Application of Cutting-Edge 3D Seismic Attribute Technology to the Assessment of Geological Reservoirs for CO_2 Sequestration

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Executive Summary

This was the last quarter of the Dickman project and efforts focused on finalizing the geologic gridded property model and flow simulation grid to achieve a satisfactory history match. The latter is critical for validation of the gridded property model. Work has already begun on the final project report (due 30 June 2010), with various components of the report allocated to researchers associated with the project. The project final report outline and content will be designed in collaboration with our DOE program officer.

Activities in Quarter
Activities in this quarter are focused on the final report on the scientific achievements and effective workflow of the Dickman CO2 sequestration project. The planned contents, authors and progresses are shown in Table 1. In addition, efforts were made to tackle the remaining challenges that may become a part of the final report, or further focus of the Dickman research. Three major tasks were performed in geology and geophysics: 1) Detailed re-interpretation of the Mississippian horizon spice volume to compare with amplitude interpretation, 2) Re-adjustment of input reservoir properties based on the results of history matching flow simulation, 3) Up-dated information on regional stratigraphy and tectonic history based on new Kansas Geological Survey (KGS) publications through 2009. The first task resulted in a paper submitted to the upcoming SEG 2010 and a poster presentation at the Annual DOE Pittsburgh CCS Conference in May 2010. In flow simulation research, two rounds of history matching simulations were performed on Dickman filed production data to yield good matches in oil and water production. Moreover, an optimized input parameter set was obtained by analyzing misfit causes. This further validated the functionality and the efficiency, as well as risks, in using the CMG black oil simulator to predict CO2 injection.

Geology and Geophysics

Comparison of spice and amplitude interpretation. Spice is an attribute computed on migrated stack traces using the continuous wavelet transform and the theory of singularity analysis (Li and Liner, 2008). It has a higher apparent resolution than amplitude, and therefore is useful when trying to map subtle features. Figure 1 shows the top Mississippian time structure map from tracking amplitude (A) and spice (B). At the top Mississippian, a zero crossing in amplitude was auto-tracked as well as the corresponding peak in spice. Both events were tracked first in 8 intersecting 2D lines, with a 2 ms window, followed with 2 iterations of standard 3D tracking. The spice map has better continuity across the mapped area with fewer tracking gaps (Figure 2). In the difficult channel zone, spice gives a better time structure picture. Tracking an event in spice seems much more helpful for distinguishing small scale features than tracking the corresponding event in an amplitude volume.

Since spice peaks correspond to amplitude zero crossings, it follows that when spice shows apparent thin beds the zero crossings are closer together, and this must relate to a local increase in data frequency. One such area in our data is near the Miss unconformity (Figure 1D). Spice and instantaneous frequency are shown for data along the line in Figure 3. As expected, the frequency is often anomalous (high or low) at the Miss. unconformity surface and could be used as a secondary attribute for mapping. However, frequency shows little vertical detail compared to spice and certainly could not be used as a substitute. Also shown in Figure 3 are negative curvature (C) and positive curvature (D). Much like coherence, curvature attributes (Marfurt, 2006) are computed with an extended operator, while spice is a point-wise computation localized in both space and time. In this case, curvatures were computed with a 20 ms time window (red bar). Setting aside the vertical resolution mismatch, curvature and spice both indicate an anomalous area between the Mckinley A-1 and Elmore 3 wells in the vicinity of the Miss unconformity (Nissen, et al., 2006). Curvature and spice are complimentary attributes that can be used to improve detailed interpretation.

Flow model adjustment based on history matching. After analysis of results from the first round of history matching runs, several adjustments were made to improve the fit. The Dickman field is a dominantly carbonate reservoir, with a large oil-water transition zone associated with most of the oil production. Flow grid models resolving the transition zone were developed for this reason.

The input reservoir property grid for the flow simulation was also calibrated based on the first round results. The propagation of permeability within the 3D grid was redone using 325 degree azimuth as a preferred direction, roughly parallel to the NW-trending fractures that were considered as open fractures (Nissen, et al., 2006).
Connate water saturation is an important input parameter for the simulation. In Dickman reservoir core analysis data, connate water saturation (0.2-0.7) seems too high. This water saturation was measured on flushed cores, therefore is likely much higher than in-situ water saturation. Statistics relating the measured water saturation from flushed cores and

the in-situ water saturation were used (Figure 4) to re-scale the measured connate water saturation. The revised values (0.2-0.3) represent a good approximation to the Dickman core data. A value of 0.2 was used in the final simulation runs.

Updated regional stratigraphy. The Kansas Geological Survey has recently updated the regional stratigraphic chart (Figure 5) for Kansas (Sawin, 2008, 2009). We have synchronized the local stratigraphy at the Dickman field to the new regional chart (Figure 5), including the project target interval of Ft. Scott to top Viola ('This Study' blue box in Figure 5). The purpose of this synchronization is to reconstruct a regional structural deformation history that may have controlled the faulting and fracturing events in the target strata.

In the studied area, a part of the younger strata including the Upper Cretaceous and Tertiary is exposed on the steep slopes of the river valleys. The surface exposures include the Upper Cretaceous sandy and chalky shale, and overlying Tertiary unconsolidated or consolidated sand, shale and gravel.

Over 4,900 ft of the older strata were penetrated in the studied area and have been correlated, some with uncertainties, to the regional stratigraphic column established mainly on outcrop studies. The subsurface strata overlaying the Pre-Cambrian basement, from the oldest to the youngest are as follows: Undifferentiated Ordovician/Cambrian and Ordovician dominated by carbonates, Mississippian carbonates, Pennsylvanian cyclic carbonates and clastic rocks, Permian red-bed secessions, and Lower Cretaceous shale and sandstones with chalky beds. The general lithology of these units, especially those taken as correlation keys in both well logs and seismic profiles, will be described in detail for the final report.

The reconstruction of major structure deformation events is based mainly on published studies (Blakely, 2004; Merriam, 1963;). Well tops in the KGS database on the southwest side of the Central Kansas Uplift (CKU) are also used to trace deposition, deformation, and preservation of strata as evidence of structural activities. The movement of the CKU controlled the local faulting and fracturing.

