Response Summary

Additional information request for ADM Well CCS #2, USEPA UIC Permit Application #IL-115-6A-0001

Item #	Section	Subsection	Topic	Notes/Deficiencies	How resolved (Comments for EPA)
1	2	2.2	Faults, Known or Suspected Within the Area of Review	"newly acquired 3D seismic data has already been acquired at the proposed ICCS site and is currently being processed." Please provide this information as soon as it is available.	Section 2.2 has been updated. Appendix M (new) contains new figures and captions showing interpreted sections, shot point map, processing information, un-interpreted section, etc.
2	2	2.3	Maps and Cross Sections	This section mentions that a "site elevation is approximately 660 feet." If this is the well site, why is it not 675 feet above MSL as mentioned in section 2.1? If this is a different site, please clarify in the text.	Correction made to Section 2.3
3	2	2.4.3.3	Fracture Pressure at the Top of the Injection Zone	What was the reason that the fracture pressure test was only run on the lower portion of the completion interval and not the entire perforated interval?	Comments added to Section 2.4.3.3. Appendix L (new) contains a copy of the CCS #1 Completion Report.
4	2	2.4.3.3	Fracture Pressure at the Top of the Injection Zone	Please explain how changes in down hole density due to the compressibility of CO_2 were considered	Modified Section 2.4.3.3
5	2	2.4.3.3	Fracture Pressure at the Top of the Injection Zone	What values for injectate density were used?	Modified 2.4.3.3 to included the density value (0.433 psi/ft.) used in the calculation.
6	2	2.4.3.4	Effective Porosity	Please define effective porosity and how it differs from bulk porosity (to which it was compared), and describe how effective porosity was determined.	Clarification made in 2.4.3.4
7	2	2.4.3.4	Effective Porosity	Will injection be effected by residual water saturation? Also see related topic in 2.4.3.7.	Comments added to 2.4.3.4. Also referral made to Section 5 discussion on irreducible water
8	2	2.4.3.4	Effective Porosity	Table 2-1 - Please explain in more detail the methodology for the placement of the divisions between sub-intervals.	Added details to 2.4.3.4
9	2	2.4.3.5	Intrinsic Permeability - Core Analysis	Please state the origin of the value used for m used in Archie's equation.	Added details to 2.4.3.5
10	2	2.4.3.5	Intrinsic Permeability - Core Analysis	Please give all values used in Archie's equation, and how this calculation determined grain size.	Provided clarification in 2.4.3.5

Item #	Section	Subsection	Topic	Notes/Deficiencies	How resolved (Comments for EPA)
11	2	2.4.3.5	Intrinsic Permeability - Core Analysis	Please explain why the interval 6,650-6,820 has a higher average porosity, yet significantly lower average permeability, than the interval immediately below (6,820-7050).	Provided clarification in 2.4.3.5
12	2	2.4.3.5	Intrinsic Permeability - Well Testing	"After this test, these perforations were acidized and a step-rate test was conducted. For the second step-rate test, treated water injected at 3.1 bpm (130 gpm) for five hours, while pressure was monitored for approximately 45 hours." It is possible that the underlined "step-rate test", should read "pressure falloff (PFO) test"? If this is so, please make the correction, if not, please explain.	Correction made to 2.4.3.5
13	2	2.4.3.7	Storage Coefficient	It does not appear that residual water saturation was included in calculations - please explain how residual water saturation will or will not influence the effective porosity, given that this will be a two phase system (CO2 and brine)	Added comment to 2.4.3.7 Also refer to 2.4.3.4 and Section 5.
14	2	2.4.3.7	Storage Coefficient	Why was the entire thickness (1,506') of Mt. Simon and an average porosity of 10% used for calculation?	Revision made to 2.4.3.7
15	2	2.4.3.7	Storage Coefficient	Was the average porosity used that of bulk porosity or effective porosity? Why was 10% used, but a value of 13.2% given in Table 2-3	Revision made to 2.4.3.7
16	2	2.4.3.8	Seepage Velocity and flow Direction of Formation water	Please cite evidence and supporting references of the slow flow rate in the Mt. Simon	Revision made to 2.4.3.7
17	2	2.4.4	Characteristics of Injection Zone Formation Water	Please support the description of reservoir fluid samples as "high quality".	Provided clarification in 2.4.4
18	2	2.4.4.5	Total Dissolved Solids	Please explain the difference in values for TDS given in paragraph two of this section (higher) compared to the values given for the area in Figure 2-19 (lower)	Provided clarification in 2.4.4.5

Item #	Section	Subsection	Topic	Notes/Deficiencies	How resolved (Comments for EPA)
19	2	2.5	Upper Confining Zone	Please provide a reference for data from the Manlove Gas Storage Field	Text correction made and reference provided in 2.5
20	2	2.5.1	Geologic Names of Confining Zone	According to Figure 2-8, shale is not the lowermost section in the Eau Claire. Please explain.	Added explanation to 2.5.3.1
21	2	2.5.3.1	Lithologic Description	Comments were received to suggest that the Eau Claire becomes a mixture of dolomite and limestone with some fine-grained siliclastics far south of the proposed injection site. Please amend to clarify the distance from the injection site where this change takes place.	Resolved by moving Fig. 2-8 reference down to 2.5.3.1; also revised text in same.
22	2	2.5.3.5	Alternate Confining Zones Proposed	For the statement "The Ordovician-age Maquoketa Shale is 206 feet thick at the CCS#1 well site with the top depth of 2,611 feet below". It is assumed that the reference datum is implied to be 2,611 feet below ground surface. Please amend to clarify.	Incorporated Fig. 2-8 reference from above; modified text to resolve 2.5.1 and 2.5.3.1 questions/comments
23	2	2.5.3.3	Intrinsic Permeability	Were permeability values determined on the small shale samples from the core plugs or cuttings? If they were, please supply these values. If not, why were they not determined?	Added comments to 2.5.3.3
24	2	2.7	Overlying Sources of Groundwater at the Site	The lowermost USDW should be stated as a formation name with an associated depth, as well as measurements obtained above and below the threshold to justify the statement.	Revisions made to Section 2.7
25	2	2.7	Overlying Sources of Groundwater at the Site	In reference to letters from Frommelt and Nightingale continue to be used, please provide a copy of such letters.	Lower USDW letters are provided in Appendix H.
26	2	2.7.1.4	Lithology	Much of the information presented in this section appears to be stated as such in the northern part of Illinois. If it is also applicable to central Illinois, please explicitly state this.	Revision made to 2.7.1.4

Item #	Section	Subsection	Topic	Notes/Deficiencies	How resolved (Comments for EPA)
27	2	2.7.2.1	Maps and Cross Section - Mississippian Bedrock	In the statement "They noted that mineralization of groundwater in the Valmeyeran and Chesterian units of the Mississippian System…" to whom does "they" refer?	Revision made to 2.7.2.1 Figure 2-25 was replaced with a new figure
28	2	2.7.2.1	Maps and Cross Section - Mississippian Bedrock	For the statement "Groundwater with low TDS occurs only in and near…" it is assumed low TDS is <10,000 mg/L. Please amend to clarify.	Revision made to 2.7.2.1 Figure 2-25 was replaced with a new figure
29	2	not specified	General Questions	The Class VI regulations also ask for:(146.82) (6) Baseline geochemical data on subsurface formations, including all USDWs in the area of review.	Added recent data from Verification Well #1 (IBDP well) in Section 2.4.4.5 in Table 2.5 & 2.6.
30	2	not specified	General Questions	Permit application section 2.7 has little more than mention of TDS in aquifers. At some time prior to injection, it is critical to obtain and list accurate values for many geochemical parameters such as pH, alkalinity, FE, CA, MG, NA, etc. prior to injection. Any potential change in geochemical parameters after injection would need good baseline data for comparison	Appendix F of the UIC permit application (dated July11) outlines the proposed monitoring program for the lowermost USDW. 11 field and indicator parameters are proposed including pH, specific conductance, temperature, dissolved oxygen, alkalinity, bromide, calcium, chloride, sodium, and total (dissolved) CO2.
31		not specified	General Questions	Please include some discussion about flow of dense fluid CO2 in the Mt. Simon -- is this different compared to brine? Include parameters such as relative permeability, hydraulic conductivity, storage capacity, etc.	Refer to discussion in Section 5
32	2	Figures	Figure 2-32	Please add an index map to show the location of the Line as located on the study site.	New figure now has cross-section location on map of counties with ADM site. Caption is revised for clarification. Location error in original
33	2	Figures	Figure 2-33	Please resize figure if possible. Much details is lost at this resolution.	Figure is now readable, but on two 11x17 sheets. Caption is revised for clarification.

Item #	Section	Subsection	Topic	Notes/Deficiencies	How resolved (Comments for EPA)
34	2	Figures	Figure 2-34	Please indicate the proposed injection site on this figure.	Site is noted on figure. Caption revised by adding reference.
35	2	Figures	Figure to be added	Please include a map displaying the coal mines and oil fields within the area of review	Added Figure 2-36, or map found in new Section 2C
36	2	Figures	Figure to be added	Please include a large-scale map showing all relevant features within the area of review (existing wells, proposed wells, plugged wells, faults, coal mines, oilfields, surface water features, etc.)	Printed out on large paper and include in delivery
37	2	Additional Inform	Suggestion	From discussions with the United States Geological Survey, additional helpful information on regional hydrogeology may be available in the following sources: *(See USEPA letter for more details than shown in this spreadsheet)*	Revision made to 2.4.3.8
38	2	Additional Inform	Suggestion	Pumpage effects in Ironton-Galesville in Chicago region: Avery, C., 1995……..	Revision made to 2.4.3.8
39	2	Additional Inform	Suggestion	Upward flow gradients in the Mt. Simon aquifer. Nicholas et al, 1987……	Revision made to 2.4.3.8
40	2	Additional Inform	Suggestion	Recent groundwater modeling reports in the great Lakes region likely provide useful data and understanding of flow in the deep bedrock aquifers of the region: Meyer, S.C. et al, 2009	Revision made to 2.4.3.8
41	2	Additional Inform	Suggestion	Regional groundwater-flow model of the Lake Michigan Basin in support of Great Lakes Basin water availability and use studies. Feinstein, D.T. et all 2010	Revision made to 2.4.3.8
42	2	Additional Inform	Suggestion	Hydrogeologic framework of bedrock units an initial salinity distribution for a simulation of groundwater flow for the Lake Michigan Basin. Lame, D.C. 2009……	Revision made to 2.4.3.8

Item #	Section	Subsection	Topic	Notes/Deficiencies	How resolved (Comments for EPA)
43	5	5.2	Method of Radius Determination	The text says "… the boundary of the AoR was extended to the green line inscribing the blue polygon" but it appears to actually *circumscribe* the blue polygon. Please verify and amend if necessary.	Correction made to 5.2
44	5	5.4.1	Simulation Software Description and General Assumptions:	Please clarify the name of the module - COSTORE or CO2STORE. The validation, verification and calibration of the software and model must be documented.	Correction made in 5.4.1
45	5	5.4.1	Simulation Software Description and General Assumptions:	Please describe how the Redlich-Kwong equation of state was "tuned and modified".	Clarification provided in 5.4.1
46	5	5.4.1	Simulation Software Description and General Assumptions:	"Initial simulation-based estimates…" Please document this assertion.	Comment added to 5.4.1
47	5	5.4.1	Simulation Software Description and General Assumptions:	Please explain how the software optimizes time step duration	Comments added to 5.4.1
48	5	5.4.2	Site Specific Assumptions and Methodology	Please provide details on the development of the petrophysical and transport properties-"… based on the interpreted well log data and analysis of core samples…"	Added comments to 5.4.2 and added Appendix K (new)
49	5	5.4.2	Site Specific Assumptions and Methodology	Please provide more detail on the decision that the low-porosity, low-permeability interval will be a flow-limiting barrier to the CO2.	Comments added to 5.4.2
50	5	5.4.2	Site Specific Assumptions and Methodology	Is permeability the same in vertical and horizontal directions within a given layer?	Clarification made in 5.4.2
51	5	5.4.2	Site Specific Assumptions and Methodology	For Figure 5-4, please add a legend explaining the meaning of the colors.	Description of color scheme provided in caption of Figure 5-4.
52	5	5.4.2	Site Specific Assumptions and Methodology	Figure 5-5 needs to have a more complete caption: please state what the four curves represent.	Added information to caption of Figure 5-5 and further discussed in Section 5.4.2

Item #	Section	Subsection	Topic	Notes/Deficiencies	How resolved (Comments for EPA)
53	5	5.4.2	Site Specific Assumptions and Methodology	Figure 5-6: It would have been useful if the information about the meaning of Pc(1), Pc(2), etc. found on page 5-4 had been included in the caption for this figure. Please also define Sw.	Explanations added to caption of Figure 5-6
54	5	5.4.3	Simulation Results	Note that the captions for figures 5-16 - 5-21 indicate that the pressure front is shown on the figures, as does the legend in the upper right corner. However, there is no white line pressure front shown. Based on Fig. 5-23 the pressure front area has declined to zero. This should be noted in the figure captions.	Comment added to caption of pertinent figures
55	5	5.4.3	Geochemical modeling:	The final paragraph states that there will be geochemical reaction of CO2 with the Eau Claire Formation: how is this possible if the CO2 never leaves the Mt. Simon, as stated in the first paragraph on this page?	Clarification added to 5.4.3
56	5	5.5.1	Tabulation of Well Data:	Within the AoR, final paragraph it is stated that the water table is generally expected to reflect the ground surface and shallow groundwater is expected to flow east and southeast. Please cite references to support these statements for this location.	Revision made to paragraph in 5.5.1
57	5	5.6	Area of Review Re-Evaluation & Corrective Action Plan	First paragraph: discrepancies between predictions and observations can also be due to faulty modeling. This should be included as an additional possibility.	Revision made to Section 5.6
58	5	5.6	Area of Review Re-Evaluation & Corrective Action Plan	Re-Evaluation Report: The Class VI regulations at 146.91 require that the original area of review evaluation to be retained throughout the life of the project and for 10 years following site closure. EPA Region 5 policy will be to apply this requirement to subsequent area of review re-evaluations.	Revision made to Section 5.6

Item #	Section	Subsection	Topic	Notes/Deficiencies	How resolved (Comments for EPA)
	2.7.1		Other	unsolicited	Revisions made to Section 2.7.1 (and subsections) to provide new results regarding geochemistry data from Ironton Galesville sampling in IBDP-Verification Well #1

SECTION 2 - HYDROGEOLOGIC INFORMATION

2.1 Elevation of Land Surface at Well Location.

The surface elevation at the proposed carbon sequestration site is approximately 675 feet above mean sea level (MSL), as referenced from the Forsyth, Illinois, United States Geological Survey (USGS) 7.5-minute topographic quadrangle map.

