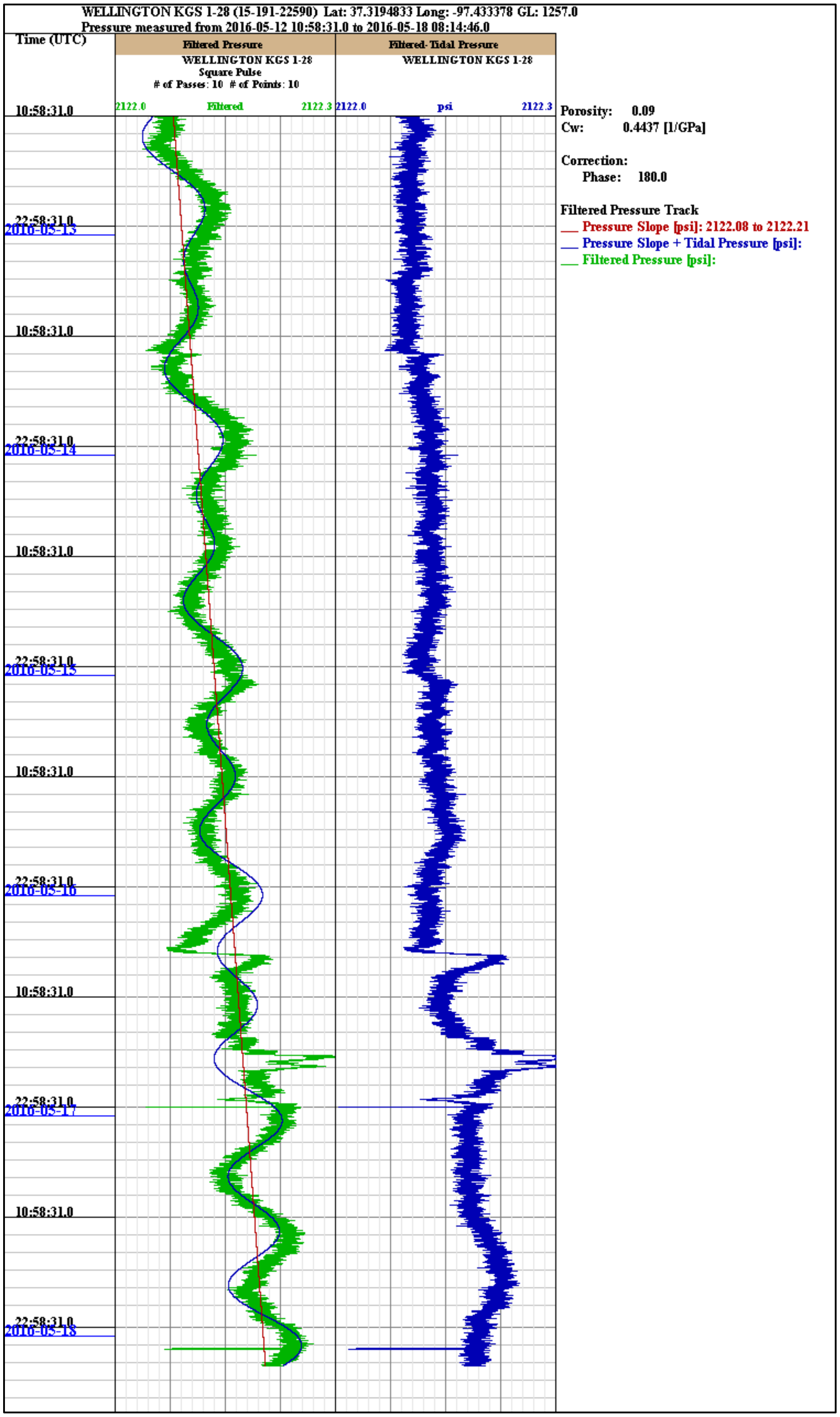

Figure 14. Short term (several hours) of pressure fluctuation included in the pressure catalog to be used to compare with relevant information from disposal wells and from earthquake database.

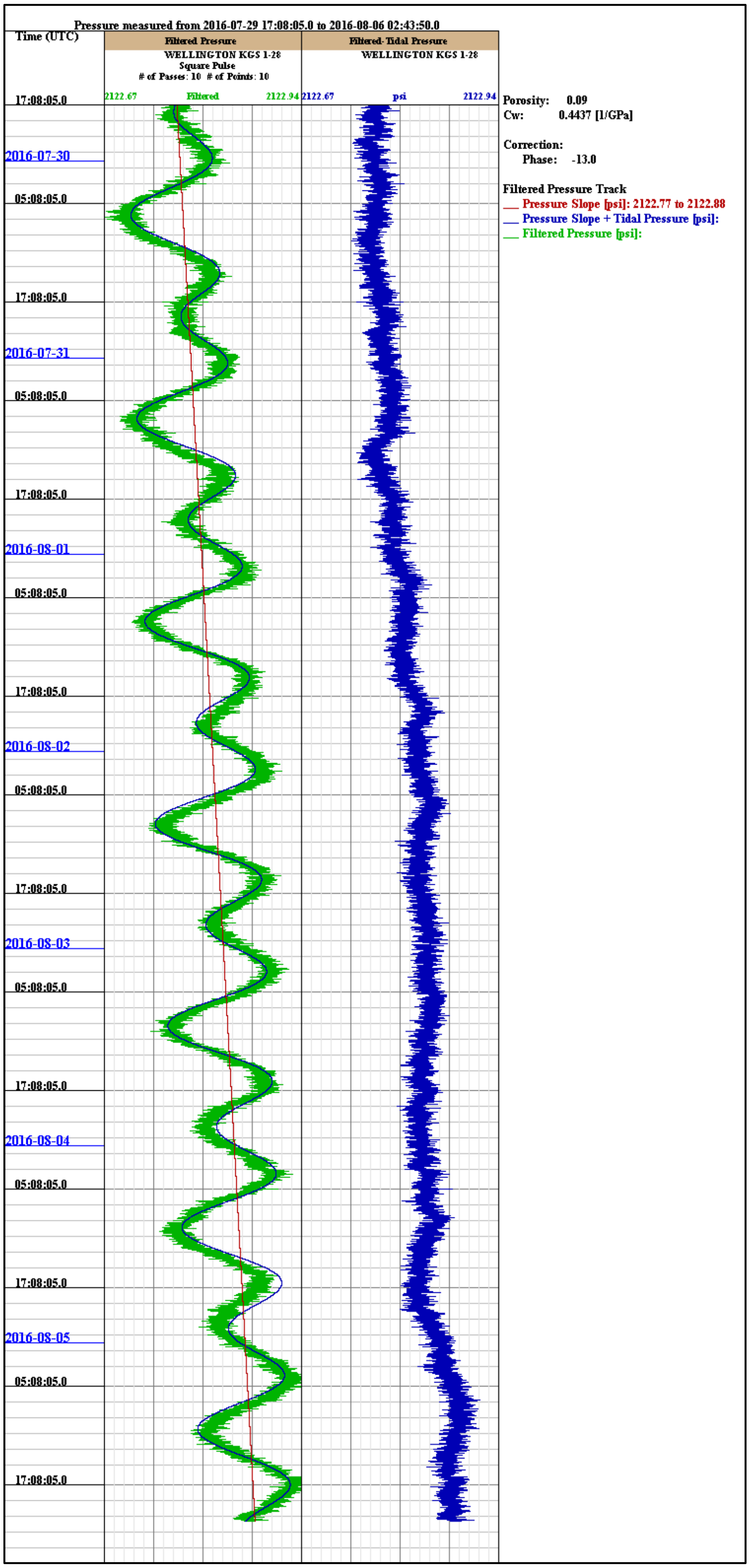

Figure 15. Pressure record from well #1-28 showing no significant pressure anomalies, only oscillations due to the solid earth tidal effects. The long-term pressure increase is shown as the red line.

The pressure catalog will include a graphic with a visual of the pressure anomaly and a written description of the pressure changes (**Figure 16**).

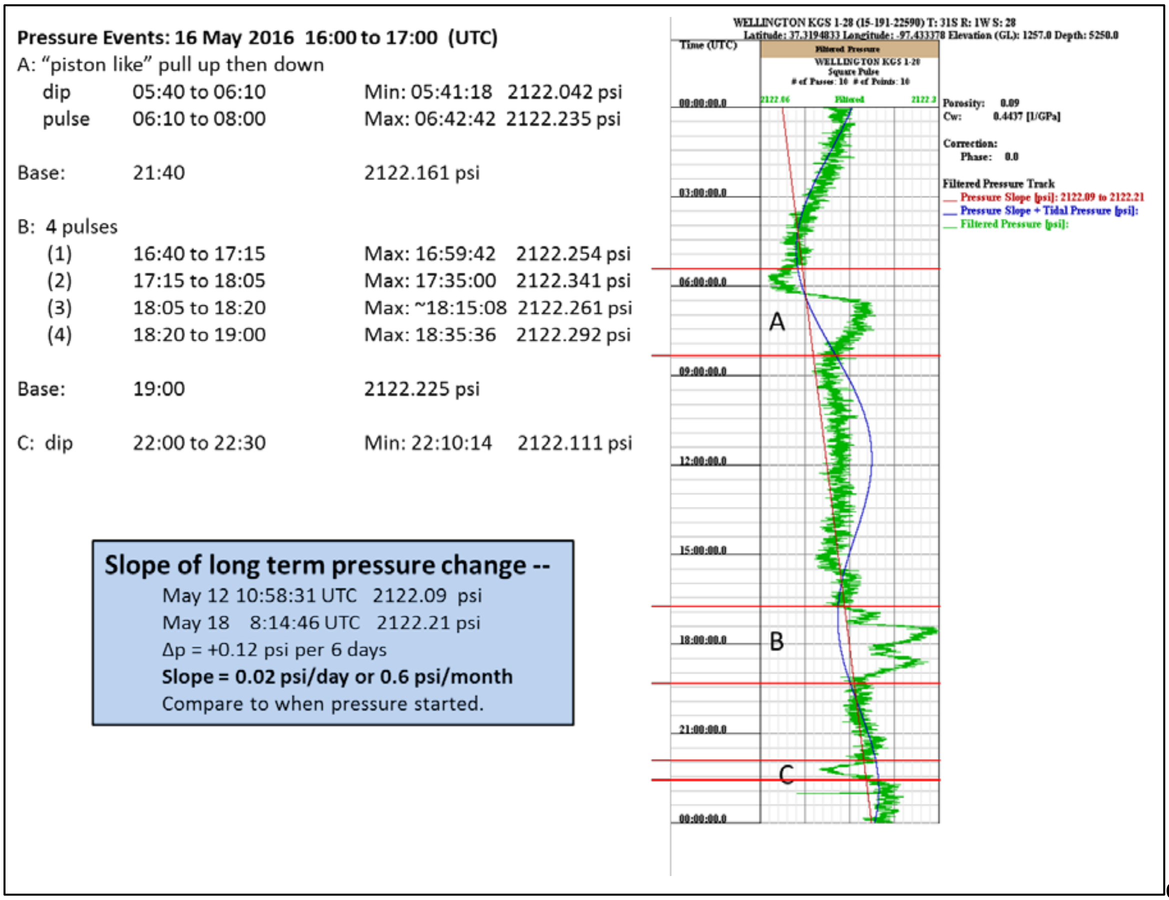

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Figure 16. Example from pressure catalog of the event shown in Figure 14 above.

All of the pressure analyses shown above will located on the KGS website and will be publically accessible (**Figure 17**).

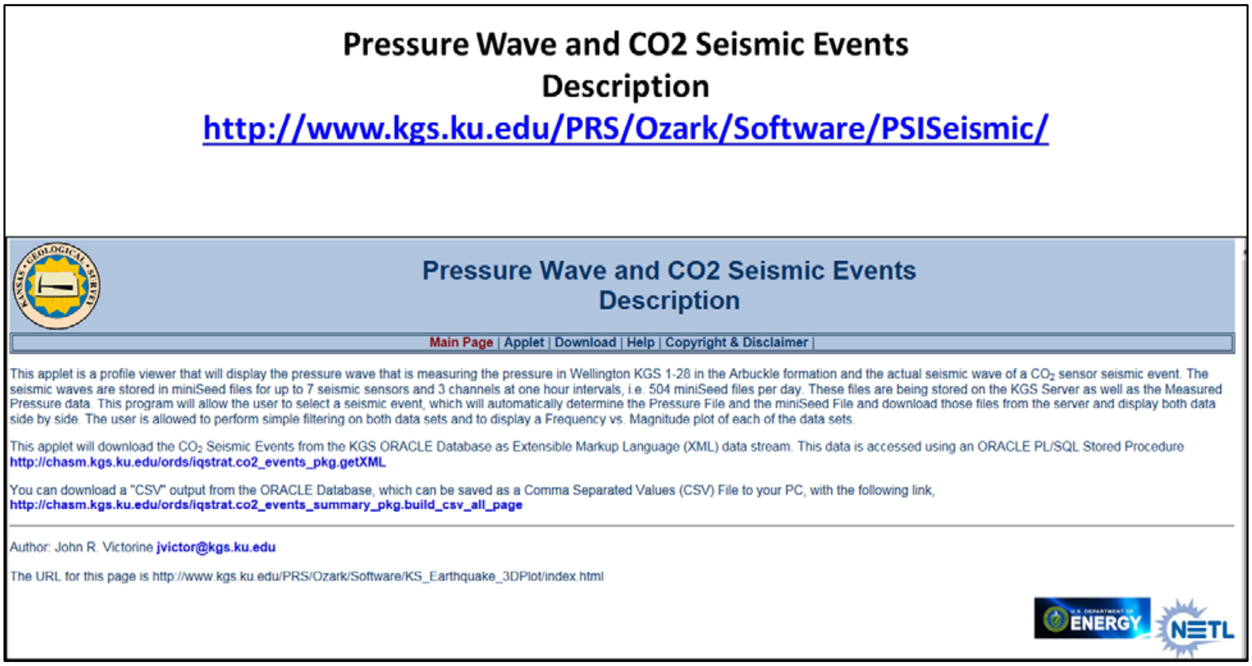
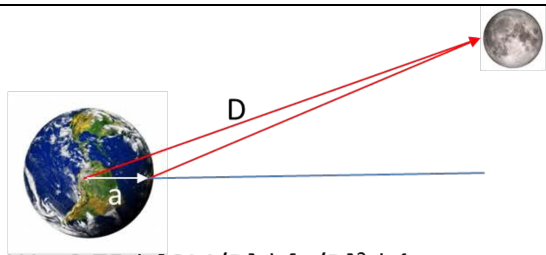


Figure 17. Access to Java web applications developed under DOE support available from the KGS website.

The solid earth tidal effects were computed solutions are shown illustrated in **Figures 18 and 19**.