After the major post-Miss. and Pre-Penn. structural movement related to the continental collision along the Ouchita mountain belt, there were at least two structural events that may have left significant footprints in the studied area. The first event was during the late Pennsylvanian time, as indicated by significant thinning of the Upper Penn. Lansing group on top of the CKU and the abrupt thickness changes (up to 200 ft) of Lansing and Kansas City groups along a NE-trending lineation. This lineation is parallel to the south boundary of the CKU. Since Lansing group conformably underlays the younger Penn. strata (Zeller et. all, 1968), these thickness changes suggest syn-depositional uplift of the CKU and local subsidence along the NW side. This event might influence the faulting and fracturing in the Dickman area, such as the NE-trending boundary fault and a couple of NW-trending faults to the north end of the survey area. The second structural event is during late Cretaceous or later, probably associated with the Laramide Orogeny. It results in secondary structures, such as the Northeast trending Aldrich Anticline seen in the Eldritch Northeast field of the studied area. They are perpendicular to the axis of the CKU, and are probably the result of uplift and adjustment caused by stresses along pre-existing zones of weakness (Ramaker, 2006). These anticlines are likely associated with strike-slip movements. As a result, the northeast trending boundary fault in the studied area may have been closed to become a sealing fault to the pay zones in Dickman, Humphrey and Sargent field areas.

Reservoir Simulation

This quarter has seen a major achievement in reservoir simulation, the completion of oil and water history matching for the Dickman field. History-match simulation is a very challenging task and has been a weak point in the CO2 injection simulation, even in recent publications. History-matching work for oil production in the Dickman filed (based on 15 wells), provided important information on methods, input parameter selection, optimization, and risk assessment for the further geological and flow modeling in CO2 sequestration researches.

The conventional role of history matching is to validate and calibrate the reservoir model. The reservoir properties, formation structural data, and production data collected from geological model analysis and the production company (Grand Mesa) can only be validated and calibrated through the history matching process. In addition, the shallow geologic section forms the cap rock for the deep saline aquifer system which is our CO_2 sequestration target. A good understanding of the shallow section is essential for safe CO_2 storage in deep saline aquifers. Dickman field history matching will also provide us a good opportunity to understand the shallow section integrity.

A major challenge for the history-matching work is lack of necessary information from a mature field like Dickman, which was discovered and put into production in 1962. From Hilpman et al. (1964), Carr (2006) and well log data, we collected the following field data:

Acreage	= 240 acres
Net Pay Zone Thickness	= 7 feet
Average depth	= 4424 feet in TVD
Oil API gravity γ_o	= 37 API (0.84 g/cm^3)
The reservoir Temperature	= 113 ^{o}F
The reservoir average pressure	= 2066 psia
TDS (Total Dissolved Solid) salinity	= 45,000 ppm
The aquifer water density	$\gamma_w = 1.03 \frac{g}{cm^3}$ at reservoir condition
The reservoir water compressibility C_w	$= 3 \times 10^{-6} \frac{1}{\text{psi}}$ at reservoir condition
Oil Water Contact (OWC)	= 4578 ft in TVD.

The pressure-volume-temperature constant at thermodynamic equilibrium (PVT data) is used to determine the volume ratios of oil and gas. The volume ratios relate the density at reservoir conditions to the density at surface conditions, therefore the in-situ volumes under formation temperature and pressure determine produced volumes at surface conditions. Since PVT data were not available in this study, it had to be evaluated by correlations. The Computer Modelling Group (CMG) software package for black oil, gas and water PVT (McCain, 1991) was used to predict fluid properties. The correlation to be used is determined by an API gravity criterion (Lasater if API > 15, otherwise Standing). API value for Dickman field is 37, so Lasater's correlation was used.

In a multiple phase flow system containing oil, gas and water, the relative permeability is a function of phase saturation. Stone correlation formulations were used to generate the relative permeability model for relative permeability of water, oil and water, gas and water, and gas (equations in Appendix A).

Figure 6 shows the simulation grid with 15 production wells and one injection well. Table 2 lists production starting date, ending date, and water break through time for all 15 production wells. As shown in Table 2, there is complete oil production data record for all production wells. However, we have complete water production records only for five wells: Dickman 1, Humphrey 2, Humphrey 3, Humphrey 4 and Tilley 5. For the remaining production wells, there is either no water production data or only partial data. Dickman 4 is the water injection well which is used to inject the field waste water back into the reservoir. Because the water injection data record is not available, we assumed that Dickman 4 injected all produced water back to the reservoir.

The relative permeability model, well perforation, net pay zone thickness, PVT and capillary pressure model are the reservoir properties being calibrated to match the water and oil production data. These properties have been updated after each of the simulation run.

In the final simulation, the original PVT model generated by Lasater's correlation was used, and generated good matching results. There was no gas or condensate recorded in Dickman field production reports. The compressibility of water is very small, and the effect of gas compressibility on the production volumes of oil and gas is not very significant.

A good oil and water history match was obtained on the production wells around the Dickman 4 injector, Dickman 1 being a good example (Figure 7). Dickman 1 is the first production well in the Dickman field and is still under production at present day. Matching the Dickman 1 production is an important step in modeling the entire field. Results also suggest that one main function of the Dickman 4 water injection well is to maintain reservoir pressure. Without it the reservoir pressure would be below 1000 psi at the end of the history matching simulation. The assumption that Dickman 4 injected all produced water back into the reservoir seems to be correct.

Well perforation data also plays an important role in history matching. Dickman A1 was reportedly perforated only in the two upper flow model layers (uppermost Mississippian), and the simulated oil production rate is consequently much lower than the real oil production rate (Figure 8, upper). This caused the simulated total Dickman field production rates to mismatch during the 1993-1998 production period of the Dickman A1 well (Figure 8, lower with dashed oval). A better history match is obtained by increasing the Dickman A1 bottom hole depth about 9 feet (Figure 9, left), so that all four simulation layers could be perforated for Dickman A1. This results in an improved result on the total field oil production rate (Figure 9, right). This suggests that either the input reservoir parameters, total volume, porosity, or permeability, need to be re-adjusted, since the real production rate is from the reported perforation zone.