2.2 Faults, Known or Suspected Within the Area of Review.

The IL-ICCS site is located in an area with no evidence of geological folds and faults. Regional mapping (Nelson, 1995) has indicated that there are no regional faults or fractures mapped within a 15-mile radius of the proposed site (Figure 2-1). Seismic reflection data were acquired near the site in order to characterize the geologic structure of the study area. Specifically, seismic surveys were undertaken to determine the presence or absence of faults and folds in the vicinity of the proposed well site. A 2D seismic survey in the vicinity of the proposed site, acquired prior to the initiation of the IBDP well, indicated that the overall structure of the area consists of nearly flat strata dipping slightly (< 1°) towards the southeast. These surveys also indicated that the morphology of the top of the Precambrian surface is not flat, and there are small undulations in the bedding of the strata (Figures 2-2 through 2-4). Study of 3D seismic reflection data acquired for the Illinois Basin Decatur Project (IBDP) site indicates that there are no resolvable faults through either the Mt. Simon Sandstone or the Eau Claire Formation (Figure 2-4). In addition, this data indicate that there is no folding in site area.

In January 2011, additional 3D seismic data were acquired in the area of the proposed ICCS injection site. Processing of this 3D seismic dataset was completed in August 2011. The resulting interpretations (Appendix M) support the earlier interpretations on the geological structure of the area. The 2011 data provide even better resolution than previous seismic data in the area due to improved Vibroseis sweep parameters, optimal frozen conditions during the time of acquisition, and other improvements. These data indicate that resolvable (from seismic reflection data) faults and folds are not present. The irregularities in the geomorphology of the Precambrian surface are displayed in increased detail, indicating the occurrence of subtle upland hills and intervening lowlands.

2.2.1 Seismic History and Risk

Since 1973, two earthquakes have been recorded within 100 km of the proposed injection site: a magnitude 3.0 quake on April 24, 1990 in Coles County approximately 41 miles to the southeast, and a magnitude 3.2 quake on January 29, 1993 in Fayette County approximately 58 miles to the south-southwest (http://earthquake.usgs.gov/earthquakes/eqarchives/epic/epic_circ.php, USGS Earthquake Search, as of March 17, 2011).

The relative seismic risk of the Decatur location is considered minimal. The probability of an earthquake of magnitude 5.0 or greater within 50 years and within 50 km is less than 1% (USGS 2009 PSHA model for Decatur, Illinois, https://geohazards.usgs.gov/eqprob/2009/). There exists a 2% probability that the Peak Ground Acceleration due to seismic activity will exceed 10% G

within 50 years (http://earthquake.usgs.gov/earthquakes/states/illinois/hazards.php). Thus, the risk of seismic activity breaching the integrity of the well or the injection formation is considered minimal.

Source:
Leetaru, H., 2011. Personal communication, Illinois State Geological Survey

Nelson, W.J., 1995. Structural features in Illinois, Illinois State Geological Survey Bulletin 100, 144 p.

2.3 Maps and Cross Sections.

Two vertical cross-sections and the location map of the proposed injection site are shown in Figures 2-5 through 2-7. Based on interpretation of 3D seismic data collected for the IBDP, two cross-sections were developed showing the bedrock stratigraphy at the proposed well site. Line A-A' is a west to east cross-section, while Line B-B' is a south to north cross-section. The surface elevations along the seismic lines range from approximately 660 feet to 680 feet. The cross-sections provide elevations on the y axis and have no vertical exaggeration. The seismic data were analyzed and interpreted by Alan Brown (Schlumberger Carbon Services) and Hannes Leetaru (ISGS). The cross-sections were prepared by Valerie Smith, Schlumberger Carbon Services.

Excluding the IBDP injection well (herein referenced as CCS #1) and the IBDP verification well (herein referenced as Verification Well #1), no other deep wells penetrate the Eminence, Ironton-Galesville, Eau Clare or Mt. Simon Formations (Figure 2-8) within the area of review (reference Section 5 for area of review information). All of the deeper horizons are projected from regional mapping. Therefore, well locations are not displayed on the cross-sections (Figures 2-6 and 2-7).

2.4 Injection Zone.

Information on the injection zone (Mt. Simon Sandstone) is based on regional geologic information from previous ISGS studies and reports, and on specific data obtained from the CCS #1 well installation (Frommelt, 2010).

Regional
The thickest and most widespread saline water bearing reservoir (saline reservoir) in the Illinois Basin is the Cambrian-age Mt. Simon Sandstone (Figure 2-8). It is overlain by the Cambrian Eau Claire Formation, a regionally extensive very low-permeability unit, and underlain by Precambrian granitic basement. There are records of 21 wells in central and southern Illinois that were drilled into the Mt. Simon (to depths greater than 4,500 feet). Many of the 21 wells penetrate less than a few hundred feet into the Mt. Simon. In addition, most wells are older and lack a suite of modern geophysical logs suitable for petrophysical analysis. Although comprehensive reservoir data for the Mt. Simon are lacking, there are sufficient data to demonstrate its regional presence. In the northern half of Illinois, the Mt. Simon is used for natural gas storage in several locations. Detailed reservoir data are available from these projects. Excluding CCS #1 and Verification Well #1, the closest Mt. Simon penetration to the ADM site

is about 17 miles southeast in Moultrie County, the Sanders Harrison #1 (Harrison #1). Only the top two hundred feet of the Mt. Simon was drilled. Based on logs from the IBDP injection and verification wells, the Mt. Simon thickness at the proposed injection site is anticipated to be about 1,500 feet.

Sample descriptions from the Harrison #1 well indicate that there is good porosity in the top 200 feet of the Mt. Simon. The nearest well with a porosity log for the entire thickness of the Mt. Simon, the Humble Oil Weaber-Horn #1 well (Weaber-Horn #1), was drilled on the Loudon Field anticline in Fayette County, a major oilfield 51 miles south of the ADM site. The Weaber-Horn #1 drilled through 1,300 feet of Mt. Simon before drilling into the Precambrian granite. The top of the Mt. Simon at the Weaber-Horn #1 well was at 7,000 feet and, based on calculations from wireline logs, the sandstone formation's gross thickness had an average porosity of about 12 percent. The Weaber-Horn #1 well log porosity data are similar to those found in deeper wells at the Manlove gas storage field (Manlove Field) in Champaign County, approximately 37 miles northeast of the ADM site. The Manlove Field is the deepest Mt. Simon gas storage field in the Illinois Basin and, prior to CCS#1, provided one of the most complete legacy reservoir data sets for characterization of the deep Mt. Simon. The permeability at the Weaber-Horn #1 well and the ADM site are expected to be similar to those at Manlove Field. A north-south trending cross section A-A' across the Hinton #7 , Harrison #1, CCS #1, and Weaber-Horn #1 wells (Figure 2-9) shows that the Mt. Simon should be porous and thick at the proposed site.

Regional Geology: Depositional Environment

The deposition of the Mt. Simon Sandstone has commonly been interpreted to be a shallow, subtidal marine environment. Most of these studies, however, were based on either surface study of the upper part of the Mt. Simon or on study of outcrops in Wisconsin or the Ozark Dome. Based on studies of the samples and logs of the CCS #1 well, the upper part of the Mt. Simon is interpreted to have been deposited in a tidally influenced system similar to the reservoirs used for natural gas storage in northern Illinois. However, the basal 600 feet of Mt. Simon sandstone is an arkosic sandstone that was originally deposited in a braided river – alluvial fan system. This lower Mt. Simon Sandstone is the principal target reservoir for sequestration because of the high secondary porosity and permeability formed by the dissolution of feldspar grains.

Source:

Driese, S.G., C.W. Byers, and R.H. Dott, Jr., 1981. Tidal deposition in the basal Upper Cambrian Mt. Simon Formation in Wisconsin: Journal of Sedimentary Petrology, v. 51, no. 2, p. 367–381.

Droste, J.B., and R.H. Shaver, 1983. Atlas of early and middle Paleozoic paleogeography of the southern Great Lakes area: Indiana Department of Natural Resources, Indiana Geological Survey, Special Report 32, 32 p.

Frommelt, D., 2010. Letter to the Illinois Environmental Protection Agency, Subject: CCS Well #1 Completion Report, Archer Daniels Midland Company – UIC Permit UIC-012-ADM, dated May 5, 2010 [Appendix L].

Kolata, D.R., 1991. Illinois basin geometry, in M.W. Leighton, D.R. Kolata, D.F. Oltz, and J.J. Eidel, eds., Interior cratonic basins: American Association of Petroleum Geologists, Memoir 51, p. 197.

Sargent, M.L., and Z. Lasemi, 1993. Tidally dominated depositional environment for the Mt. Simon Sandstone in central Illinois: Great Lakes Section, Geological Society of America, Abstracts and Programs, v. 25, no. 3, p. 78.

2.4.1 Geologic Name(s) of Injection Zone.

The proposed injection zone (refer to Section 2.4.2 for anticipated depth) is the Cambrian-age Mt. Simon Sandstone. CO_2 injected through the well will be contained in the injection zone and will flow into the Mt. Simon at the injection interval. The injection interval is a portion of the Mt. Simon where the injection well is perforated.

2.4.2 Depth Interval of Injection Zone Beneath Land Surface.

The Mt. Simon was found at a depth of 5,545 feet to 7,051 feet (Frommelt, 2010) based on borehole logging data for the CCS #1 well. An interval of high porosity and permeability was identified at the base of the Mt. Simon. This basal interval was selected as the initial injection interval for the CCS #1 well and was perforated from 6,982 to 7,050 feet.

For the IL-ICCS CO_2 injection project, the planned injection interval is a relatively high permeability zone in the lower Mt. Simon. The approximate gross interval is 6,700 to 7,050 feet. The perforation depths are to be finalized after drilling and will be reported in the well completion report.

2.4.3. Characteristics of the Injection Zone.

Based on the data from the CCS #1 well (Frommelt, 2010), the proposed injection zone is expected to be a porous and permeable sandstone that, in some intervals, is an arkosic sandstone. Grain size varies from very-fine grained to coarse grained. The sandstones are primarily composed of quartz, but some intervals contain more than 15 percent feldspar. Diagenetic clay minerals are not common.

2.4.3.1 Lithologic Description

The Mt. Simon Sandstone regionally varies in lithology from conglomerates to sandstone to shale. Six dominant lithofacies have been recognized: cobble conglomerate, stratified gravel conglomerate, poorly-sorted sandstone, well-sorted sandstone, interstratified sandstone and shale, and shale (Bowen et al., 2011).

The poorly-sorted sandstone lithofacies is the most common regionally and within the Mt. Simon in the CCS #1 well, which contains discrete intervals of predominantly finer-grained sandstone and coarser-grained sandstone. The basal portions of some of the coarser-grained strata are often conglomeratic. In addition, the arkosic interval at the base of the Mt. Simon in the CCS #1 well

is about 40 feet thick and interbeds of dark gray shale laminae occur between some of the sandstone strata (Morse and Leetaru, 2005).

The principal cementing material is quartz in the form of overgrowths and feldspar precipitation. Most of the very fine-grained intervals contain large amounts of detrital and authigenic potassium feldspar. The lower part of the Mt. Simon tends to have more feldspar-rich zones than the upper part. These zones consequently tend to have greater feldspar framework grain dissolution and increased porosity. These feldspar-rich intervals may have the best reservoir characteristics for sequestration (Bowen et al. 2011).

Source:
Bowen, B.B., R.I. Ochoa, N.D. Wilkens, J. Brophy, T.R. Lovell, N. Fischietto, C.R Medina, and J.A. Rupp, 2011. Depositional and Diagenetic Variability Within the Cambrian Mount Simon Sandstone: Implications for Carbon Dioxide Sequestration: Environmental Geosciences, v. 18, p. 69-89.

Morse, D.G., and H.E. Leetaru, 2005. Reservoir characterization and three-dimensional models of Mt. Simon Gas Storage Fields in the Illinois Basin: Illinois State Geological Survey, Circular 567, 72 p. CD-ROM.

2.4.3.2 Injection Zone Thickness

The entire (gross) Mt. Simon interval is estimated to be 1,500 feet in thickness, based on CCS #1 well logs. Drilling and testing of the CCS #1 injection well has determined the thickness of individual porous intervals.