Tide-generating Potential (W)
Spherical harmonic of the second order

$W = 0.75 * [GM/D] * [a/D]^2 * \{$

$\quad (3*\cos(2*\lambda_m) - 1) * (3*\cos(2*\lambda_e) - 1) / 12.0$ — Long Term ~14 day cycle

$\quad + \sin(\lambda_m) * \sin(\lambda_e) * \cos(\omega t - \phi_m - \phi_w + \phi_{corr})$ — Diurnal ~1 day cycle

$\quad + \cos^2(\lambda_m) * \cos^2(\lambda_e) * \cos[2*(\omega t - \phi_m - \phi_w + \phi_{corr})]\}$ Semi-diurnal ~1/2 day cycle

where

- λ_e = latitude of the Wellington KGS 1-28 well 37.3194833
- λ_m = latitude of the moon (*varies with time*) – using the degrees above horizon
- ϕ_e = longitude of the Wellington KGS 1-28 well -97.433378
- ϕ_m = longitude of the moon (*varies with time*) – using the Right Ascension (R.A.)
- ϕ_{corr} = phase correction, need to incorporate the varying distance of the moon from earth and the suns influence.

$\omega = 0.000011600804$ [Hz]	Frequency of the Earth's rotation
$G = 6.67408 \times 10^{-11}$ [m^3]/{[kg][sec^2]}	Gravitational Constant
$M = 7.34767309 \times 10^{22}$ [kg]	Mass of Moon
$a = 6.371 \times 10^6$ [m]	Radius of Earth
$D = 3.84402 \times 10^8$ [m]	Average Distance between Earth and Moon (*varies with time*)

Reference: Melchior, P., 1966: The Earth Tides, Pergamon.

Figure 18. Example of computing solid earth tidal effects on bottom hole pressure including semi-diurnal, diurnal, and long term cycles.

Volumetric strain at the surface of the earth (θ)

$\theta = 0.49 * W / (a * g)$
where
W = Tide-generating potential - Spherical harmonic of the second order
a = 6.371×10^6 [m] Radius of Earth
g = 9.8 [m]/[sec^2] Gravitational Acceleration

Tidal Pressure (P)

$P = \theta / (C_w * \phi)$

θ = volumetric strain at the surface of the earth
C_w = compressibility of water { 133.01 °F; C_w = .4437 [Gpa]$^{-1}$ }
ϕ = porosity of the aquifer { ~ 0.09 }
Wellington KGS 1-28 at 5020'

Figure 19. Solid earth tidal effect on tidal pressure.

Task 3. Site Characterization of Mississippian Reservoir for CO2-EOR – Wellington Field

Update on performance and monitoring of CO_2 injection into the Mississippian spiculitic (cherty) dolomite at Wellington Field, Kansas

CO2 Injection into the Mississippian reservoir completed – Berexco completed injection of 1,101 truckloads of CO2 over a 165 day or 5 month period. A total of 21,784 US tons, 19,803 metric tons, or approximately 374,000 MCF of CO2 was attained on June 21, 2016 when the last truckload of CO2 was delivered to the Mississippian injection well, Wellington KGS #2-32.

The expenditures for purchasing CO2 were $1,964,000 with an overall price for CO2 was $90.16 per US ton from Linde Group. The CO2 injection was completed in 165 days or approximately 5 months with an average of 120 tonnes per day of CO2 injected (**Figures 20 and 21**).

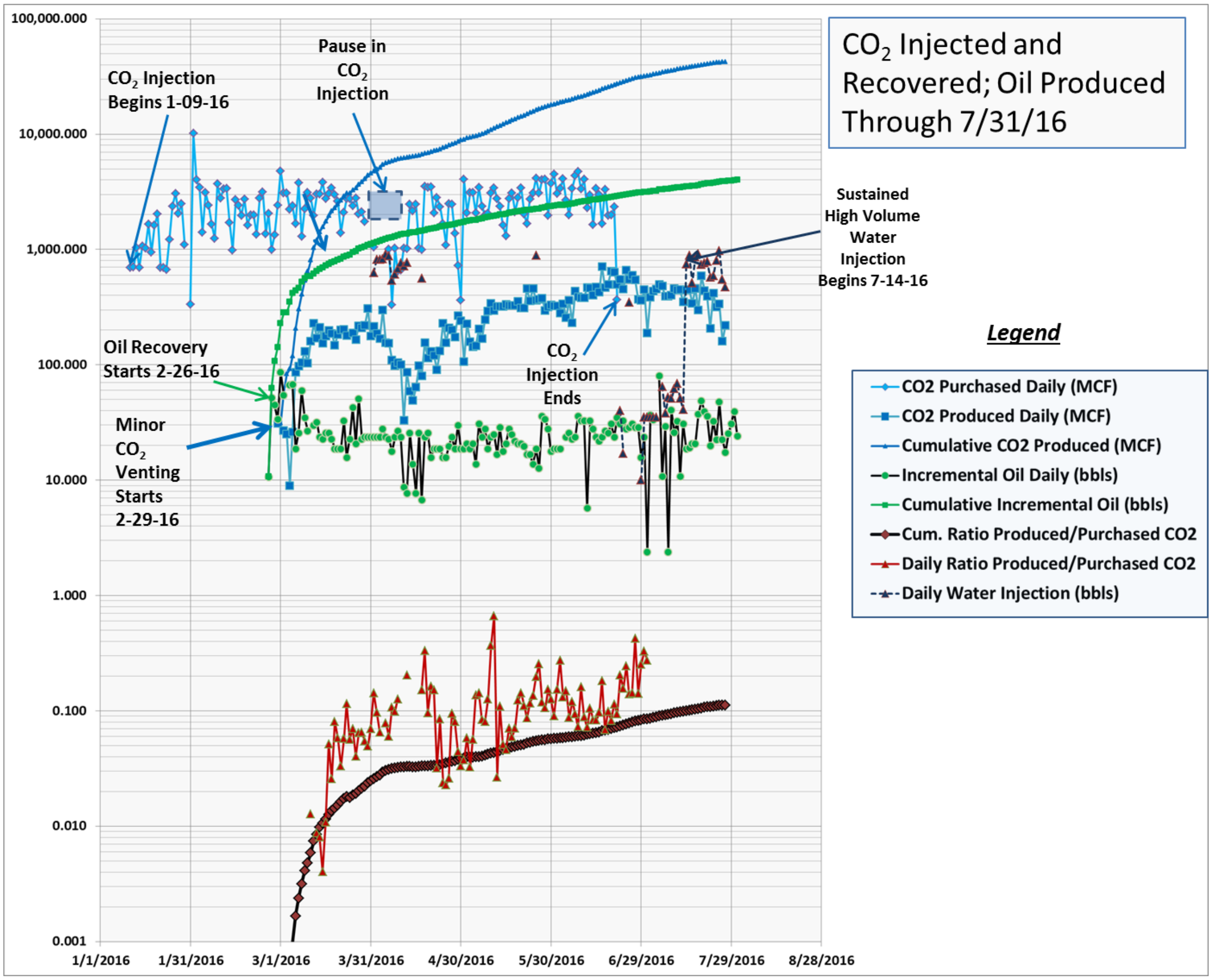


Figure 20. CO2 injected and CO2 and oil recovered in pilot scale injection in the Mississippian oil reservoir in Wellington Field.

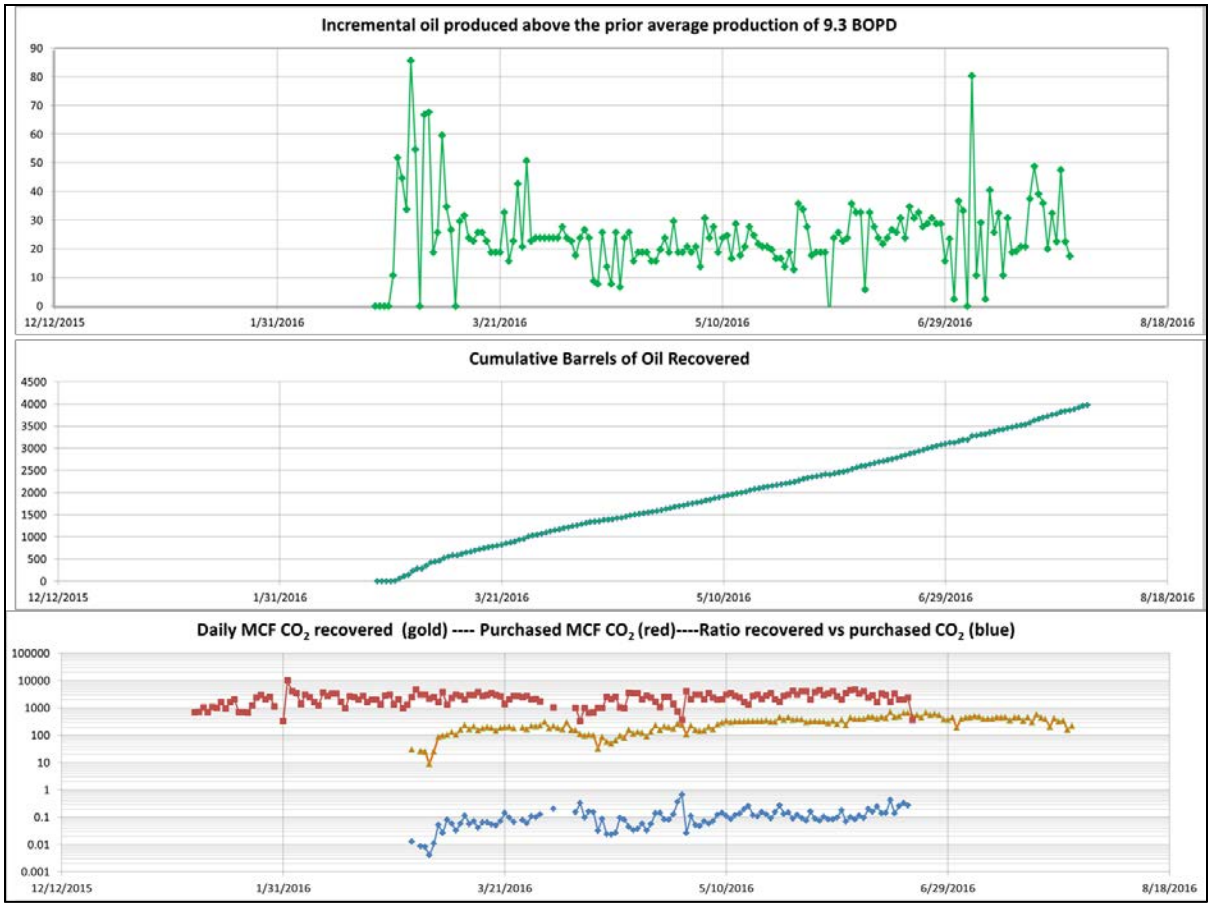


Figure 21. Incremental and cumulative barrels of oil recovered comparison of CO2 recovered vs. purchased. CO2 recovered has remained a comparatively low levels compared the CO2 that has been injected suggesting conformance of the CO2 plume. Incremental oil has actually increased slightly since water injection began indicating that the CO2 is being pushed away rather uniformly away from the injection well, #2-32. The response closely resembles what has been forecast from the simulations.

Figures 22-26 provide additional detail about the latest field performance including the daily report of the injection well and the associated CO2 or water injected and oil recovered as the pilot moved from CO2 to water injection (**Figure 22**). **Figure 23** is a map of the brine alkalinity samples at the 17 wells surrounding the CO2 injection well, #2-32. The higher values of alkalinity are associated with locations were brine is charged with dissolved CO2. By comparison, a map of alkalinity for April 27th indicates a reduced CO2 plume focused on locations west of the injection well. It had been previously demonstrated the area of the east between in injection well, #2-32, and the producing well #63 is an area of reduced permeability and a small fault that runs north-northwest between the wells. The reduced permeability reflects more a change in the matrix dolomite pores as is note in both well logs and seismic. Furthermore, the sequence stratigraphic framework illustrated in the previously quarterly report reveals the location of the injection well is located in a separate westerly prograding porous wedge of dolomite reservoir while well #63 in located in another.

Figures 25 and 26 show the notable changes that occurred in the oil and CO2 produced and the bottom hole pressure of the well that were sampled around the CO2 injection well in 7/20/16 compared to 6/22/16 when the CO2 injection ended. It is clear from these maps that the response has notable changed when the small scale test moved to a post CO2 injection waterflood. Also of note is that the oil production has increased beyond the inner wells, e.g. to the north in well #45, where the simulation has forecasted the movement of the plume and the oil bank.

Latest from well completion report

- **6/22/16 1302 BBL CO2 injected @ 213# TP. Current rate 1226 BPD. E. Nelson 40 BO.** **CO2 pump shut down permanently 4:00 pm, 6/22/16. Killed well with 40 BW and left shut in.**
- 6/23/16 Injected 147 BBL CO2 before shut in 6/22. SITP- 430#. Opened to water injection line and put 13 BW down well and shut in. Tubing pressure built to 30# after 2 hours. Put 2 BW down tubing and killed well. E. Nelson 42 BO.
- 6/24/16 E. Nelson 37 BO.
- 6/25/16 Shut in KGS 2-32 at 8:15 am on 6/25/16. Tubing pressure zero when SI. Total of 404 BW was put down well to keep killed since 6/22/16 at 4:00 pm. E. Nelson 38 BO.
- 6/26/16 E. Nelson 40 BO.
- 6/27/16 Started shooting 2D seismic across field - could not complete due to wet ground. Linde completed removal of CO2 storage tanks. KGS #2-32 SITP 660# at 6:00 pm. E. Nelson 38 BO
- 6/28/16 672# SITP. Could not complete shooting seismic due to muddy fields. E. Nelson 38 BO.
- 6/29/16 710# SITP. Plan to resume water injection at low volumes to maintain/restore 2-32 tubing pressure at zero until seismic is complete. Then plan to resume full volume water injection. Put 10 BW down well to put tubing on vacuum. E. Nelson 25 BO. Had wells shut in for seismic 6/27 and 6/28.
- 6/30-7/4/16 Put avg 35 BWPD down well to keep killed. E. Nelson avg 32.8 BOPD- had lead line leak 7/1.
- 7/5/16 710# TP- well quit taking water. Killed with injection pump and increased rate. E. Nelson 56.8 BO.
- 7/6/16 65 BW @ 0# TP. E. Nelson 16.7 BO- wells down due to electrical storm.
- 7/7/16 38 BW @ 0# TP. E. Nelson 38 BO.
- 7/8/16 52 BW @ 0# TP. E. Nelson 50 BO.
- 7/9/16 51 BW @ 0# TP. E. Nelson 13 BO.
- 7/10/16 62 BW @ 0# TP. E. Nelson 35 BO.
- 7/11/16 69 BW @ 0# TP. E. Nelson 42 BO.
- 7/12/16 51 BW @ 0# TP. E. Nelson 20 BO- #53 quit pumping.
- **7/13/16 Finished shooting 2D seismic line.** Increased injection to 800 BWPD.

Figure 22. Daily report in the injection well, #2-32.