Several different capillary pressure models were tested in the simulation to study the influence of the capillary pressure for transition zones. The simulation results indicate that the capillary pressure almost had no influence either on the oil or water production rate, so the capillary pressure effect was removed from the final calculation. Figure 10 shows the reservoir pressure distribution at the end of history matching simulation.

Work Plan for the Next Quarter

No work plan as this is last quarter of the project.

Cost and Milestone Status

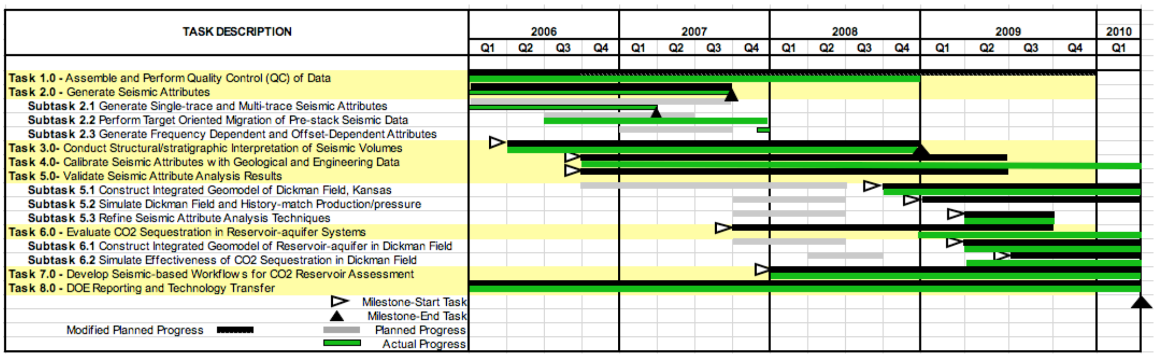
Baseline Costs Compared to Actual Incurred Costs

2009 Jan 1 – Mar 31	Plan	Costs	Difference Plan minus Costs
Federal	$25,000	$10,560	($24,440)
Non-Federal	$9,410	$0	($9,410)
Total	$34,910	$10,440	($33,850)

Forecasted cash needs vs. actual incurred costs

Notes:
1. Federal plan amount based on original award of $400K averaged over 12 reporting quarters.
2. Cost this period reflects 2 months salary for J. Zeng
3. Non-Federal plan amount based on original budget cost share of $150,573 averaged as above.

Actual Progress Compared to Milestones



Summary of Significant Events

No problems to report.

Project Personnel

Prof. Christopher Liner is Principle Investigator and lead geophysicist. He is a member of the SEG CO_2 Committee, Associate Director of the Allied Geophysical Lab, and has been selected to deliver the 2012 SEG Distinguished Instructor Short Course.

Dr. Jianjun (June) Zeng has been working exclusively on this project since Dec 2007 and is lead geologist. She will be funded through the end of 2009.

Heather King is a graduate MS student in geophysics who joined the project in January 2009 as a research assistant. She will be funded out of the project Jan-May and Sept-Dec 2009. Heather when she anticipates graduating. Her thesis will focus on Fort Scott to demonstrate the integrity of this formation as a seal for injected CO2. This will involve subtle structure and stratigraphy inferred by interpretation of multiple seismic attributes.

Dr. Po Geng has been working on this project as a specialist consultant since February, 2009. He will be funded out of the project, considered part-time, through the end of 2009.

Technology Transfer Activities

An invited lecture will be given at the Offshore Technology Conference in Houston, TX. Two posters will be presented at the DOE Annual CCS Conference in Pittsburgh, PA.

Contributors

Christopher Liner (P.I, Geophysics)

Jianjun (June) Zeng (Geology and Petrel Modeling)

Po Geng (Flow Simulation)

Heather King (Geology and Geophysics, MS Candidate)

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Appendix A: Relative Permeability Equations

Stone correlation formulations were used to generate the relative permeability model for relative permeability of water, oil and water, gas and water, and gas. The relevant equations are:

$$k_{rw} = k_{rwiro}\left(\frac{S_w - S_{wcrit}}{1 - S_{wcrit} - S_{oirw}}\right)^{n_w}$$

$$k_{row} = k_{rocw}\left(\frac{S_o - S_{orw}}{1 - S_{wcrit} - S_{orw}}\right)^{n_{ow}}$$

$$k_{rog} = k_{rogcg}\left(\frac{S_l - S_{org} - S_{wcon}}{1 - S_{gcon} - S_{org} - S_{wcon}}\right)^{n_{og}}$$

$$k_{rg} = k_{rgcl}\left(\frac{S_g - S_{gcrit}}{1 - S_{gcrit} - S_{oirg} - S_{wcon}}\right)^{n_g}$$

where

S_{wcon} - Endpoint Saturation: Connate Water

S_{wcrit} - Endpoint Saturation: Critical Water

S_{oirw} - Endpoint Saturation: Irreducible Oil for Water-Oil Table

S_{orw} - Endpoint Saturation: Residual Oil for Water-Oil Table

S_{oirg} - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table

S_{org} - Endpoint Saturation: Residual Oil for Gas-Liquid Table

S_{gcon} - Endpoint Saturation: Connate Gas

S_{gcrit} - Endpoint Saturation: Critical Gas

k_{rocw} - k_{row} at Connate Water

k_{rwiro} - k_{rw} at Irreducible Oil

k_{rgcl} - k_{rg} at Connate Liquid

k_{rogcg} - k_{rog} at Connate Gas

n_w - Exponent for calculating k_{rw} from k_{rwiro}

n_{ow}- Exponent for calculating k_{row} from k_{rocw}

n_{og}- Exponent for calculating k_{rog} from k_{rogcg}

n_g - Exponent for calculating k_{rg} from k_{rgcl}

The following parameters were used in the final calculation:

$S_{wcon} = S_{wcrit} = S_{oirw} = S_{orw} = S_{oirg} = S_{org} = 0.2$,

$S_{gcon} = S_{gcrit} = 0.05$,

$k_{rocw} = k_{rogcg} = 0.6$,

$k_{rwiro} = k_{rgcl} = 0.8$,

$n_w = n_{og} = n_g = 3$,

$n_{ow} = 4$

Tables

Table 1: Table of contents and assignments for planned final report of the Dickman study