While CO_2 may be stored in the entire thickness, the perforated or injection interval will be much smaller and is planned for a high porosity zone relatively deep in the Mt. Simon. Injectivity is primarily a product of net formation thickness (*b*) and permeability (*k*) or permeability-thickness (*kb*), while storage volume is primarily a function of net formation thickness and effective porosity. Because of the thickness and permeability of the Mt. Simon noted in the CCS #1 well, Weaber-Horn, and Hinton wells, nominal injection capacity of 3,000 metric tonnes per day (MT/day) is anticipated to be highly probable. CO_2 reservoir flow modeling (see Section 5.4 of this application) shows that the lower zone can readily accept the 3,000 MT/day injection rate.

2.4.3.3 Fracture Pressure at Top of Injection Zone

At the CCS #1 well, a step-rate test (Earlougher, 1977) was conducted on September 26, 2009 into the initial 25-foot perforated interval from 7,025 to 7,050 feet at the base of the Mt. Simon. [Another set of perforations was added (6,982 to 7,012') at a later date. More details are available in (UIC Form 4h, CCS Well #1 Completion Report, April 29, 2010), included as Appendix L.] The primary purpose of the test was to estimate the fracture pressure of the injection interval. A bottom-hole pressure gauge with surface readout was used. The pressure gauge was located at 6,891 feet inside the tubing, 134 feet above the uppermost perforation. All tests were done by injecting water. CO_2 or other compressibile fluids were not used. Water with clay-stabilizing potassium chloride was injected in 1.0 barrel per minute (bpm) increments starting at 2.0 bpm (84 gallons per min, gpm) to 8.0 bpm (336 gpm). Each rate was maintained

for approximately 45 minutes. The pressure near the end of each injection period was plotted against the injection rate to determine the fracture pressure (Figure 2-10).

In Figure 2-10, the first line with the greater slope at lower rates and pressure is the perforated interval's response to water injection prior to fracturing. The second line with the lower slope at higher rates and pressures is after the fracture developed. The intersection of the two straight lines is 4,966 psig. To find the fracture pressure at the top of the perforations, the hydrostatic pressure of the water (0.433 psi/ft) in the wellbore between 6,891 (location of pressure gauge) and 7,025 feet was added to the 4,966 psig. The fracture pressure at 7,025 feet is 5,024 psig. This corresponds to a fracture gradient of 0.715 psi/ft.

Based on this fracture gradient, the fracture pressure at the estimated depth of the uppermost perforation requested in the permit for this well (6,700 ft) is calculated to be 4,790 psi.

Source:
Earlougher, Jr., R.C., 1977. *Advances in Well Test Analysis*, Monograph Series, Society of Petroleum Engineers of AIME, Dallas.

2.4.3.4 Effective Porosity

Compensated neutron and litho-density open-hole porosity logs were run in the CCS #1 well. The neutron and density logs provide total porosity data (all pore space). Effective porosity, as shown in this section, is considered to be connected pore space only which includes the effect of irreducible brine saturation (Note: irreducible water saturation is the lowest water saturation, S_{wi}, that can be achieved in a core plug by displacing the water by oil or gas). Effective porosity was determined by lab testing using helium porosimetery on a limited number of core plug samples. See Appendix L of the CCS #1 well completion report (Frommelt, 2010) for additional discussion about the helium porosimetery method.

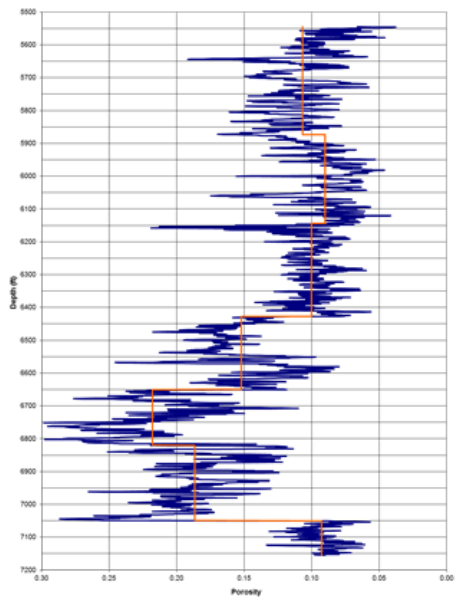
Comparison of the neutron-density crossplot porosity (average neutron and density porosity) and core porosity (Figure 2-11) showed similar values. Additionally, the open-hole log based porosity was classified using Schlumberger ELemantal Log Analysis (ELAN) as described in CCS#1 Geophysical Log Descriptive Report found in Appendix K.

Based on porosity trends, there are 7 major sub-intervals present in the Mt. Simon. Table 2-1 lists the intervals identified and the average effective porosity of each. Based on the neutron-density crossplot porosity, the 68-foot injection interval for CCS #1 (6,982-7,050 feet) had an average effective porosity of 21.0%.

Reservoir modeling for CCS#2 injection, as discussed in Section 5, accounts for irreducible water and assumes a S_{wi} of 35%. This value of S_{wi} may ultimately be adjusted in the model to help the model match actual injection results.

Table 2-1: Average effective porosity based on the neutron-density crossplot porosity for CCS #1. The seven sub-intervals were selected based on major changes in the trend of porosity from the neutron-density logs. The log based porosity trends were also cross checked with other log data (e.g. resistivity) and available core data. A figure showing the seven zones is shown to the right of the table.

Sub-Interval (feet)	Effective Porosity (%)
5,545-5,874	10.8
5,874-6,144	8.72
6,144-6,428	10.1
6,428-6,650	15.2
6,650-6,820	21.8
6,820-7,050	18.7
7,050-7,155	9.84



2.4.3.5 Intrinsic Permeability

Intrinsic permeability, *k*, was directly available from the results of the core analyses and well testing of CCS #1. However, to estimate permeability over a larger interval where core is not available, a relationship between core permeability and log porosity is required.

Core Analysis

A core porosity-permeability transform was developed (Figure 2-12) based on a visual grain size description. This transform was used with the crossplotted neutron-density porosity and cementation exponent (m) calculated using Archie's equation (Archie, 1942) to estimate permeability with depth. (See following paragraph for more information on the values used in the Archie equation.) Average permeability for sub-intervals of the Mt. Simon for CCS #1 is in Table 2-2. Based on the neutron-density crossplot porosity and the core porosity-permeability transform, the 68-foot injection (perforated) interval (6,982-7,050 feet) in CCS #1 has a geometrical average intrinsic permeability of 194 mD (Frommelt, 2010).

In Archie's equation in the format of Sw^n=(a/(phi^m))*Rw/Rt, it was assumed that Sw^n = 1. (Rt = fluid saturated rock resistivity, phi = porosity, Rw = brine resisitivity, m = cementation exponent, a = tortuosity factor, Sw = brine saturation, n = saturation exponent) Deep resisitivity measurements from open hole logs on CCS#1 were used for Rt. Crossplotted neutron-density porosity was used for phi and an "a" of 1 was used. Rw was calculated from temperature corrected conductivity measurements made from fluid samples. After solving for "m",

considerable effort was made adjusting the classifications of "m" (Figure 2-12) to produce the best match between estimated permeability and core-measured values of permeablitilty.

It is apparent in Figure 2-12 that permeability and porosity in the Mt. Simon formation are not directly related. A coarse grain sandstone section can have similar porosity to a finer grain sandstone section, yet the permeabilities can be higher in the coarse grain section. Grain size is not the only factor in controlling permeability. Diagenesis is believed to play a significant role.

[Other work relating porosity and permeability was also done using extensive use of wireline logs, including nuclear magnetic resonance methods and is discussed briefly in the Modeling section (Section 5) and Appendix K of this application.]

Table 2-2: Average intrinsic permeability based on a transform of core permeability and core porosity related to the neutron-density crossplot porosity for the sub-intervals shown. The seven sub-intervals were selected based on major changes in the trend of porosity from the neutron-density logs.

Sub-Interval (feet)	Intrinsic Permeability (mD)
5,545-5,900	19.4
5,900-6,150	10.2
6,150-6,430	8.44
6,430-6,650	8.21
6,650-6,820	8.64
6,820-7,050	107
7,050-7,165	4.37

Source:
Archie, G.E., 1942. The electrical resistivity log as an aid in determining some reservoir characteristics: Journal of Petroleum Technology, v. 5, p. 54-62.

Well Testing
Step rate / pressure falloff (PFO) tests of varying duration were conducted in September and October 2009 as part of the initial completion of CCS #1 (Frommelt, 2010). A pressure falloff test involves two segments. During the first test segment, the reservoir is stressed by injecting fluid, which increases the reservoir pressure. During the second test segment, the reservoir pressure is monitored as it returns to its pre-test pressure. The initial perforations in the injection interval were 7,025 to 7,050 feet. Water treated with a clay-stabilizing potassium chloride was injected at 1.5 to 2.0 barrels per minute (bpm) (63 to 84 gallons per minute) for nearly two hours. A 19.5 hour PFO followed this injection period.

After this test, these perforations were acidized and a step-rate test was conducted. For the second step-rate / pressure fall off test, treated water was injected at 3.1 bpm (130 gpm) for five hours, while pressure was monitored for approximately 45 hours.

The third PFO test was conducted after the well was perforated and stimulated. An additional 30 feet of perforations were added at 6,982 to 7,012 feet. The perforated zone received a second acid treatment. Additional information regarding perforations and acid treatment are described in the CCS #1 Completion Report, Appendix L (Frommelt, 2010). For the third PFO test, the treated water was injected at an increasing rate of 3.1 to 4.2 bpm (130 to 176 gpm) over 6.5 hours and then at 4.2 bpm (176 gpm) for an additional 6.5 hours. During this third PFO test, pressure was monitored for 105 hours.

Pressure Transient Analyses

PIE pressure transient software was used to analyze the pressure data for reservoir flow properties. Conventional semi-log, log-log and nonlinear regression analyses were used to analyze the data. (Well-Test Solutions, Ltd., http://welltestsolutions.com/index.html)

During the first PFO, because only 25 feet of perforations were open in a very large vertical formation (gross thickness 1,506 feet), a partial penetration or partial completion effect was expected. The derivative (log-log plot) of the falloff test is used to qualitatively identify reservoir features including the partial penetration effect (reference Figure 2-13) and to determine permeability. Two radial, 2-dimensional responses (horizontal derivative) were measured during this test between 0.1 and 1 hrs (PPNSTB) and 20 to 100 hrs (STABIL). The first period corresponds to radial flow across the 25 feet perforated interval; the second period corresponds to the pressure response across a larger thickness that would be between two much lower permeability sub-units. The transition between the two radial responses (SPHERE) is a spherical flow (3-dimensional flow) period that is influenced by vertical permeability or the ratio of vertical to horizontal permeability (k_v/k_h).

To observe the effect of the acid treatment and the second set of perforations to the overall injection interval, the derivatives of the three pressure falloff tests were overlain (Figure 2-14). The data between 0.1 and 1.0 hrs match relatively well and the data between 1.0 and 100 hrs match very well. Similar trends of the first radial period, transition and final radial period indicates that the second set of perforations did not change the permeability estimated from the pressure transient tests or contribute to the perforated interval. As such, the subsequent pressure transient analyses used a single layer, partial penetration model with 25 feet of perforations open at the base of the layer.

Simulation of the pressure transient data using analytical solutions (Figure 2-15), gave a permeability of 185 mD over 75 feet of vertical thickness. The transition period gave a vertical permeability over the 75 feet as 2.45 mD (k_v/k_h = 0.0133). The Mt. Simon initial pressure at CCS #1 at 7,025 feet is about 3,200 psig.

For the injection interval, the permeability estimates from the different methods are very close. Based on the neutron-density crossplot porosity and the core porosity-permeability transform, the 68-foot, injection (perforated) interval (6,982 to 7,050 feet) has an average intrinsic permeability of 194 mD. Using the PIE pressure transient software for the third PFO, permeability was estimated to be 185 mD over 75 feet of vertical thickness. Permeability for this same 75 feet of rock was calculated using core and well log analyses. The permeability from this analysis was estimated to be 182 mD.

Source:
Leetaru, H.E., D.G. Morse, R. Bauer, S. Frailey, D. Keefer, D. Kolata, C. Korose, E. Mehnert, S. Rittenhouse, J. Drahovzal, S. Fisher, J. McBride, 2005. Saline reservoirs as a sequestration target, in An Assessment of Geological Carbon Sequestration Options in the Illinois Basin, Final Report for U.S. DOE Contract: DE-FC26-03NT41994, Principal Investigator: Robert Finley, p 253-324

Frailey, S.M., Damico, J., Leetaru, H.E., 2010. Reservoir Characterization of the Mt. Simon Sandstone, Illinois Basin, USA, proceedings, 10th International Conference on Greenhouse Gas Control Technologies (GHGT-10), Amsterdam, September 19-23, 2010

2.4.3.6 Hydraulic Conductivity

Intrinsic permeability (k) and hydraulic conductivity (K) are related according to the following equation (Freeze and Cherry, 1979):

$$K = k\,\rho\,g/\mu$$

where ρ= fluid density
g= gravitational acceleration
μ= dynamic viscosity

Intrinsic permeability (k) is a property of the rock, while hydraulic conductivity (K) includes properties of the rock and fluid. Intrinsic permeability is also known as permeability and is discussed in Section 2.4.3.5. Formation water density and dynamic viscosity are discussed in Sections 2.4.4.3 and 2.4.4.4, respectively. For the range of viscosity and density discussed, the hydraulic conductivity will vary.

The 68-foot injection interval in CCS #1 (6,982 to 7,050 feet) had an average intrinsic permeability of 194 mD (see Section 2.4.3.5); this converts to a hydraulic conductivity of 3.9×10^{-4} cm/sec, using the water properties at this depth.