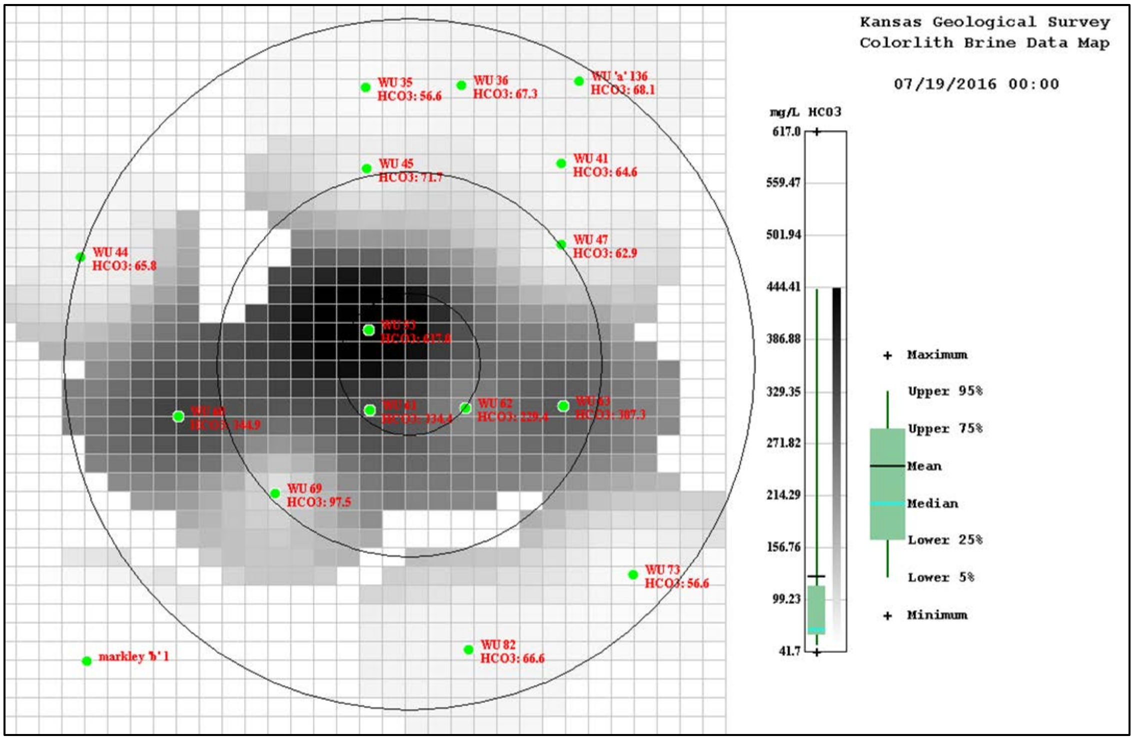


Figure 23. Map of brine alkalinity for 7/9/16 sampling.

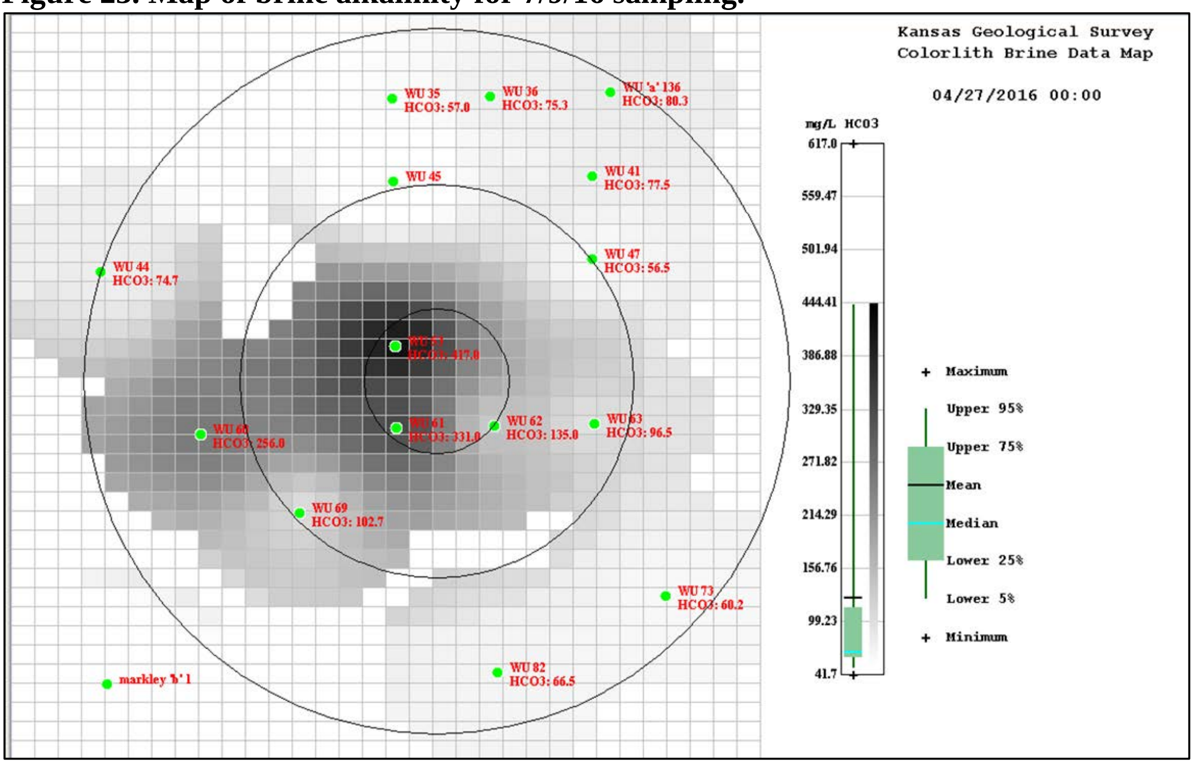


Figure 24. Map of alkalinity for April 27, 2016.

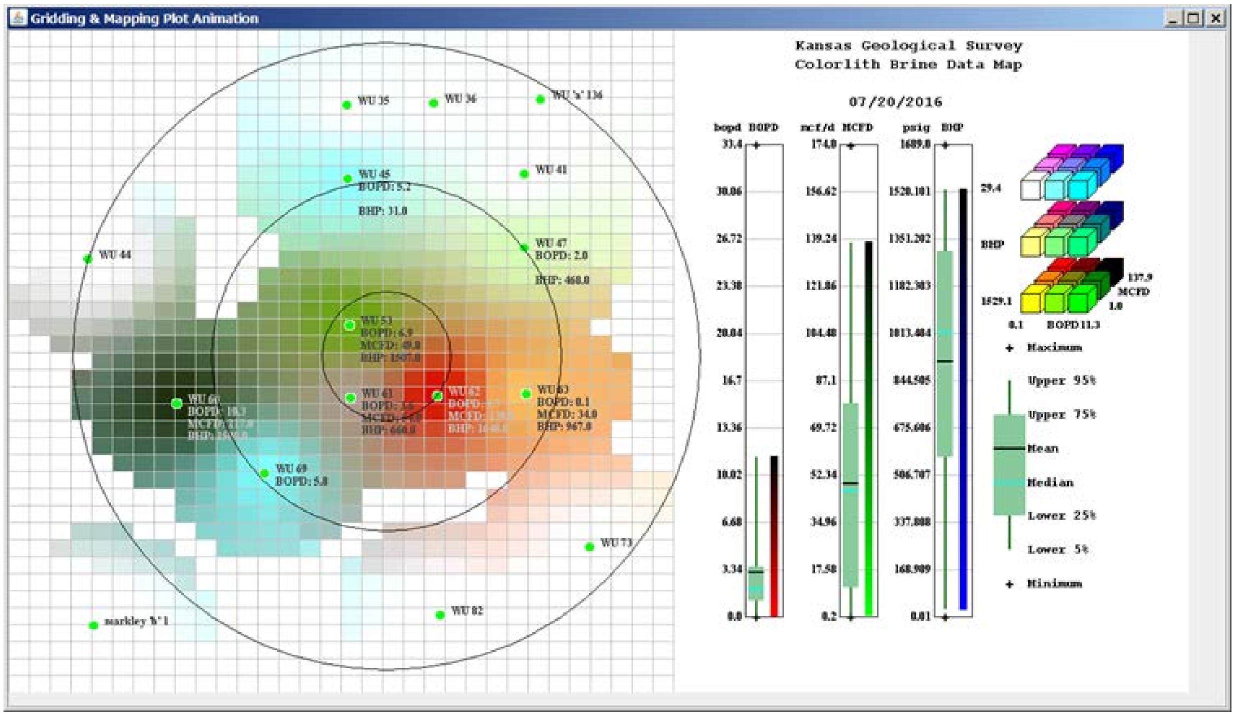


Figure 25. Map of oil and CO2 produced and bottom hole pressure for 7/20/16, nearly one month after the CO2 injection ended.

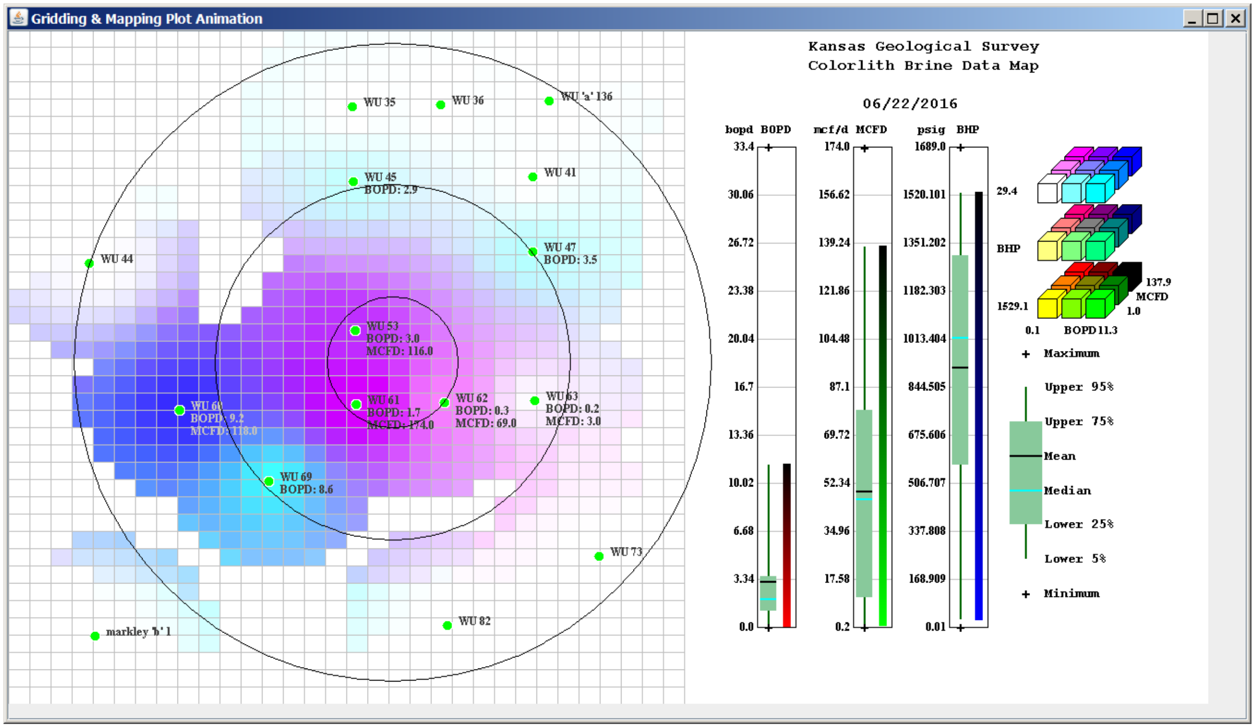


Figure 26. Map of oil and CO2 produced and bottom hole pressure for 6/2216, a day after the CO2 injection was ended.

Figures 27 to 33 are a series of charts are used to illustrate the production information used to as input to construct a reservoir simulation.

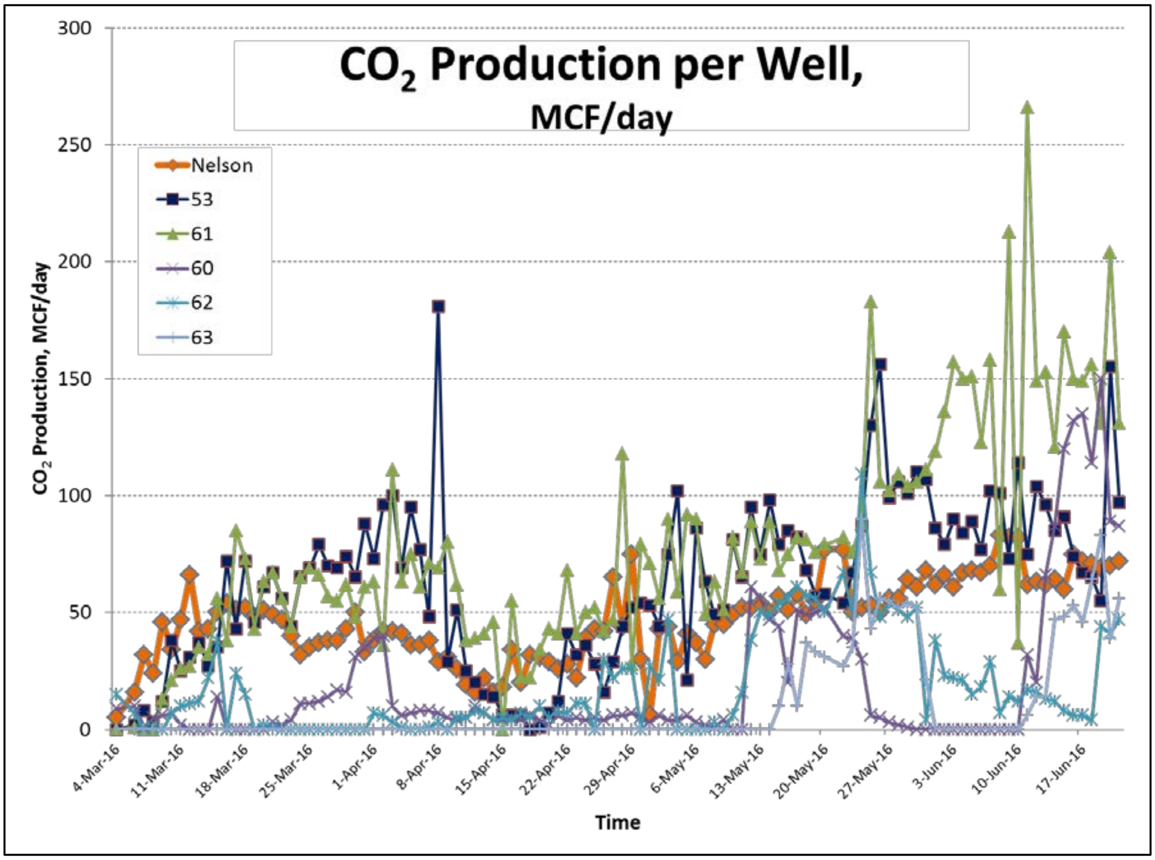


Figure 27. CO2 production per well, MCF/day.