	Well name	Water Data Collection Starting Time	Water Breakthrough Time	Production Starting Date	Production End Date
1	Dickman A1	N/A	N/A	1/1/1993	2/28/2006
2	Humphrey 1	N/A	N/A	1/1/1973	11/30/1994
3	Sargent 5	N/A	N/A	9/1/1972	11/30/2005
4	Tilley 2	N/A	N/A	11/1/1962	4/30/1998
5	Dickman 1	1/1/1962	1/1/1962	1/1/1962	1/31/2009
6	Humphrey 2	12/1/1994	12/1/1994	12/1/1994	1/31/2009
7	Humphery 3	10/1/2000	10/1/2000	10/1/2000	1/31/2009
8	Humphrey 4	4/1/2008	4/1/2008	4/1/2008	1/31/2009
9	Tilley 5	8/31/1997	8/31/1997	7/1/1995	1/31/2009
10	Dickman 2	1/1/1993	1/1/1993	9/1/1962	1/31/2009
11	Dickman 3	1/1/1993	1/1/1993	11/1/1962	1/31/2009
12	Dickman 6	1/1/1993	1/1/1993	11/1/1976	1/31/2009
13	Elmore 1	1/1/1993	1/1/1993	2/1/1963	6/30/2002
14	Phelps 1a	1/1/1993	1/1/1993	6/1/1977	1/31/2009
15	Tilley 1b	1/1/1993	1/1/1993	11/1/1962	1/31/2009

Table 2: Production starting date, ending date and water break through time for all 15 production wells in Dickman field. Notice only 5 wells (Dickman 1, Humphrey 2, Humphery 3, Humphrey 4 and Tilley 5) have a complete water production record.

Figures

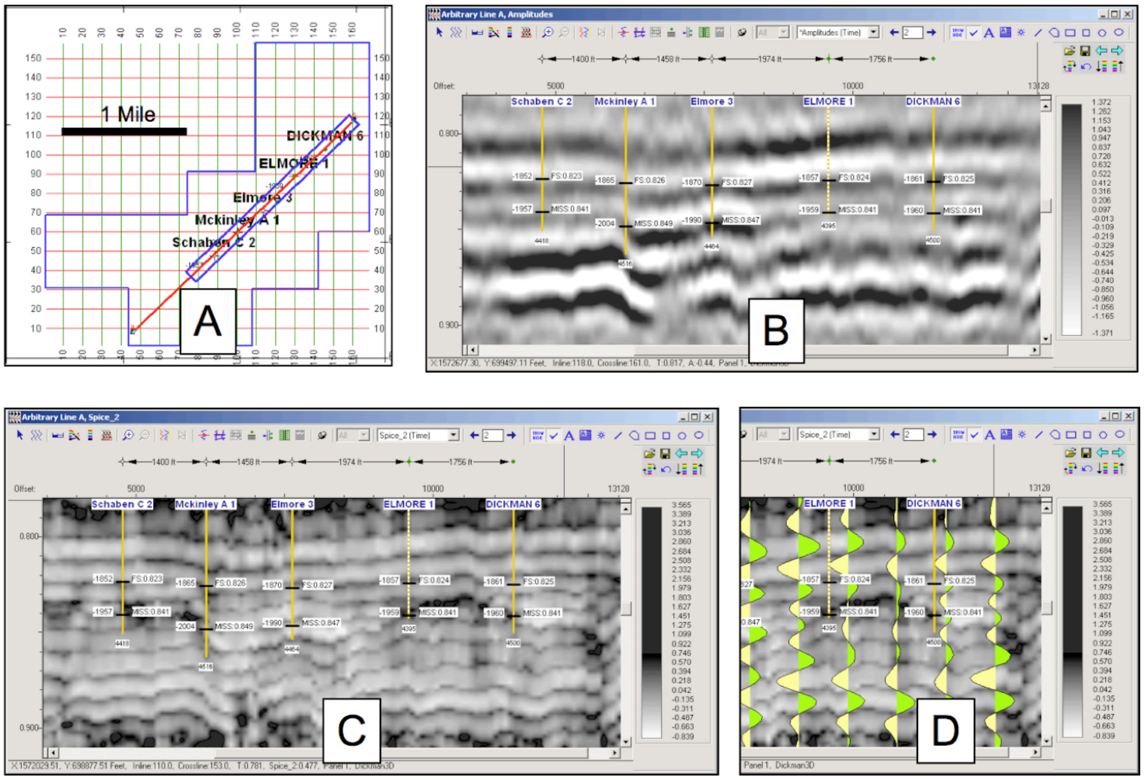

Figure 1. Relationship between seismic amplitude and spice data. A) Base map showing vertical seismic line through selected wells. B) Amplitude section and formation tops. C) Spice data with tops. D) Spice data with amplitude wiggle trace overlay.