Source:
Freeze, R. A. and J. A. Cherry, 1979. *Groundwater*. Englewood Cliffs, N.J., Prentice-Hall, Inc.

2.4.3.7 Storage Coefficient

The storage coefficient or storativity, S, ranges from 5×10^{-5} to 5×10^{-3} for confined aquifers (Freeze and Cherry, 1979). S is commonly determined by well testing; however, S is a function of fluid compressibility (c_f) and rock compressibility (c_r) and can be estimated from the following equation:

$$S = \rho\,g\,h(c_r + \varphi\,c_f)$$

where φ= porosity
h= formation thickness
ρ= fluid density
g= gravitational acceleration

Rock compressibility can be expressed as the inverse of the bulk modulus (K_b) and in terms of the Young's modulus (E) and Poisson's ratio (v) (Huang and Rudnicki, 2006):

$$c_r = 1/K_b = 3(1 - 2v)/E$$

Fluid density is discussed in Section 2.4.4.3. Gravitational acceleration approximately equals 9.81 m/sec^2. For this calculation, the Mt. Simon is assumed to be 1,506 feet thick and have 13.2% porosity (φ). As discussed in Freeze and Cherry (1979), storage coefficient is a term used to describe the hydraulic properties of a confined aquifer. Thus, the entire aquifer thickness and an average effective porosity were used to estimate the storage coefficient. Young's modulus (E) and Poisson's ratio (v) were determined by Weatherford Laboratory (see CCS #1 Completion Report, Appendix L (Frommelt, 2010) for more details) for Mt. Simon samples collected at depths of 6,761 and 6,770 feet. These values were used to compute c_r using the equation shown above. These compressibility values are consistent with bulk compressibility values for sandstone reservoirs, which ranged from 6.5×10^{-5} to 2.7×10^{-4} MPa^{-1} at 7,000 psi (48.3 MPa) confining pressure (Zimmerman, 1991). Fluid compressibility (c_f) is known to vary with pressure and temperature changes (Huang and Rudnicki, 2006). Using two samples collected from CCS #1 (MDT-1 & MDT-4), fluid compressibility and storativity values were estimated (reference Section 2.4.4, Table 2-4).

Based on the range of values described here, storativity was estimated to range from 4.9×10^{-5} to 9.0×10^{-4} (Table 2-3). These values are consistent with values published by Freeze and Cherry (1979). "Storage coefficient" is a term used to describe the hydraulic properties of a confined aquifer and will not be influenced by residual water saturation. Storage coefficient is defined for groundwater flow, but not two-phase (e.g., water-air, water-CO_2) flow. As described in Freeze and Cherry (1979), the term has roots in aquifer testing and is best applied for describing 2D flow through aquifers. For two-phase flow problems where 3D flows may be important, porosity and permeability are better terms to use than storage coefficient and transmissivity.

Table 2-3. Estimates of rock (c_r) and fluid (c_f) compressibility and storativity (S) for CCS #1

Depth (ft)	Pressure (psi)	Pressure (MPa)	T (°C)	ρ (g/L)	c_r (1/Mpa)	c_f (1/Mpa)	Φ (-)	h (m)	S (vol/vol)
5772	2582.9	1.78E+01	48.8	1089.7	2.02E-04	2.04E-04	0.132	459.0	8.59E-04
7045	3206.1	2.21E+01	52.1	1123.5	2.02E-04	1.83E-04	0.132	459.0	9.00E-04
5772	2582.9	1.78E+01	48.8	1089.7	3.68E-05	2.04E-04	0.132	459.0	4.87E-05
7045	3206.1	2.21E+01	52.1	1123.5	3.68E-05	1.83E-04	0.132	459.0	6.38E-05

2.4.3.8 Seepage Velocity (ft/yr) and Flow Direction of Formation Water

This section discusses the natural seepage velocity and flow direction in the Mt. Simon sandstone. The predicted behavior of the injected CO_2 in the Mt. Simon sandstone is discussed in Section 5.

In northern Illinois and southern Wisconsin, groundwater flow in the Mt. Simon sandstone and other bedrock aquifers is fairly well understood. Several calibrated groundwater flow models have been developed by the Illinois State Water Survey (Meyer et al., 2009), the Wisconsin Geological and Natural History Survey (SWRPC & WGNHS, 2005) and the U.S. Geological Survey (Mandle and Kontis, 1992; Feinstein et al., 2010). However, groundwater flow in the

deeper part of the Illinois Basin is not well understood because few wells penetrate deep formations such as the Mt. Simon Sandstone. However, based on limited field data and numerical modeling some information on groundwater flow is available. Within the Mt. Simon Sandstone, Bond (1972) determined that groundwater flows from west to east beneath the northern third of Illinois. Bond (1972) also noted that groundwater flows to the south in the deeper part of the Illinois Basin, but some data supporting this conclusion were questionable. Within the deeper part of the Illinois Basin, groundwater flow in the Mt. Simon Sandstone is generally very slow, on the order of inches per year (Cartwright, 1970; Gupta and Bair, 1997). Finally, Bond (1972) noted that groundwater flows upward from the Mt. Simon aquifer to the Ironton-Galesville in the Chicago area, where pumpage has lowered pressures in the Ironton-Galesville. The flow patterns described by Bond (1972) are generally consistent with those patterns described by Meyer et al. (2009) and Mandle and Kontis (1992).

Gupta and Bair (1997) used a steady-state, variable density, groundwater flow model to evaluate flow in the Mt. Simon Sandstone in the Midwest (Ohio, Indiana and parts of Illinois, Wisconsin, Michigan, Pennsylvania, West Virginia and Kentucky), including the eastern portion of the Illinois Basin. Results from this modeling indicated that flow in the shallow layers, such as in the Pennsylvanian bedrock, follows topographic-driving forces –recharge in upland areas and discharge in topographic lows such as river valleys. For deeper layers such as the Mt. Simon Sandstone, the flow patterns are influenced by the geologic structure with flow away from arches such as the Kankakee Arch and toward the deeper parts of the Illinois Basin (Figure 2-16). The model also indicated that groundwater flows upward from the Mt. Simon to the Eau Claire and downward from the Ironton-Galesville into the Eau Claire (Figure 2-17), but these vertical velocities are very small, <0.01 inches per year.

The modeling results of Gupta and Bair agree with results of Cartwright (1970). Cartwright (1970) estimated that 59,000 acre-ft of groundwater discharged from the Illinois Basin bedrock to streams. Cartwright (1970) also argued that 95% of this discharge flowed through vertical fractures in the Wabash valley fault zone and the Duquoin-Loudon anticlinal belt. These modeling results also agree with a hypothesis described by Bredehoeft et al. (1963) to explain the high brine concentrations (3 to 6 times higher than present seawater) found in some deep basins including the Illinois Basin. Bredehoeft et al. (1963) argued that confining layers such as the Eau Claire act as semi-permeable membranes, allowing water to pass out of permeable formations such as the Mt. Simon while retarding the passage of charged salt particles. The clay minerals in the confining layer have a net negative charge which retards the anions in the water. These anions then retard the movement of the cations (positive charge) via electrical attraction. This process happens very slowly, over geologic time periods of hundreds of thousands of years. The information presented above reflects our current understanding on groundwater flow in the Illinois Basin. This understanding is based on very limited data of which some is specific to the Mt. Simon but outside of the Illinois Basin. Intensive monitoring of the CO_2 plume during and after injection is expected to provide additional information.

Source:

Bond, D.C., 1972. Hydrodynamics in deep aquifer of the Illinois Basin, Illinois State Geological Survey Circular 470, Urbana, IL, 72 p.

Bredehoeft, J.D., C.R. Blyth, W.A. White and G.B. Maxey, 1963. Possible mechanism for concentration of brines in subsurface formations. Bulletin of the American Association of Petroleum Geologists 47(2): 257-269.

Cartwright, K., 1970. Groundwater discharge in the Illinois Basin as suggested by temperature anomalies: Water Resources Research, vol. 6, no. 3, p. 912-918.

Feinstein, D.T., R.J. Hunt and H.W. Reeves, 2010. Regional groundwater-flow model of the Lake Michigan Basin in support of Great Lakes Basin water availability and use studies, U.S. Geological Survey Scientific Investigations Report 2010-5109: 379.

Gupta, N., and E.S. Bair, 1997. Variable-density flow in the midcontinent basins and arches region of the United States, Water Resources Research, 33(8): 1785-1802.

Huang, T., and Rudnicki, J.W., 2006. A mathematical model for seepage of deeply buried groundwater under higher temperature and pressure, Journal of Hydrology, Vol. 327, 42-54.

Mandle, R.J., and A.L. Kontis, 1992. Simulation of regional ground-water flow in the Cambrian-Ordovician aquifer system in the northern Midwest, United States. Washington, D.C., U.S. Geological Survey Professional Paper 1405-C: 97.

Meyer, S.C., G.S. Roadcap, Y.-F. Lin and D.D. Walker, 2009. Kane County Water Resources Investigations: Simulation of Groundwater Flow in Kane County and Northeastern Illinois, Illinois State Water Survey Contract Report 2009-07: 425.

Southeastern Wisconsin Regional Planning Commission and Wisconsin Geological and Natural History Survey, 2005. A Regional Aquifer Simulation Model for Southeastern Wisconsin, Southeastern Wisconsin Regional Planning Commission Technical Report 41**:** 143.

Zimmerman, R.W., 1991. Compressibility of sandstones, Elsevier Publishing Co., Amsterdam.

2.4.4 Characteristics of Injection Zone Formation Water

Information on the injection zone formation water is primarily based on data obtained by the ISGS from the CCS #1 well installation (Frommelt, 2010). Fluid samples were collected from the CCS #1 open borehole after drilling and wireline geophysical testing were completed. Schlumberger's Modular Formation Dynamics Tester (MDT) and Quicksilver wireline equipment were run on April 28 and 29, 2009. The tool was used to collect formation pressure, formation temperature, and reservoir fluid samples at five depths (Table 2-4). The Quicksilver probe is designed to draw filtrate-contaminated fluid to the perimeter of the probe, where it is pumped into a flowline. This enables the probe center to discretely collect relatively high-quality reservoir fluid into a separate sampling flowline. The fluid properties (such as resistivity)

in both flowlines are monitored in real time to control the independent pumping systems during sampling. Fluid sample volumes for the CCS#1 samples varied from 450 mL to 900 mL. These samples were analyzed by the Illinois State Water Survey.

Table 2-4. Data for fluid samples collected from the Mt. Simon sandstone in CCS#1 using the MDT sampler in April 2009

Sample ID	Sample Depth (feet)	Formation Pressure (psi)	Formation Temperature (°F)	TDS (mg/L)	Density (g/L)
MDT-4	5,772	2,582.9	119.8	164,500	1,089.7
MDT-3	6,764	3,077.5	125.1	185,600	1,120.7
MDT-14	6,764	3,077.5	125.1	179,800	Not analyzed
MDT-5	6,840	3,105.9	125.0	182,300	1,124.1
MDT-2	6,912	3,141.8	125.8	211,700	1,136.5
MDT-9	6,840	3,105.9	125.0	219,800	Not analyzed
MDT-1	7,045	3,206.1	125.7	228,100	1,123.5
MDT-8	7,045	3,206.1	125.7	201,500	Not analyzed

2.4.4.1 Temperature

Based on the MDT sampler (Table 2-4), formation temperatures ranged from 119.8°F (48.8 °C) at a depth of 5,772 feet to 125.8°F (52.1°C) at depth of 6,912 feet.

2.4.4.2 Pressure

The formation pressure measured with the MDT tool in CCS #1 (Table 2-4) varied with depth and had a minimum pressure of 2,583 psi recorded at 5,772 feet and a maximum pressure of 3,206 psi recorded at 7,045 feet.

2.4.4.3 Density

Based on five brine samples collected with the MDT sampler at the CCS #1 well, the fluid density ranged from 1,090 to 1,137 g/L, with an average of 1,119 g/L.

2.4.4.4 Viscosity

Dynamic viscosity is a function of brine temperature, salinity, and formation pressure. Viscosity increases with higher salinity and with lower temperatures. Viscosity slightly increases with higher formation pressure (Kestin et al., 1981). Kestin et al. (1981) studied the viscosity of NaCl brines.

Because the Mt. Simon brine is predominantly NaCl brine, using the method of Kestin et al. (1981) is appropriate. Using the data in Table 2-4, the brine viscosity for the Mt. Simon brine is estimated to range from 5.4×10^{-4} to 5.7×10^{-4} Pa sec with an average of 5.5×10^{-4} Pa sec.

Source:
Kestin, J., E. Khalifa and R.J. Correia, 1981. Tables of dynamic and kinematic viscosity of aqueous NaCl solutions in the temperature range 20-150°C and the pressure range 0.1-35 MPa. *Journal of Physical and Chemical Reference Data,* 10(1): 71-87.

2.4.4.5 Total Dissolved Solids

Salinity, expressed as TDS, also affects the injection capacity because it reduces the CO_2 solubility in water. Figure 2-18 illustrates the relative density of deep aquifer brines in the Illinois Basin. Figure 2-19 shows the broad distribution of TDS in the Mt. Simon which should exceed 60,000 mg/L over much of the Illinois Basin and 180,000 mg/L in the deeper portions of the basin. Figure 2-19 also shows the approximate position of the 20,000 mg/L TDS iso-concentration line for the Mt. Simon sandstone in the northern part of the state. South of this line, the groundwater is expected to exceed 20,000 mg/L TDS.