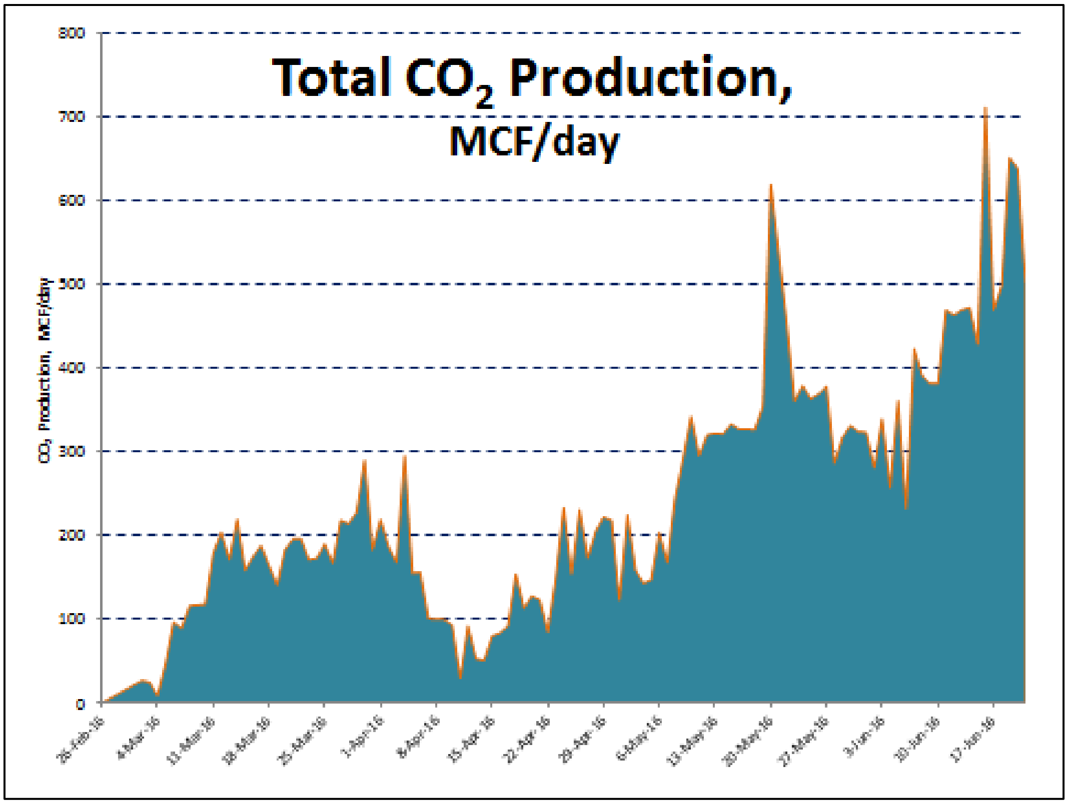


Figure 28. Total CO2 production, MCF/day

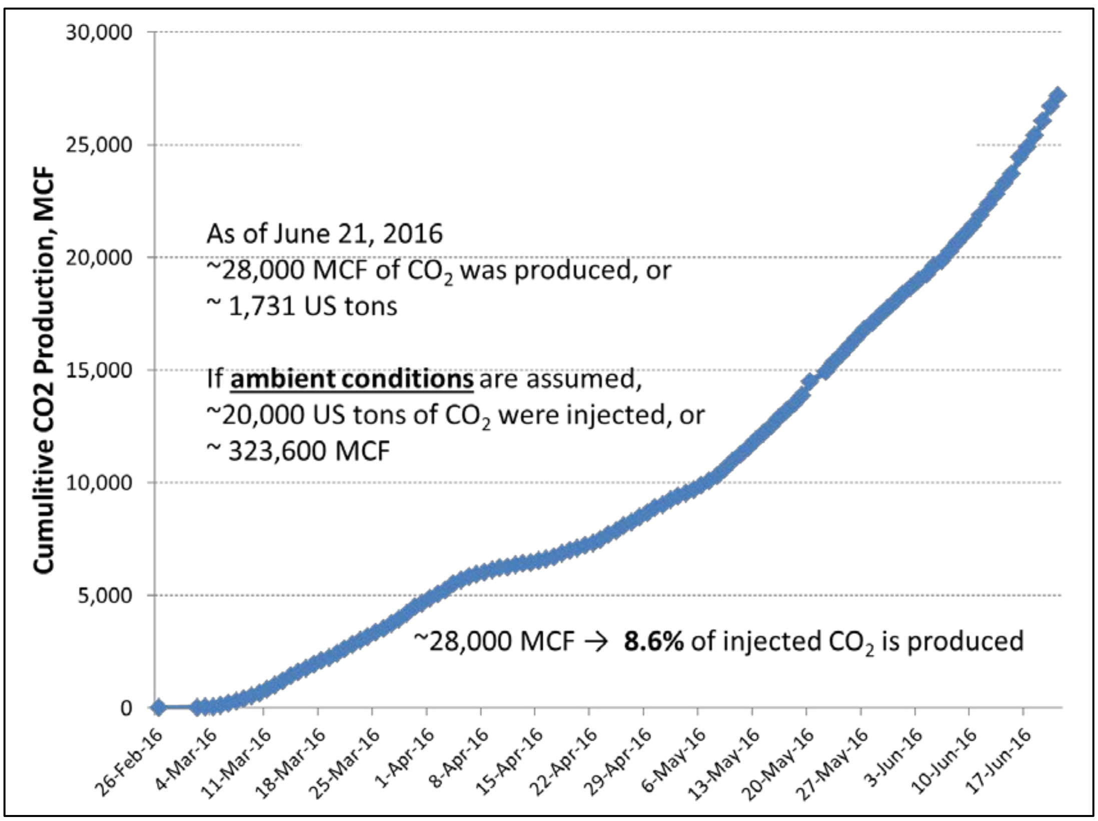


Figure 29. Cumulative CO2 production, MCF.

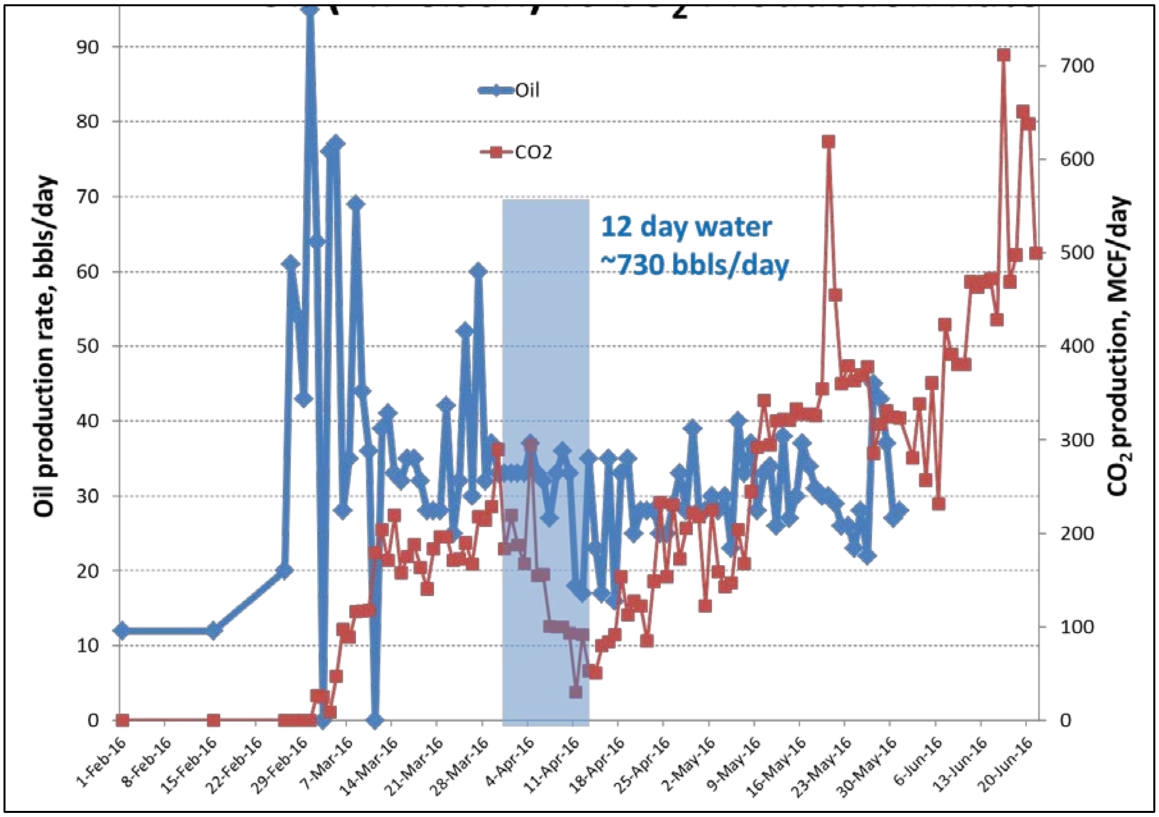


Figure 30. Oil produced at East Nelson tank battery compared to CO2 production rate.

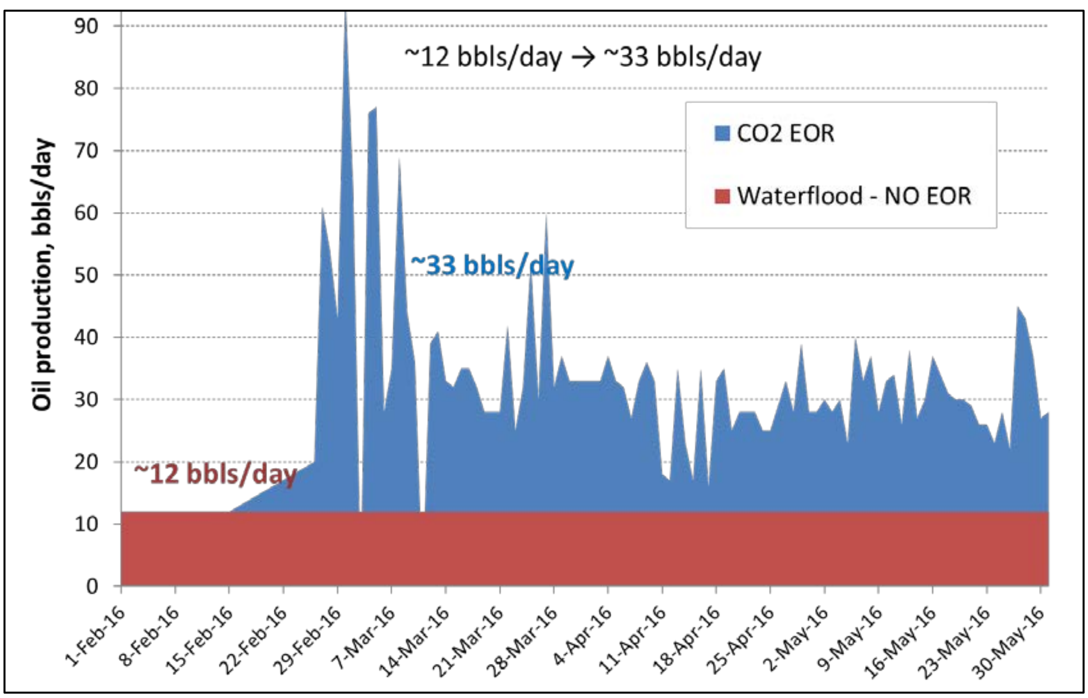


Figure 31. Oil production rate at East Nelson tank battery in bbls/day comparing CO2-EOR versus assumed production without CO2.

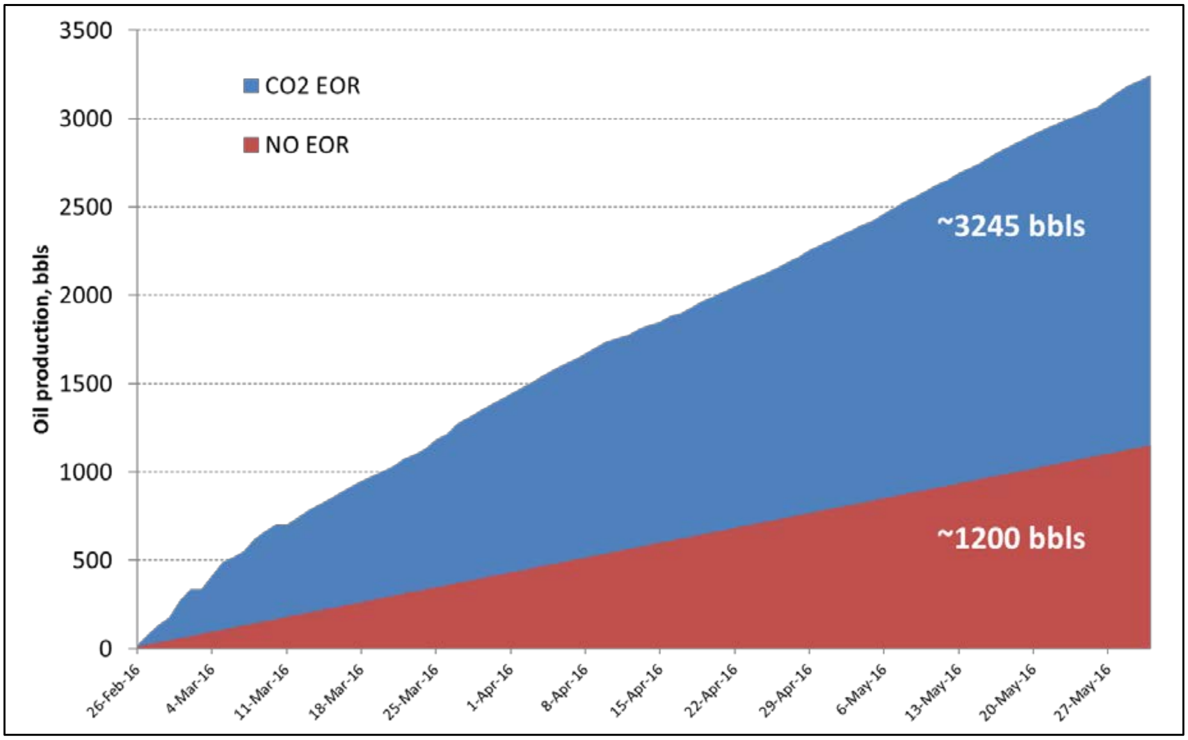


Figure 32. Cumulative oil production, bbls., March-June 16.

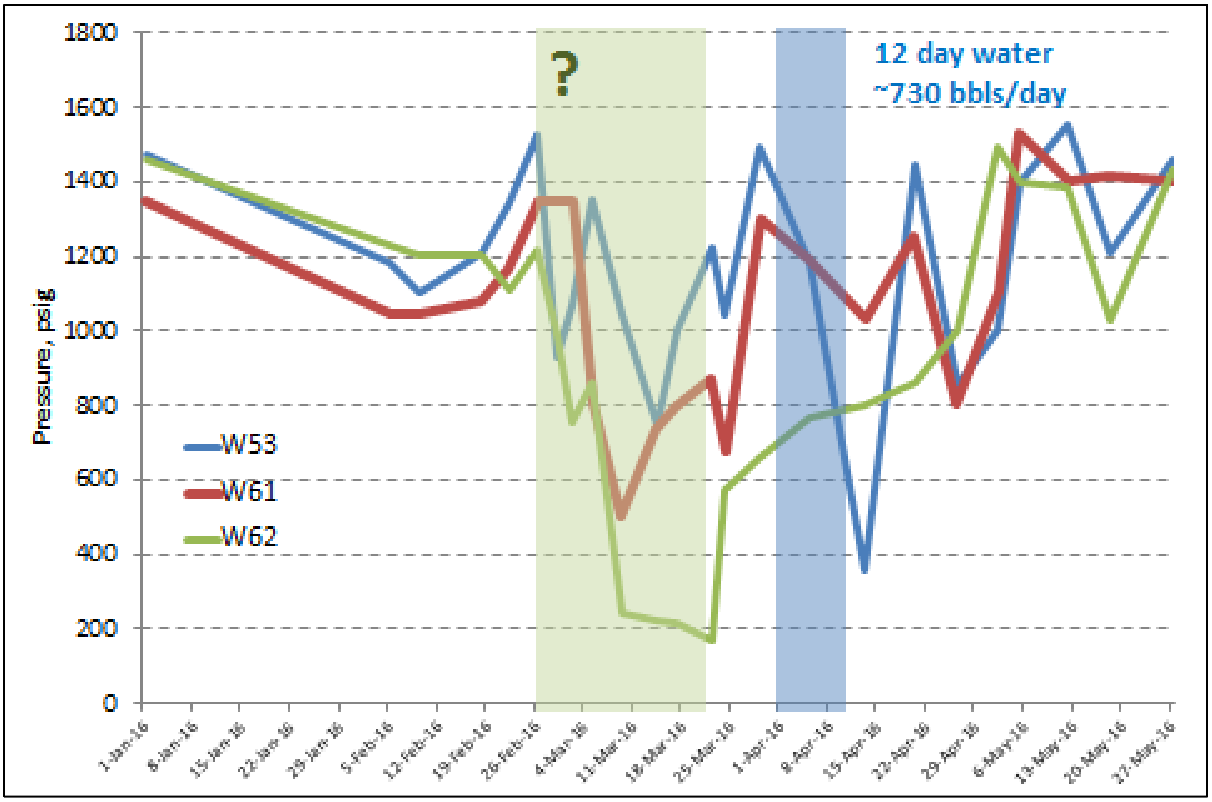


Figure 33. Bottom hole pressure, psig.