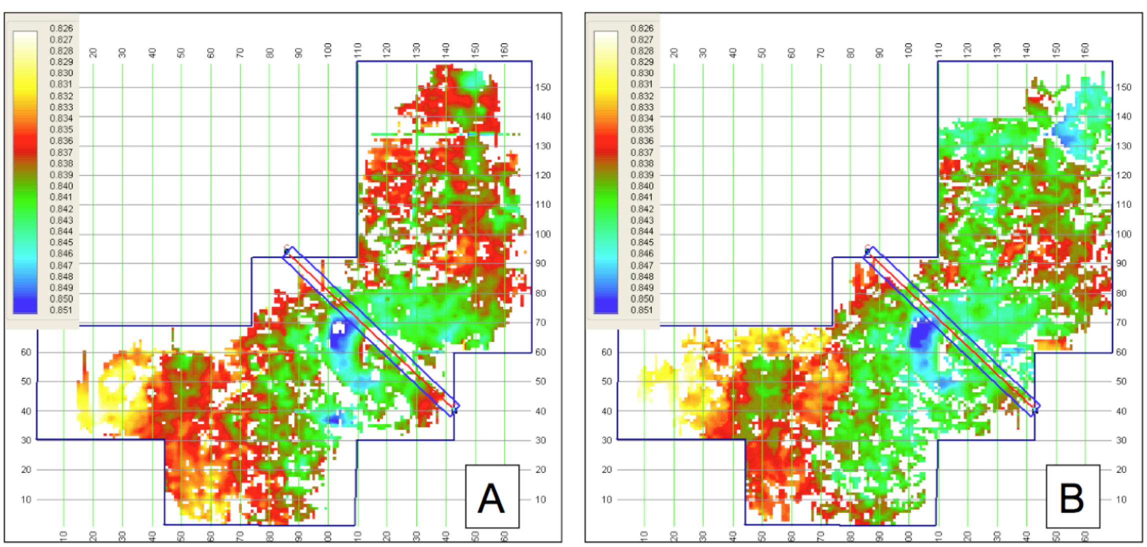

Figure 2. Top Mississippian time structure maps. (A) Tracking result using zero crossing in the amplitude volume. (B) Tracking result using peak in spice volume. Note improved continuity on this irregular, karst surface in the spice-generated map.

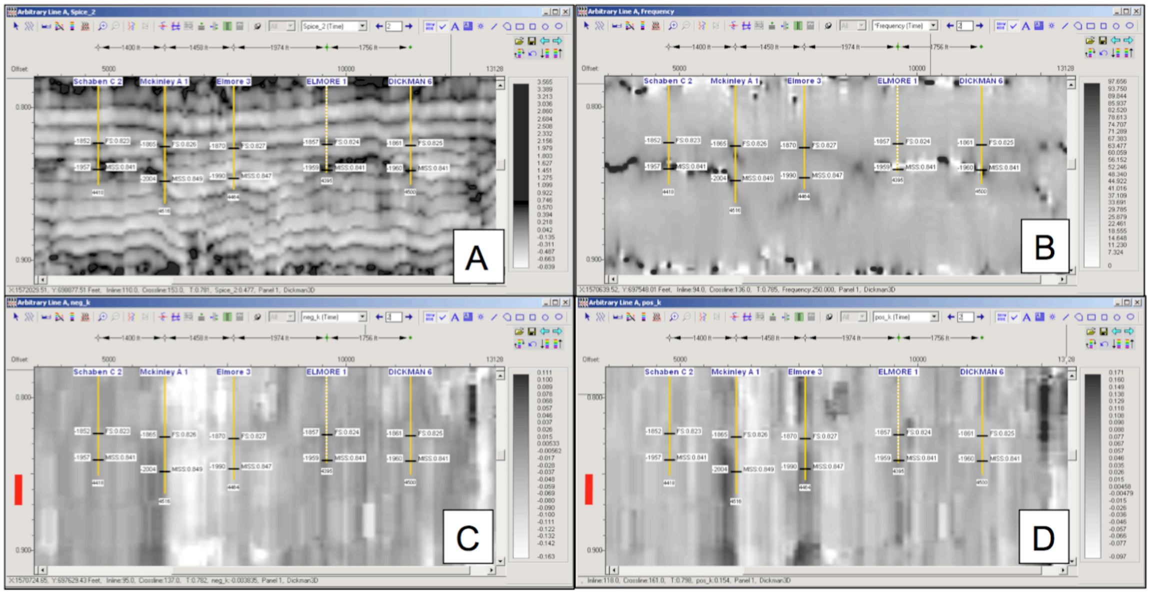

Figure 3. Relationship of spice to other attributes in vertical view along line in Fig 2. (A) Spice; (B) Instantaneous frequency; (C) Negative curvature; (D) Positive curvature.

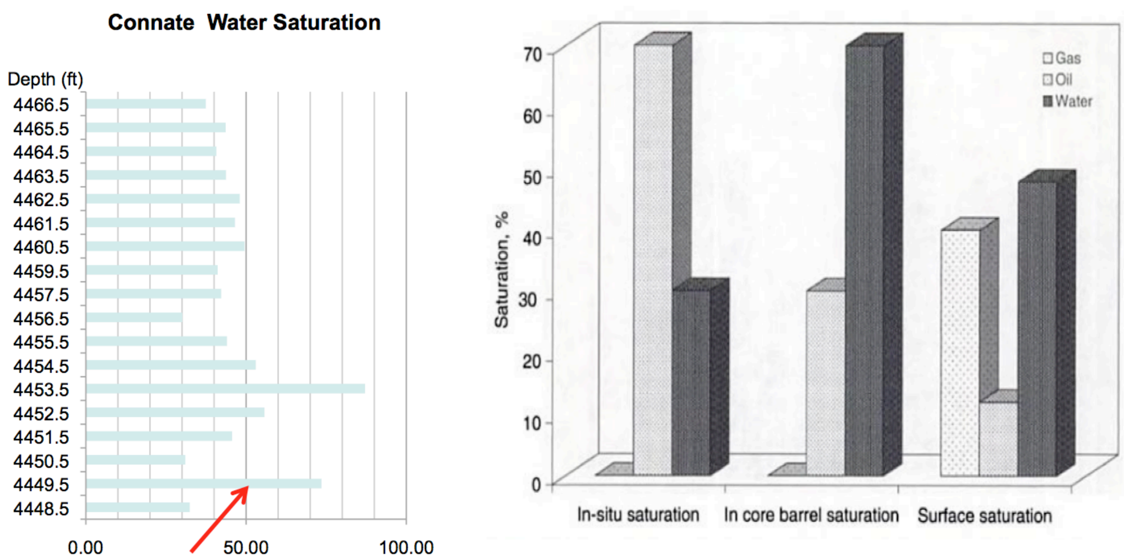

Figure 4. Left: Water saturation from Dickman 2 well core measurement (other wells show similar range of water saturation). Right: Typical alterations in the fluid saturations of a core sample from virgin productive formation that was badly flushed with water-based drilling mud (from Dandekar, 2006). A 70% water saturation measured from flushed cores corresponds to 30% in-situ water saturation.