At the IBDP site, samples collected from CCS #1 varied with depth (Table 2-4), with TDS of 164,500 mg/L TDS at 5,772 feet and 228,100 mg/L TDS at 7,045 feet. The samples' average TDS is 190,000 mg/L . The proposed IL-ICCS site is within one mile of the CCS #1 well and similar concentrations of TDS are anticipated. Table 2-5 provides a summary (from IBDP wells) of TDS and ionic constituent data for Quaternary sands-and-gravel deposits and the Pennsylvanian-age Lower Mattoon sandstones (referred to asshallow groundwater), the Ironton-Galesville Sandstone, and Mt Simon Sandstone.

It is important to note that the values measured at the site are higher than those for the area shown in Figure 2-19. The contour values shown in Figure 2-19 were based on regional data and are not site specific. The data collected from the samples taken in CCS #1 provide the best estimate of what will be encountered at CCS #2. However, the overall regional trends are still described by Figure 2-19.

To provide additional information for formations which have not been sampled, salinity estimates were estimated based on open hole log resistivity and porosity data obtained in Verification Well #1. The salinity was estimated assuming 100% water saturation and then using a simplified Archie equation where apparent water resistivity calculation (RWA) equals resistivity multipled by porosity squared (RWA = Rt x phi^2) and then entering RWA and temperature and reading an equivalent NaCl salinity off Schlumberger's GEN-9 Log Interpretation Chart [Appendix N]. These values (Table 2-6) are in general agreement with the values in Table 2-5 (for formations which were sampled). Note that the salinity estimates using this technique can be skewed (to the low side) if resistivities are affected by fresh drilling mud or hydrocarbons.

Table 2-5: Fluid chemistry data for shallow groundwater, the Ironton-Galesville, and Mt Simon Formations.

Constituent	Shallow Groundwater	Ironton-Galesville	Mt. Simon
Conductivity (mS/cm)	1.5	80	170
TDS (mg/L)	1,000	65,600	190,000
Cl^- (mg/L)	170	36,900	120,000
Br^- (mg/L)	1	180	680
Alkalinity (mg/L)	380	130	80
Na^+ (mg/L)	140	17,200	50,000
Ca^{2+} (mg/L)	100	5,200	19,000
K^+ (mg/L)	1	520	1,700
Mg^{2+} (mg/L)	50	950	1,800
pH (units)	7.2	6.9	5.9

Table 2-6: Estimated Salinity from Verification Well #1 open hole resistivity and porosity logs using Schlumberger GEN-9 Log Interpretation Chart.

Formation	Depth Interval	Resistivity ohmm	Porosity (V/V)	RWA (RT * phi^2) ohmm	Temperature (DegF)	Salinity (per SLB GEN-9 chart using RWA and temperature) ppm
Chapel	444 to 450	16	0.10	0.16	65	45000
Renault	1284 to 1286	20	0.10	0.20	70	35000
St. Louis	1462 to 1478	3	0.24	0.17	71	30000
Borden	1606 to 1612	2.5	0.22	0.12	72	60000
Burlington-Keokuk Limestone	1850 to 1860	35	0.05	0.09	75	80000
Moccasin Springs	2254 to 2256	2	0.20	0.08	82	80000
Moccasin Springs	2540 to 2550	80	0.03	0.07	84	90000
Galena	2797 to 2800	600	0.02	0.24	87	25000
Galena	2808 to 2810	80	0.05	0.20	87	28000
Plateville	3094 to 3102	40	0.06	0.14	90	45000
St. Peter	3255 to 3265	11	0.23	0.58	92	8000
St. Peter	3305 to 3315	8.5	0.23	0.45	92	11000
St. Peter	3400 to 3410	11	0.20	0.44	93	12000
Ironton-Galesville	4903 to 4906	8.5	0.13	0.14	103	35000
Ironton-Galesville	5004 to 5008	8	0.10	0.08	103	65000
Eau Claire	5089 to 5091	80	0.03	0.07	104	75000
Mt. Simon	5559 to 5563	3.5	0.10	0.04	111	140000
Mt. Simon	5795 to 5800	2	0.13	0.03	113	190000
Mt. Simon	6032 to 6038	5.5	0.09	0.04	114	170000
Mt. Simon	6416 to 6418	1.8	0.18	0.06	118	80000
Mt. Simon	6841 to 6843	0.7	0.24	0.04	120	130000
Mt. Simon	6980 to 6990	0.8	0.23	0.04	120	130000

Source:
Leetaru, H.E., D.G. Morse, R. Bauer, S. Frailey, D. Keefer, D. Kolata, C. Korose, E. Mehnert, S. Rittenhouse, J. Drahovzal, S. Fisher, J. McBride, 2005. Saline reservoirs as a sequestration target, in An Assessment of Geological Carbon Sequestration Options in the Illinois Basin, Final Report for U.S. DOE Contract: DE-FC26-03NT41994, Principal Investigator: Robert Finley, p 253-324

2.4.4.6 Potentiometric Surface

Little information is available about the potentiometric surface in the Mt. Simon sandstone in Macon County because very few wells penetrate the Mt. Simon in central Illinois. The best

available information regarding the potentiometric surface is discussed in Section 2.4.3.8 of this document.

Using the formation pressure (p) and fluid density (ρ) data in Table 2-4, the potentiometric head (b) was calculated using the relationship $p = \rho g h$, where g is the gravitational constant. The mean potentiometric head in the Mt. Simon has an elevation 249.5 feet MSL. If the well were filled with freshwater (ρ= 1,000 g/L), the potentiometric head would have an elevation of 996.1 feet MSL.

2.4.5 Additional or Alternative Zones Considered for Injection

No other geologic zones are being considered for CO2 injection at the IL-ICCS site.

2.5 Upper Confining Zone

Information on the upper confining zone, the Eau Claire Formation, is based on specific data obtained from the CCS #1 well installation (Frommelt, 2010) and is supplemented by regional geologic information from previous ISGS studies and reports. In order for a saline reservoir to be used for injection of CO_2, there must be an effective hydrologic seal that restricts upward fluid movement. Within the Illinois Basin, three thick and wide-spread shale units function as major regional seals. These units are the Cambrian-age Eau Claire Formation, the Ordovician-age Maquoketa Formation, and the Devonian-age New Albany Shale (Figure 2-8). The Eau Claire Formation has no known penetrations (with the exception of the IBDP injection and verification wells) within a 17-mile radius surrounding the proposed IL-ICCS site; therefore, integrity of the upper confining zone is not an issue.

Gas storage projects in the Illinois Basin confirm that the Eau Claire is an effective seal in the northern and central portions of the Basin. Core analysis data from the Manlove Gas Storage Field (Larson, 1965), 37 miles to the northeast of the proposed site, show that the Eau Claire shale intervals have vertical permeability values of less than 0.1 mD.

A diagrammatic north-south cross section of the Basin through the central part of Illinois (Figure 2-20) shows that the Eau Claire Formation, the primary seal, has a laterally persistent shale interval above the Mt. Simon and is expected to provide an excellent seal.

Wireline logs from the CCS #1 well and two geologic cross sections near the proposed site (Figures 2-6 and 2-7) indicate that at the IL-ICCS site, there should be about 500 feet of Eau Claire Formation directly above the Mt. Simon Sandstone.

Source:

Larson, K.R., 1965. Exhibit 25: Core Analyses. In the matter of the Application of the Peoples Gas Light and Coke Company for an order and certificate of convenience and necessity to develop, construct, operate and maintain the Mahomet Storage Field in Champaign and Piatt Counties, Illinois Commerce Commission, Docket No. 51416 [Unpublished data, a copy of which is available for inspection at the Library of the Illinois State Geological Survey, Champaign IL].

2.5.1 Geologic Name(s) of Confining Zone

The primary confining zone (seal) is the Cambrian-age Eau Claire Formation. Based on the data from CCS #1, the Eau Claire has a total thickness of 497.5 feet. The shale section of the Eau Claire has a thickness of 198.1 feet and is the lowermost section within the formation.

2.5.2 Depth Interval of Upper Confining Zone Beneath Land Surface

At CCS #1, the Eau Claire Formation occurs at a depth of 5,047 feet to 5,545 feet below ground surface. The shale section of the Eau Claire occurs at a depth of 5,347 to 5,545 feet.

2.5.3 Characteristics of Confining Zone

2.5.3.1 Lithologic Description

The Cambrian-age Eau Claire Formation is composed primarily of a sandstone, sandy dolomite, and sandy dolomitic siltstone in northern Illinois (Figure 2-8), but shale and siltstone components are more dominant in the central part of the Illinois Basin (Willman et al., 1975). In the southern part of the basin, the Eau Claire is a mixture of dolomite and limestone with some fine-grained siliciclastics.

In the CCS #1 well, the Eau Claire Formation consists of 198 feet of shale (5,347 to 5,545 feet) overlain by 300 feet (5,047 to 5,347 feet) of very-fine grained limestone interbedded with thin siltstone layers. Bell et al. (1964) provided a detailed description of a sample study of the Eau Claire Formation from the Weaber-Horn #1 well, 51 miles to the south, where the formation is 580 feet thick. In this well, the Eau Claire consists of, in descending order, 247 feet of dolomitic limestone, 83 feet of dolomitic siltstone and dolomitic shale, 75 feet of dolomite, 120 feet of sandy siltstone and silty, fine-grained sandstone, 10 feet of dolomite, and 45 feet of argillaceous siltstone and shale. To compare it with the Eau Claire in ADM CCS #1, the formation in the Weaber-Horn #1 consists of 405 feet of carbonate strata overlying 175 feet of fine-grained clastic strata. The shale component, however, much more prominent in ADM CCS #1, where it comprises the lower 198 feet. Within Weaber-Horn #1, the shale component is subordinate to the thicker silty sandstones and siltstones. In summary, within about 50 miles to the south, the lower portion of the Eau Claire lithologically coarsens with shale decreasing and siltstone and very fine-grained sandstone increasing. The upper portion of the Eau Claire lithologically to the south remains dominated by carbonate strata but a very fine-grained clastic interval appears in the mid-section of the upper part of the formation.

From limited x-ray diffraction data, the mineralogy of the shale is 60 percent clay minerals and 37 percent quartz and potassium feldspar. The shale is laminated and dark gray to black in color.

Source:
Bell, A.H., E. Atherton, T.C. Buschbach, D.H. Swann, 1964. Deep Oil Possibilities of the Illinois Basin, Illinois State Geological Survey, Circular 368, 38 p.

Willman, H.B., E. Atherton, T.C. Buschbach, C. Collinson, J.C. Frye, M.E. Hopkins, J.A. Lineback, and J.A. Simon, 1975. Handbook of Illinois Stratigraphy, Illinois State Geological Survey Bulletin 95, 261 pp.

2.5.3.2 Geomechanical Data

Geomechanical data were collected by lab and field testing. Lab testing was used to determine elastic parameters for a single Eau Claire shale sample. Field testing, a mini-frac test, was conducted to determine the in situ fracture pressure.

An Eau Claire shale sample was collected from CCS #1 at a depth of 5,478.5 feet. This sample was tested by Weatherford Labs (Houston, TX) and has the following properties—Young's modulus of 5.50×10^6 psi, Poisson's ratio of 0.27, bulk modulus of 3.92×10^6 and shear modulus of 2.17×10^6 psi.

"Mini-frac" testing was conducted within the Eau Claire to determine the effectiveness of the shale as a caprock seal (Frommelt, 2010). Mini-fracs are very small volume tests that inject fluid up to the parting pressure of the injection zone.

A mini-frac test using Schlumberger's Modular Dynamics Testing tool was conducted across a 2.8-foot shale interval of the Eau Claire, centered at a depth of 5,435 feet. The test was designed for four short-term injection/falloff test periods (15 to 60 minutes in duration). The fracture pressure from these four tests ranged from 5,078 to 5,324 psig, corresponding to a fracture gradient ranging from 0.93 to 0.98 psi/ft in the Eau Claire shale.

2.5.3.3 Intrinsic Permeability

None of the CCS #1 sidewall rotary core plugs penetrated shale. From the whole core collected from the Eau Claire, none of the individual shale layers at the inch to centimenter scale were thick enough for obtaining a core plug for permeability analyses. The shale dominated portion of the whole core parted horizontally in very small increments such that drilling horizontal plugs and vertical plugs was not possible. No permeability tests were done on shale samples from cuttings.

Within the upper confining interval of 5,047 to 5,545 feet, 12 Eau Claire plugs were available for porosity and permeability testing. The plugs are described as very fine grained sandstones, microcrystalline limestone, and siltstone. Because sidewall rotary core plugs are taken horizontally, the permeability data from these plugs indicate the horizontal (not vertical) permeability. The average horizontal permeability for the 12 sidewall rotary core plugs is 0.000344 mD.

The average vertical permeability for the upper confining shale layer is expected to be much lower than 0.000344 mD because this value is based on the non-shale horizontal permeability values. Vertical permeability on plugs is generally lower than horizontal permeability and shale permeability is generally much lower than sandstone, limestone, and siltstone.

The Illinois State Geological Survey database of UIC wells with core from the Eau Claire was also used to characterize the upper confining seal. This database shows that the Eau Claire's median permeability is 0.000026 mD and median porosity is 4.7%. At the Ancona Gas Storage Field, located approximately 80 miles to the north of the proposed IL-ICCS site, cores were obtained through 414 feet of the Eau Claire, and 110 analyses were performed on a foot-by-foot basis on the recovered core. Most vertical permeability analyses showed values of <0.001 to 0.001 mD. Only five analyses were in the range of 0.100 to 0.871 mD, the latter being the maximum value in the data set. This indicates that even the more permeable beds in the Eau Claire Formation are expected to be relatively tight and tend to act as sealing lithologies.