Figures 34 through 38 show the forecast of reservoir performance made by the simulation on July 1, 2016. Recommendations from the simulation is that for optimal CO2 sweep efficiency continue water injection at maximum capacity at wells 2-32, 52, and 55. CO2 production is likely to increase in the next few months based on the shape of a production curve;

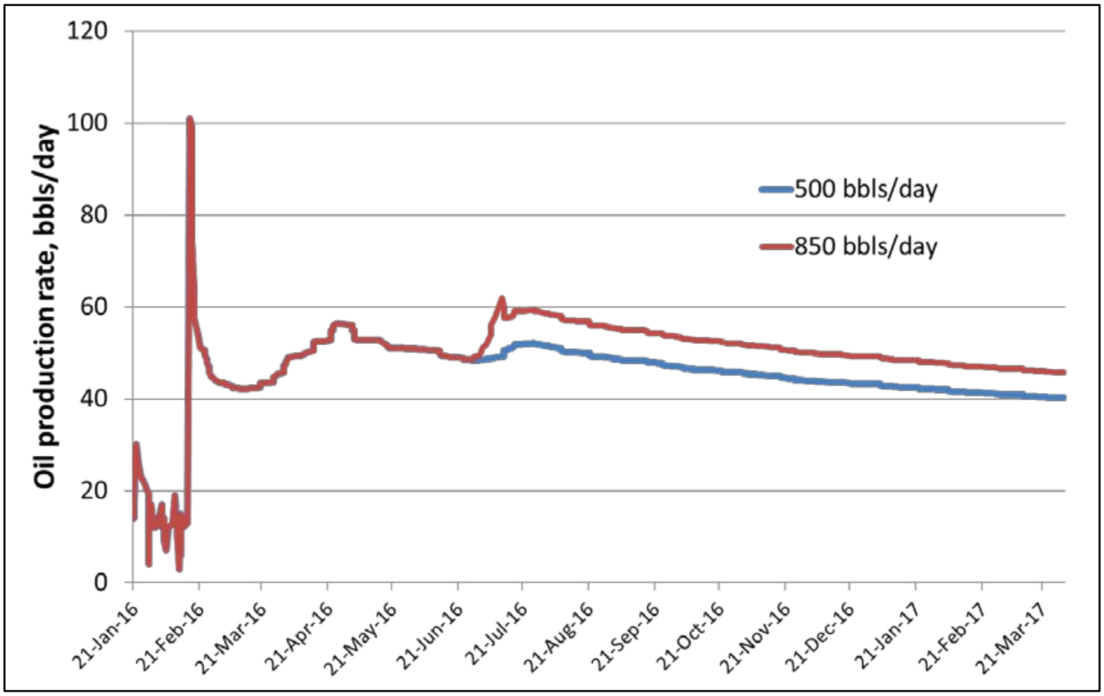


Figure 34. Forecasted oil production for theEast Nelson tank battery producing oil from the wells around the CO2 injection well. 850 barrels per day was chosen as the target injection rate for water. The forecasted bump in production at the end of June when the injection is converted from CO2 to water was also realized by the actual performance.

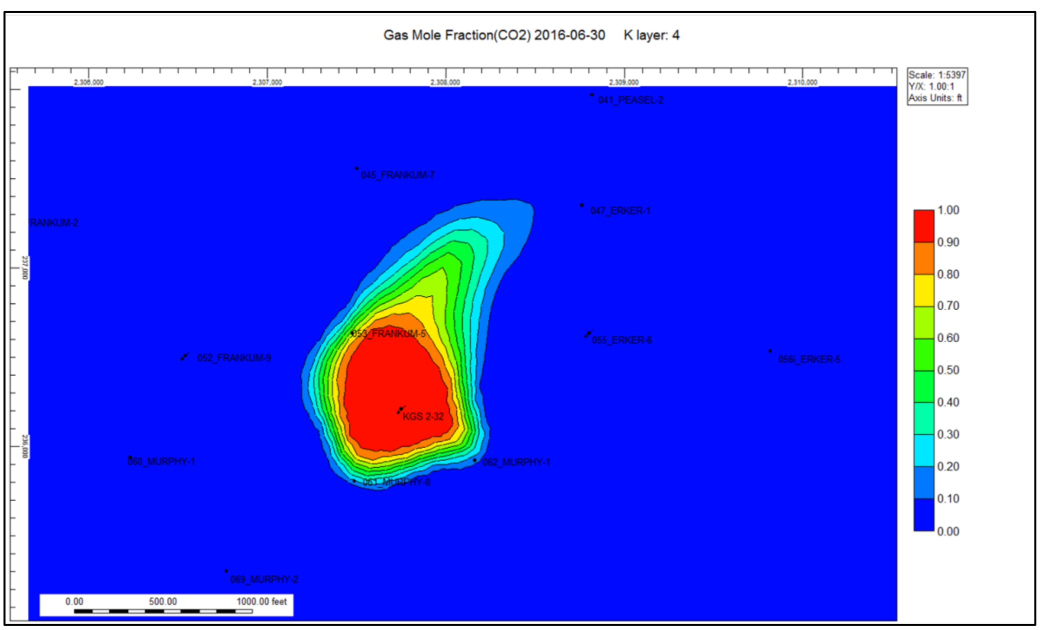


Figure 35. Forecast CO2 plume at the end of June 2016 just after the time that the CO2 injection ended on June 21.

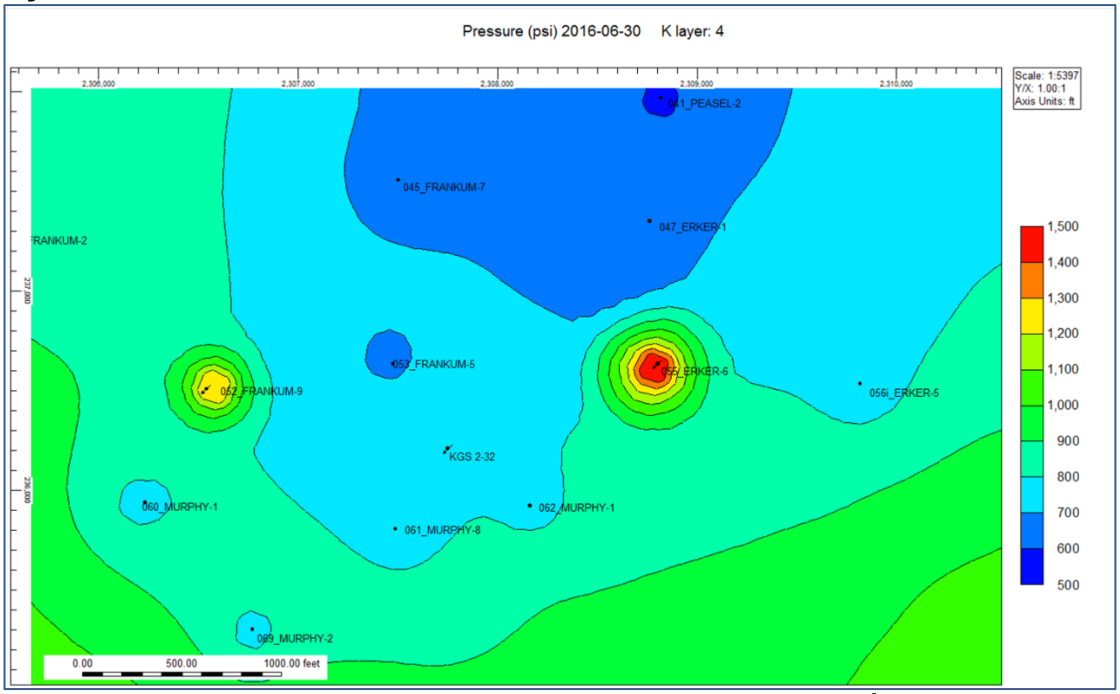


Figure 36. Bottom hole reservoir pressure at the end of June 30th . Note pressure sink north of the injection well, #2-32, the well highlighted in red. CO2 plume is going to the lower pressure area managed in part by the injection well and a pressure barrier to the south of the injection well.

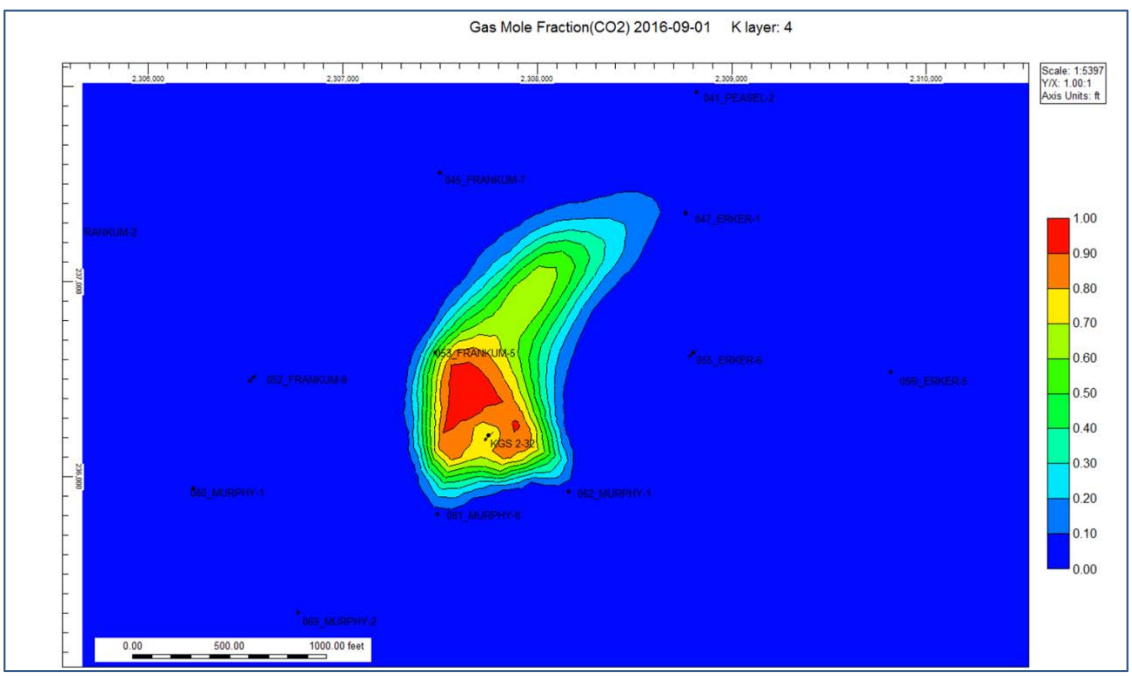


Figure 37. CO2 plume forecasted on September 1, 2016.

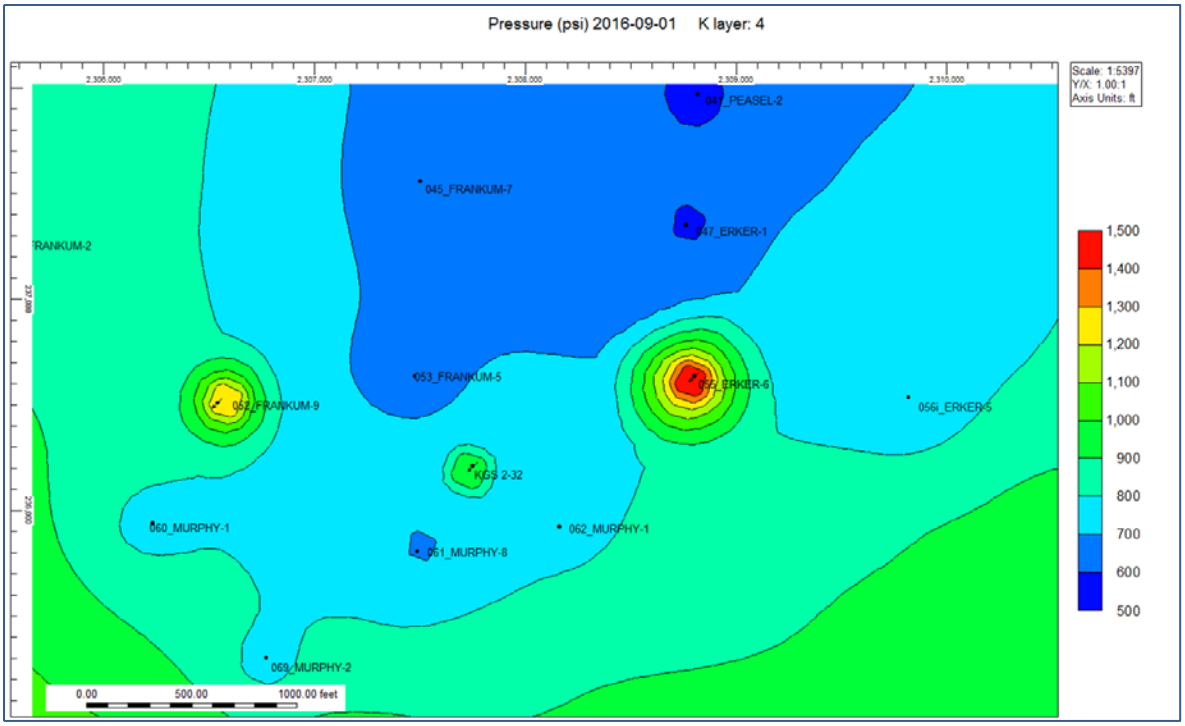
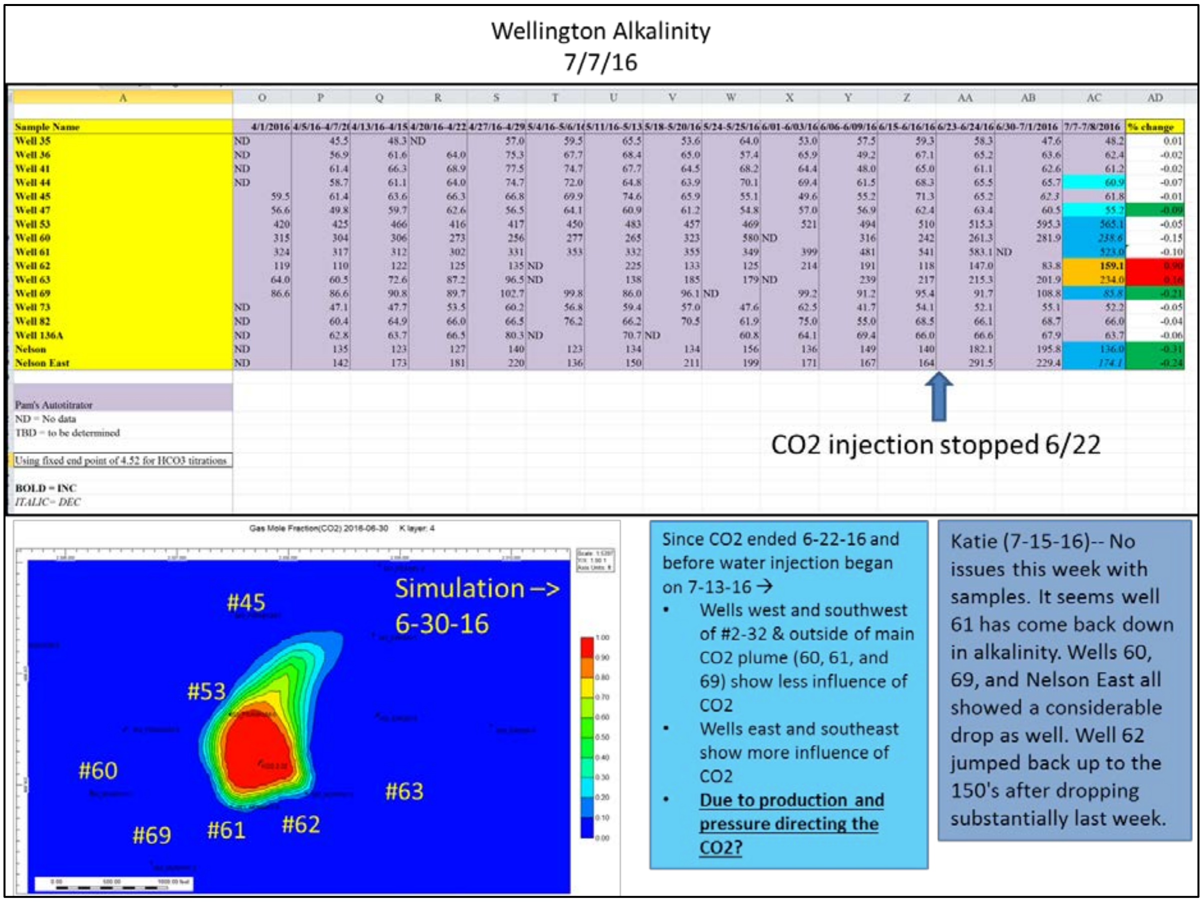