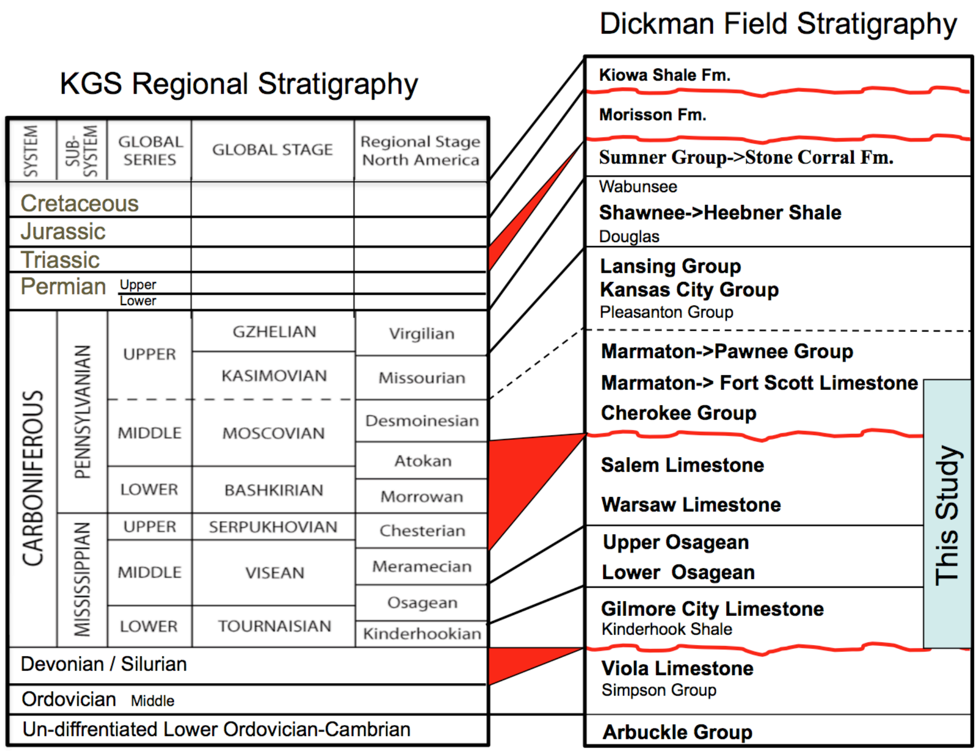

Figure 5. Chart to the left is the stratigraphic rank accepted by the Kansas Geological Survey (Sawin et al., 2008). The chart to the right shows correlation to Dickman local stratigraphic units, with higher confidence correlations in bold. The blue vertical bar indicates the target strata for Dickman research.

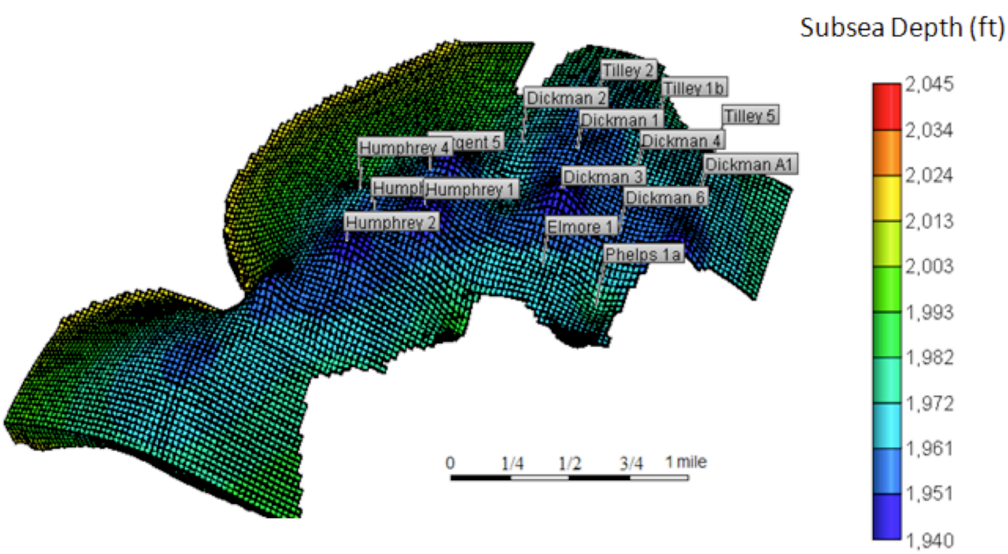

Figure 6: History matching flow simulation grid showing all 15 production wells and the Dickman 4 injection well.