Source:
Illinois State Geological Survey Mt. Simon database

2.5.3.4 Hydraulic Conductivity

Intrinsic permeability (k) and hydraulic conductivity (K) are related according to the following equation (Freeze and Cherry, 1979):

$$K = k \rho g / \mu$$

where ρ = fluid density
g = gravitational acceleration
μ = dynamic viscosity

Intrinsic permeability (k) is a property of the rock, while hydraulic conductivity (K) includes properties of the rock and fluid. Because fluid samples were not collected from the Eau Claire, the properties of the fluid properties of CCS #1 sample MDT-4 (Table 2-4), which is the Mt. Simon brine sample collected closest to the Eau Claire, were used for these calculations. Its measured properties include temperature of 119.8°F and density of 1,089.7 g/L. Its dynamic viscosity was estimated to be 758.0 μPa sec. For an intrinsic permeability value of 0.000344 mD, the hydraulic conductivity equals 4.8×10^{-10} cm/sec.

Source:
Freeze, R.A. and J.A. Cherry, 1979. *Groundwater*. Englewood Cliffs, N.J., Prentice-Hall, Inc.

2.5.3.5 Alternative Confining Zones Proposed, Include Explanation and Depth Interval(s)

Secondary seals provide additional backup containment of the CO_2 should an unlikely failure of the primary seal occur. Secondary seals listed here are units with low permeability that are regionally present and serve as confining seals for oil, gas and gas storage fields throughout Illinois where they are present.

Study of the wireline logs of the CCS #1 well and regional studies indicate that there are two laterally continuous, secondary seals at the IL-ICCS site (Frommelt, 2010). The Ordovician-age Maquoketa Shale is 206 feet thick at the CCS #1 well site with the top at a depth of 2,611 feet below Kelly Bushing (KB). Kelly Bushing is defined as ground level plus 15 feet. This shale is a regional seal for hydrocarbon production from the Ordovician Galena (Trenton) Limestone. The

top of the Devonian-Mississippian-age New Albany Shale (Figure 2-21) is at a depth of 2,088 feet and is about 126 feet thick at the CCS #1 well site. Extensive data from oil fields through the Illinois Basin shows that this shale is an excellent seal for hydrocarbons; hence, it should also be an excellent secondary seal against the vertical migration of CO_2 at this site.

There are also many minor, thinner Mississippian- and Pennsylvanian-age shale beds that will also form seals against CO_2 vertical migration.

2.6 Lower Confining Zone

Information on the lower confining zone (Precambrian granite) is based on the specific data obtained from the CCS #1 well installation (Frommelt, 2010).

Because the lower confining zone is the basement granite and no other sedimentary rocks are below the granite, no data will be collected on the granite for the ICCS project. The fracture pressure, porosity, and permeability of the granite will not impact injection or fluid migration as the CO_2 injection interval will almost certainly be above this interval and the CO_2 is expected to move upward away from the granite.

2.6.1 Geologic Name(s) of Confining Zone

The lower confining zone is the Precambrian granite basement.

2.6.2 Depth Interval of Lower Confining Zone Beneath

At CCS #1, the top of the Precambrian granite is at a depth of 7,165 feet, which indicates that the base of the Mt. Simon in the IL-ICCS injection well will be at a similar depth.

2.6.3 Characteristics of Confining Zone

2.6.3.1 Lithologic Description

The Precambrian-age rock in the Illinois Basin is composed of a medium- to coarse-grained granite or rhyolite and is between 1.1 to 1.4 billion years old (Bickford et al., 1986).

Source:
Bickford, M.E., W.R. Van Schmus, and I. Zietz, 1986. Proterozoic history of the mid-continent region of North America: Geology, vol. 14, no. 6, pp. 492–496.

2.6.3.2 Fracture Pressure at Depth

The ISGS could not find any data on fracture pressure of granites in Illinois. No tests were conducted at the IBDP injection or verification wells to determine the fracture pressure of the lower confining zone. The fracture pressure of the granite is not anticipated to have any effect on the injection or storage of CO_2 in the overlying Mt. Simon Sandstone.

2.6.3.3 Intrinsic Permeability

The top of the granite occurs at depth of 7,165 feet. A total of 65 feet of granite was drilled at CCS #1. At 7,200 feet, one sidewall core plug was collected; the permeability was determined to be 0.0091 mD.

2.6.3.4 Hydraulic Conductivity

Using the pressure and fluid properties obtained for MDT-1 (Table 2-4), hydraulic conductivity for the granite is estimated to be 1.8×10^{-8} cm/sec.

2.6.3.5 Alternative Confining Zones Propose

There are no alternative lower confining zones since no wells in Illinois have found anything else but the Precambrian granite basement below the Mt. Simon Sandstone.

2.7 Overlying Sources of Groundwater at the Site.

To determine the lowermost underground source of drinking water (USDW) at the site, extensive field investigations were undertaken. Field investigations included coring from a depth of 146 to 504 feet, running several geophysical logs, packer testing seven intervals to find rock with sufficient permeability for groundwater monitoring, and limited borehole sampling to evaluate water quality. Pennsylvanian bedrock was recovered from this borehole and included fine-grained sandstone, limestone, siltstone, shale and some coal. None of the rock appeared to be capable of producing much water. Details about these field investigations can be found in letter from Dean Frommelt of ADM to Illinois EPA, dated September 29, 2009 (Frommelt, 2009) [Appendix H]. In summary, shallow Pennsylvanian sandstones (e.g., the lower Bond Formation sandstone or Lower Mattoon sandstones) produced groundwater with TDS values less than 10,000 mg/L and the Inglefield Sandstone produced groundwater with TDS values greater than 10,000 mg/L. In a December 2, 2009 letter (Nightingale, 2009), the Illinois EPA approved the Pennsylvanian bedrock as the lowermost USDW in the vicinity of the ADM site (e.g.,the IBDP site) [Appendix H]. As the IBDP site is located less than one mile from the proposed IL-ICCS project site, it is assumed that the Pennsylvanian bedrock would also be determined as the lowermost USDW at the IL-ICCS site.

Recent water quality sampling at the site is consistent with these field investigations. Samples were collected from a monitoring well (MMV-04B) screened at depths of 275 to 295 feet. Samples from this well were collected from August 2009 through July 2011 and have an average of 18,471 mg/L TDS and range from 8,575 to 28,629 mg/L TDS. Meanwhile, four wells installed for the Class I UIC permit (wells G101-G104, screened at depths of 130 to 140 feet) indicate that this shallower groundwater has an average TDS of 1,151 mg/L.

Source:
Frommelt, D. 2009. Letter to Illinois Environmental Protection Agency, Subject: Lowermost underground source of drinking water (USDW), Archer Daniels Midland Company – UIC Permit UIC-012-ADM, dated September 29, 2009. [Appendix H]

Nightingale, S. 2009. Letter to Archer Daniels Midland Company, Subject: Lowermost underground source of drinking water (USDW), Permit No. UIC-012-ADM, Log No. PS09-206, dated December 2, 2009. [Appendix H]

2.7.1 Characteristics of the Aquifer Immediately Overlying the Confining Zone

2.7.1.1 Elevation at Top of Aquifer

The first aquifer overlying the Eau Claire Formation (the primary seal for the Mt. Simon Sandstone) which contains salt water at the proposed location is the Cambrian–age Ironton-Galesville Formation (Figure 2-8). Based on the geophysical logging in CCS #1, the Ironton-Galesville was found at depths of 4,928 to 5,047 feet (119 feet thick) (Frommelt, 2010). Based on the geophysical logging in Verification Well #1, the Ironton-Galesville was found at depths of 4,901 to 5012 feet (111 feet thick). This thickness range corresponds with regional mapping of the Ironton-Galesville formation that shows it to be between 100 and 150 feet thick at the CCS#2 site (Figure 2-22).

2.7.1.2 Potentiometric Surface

Little information is available about the potentiometric surface in the Ironton-Galesville Formation in Macon County because very few wells penetrate the Ironton-Galesville in central Illinois. Recently obtained data at IBDP Verification Well #1 finds the Ironton-Galesville to have a pressure of 2,073 psi at a depth of 4,918 ft. Assuming the well is filled with freshwater, this pressure equates to an elevation of 550.9 feet, which is approximately 133.1 feet below ground surface.

2.7.1.3 Total Dissolved Solids

Regional mapping of the formation by the USGS shows that the proposed IL-ICCS injection well should encounter saline waters (Figure 2-23) in this interval. Recently obtained data at IBDP - Verification Well #1 from the Ironton-Galesville found TDS to be 65,600 mg/L. Water quality data collected from IBDP CCS #1 were previously discussed in section 2.4.4.5.

2.7.1.4 Lithology

The Ironton and Galesville Sandstones are considered as a single undifferentiated sandstone unit in this report for two reasons. Both units are not exposed in Illinois and the contact between the units cannot be recognized in many of the borings through the units (Buschbach, 1964). Buschbach noted that the two sandstones are difficult to differentiate without a “good” set of well samples. Since the contact between the two formations is primarily based on grain-size (Emrich, 1966), the contact also is difficult to recognize on wireline logs. In addition, the Ironton-Galesville Sandstone constitutes a widespread aquifer in the northern Illinois and southern Wisconsin and has been traced to about 20 miles south of Macon County (Emrich, 1966). Emrich provided descriptions of both sandstones from the subsurface of northern Illinois:

the Ironton is a relatively poorly sorted, fine- to coarse-grained, dolomitic sandstone, whereas the Galesville is a sandstone that is relatively better sorted, finer grained, and "cleaner" than the overlying Ironton. The CCS #1 well and Verification Well #1 are the only wells that penetrated this interval within a 17-mile radius of the proposed site. No lithologic data for the Ironton-Galesville were collected during the drilling of these wells.

Sources:
Buschbach, T.C., 1964. Cambrian and Ordovician Strata of Northeastern Illinois, Illinois State Geological Survey, Report of Investigations 218, 90 p.
Emrich, G.H., 1966. Ironton and Galesville (Cambrian) Sandstones in Illinois and adjacent areas, Illinois State Geological Survey, Circular 403, 55 p.

2.7.1.5 Aquifer Thickness

Based on the geophysical logging in CCS #1, the Ironton-Galesville was found to be 119 feet thick.

2.7.1.6 Specific Gravity

Little information was available about the specific gravity of fluids in the Ironton-Galesville Formation in Macon County because very few wells penetrate the Ironton-Galesville in central Illinois. No water quality data were for the Ironton-Galesville were collected during the drilling of CCS #1 for the Ironton-Galesville. New data (2011) from IBDP Verification Well #1 found the specific gravity of swab samples from Perforated Zone 10 (5001') and Perforated Zone 11 (4918') was 1.046 and 1.043 g/cc, respectively.

2.7.2 Underground Sources of Drinking Water

2.7.2.1 Maps and Cross Sections

Maps and Cross-sections/ Quaternary Deposits

Sand and gravel aquifers are found in the Quaternary (Pleistocene and recent) geologic deposits (Figure 2-24). Larson et al. (2003) described these deposits for DeWitt, Piatt, and northern Macon Counties. While the water quality of groundwater in these aquifers is not known precisely, these aquifers are used for water supplies and are considered to be underground sources of drinking water.

The vertical sequence of sand and gravel aquifers in the IL-ICCS site area is illustrated in Figure 2-25. Thin sand and gravel aquifers may be present within the Banner Formation (Figure 2-27), the lower portion of the Glasford Formation (Figure 2-28), and the Tiskilwa Formation (Figure 2-29). Somewhat thicker sand and gravel aquifers (5 to 20 feet thick) may occur in the upper portion of the Glasford Formation (Figure 2-30) and are likely found within 100 feet of the ground surface. The Mahomet aquifer, a major regional aquifer that occurs in part of Macon County, is not located beneath the IL-ICCS site (Figure 2-26), but is present approximately 5 miles to the north.

Maps and Cross-sections/ Pennsylvanian Bedrock

The uppermost bedrock at the site is Pennsylvanian-age bedrock (Figure 2-31). For the Illinois Department of Natural Resources, Office of Mines and Minerals (IDNR-OMM), the ISGS previously produced county-wide cross-sections to help IDNR-OMM determine the depth of oil-field casing needed to protect underground sources of drinking water (USDW). A cross-section was produced for Christian and Macon Counties, as shown in Figures 2-32 & 2-33 (Vaiden, 1991). These cross-sections were developed using water quality data from the ISWS and estimates from geophysical logs using the technique of Poole et al. (1989). The source of the water quality data is noted on the cross-section. This cross-section indicates that the water quality in the uppermost Pennsylvanian bedrock is less than 10,000 mg/L, but the TDS rapidly increases below the No. 2 Coal (Figures 2-32, 2-33 & 2-34) and generally exceeds 10,000 mg/L.

Maps and Cross-sections/Mississippian Bedrock

Because water quality data for the Mississippian bedrock is not available at the site or in Macon County, regional data are the only source for this data. Brower et al. (1989) noted that mineralization of groundwater in the Valmeyeran and Chesterian units of the Mississippian System was low in outcrops (and in subcrops beneath Quaternary strata) and reached a maximum of 100,000 to 160,000 mg/L TDS in the deep subsurface in Illinois Basin (Figure 2-34). There are no Mississippian unit outcrop/subcrop areas in Macon County. Figure 2-34 shows the estimated position at which 10,000 mg/L TDS groundwater is encountered in the Valmeyeran and Chesterian, respectively. It is not expected that Mississippian-age strata at the proposed injection site will be a USDW.