Figure 38. Pressure predicted for September 1, 2016.

Figure 39 through 48 convey results for the well based monitoring including brine geochemistry. The analysis continues.



Wellington Alkalinity
7/7/16

Sample Name	4/1/2016	4/5/16-4/7/2(	4/13/16-4/15	4/20/16-4/22	4/27/16-4/29	5/4/16-5/6/1(	5/11/16-5/13	5/18-5/20/16	5/24-5/25/16	6/01-6/03/16	6/06-6/09/16	6/15-6/16/16	6/23-6/24/16	6/30-7/1/2016	7/7-7/8/2016	% change
Well 35	ND	45.5	48.3	ND	57.0	59.5	65.5	53.6	64.0	53.0	57.5	59.3	58.3	47.6	48.2	0.01
Well 36	ND	56.9	61.6	64.0	75.3	67.7	68.4	65.0	57.4	65.9	49.2	67.1	65.2	63.6	62.4	-0.02
Well 41	ND	61.4	66.3	68.9	77.5	74.7	67.7	64.5	68.2	64.4	48.0	65.0	61.1	62.6	61.2	-0.02
Well 44	ND	58.7	61.1	64.0	74.7	72.0	64.8	63.9	70.1	69.4	61.5	68.3	65.5	65.7	60.9	-0.07
Well 45	59.5	61.4	63.6	66.3	66.8	69.9	74.6	65.9	55.1	49.6	55.2	71.3	65.2	*62.3*	61.8	-0.01
Well 47	56.6	49.8	59.7	62.6	56.5	64.1	60.9	61.2	54.8	57.0	56.9	62.4	63.4	60.5	55.2	-0.09
Well 53	420	425	466	416	417	450	483	457	469	521	494	510	515.3	595.3	565.1	-0.05
Well 60	315	304	306	273	256	277	265	323	580	ND	316	242	261.3	281.9	*238.6*	-0.15
Well 61	324	317	312	302	331	353	332	355	349	399	481	541	583.1	ND	523.0	-0.10
Well 62	119	110	122	125	135	ND	225	133	125	214	191	118	147.0	83.8	**159.1**	0.90
Well 63	64.0	60.5	72.6	87.2	96.5	ND	138	185	179	ND	239	217	215.3	201.9	234.0	0.16
Well 69	86.6	86.6	90.8	89.7	102.7	99.8	86.0	96.1	ND	99.2	91.2	95.4	91.7	108.8	*85.8*	-0.21
Well 73	ND	47.1	47.7	53.5	60.2	56.8	59.4	57.0	47.6	62.5	41.7	54.1	52.1	55.1	52.2	-0.05
Well 82	ND	60.4	64.9	66.0	66.5	76.2	66.2	70.5	61.9	75.0	55.0	68.5	66.1	68.7	66.0	-0.04
Well 136A	ND	62.8	63.7	66.5	80.3	ND	70.7	ND	60.8	64.1	69.4	66.0	66.6	67.9	63.7	-0.06
Nelson	ND	135	123	127	140	123	134	134	156	136	149	140	182.1	195.8	136.0	-0.31
Nelson East	ND	142	173	181	220	136	150	211	199	171	167	164	291.5	229.4	*174.1*	-0.24

Pam's Autotitrator
ND = No data
TBD = to be determined
Using fixed end point of 4.52 for HCO3 titrations
BOLD = INC
ITALIC= DEC

Figure 39. Changes in alkalinity shown by well from weekly sampled highlighted changes shortly after converting CO2 injection to waterflooding.

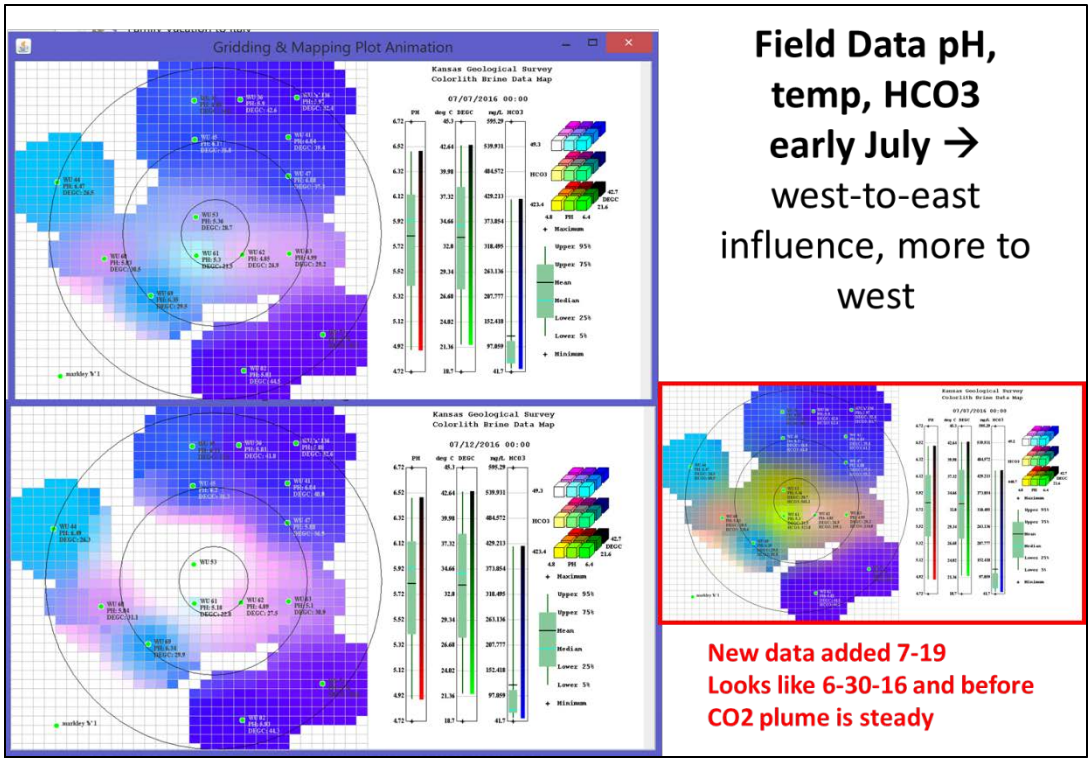


Figure 40. Maps comparing ph, temperature, and bicarbonate.

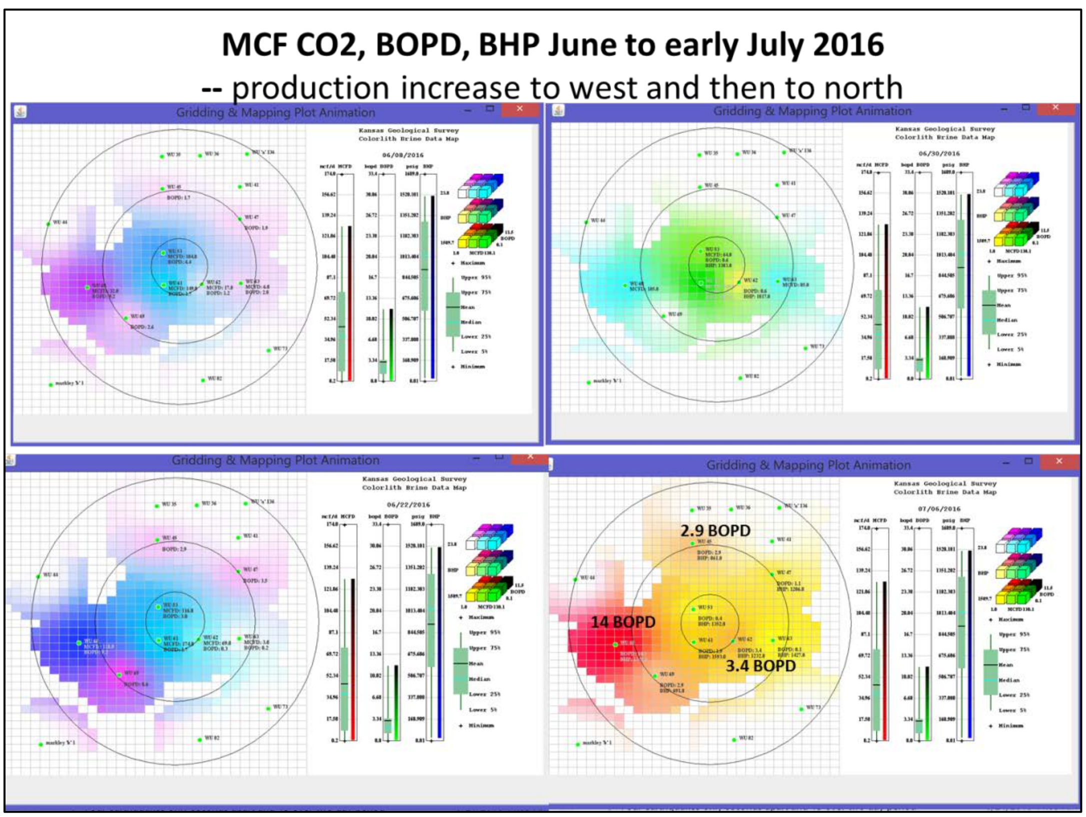


Figure 41. Maps comparing CO2 and oil produced and bottom hole pressure.

	A	B	C	D	E	F	G	H	I	J
1	Determination start	ID1.Value	pH	Alkalinity Dynamic (mg/L)	dynamic ep volume (mL)	Alkalinity Fixed (mg/L)	fixed ep volume (mL)	Ph4 (post-run buffer calibration check)	Sample size (g)	Corrected_Alkalinity (HCO3 mg/L)
603	2016-05-12 14:47:56 UT	WellNelsonEast_201605	5.29	156.19	5.119	139.95	4.587	4	46.8	136.4
604	2016-05-13 15:38:16 UT	wellNelson_20160506	5.64	142.09	4.657	126.61	4.15	4	46.8	123.4
605	2016-05-13 18:04:00 UT	wellNelsonEast_201605	5.71	146.64	4.806	130.4	4.274	3.99	48.3	123.1
606	2016-05-16 16:10:29 UT	wellNelson_20160513	5.73	161.15	5.282	139.28	4.565	3.99	47.3	134.3
607	2016-05-17 13:38:56 UT	wellNelsonEast_201605	5.92	176.77	5.794	155.79	5.106	3.98	47.5	149.5
608	2016-05-18 15:19:11 UT	wellNelsonEast_201605	6.03	164.24	5.383	146.6	4.805	3.99	46.5	143.8
609	2016-05-24 16:13:45 UT	wellNelsonEast_201605	5.54	239.41	7.847	213.29	6.991	3.99	46.1	211.0
610	2016-05-25 17:43:39 UT	wellNelson_20160520	6.02	145.68	4.775	130.48	4.277	3.99	47.2	126.1
611	2016-05-26 10:20:12 UT	wellNelson_20160520	5.71	156.23	5.121	138.89	4.553	3.99	47.1	134.5
612	2016-05-27 10:19:04 UT	wellNelsonEast_201605	5.57	237.95	7.799	211.31	6.926	4	47.6	202.4
613	2016-05-27 14:04:08 UT	wellNelson_20160525	5.54	166.49	5.457	156.8	5.14	4	47.1	151.8
614	2016-05-27 16:17:49 UT	wellNelsonEast_201605	5.82	204.93	6.717	189.48	6.211	4	46.3	186.6
615	2016-06-01 08:26:24 UT	wellNelsonEast_201605	5.59	215.86	7.075	203.25	6.662	3.99	46.6	198.9
616	2016-06-01 19:47:58 UT	wellNelson_20160525	5.98	168.19	5.513	157.94	5.177	4	46.3	155.6
617	2016-06-09 09:59:10 UT	wellNelsonEast_201606	5.31	187.89	6.159	158.52	5.196	3.99	47.3	152.8
618	2016-06-09 11:15:38 UT	wellNelson_20160602	5.7	146.39	4.798	127.37	4.175	3.99	47	123.6
619	2016-06-10 10:59:57 UT	wellNelsonEast_201606	5.32	2.78	0.091	177.82	5.828	3.99	47.3	171.4
620	2016-06-10 12:58:40 UT	wellNelson_20160602	5.9	161.11	5.281	142.54	4.672	4	47.7	136.3
621	2016-06-16 16:16:29 UT	wellNelson_20160609	5.63	174.09	5.706	150.73	4.941	3.99	47.6	144.4
622	2016-06-17 08:48:51 UT	wellNelson_20160609	5.71	174.14	5.708	155.41	5.094	4	47.5	149.2
623	2016-06-20 15:05:14 UT	wellNelsonEast_201606	5.47	210.32	6.894	173.09	5.673	3.99	47.5	166.2
624	2016-06-21 10:19:17 UT	wellNelsonEast_201606	5.46	215.38	7.06	177.1	5.805	4	48.3	167.2
625	2016-06-21 14:32:57 UT	wellNelson_20160616	5.7	170.81	5.599	148.36	4.863	4	48.5	139.5
626	2016-06-22 08:44:33 UT	wellNelson_20160616	5.45	168.15	5.511	144.98	4.752	4	47.8	138.3
627	2016-06-22 13:30:41 UT	wellNelsonEast_201606	5.61	194.3	6.369	170.5	5.589	4	47.5	163.7
628	2016-06-29 10:59:03 UT	wellNelsonEast_201606	5.36	191.52	6.278	168.79	5.533	4	47.2	163.1
629	2016-07-01 09:54:03 UT	wellNelson_20160624	5.96	207.7	6.808	185.7	6.087	4	46.7	181.3
630	2016-07-01 11:59:54 UT	wellNelsonEast_201606	5.76	334.07	10.95	300.32	9.844	4	47.6	287.7
631	2016-07-01 14:43:54 UT	wellNelson_20160624	5.6	211.88	6.945	187.66	6.151	4	47	182.1
632	2016-07-01 16:31:14 UT	wellNelsonEast_201606	5.77	329.77	10.809	299.18	9.807	4	46.8	291.5
633	2016-07-05 16:54:36 UT	wellNelson_20160701	5.84	220.57	7.23	199.62	6.543	4	46.5	195.8
634	2016-07-06 09:37:59 UT	wellNelson_20160701	5.64	224.3	7.352	197.9	6.487	3.99	47.5	190.0
635	2016-07-06 15:40:38 UT	wellNelsonEast_201607	5.59	267.06	8.754	239.01	7.834	4	47.5	229.4
636	2016-07-07 10:24:44 UT	wellNelsonEast_201607	5.37	262.02	8.588	228.73	7.497	3.99	46.7	223.3
637	2016-07-14 09:41:38 UT	wellNelsonEast_201607	5.32	203.7	6.677	178.72	5.858	4	46.8	174.1
638	2016-07-14 10:16:53 UT	wellNelson_20160708	5.61	156.51	5.13	136.63	4.478	3.99	45.8	136.0
639	2016-07-15 08:39:38 UT	wellNelson_20160708	5.43	156.59	5.133	134.32	4.403	4	46.4	132.0
640	2016-07-15 09:09:13 UT	wellNelsonEast_201607	5.3	206.89	6.782	175.82	5.763	3.99	47.7	168.1
641										
642										