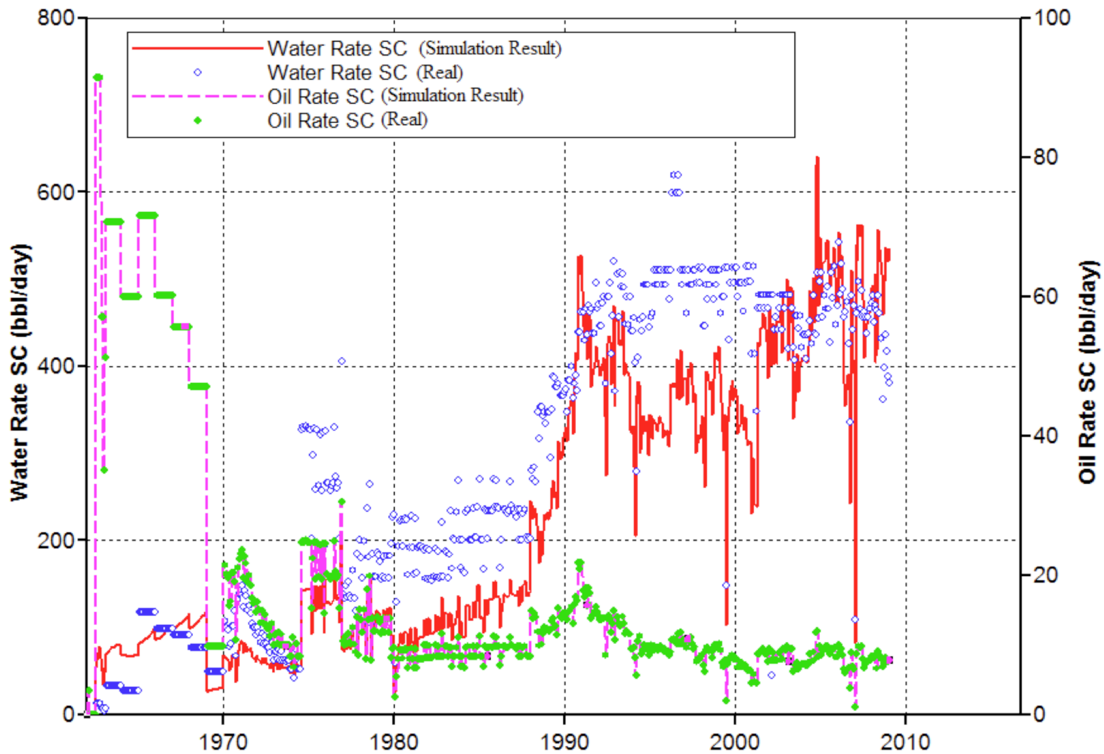

Figure 7: History matching results for Dickman 1 production well (1962- 2009). A good match on oil and water production rate was obtained here.

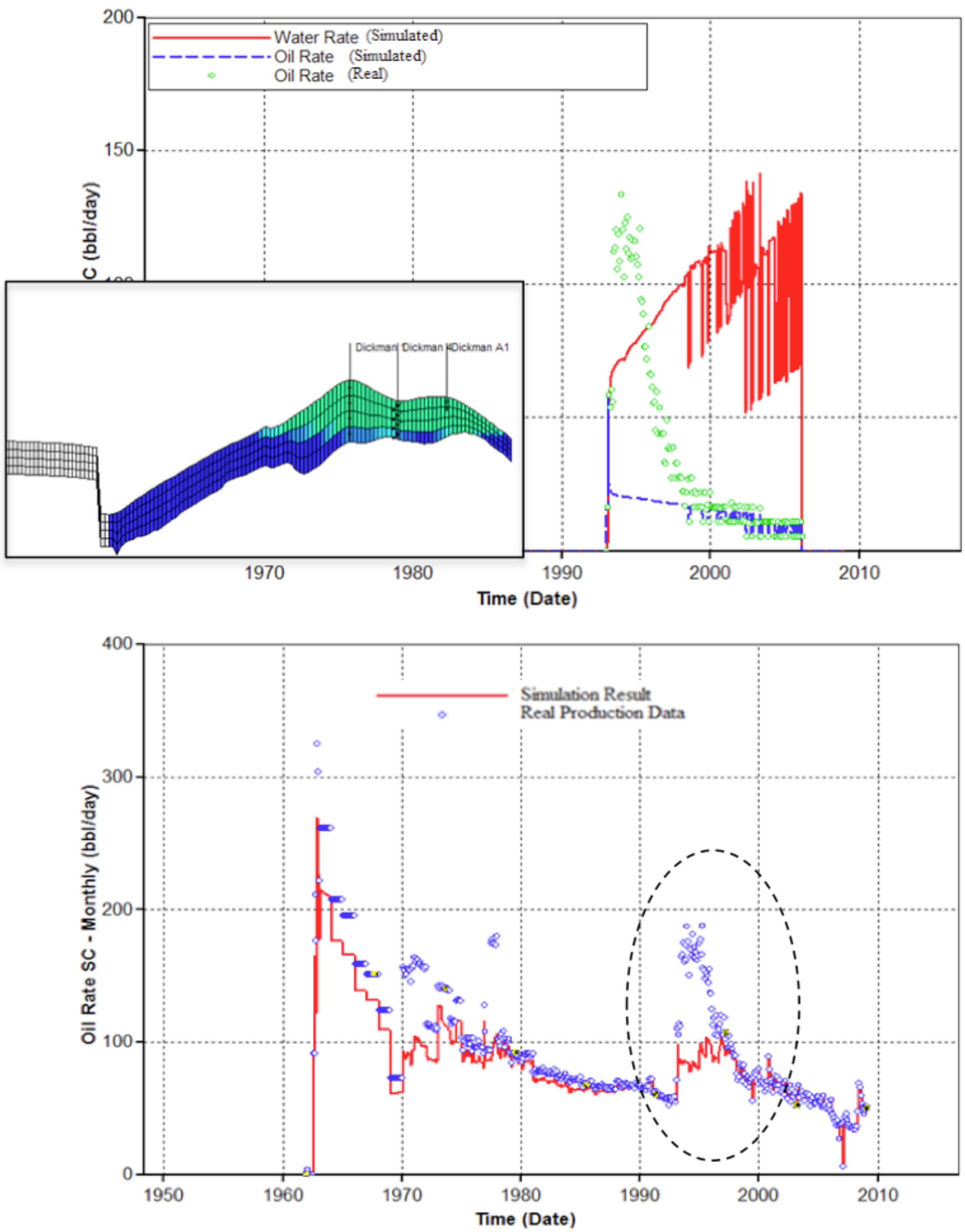

Figure 8: Upper: Simulation result for Dickman A1 for all production years (1993-1998) using perforations in only the two top simulation layers. The simulated oil production rate (dash blue line) is much lower than the real rate (green dots). Lower: Dickman field total oil production rate shows significant mismatch in the 1993-1998 time period resulting from errors with the Dickman A1 well.