Source:

Brower, R. D., A. P. Visocky, I. G. Krapac, B. R. Hensel, G. R. Peyton, J. S. Nealon and M. Guthrie, 1989. Evaluation of underground injection of industrial waste in Illinois, Illinois Scientific Surveys Joint Report 2: 89.

Larson, D.R., B.L. Herzog and T.H. Larson, 2003. Groundwater Geology of DeWitt, Piatt, and Northern Macon Counties, Illinois. Champaign, IL, Illinois State Geological Survey Environmental Geology 155: 35.

Poole, V.L., K. Cartwright and D. Leap, 1989. Use of Geophysical Logs to Estimate Water-Quality of Basal Pennsylvanian Sandstones, Southwestern Illinois. Ground Water 27(5): 682-688.

Vaiden, R.C., 1991. Cross-Section E-E', Christian and Macon Counties. Unpublished cross section throughout oil producing areas of Illinois, used to estimate total dissolved solids in certain sandstones. Champaign, IL, Illinois State Geological Survey.

2.7.2.2 Lowest Depth of Underground Source of Drinking Water (USDW)

The Pennsylvanian bedrock is anticipated to be the lowermost USDW at the IL-ICCS project site. The depth of the lowermost USDW is expected to be similar to the depths found at the IBDP site compliance wells, or approximately 140 feet below the ground surface.

Source: Quarterly Groundwater Report For Illinois EPA Underground Injection Control Permit Number UIC-012-ADM (2010 Q4), Locke, R. and Mehnert, E. December 17, 2010.

2.7.2.3 Elevation of Potentiometric Surface of Lowest USDW Referenced to Mean Sea Level

The potentiometric surface of lowest USDW is expected to be approximately 55 to 59 feet below the ground surface, based on potentiometric data collected from the four groundwater compliance monitoring wells at the IBDP site during the 4th quarter of 2010 (Locke and Mehnert, 2010). The potentiometric surface of the lowermost USDW is anticipated to be approximately 620 feet above MSL at the IL-ICCS project site.

Source:
Locke, R. A. II, and Mehnert, E., December 17, 2010. Quarterly Groundwater Report For Illinois EPA Underground Injection Control Permit Number UIC-012-ADM (2010 Q4) submitted by the Illinois State Geological Survey to Mark Carroll, Environmental Compliance Manager, ADM Decatur Corn Processing Plant.

2.7.2.4 Distance to Nearest Water Supply Well

Water well records were found in the Illinois State Water Survey database for three private water supply wells located in the southeast quarter of Section 32 (**Figure 2-35**). These wells are likely to be located within ¼ to ½ mile of the injection well. These wells are described in Table 2-7.

Table 2-7: Description of nearest potable water wells in Section 32, T17N, R3E

API #	Well Owner	Well Depth (ft)	Well Diameter (in)	Year Drilled
121152203900	Gary Sebens	55	36	1988
121152221200	Gary Sebens	38	36	1990
121152283500	Anna Stiles	56	36	1992

2.7.2.5 Distance to Nearest Downgradient Water Supply Well

The wells described above are likely to be the closest wells downgradient from the injection well. Shallow groundwater likely flows to the south and east, which is the same direction that the land surface slopes (toward Lake Decatur).

2.8 Minerals and Hydrocarbons

2.8.1 Mineral or Natural Resources beneath or within 5 miles of the Site

2.8.1.1 Stone, Sand, Clay and Gravel

Sand and gravel resources are commonly present in the low terraces and floodplain of the Sangamon River and its tributaries. Several sand and gravel pits have operated in the area in the past and currently there are one active and two idle operations in or near the project area. The nearest active sand and gravel pit is approximately 12 miles to the west-southwest of the ADM site. Relatively thick limestone deposits, suitable for construction aggregates, generally occur at depths greater than 1,100 feet. Access to these limestones is possible only through underground mining methods, which is not economically feasible at the present time.

Source:
Hester, N.C., 1969. Sand and gravel resources of Macon County, Illinois: Illinois State Geological Survey Circular 446, 16 p.

Lamar, J.E., 1964. Subsurface limestone resources in Macon County: Illinois State Geological Survey Unpublished Manuscript 141

2.8.1.2 Coal

The nearest active coal mines are the Viper Mine (about 35 miles west-northwest in Logan County) and Crown III Mine (operated by Springfield Coal Company, about 65 miles southwest in Macoupin County).

The nearest historical coal mining on record at the ISGS were the three mines in Decatur. The closest (Figure 2-36) is within 5 miles of the proposed site, the Decatur No. 1 Mine. The shaft for this mine was northeast of the intersection of Eldorado and Jefferson Streets in Decatur (about 3 miles southwest of the site), and was about 600 feet deep. This longwall mine has no surviving map of the workings, but the main haulage entry was shown on the adjacent mine map, Macon County No. 2 Mine, which was connected underground. The Decatur No. 1 Mine operated from 1879 until 1914. The reported production was 1,780,000 tons, which would have undermined about 475 acres. The adjacent Macon County No. 2 Mine produced 2,660,000 tons, and undermined 430 acres. The portions of the only surviving map indicate that these mines operated west of Illinois Route 47/121. The third mine in Decatur is farther southwest, near the intersection of US Route 51 and Cantrell Street in Decatur. The Macon County No. 1 Mine operated from 1903 until 1947 and produced 4,590,000 tons. This production undermined over 670 acres. All of these mines recovered the Springfield Coal, which is between 4.0 and 5.0 feet thick in this area.

The presence of other unlocated or unrecorded old coal mines is unlikely. The first recorded coal exploration was in 1875, but coal was not found until 1876, on the third test hole. The great depth to the coal prevented small operators from opening the local mines that prevailed in many other counties.

Source:
Chenoweth, C., and A. Louchios, 2004. Directory of Coal Mines in Illinois, 7.5-minute Quadrangle Series: Decatur Quadrangle, Macon County, Illinois. Illinois State Geological Survey, 12 p., with "Coal Mines in Illinois – Decatur Quadrangle, Macon County, Illinois", Illinois State Geological Survey Maps (1:24,000).

Illinois State Geological Survey, 2006. Directory of Coal Mines in Illinois, Logan County, 10 p.

Illinois State Geological Survey, 2006. Directory of Coal Mines in Illinois, Macoupin County, 17 p.

Existing Mineral Resources Near IL-ICCS Site location: Sec 32, T 17N, R E

A review of the known coal geology within a five mile radius of the proposed drilling site indicates that although several high-sulfur coals are present throughout the area, only the Springfield coal has a thickness of between 42 and 66 inches, which is considered mineable. Mining is restricted today due to urbanization and commercial development at the surface.

This restriction extends to five miles in all directions except to the north, north-east and east, where the coal is technically "available" for mining. "Available" coal means that the coal is not known to have geological, technological or land-use restrictions that would negatively impact the economics or safety of mining. These resources are not necessarily economically mineable at the present time, but they are expected to have mining conditions comparable with those currently being mined in the state. The top of the Springfield coal in the CCS #1 well is at a depth of 647 feet and its thickness, based on geophysical log analysis, is about 4 to 5 feet thick. In general, the coal bed dips gently eastward as the depth of the coal ranges from 500 feet deep five miles west of the site, to 725 feet deep five miles east of the site. Price, depth and coal thickness are inter-related economic factors that determine if coal might be mined in the future. Prior to 1947, there was mining in this seam over 3 miles to the southwest from the site, where it is thicker.

Source: ISGS County Coal Map Data, Macon County, Illinois: available on the ISGS Coal Section website at: http://www.isgs.uiuc.edu/maps-data-pub/coal-maps/counties/macon.shtml

Treworgy, C., C. Korose, C. Chenoweth, and D. North, 2000. Availability of the Springfield Coal for Mining in Illinois, Illinois State Geological Survey, Illinois Minerals 118.

2.8.1.3 Oil and Gas

Oil and natural gas have been produced from both oil fields and solitary wells in the area of interest. The largest of these oil fields is the Forsyth Field, part of which is northwest of the IL-ICCS Site (Figure 2-36). The field produces from Silurian strata between depths of about of 2,070 and 2,200 feet. The producing zone is usually about 10 feet thick, but zones up to 60 feet thick have been recorded. In 2008, 6,100 barrels (bbls) of oil were produced from 48 producing wells. The total production for the field is 650,100 bbls of oil, as of the end of 2008.

The next nearest oil field in the area of interest is the Oakley Field, the western edge of which is located about 3.5 miles east from the ADM ICCS Site. The field produces from Devonian strata

between depths of about of 2,255 and 2,310 feet. The producing zone is usually about 5 to 25 feet thick. In 2008, 1,200 bbls of oil were produced from 2 producing wells. The total production for the field is 43,100 bbls of oil, as of the end of 2008.

The third oil field in the area of interest is the Decatur Field, the eastern edge of which is located less than 6 miles west of the ADM ICCS Site. The field produces from Silurian strata between depths of about of 2,000 and 2,500 feet. The producing zone is usually about 10 to 20 feet thick. In 2008, 400 bbls of oil were produced from 9 producing wells. The total production for the field is 49,900 bbls of oil, as of the end of 2008.

In addition, there is a single oil well "field," Decatur North, located about 1 mile north of the proposed injection well site. The well produced 125 barrels from Silurian strata at a depth of 2,220 to 2,224 feet. This well was plugged and abandoned in late 1954 after eight months of production.

There is also a single production well, now plugged, that is located about 2 miles to the west of the ADM ICCS Site. The well was drilled in 1984 and abandoned in 1993. The well production was from Silurian strata at depths of about 2,040 to 2,050 feet. The total production for the well is about 2,200 bbls.

Natural gas is produced from several wells in the area that were drilled primarily for water. The gas is produced from Pleistocene sediments at depths of about 80 to110 feet deep. The gas is suitable for domestic or agricultural usage but not for commercial development as a natural gas field.

Source:
Various years, Illinois Annual Oil Field Reports, Illinois State Geological Survey.

ISGS ILWATER database available at: http://www.isgs.uiuc.edu/maps-data-pub/wwdb/launchims.shtml

2.9 References cited in the figures

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Frommelt, D., 2010. Letter to the Illinois Environmental Protection Agency, Subject: CCS Well #1 Completion Report, Archer Daniels Midland Company – UIC Permit UIC-012-ADM, dated May 5, 2010. [Appendix L]

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Leetaru, H., 2011. Personal communication, Illinois State Geological Survey.

Kolata, D.R., 2005. Bedrock Geology of Illinois, Illinois State Geological Survey Illinois Map 14: 1:500,000.

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Loyd, O,B. and W.L. Lyke, 1995. Ground Water Atlas of the United States, Segment 10: Illinois, Indiana, Kentucky, Ohio and Tennessee, United States Geological Survey Hydrologic Investigations Atlas 730-K, 30 p

Willman, H.B., E. Atherton, T.C. Buschbach, C. Collinson, J.C. Frye, M.E. Hopkins, J.A. Lineback, and J.A. Simon, 1975. Handbook of Illinois Stratigraphy, Illinois State Geological Survey Bulletin 95, 261 pp.

V. Smith, personal communication, Schlumberger Carbon Services, 2011

Figure 2-1: Regional structure map showing no regional structures within a 15-mile radius of the ADM Plant near Decatur, Macon County. Source: Illinois State Geological Survey.

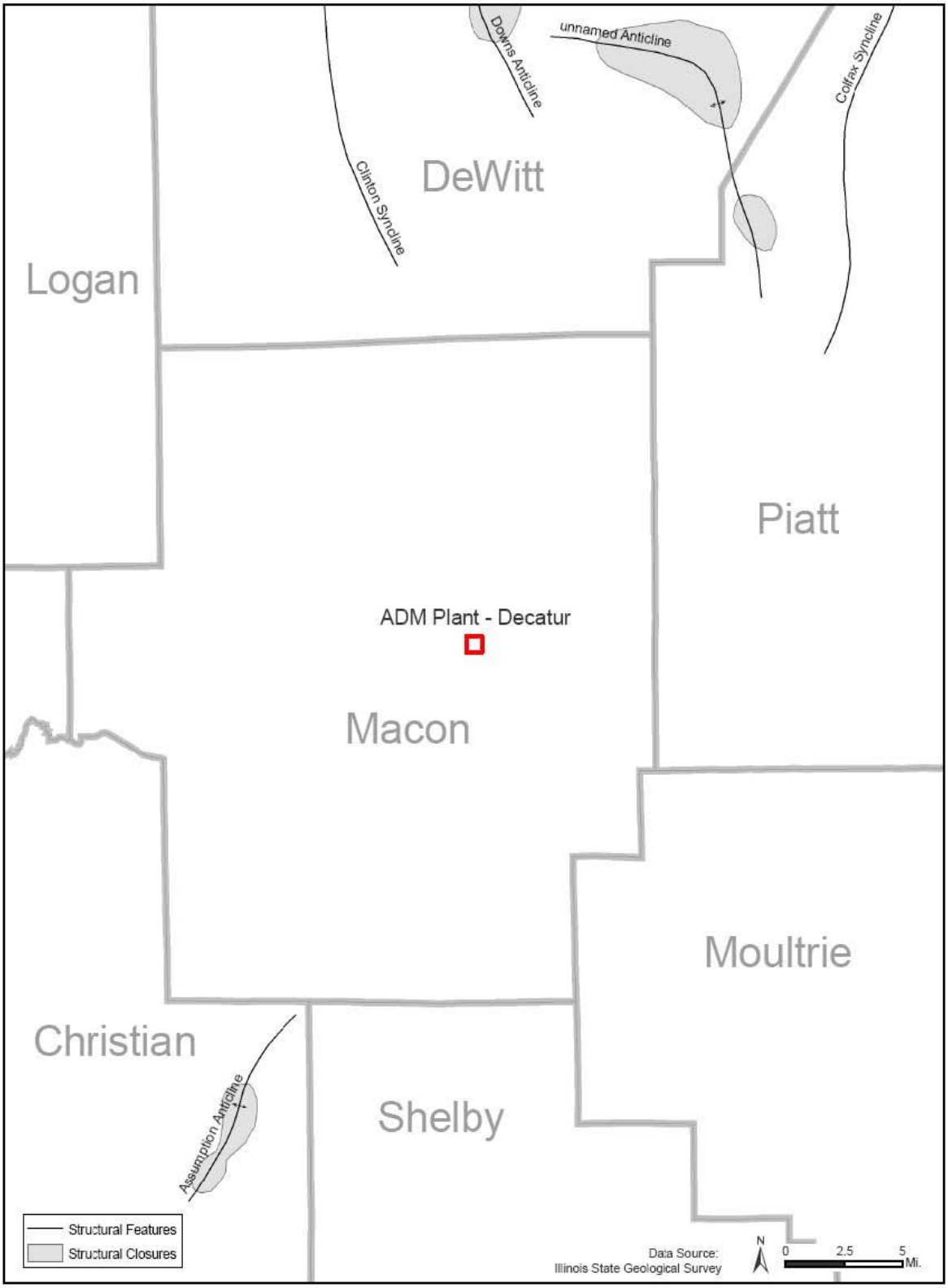


Figure 2-2: Aerial photo over the proposed injection site (IL-ICCS well location labeled). The yellow lines denote seismic lines that were recorded. Reference Figures 2-3 and 2-4 for corresponding geologic cross-sections. Source: Byers, ISGS, 2011