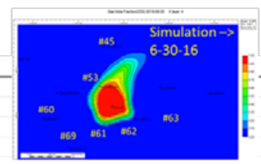
Summary Average Graphs Sheet1

Nelson tank battery and SWD

- Nelson East increases in alkalinity after the CO2 injection ceases.
- Explanation ? → pressure decline after CO2 injection ceases and CO2 comes out of solution?

Figure 42. Tabulated data from brine samples taken from Nelson East tank battery comparing before and after CO2 injection was ended.

- **Well #45 – Conductivity/TDS declined since the CO2 injection ended on 6-22 in a manner that it did after 11 days of water injection in early April**



Well	45						
Sampling Date	pH-average	Max Temp.(°C	pH-mV	Conductivity (ı	Resistivity (Ω -	TDS (g/L)	Notes
1/19 - 20/16	5.43	23.3					
1/27/2016	6	24.3					
2/3 - 2/4/16	6.04	24.6					
2/10 - 2/12/16	Offline	Offline					
2/18 - 2/19/16	Offline	Offline					
2/23 - 2/24/16	Offline	Offline					
2/25/2016	Offline	Offline					
3/2 - 3/4/16							
3/7 - 3/8/16							
3/15 - 3/17/16	6.28	35.5	42.1	192.2	5.19	192.4	Good oil cut (3-5mL), oil smells weird like pumkin. Well
3/23 - 3/25/16	6.17	35.2	46	187.5	5.34	187.3	Good oil cut (~10mL)
4/1/2016	6.09	35	50.9	184.3	5.43	184.1	Small oil cut (3-5mL)
4/5 - 4/7/16	6.13	34.6	48.5	189.6	5.27	189.7	Small oil cut (1-3mL)
4/13 - 4/15/16	6.3	35.1	41.1	185.6	5.39	185.6	Small oil cut (3-5mL)
4/20 - 4/22/16	6.28	35.6	39	177.7	5.62	177.8	Small oil cut (1-3mL)
4/27 - 4/29/16	6.44	34.7	28.9	181	5.53	180.9	Small oil cut (~5mL)
5/4 - 5/6/16	6.37	35.7	36	180.5	5.54	180.4	Small oil cut (~5mL)
5/11 - 5/13/16	6.31	35.3	37.6	177.8	5.62	177.9	Small oil cut (3-5mL)
5/18 - 5/20/16	6.38	35.6	34	187.2	5.34	187.2	Small oil cut (3-5mL)
5/24 - 5/26/16	6.28	36.1	36.2	182	5.49	182.1	Good oil cut (20-25mL)
6/1 - 6/3/16	6.38	36.1	30.8	181	5.53	181	Small oil cut (15-20mL)
6/8 - 6/10/16	6.23	37	41.3	184.7	5.41	184.9	Small oil cut (5-10mL)
6/15 - 6/16/16	6.23	37.4	38.8	183.4	5.45	183.6	Small oil cut (5-10mL)
6/23 - 6/24/16	6.22	36.7	38.3	182.1	5.49	182.2	Good oil cut (30-60mL)
6/30 - 7/1/16	6.17	33.1	41.1	179.9	5.55	180.1	Good oil cut (~10mL)
7/7 - 7/8/16	6.17	36.8	40.4	176.9	5.65	176.9	Small oil cut (2-3mL)

Figure 43. Comparing ph, temperature, and conductivity from produced in well #45 located north of the injection well. Little change indicating that CO2 plume is nearby, but

increases in oil produced indicate that the oil bank has arrived at well #45 (See Figure 44 below).

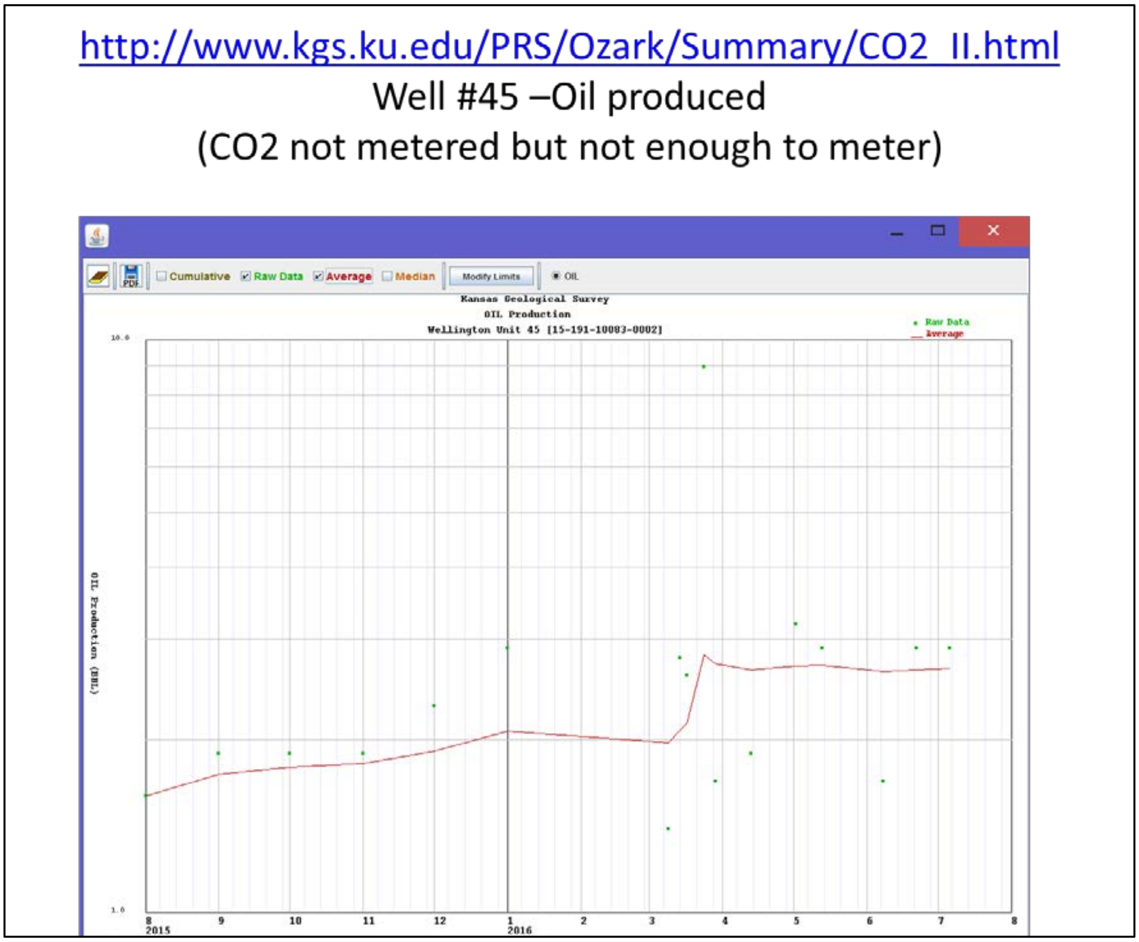


Figure 44. Oil produced in BOPD from well #45. Oil production increased two months after CO2 injection started. Chart is based on Java driven well tool.

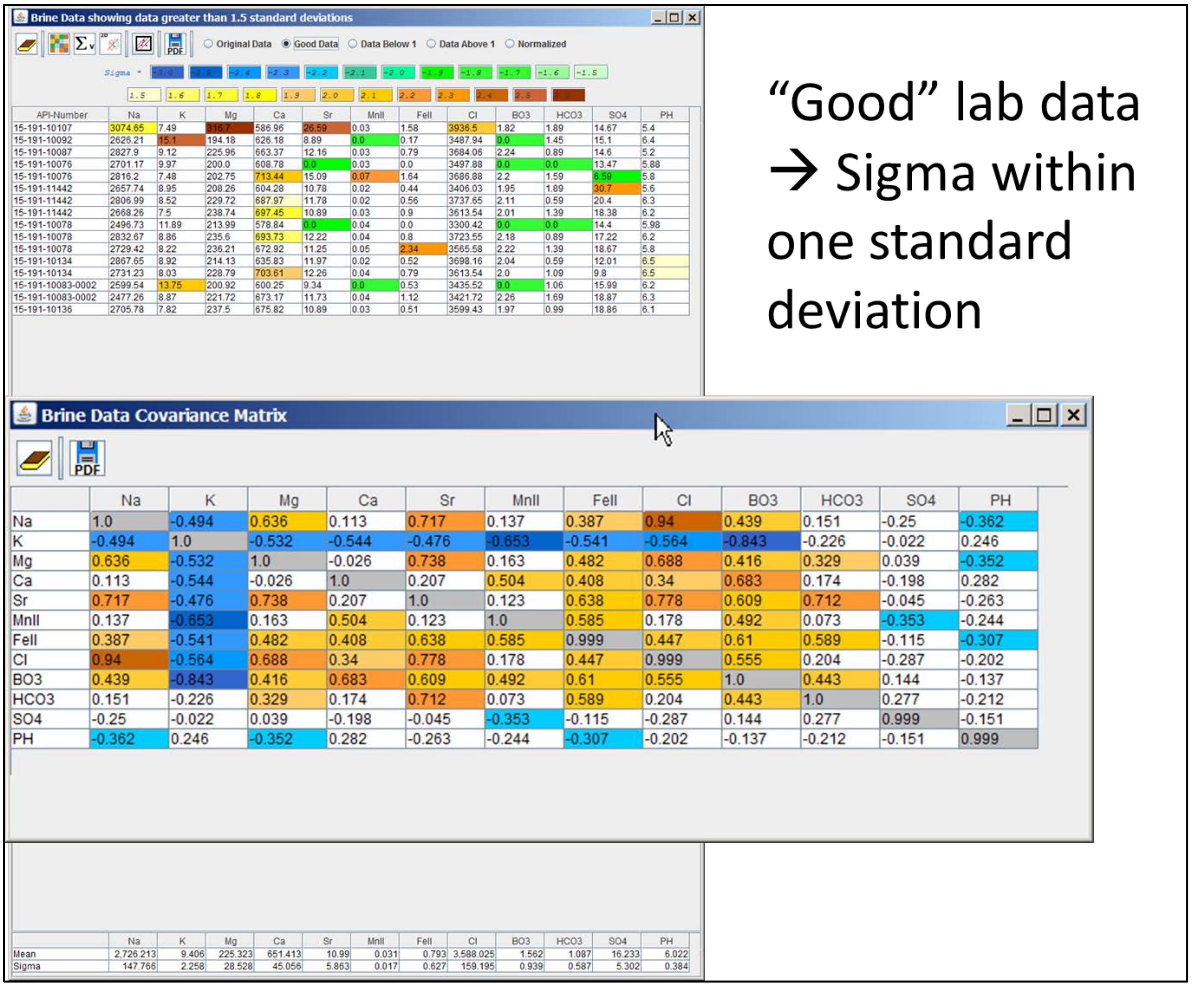


Figure 45. Lab data on water chemistry continues to be acquired. Weekly sampling of 17 wells created a backlog so specific wells were run sooner so the CO2 plume could be tracked. The chemical data will be used to model the CO2 sequestration process.