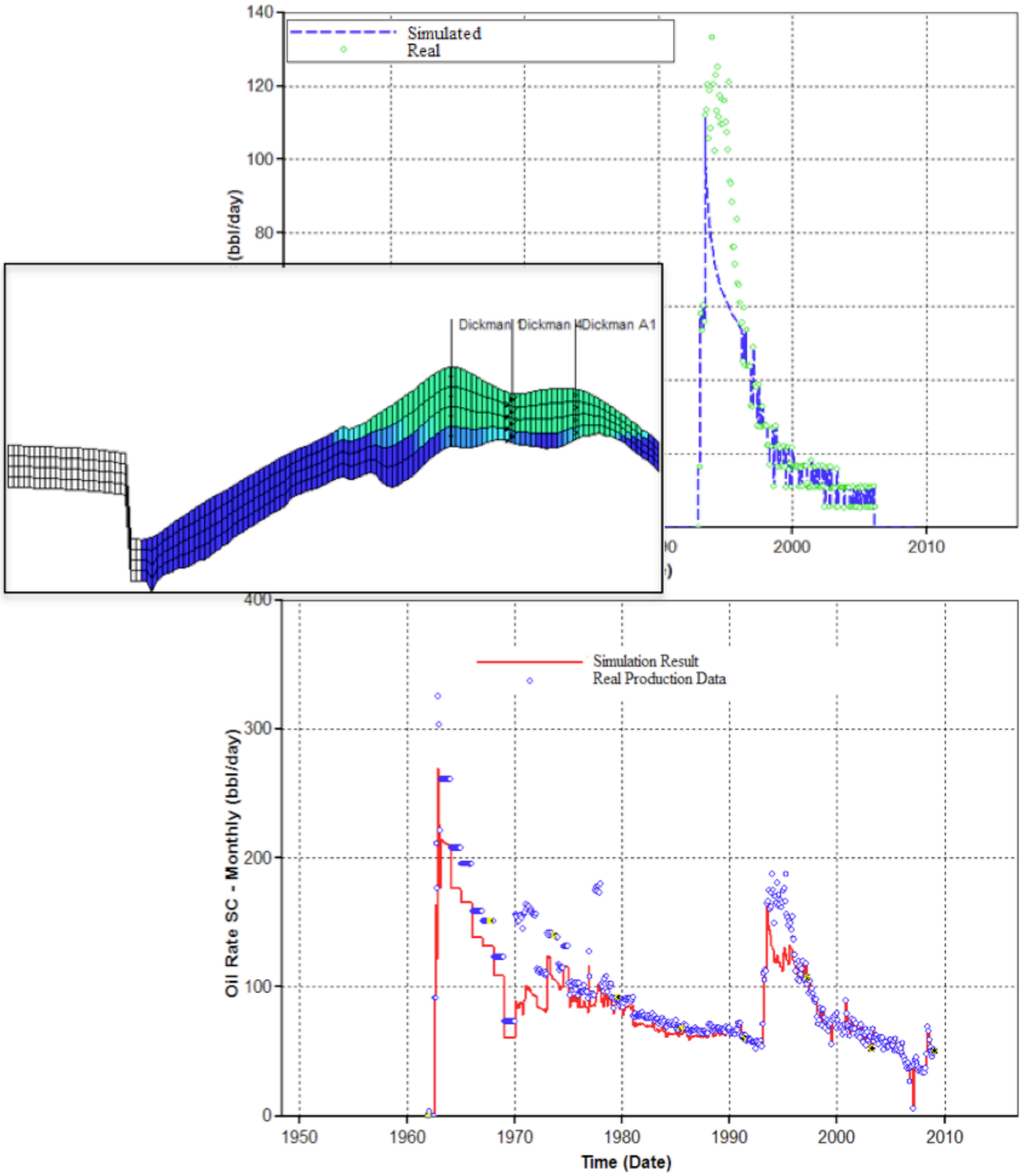

Figure 9. Upper: Improved match for oil production rate at Dickman A1 well after all four simulation layers are assumed to be perforated. Lower: Dickman field total daily oil production rate shows an improved match after all four simulation layers are perforated at the Dickman A1 well. To achieve this match, it was necessary to assume the Dickman A1 well had total depth six feet deeper than the reported value, or there was communication between the simulation layers.

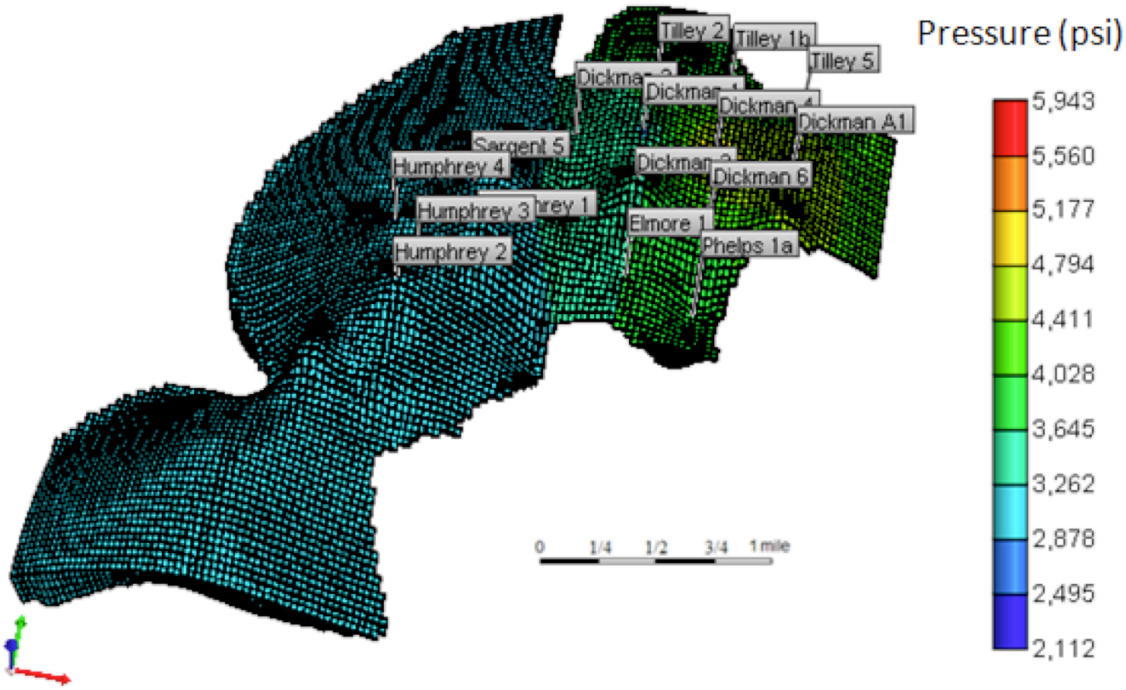

Figure 10. Final reservoir pressure at the end of the history match simulation run.