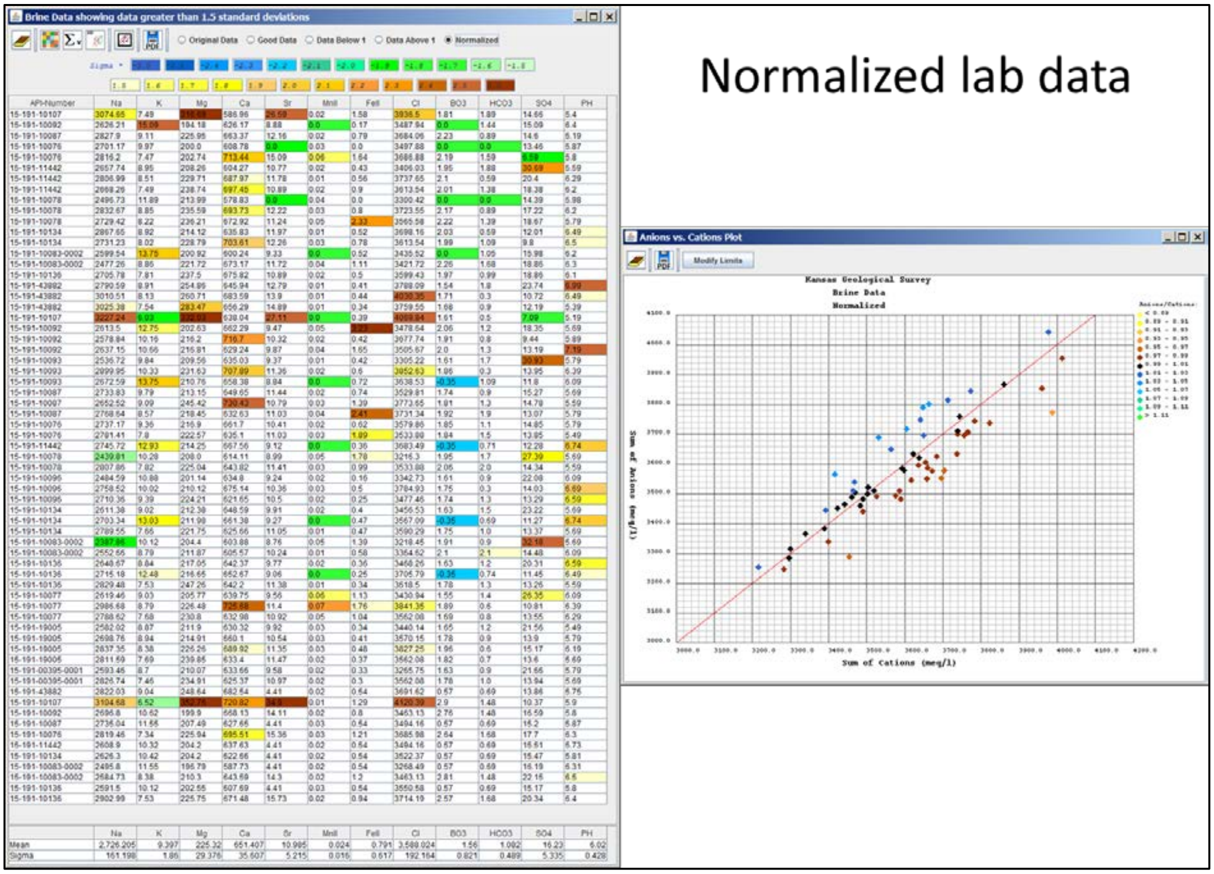


Figure 46. Cation and anion balance is used to check the accuracy of the measurements. The Tables highlights wells where departure for charge balance is noted. Anion and cation data can be normalized in the same Java web application used to assist in comparing brine geochemistry.

Normalized data
Eigenvector Matrix used
in PCA Analysis

Brine Data Eigenvector Matrix

	1	2	3	4	5	6	7	8	9	10	11	12
Na	-0.307	0.471	0.274	-0.53	-0.254	-0.008	0.181	-0.055	-0.11	-0.015	-0.195	-0.418
K	-0.432	-0.156	0.348	-0.089	0.283	0.309	-0.193	-0.476	0.169	0.156	-0.224	0.338
Mg	-0.468	-0.036	-0.269	0.564	-0.03	0.312	0.209	-0.109	-0.042	-0.237	-0.085	-0.41
Ca	-0.031	0.252	0.0	0.211	-0.137	0.167	-0.657	0.253	0.197	0.489	-0.019	-0.261
Sr	0.488	0.164	0.433	0.162	0.447	0.14	0.051	-0.185	0.226	-0.188	0.075	-0.412
MnII	-0.062	-0.112	0.501	0.274	-0.163	0.06	0.328	0.065	-0.376	0.458	0.401	0.028
FeII	0.129	0.163	-0.502	-0.21	0.096	0.154	0.069	-0.553	-0.085	0.359	0.406	-0.113
Cl	0.223	-0.73	0.005	-0.247	-0.264	0.173	-0.003	-0.069	0.035	0.153	-0.24	-0.408
BO3	-0.406	-0.265	-0.036	-0.282	0.513	-0.164	-0.037	0.36	0.123	0.02	0.417	-0.267
HCO3	-0.141	-0.099	0.168	0.095	-0.453	-0.391	-0.181	-0.358	0.417	-0.236	0.421	-0.065
SO4	0.05	0.042	0.022	-0.218	-0.243	0.716	0.051	0.263	0.23	-0.275	0.364	0.202
PH	-0.011	0.076	-0.092	0.06	-0.019	-0.082	0.549	0.124	0.688	0.385	-0.17	0.077

	1	2	3	4	5	6	7	8	9	10	11	12
Eigen	0.057	0.066	0.14	0.205	0.248	0.435	0.533	0.833	1.065	1.441	2.618	4.36
%	0.4	0.5	1.1	1.7	2	3.6	4.4	6.9	8.8	12	21.8	36.3

Figure 47. Java web application is used to perform a principle component analysis on the brine geochemistry using raw or normalized results. Shown in figure is an eigenvector matrix.

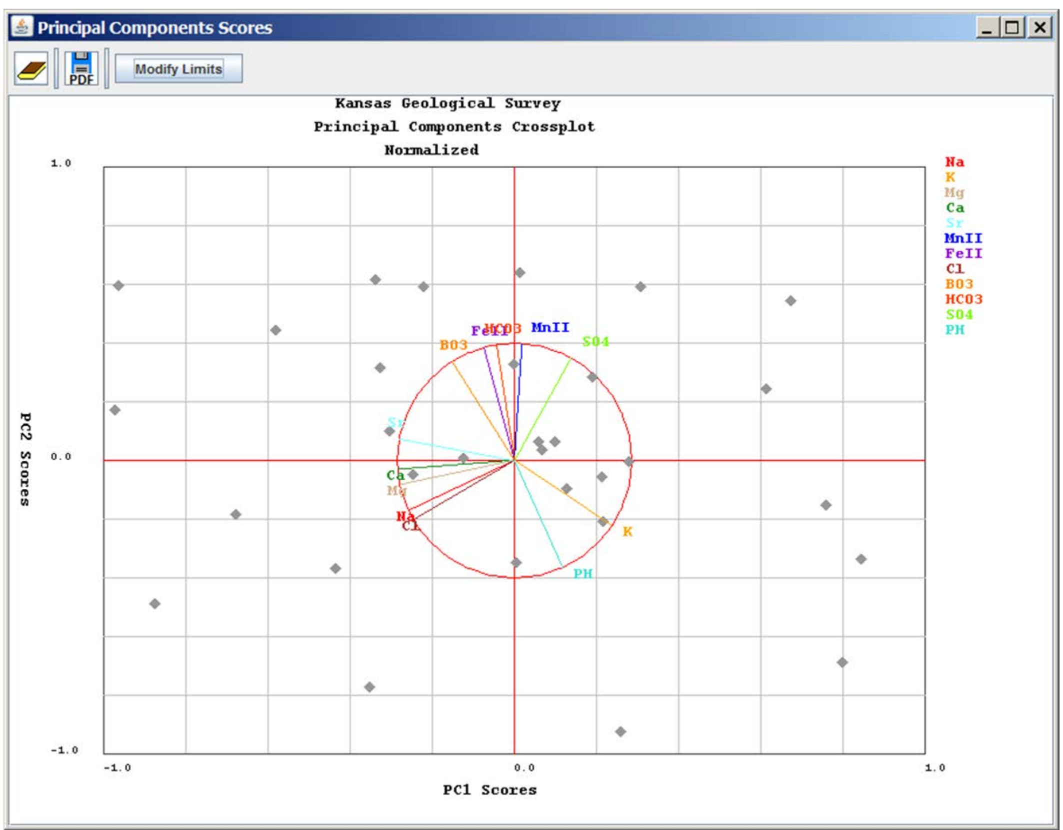


Figure 48. Normalized lab data used in this chart of PCA scores and loading.

SUMMARY

1. The mobilized oil recovered to date continued to represent only a very small fraction of the pore volume and performance and simulation data indicate that the sweep is occurring mainly in the upper part of the reservoir at the elevation of the perforations.
2. With more CO2 and longer perforated interval, a large amount of CO2 could be injected with increased incremental oil produced and eventually more CO2 stored.
3. The CO_2 that has been produced is less than 15% of the Co2 that has been injection
4. The CO2 plume has been relatively stable to the point that the injection of CO2 ceased and waterflood began.
5. CO2 plume is moving north toward well #45 as forecasted by the simulation. However, CO2 plume has not appreciably moved since waterflood began on June 21.
6. The CO2 plume and oil bank are well behaved in the sense the sweep is quite uniform and the recovery of oil and CO2 has remained steady. CO2 has not broken through at any location including along the small fault bordering the east side of the CO2 injection well.
7. The matrix porosity and permeability are dominating the CO2 injection sweep demonstrate the viability of this dolomitic reservoir for using CO2 for both incremental oil recovery and CO2 storage.
8. CO2 finally reached well #63 located to the east of the injection well. The delay is not unanticipated with the diminished response to pressurization before CO2 injection and a subdued response during a pressure pulse test in May 2015. Interpretation of 3D seismic also indicates a northeast-to-southwest area of reduced permeability and porosity in the vicinity of well #63 that appears to be responsible for the delayed response. The small fault associated with the area of reduce porosity and permeability has no other effects on the CO2 injection compares to normal variations in reservoir properties as conveyed by the existing seismic data and interpretations.
9. Induced seismicity of small, but notable rates reached Wellington Field in early 2015 prior to repressurization and CO2 injection in the Mississippian reservoir. The Wellington seismometer array has documented this advance with a dependable earthquake catalog that is updated on a weekly basis.
10. Steps have been taken by Kansas regulators to limit rates and volumes of brine injection into the Arbuckle in the area due to this expansion of earthquakes and the development of earthquake clusters as noted with the Wellington array and the temporary array of the KGS.
11. The Wellington array has provided important surveillance of this seismicity, but more important, will provide new scientific understanding of the properties of earthquakes, including geomechanical information that will augment other well based and seismic information from Wellington. The objective will be to address what comprises safe and effective injection and understand the mechanisms of induced seismicity to further limit or prevent induced seismicity in the future.
12. Introduction of continuous downhole pressure monitoring in the Arbuckle in the idle well #1-28 shows considerable promise to establish that static pressure in the lower Arbuckle has risen since the well was last tested in August 2011. The resolution of the pressure transducer is also investigating the potential to short term pressure perturbations that may be from start-up of larger brine disposal wells or co-seismic events when earthquakes occur. The well information will be compared with updates to the regional brine

simulations and is currently being compared in time with events from the Wellington earthquake catalog.

FUTURE PLANS

- Continue post-injection monitoring on a monthly basis for wells that are responding to flood.
- Continue weekly sampling of wells to monitor production including CO2, oil, and brine recovered,.
- Perform on-site and lab geochemical analysis for select wells with the exception of alkalinity that is limited only to measurements at the well.
- Continue operation of the Wellington seismometer array.
- Continue baseline pressure measurements in the perforated lower Arbuckle zone of the shut-in Class VI injection well.
- Continue to acquire SAR satellite images and recording cGPS for analysis of ground motion.
- Completing the processing of a long offset 2D lines as soon as the CO2 injection ends in the Arbuckle.
- Passive seismic monitoring will continue as a very important component for DOE and EPA.
- BP3 tasks and budget have been updated for the Arbuckle injection pending Class VI permit and extending the project beyond September 30th.

PRODUCTS

Publications, conference papers, and presentations

Presentations at KU Engineering Environmental Conference in Lawrence and CCUS meeting in Washington DC.

PARTICIPANTS & OTHER COLLABORATING ORGANIZATIONS

A project organization chart follows (**Figure 49)**. The work authorized in this budget period includes office tasks related to preparation of reports and application for a Class VI permit to inject CO_2 into the Arbuckle saline aquifer.

Organizational Structure
Small Scale Field Test - Wellington Field (FE0006821)

UNIVERSITY OF KANSAS Center For Research

Kansas Geological Survey

Name	Project Job Title	Primary Responsibility
W. Lynn Watney	Project Manager, Joint PI	Geology, Information Synthesis, Point of Contact
Jason Rush	Joint PI	Geology, Static Modeling, Data Integration, Synthesis
Tiraz Birdie	Consulting Engineer	Reservoir Engineer, Dynamic Modeling, Synthesis
Yevhen 'Eugene' Holubnyak	Petroleum Engineer	Reservoir Engineer, Dynamic Modeling, Synthesis
John Doveton	Co-Principal Investigator	log petrophysics, geostatistics
Kerry D. Newell	Co-Principal Investigator	Fluid Geochemistry
Fatemeh 'Mina' FazelAlavi	Engineering Assistant	Log Data analysis, Modeling
John Victorine	Software Programmer	Database management, web tool design
Jennifer Hollenbock	Project Coordinator	Project Management, communication, data handling
KU Department of Geology		
George Tsoflias	Co-Principal Investigator	Wellington Seismometer Array, Seismic imaging
Jennifer Roberts	Co-Principal Investigator	Microbial biogeochemistry and CO2 sequestration
Leigh Sterns	Affiliated Scientist	cGPS processing for InSAR interpretation

Name	Primary Responsibility
Dana Wreath - Vice President	Manager, engineer
Staff of Wellington Field	Daily Field operations
Beredco Drilling Team	Drilling and completion activities
Linde, LLC	**CO2 Supply**
Earl Lawson - *Vice President*	

Lawrence Berkeley National Laboratory

Name	Project Job Title	Primary Responsibility
Tom Daley	Co - Principal Investigator	Geophysicist, crosshole and CASSM data
Barry Freifeld	Co - Principal Investigator	Mechanical Engineer, U-Tube Sampler

T. Birdie Consulting

Name	Project Job Title	Primary Responsibility

Figure 49. Updated Organizational Chart.

IMPACT

The response of the CO2-EOR has been successful. Downhole pressure monitoring is important in validating hypotheses to explain the effects of large scale injection. All of information requested EPA by has been submitted for the application of a Class VI injection permit.

CHANGES/PROBLEMS

Funds are very tight due to the no cost time extensions necessary to permit review and response to for the Class VI permit.

BUDGETARY INFORMATION

Cost Status Report

Baseline Reporting Quarter	10/1/15 - 12/31/15 Q17	1/1/16 - 3/31/16 Q18	4/1/16 - 6/30/16 Q19	7/1/16 - 9/30/16 Q20
Baseline Cost Plan (from SF-424A)				
Federal Share	$325,087.75	$325,087.75	$325,087.75	$325,087.75
Non-Federal Share	$0.00	$0.00	$0.00	$0.00
Total Planned (Federal and Non-Federal)	$325,087.75	$325,087.75	$325,087.75	$325,087.75
Cumulative Baseline Cost	$13,008,472.53	$13,333,560.28	$13,658,648.03	$13,983,735.78
Actual Incurred Costs				
Federal Share	$329,868.02	$271,440.25	$1,743,607.98	$0.00
Non-Federal Share	$0.00	$0.00	$69,879.00	$0.00
Total Incurred Costs-Quarterly (Federal and Non-Federal)	$329,868.02	$271,440.25	$1,813,486.98	$0.00
Cumulative Incurred Costs	$3,278,018.21	$3,549,458.46	$5,362,945.44	$5,362,945.44
Variance				
Federal Share	-$4,780.27	$53,647.50	-$1,418,520.23	
Non-Federal Share	$0.00	$0.00	-$69,879.00	
Total Variance-Quarterly Federal and Non-Federal)	-$4,780.27	$53,647.50	-$1,488,399.23	
Cumulative Variance	**$9,730,454.32**	**$9,784,101.82**	**$8,295,702.59**	