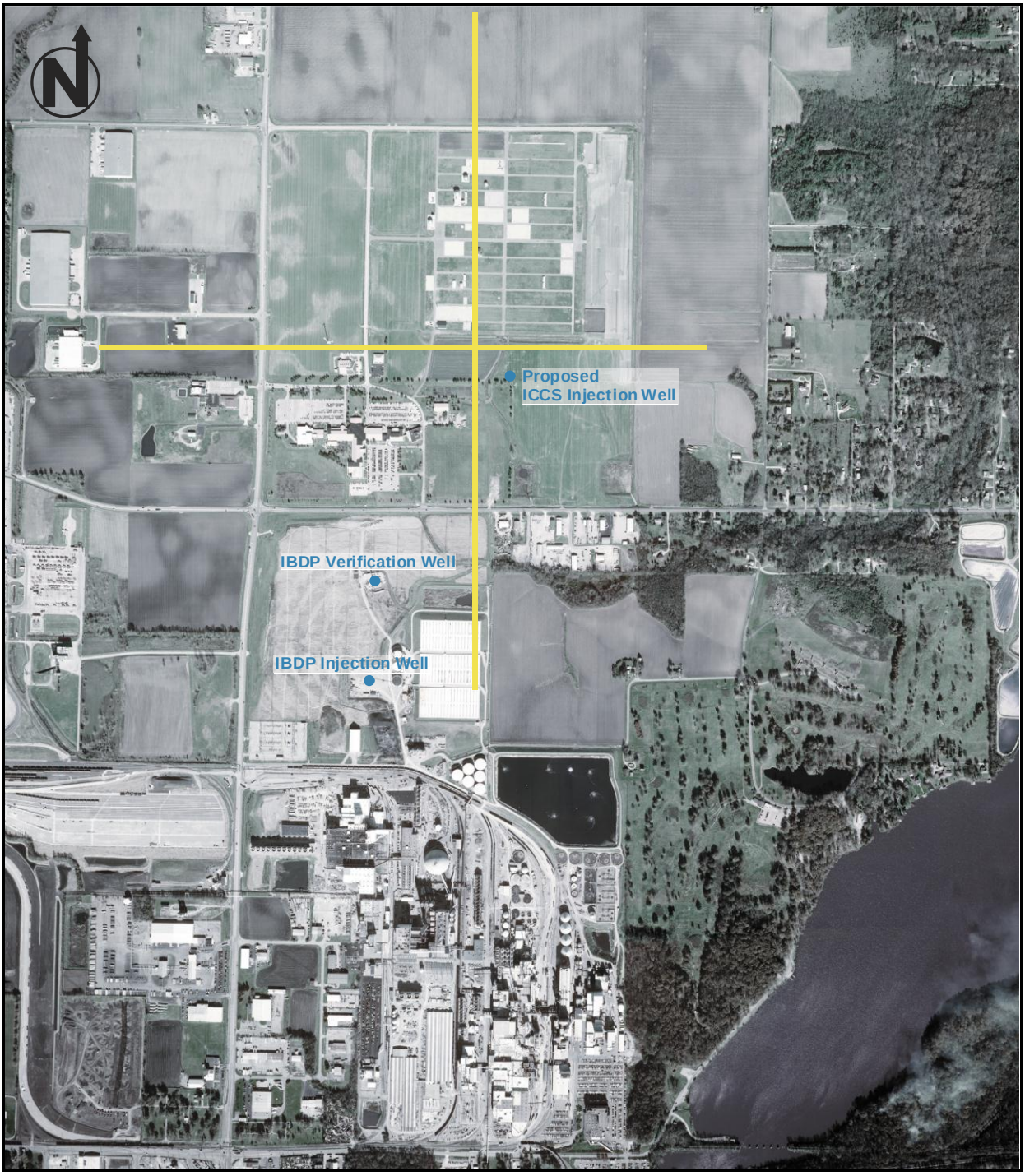


Figure 2-3: East-West seismic reflection profile along the proposed IL-ICCS injection site. Source: Leetaru, 2011

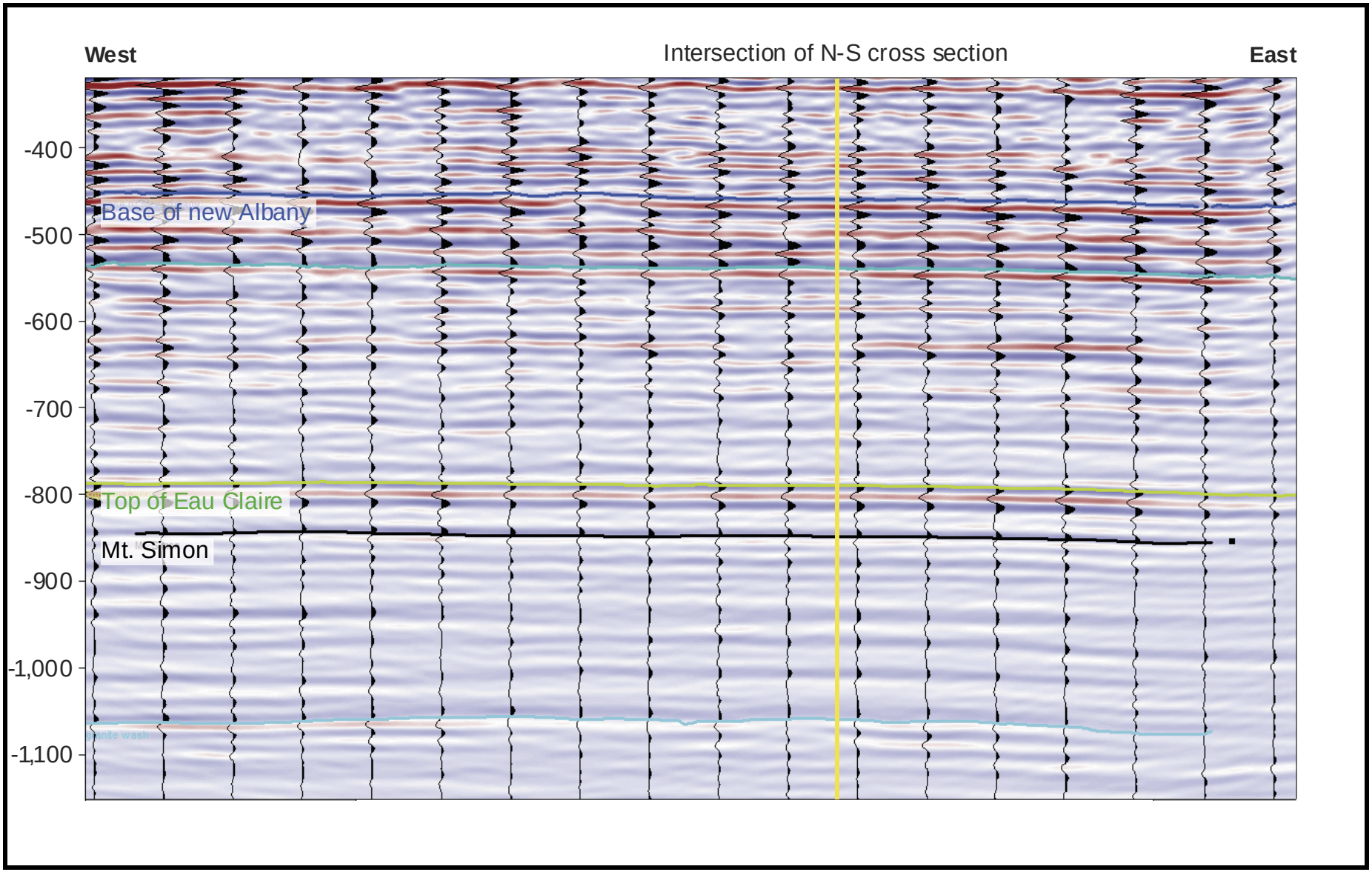


Figure 2-4: North-South seismic reflection profile along the proposed IL-ICCS injection site. Source: Leetaru, 2011

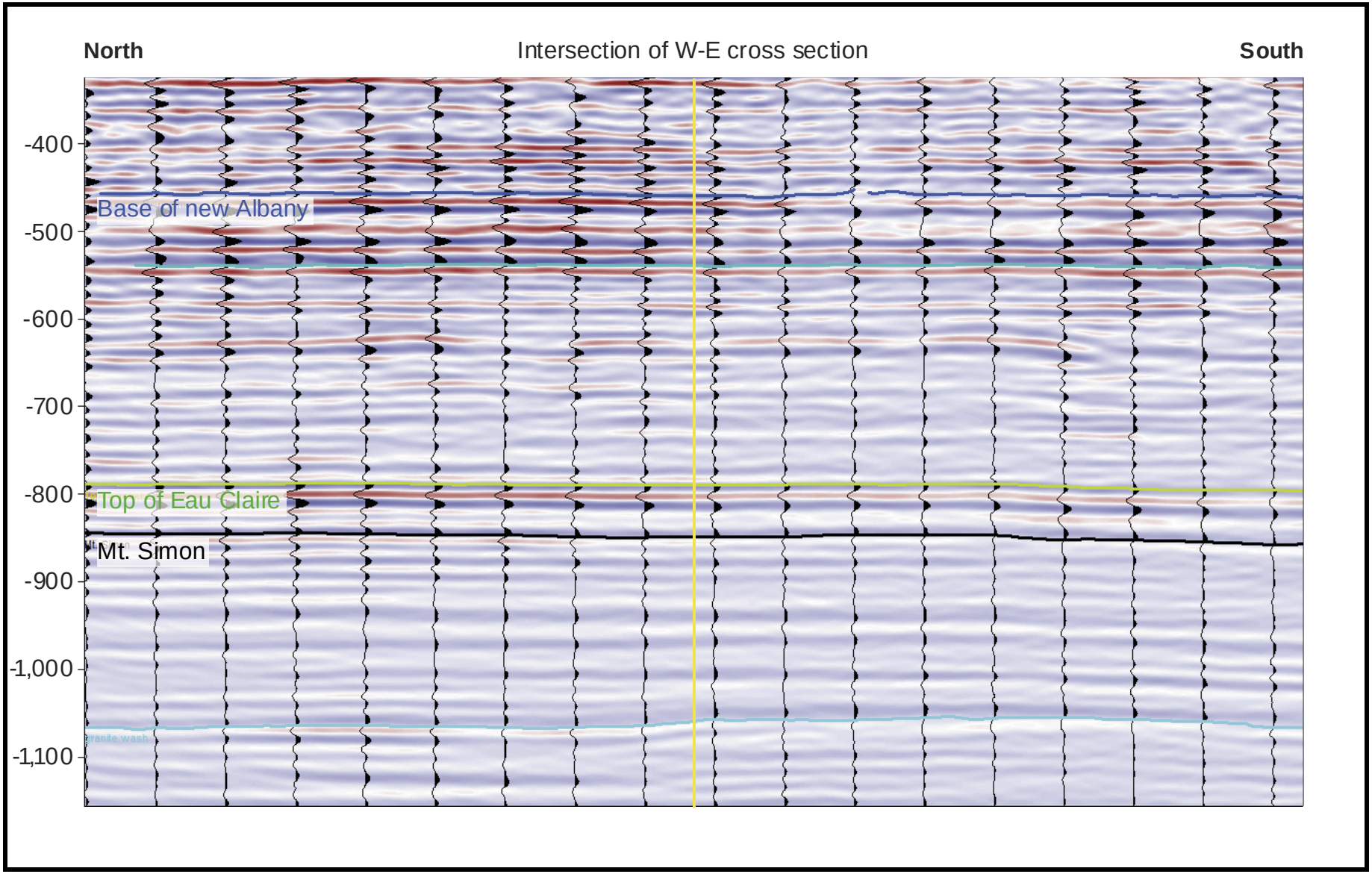


Figure 2-5: Location of cross-sections illustrating the regional geology of the injection site (Figure 2-6 and 2-7 are cross-sections referenced). Source: Smith, Schlumberger Carbon Services, 2011

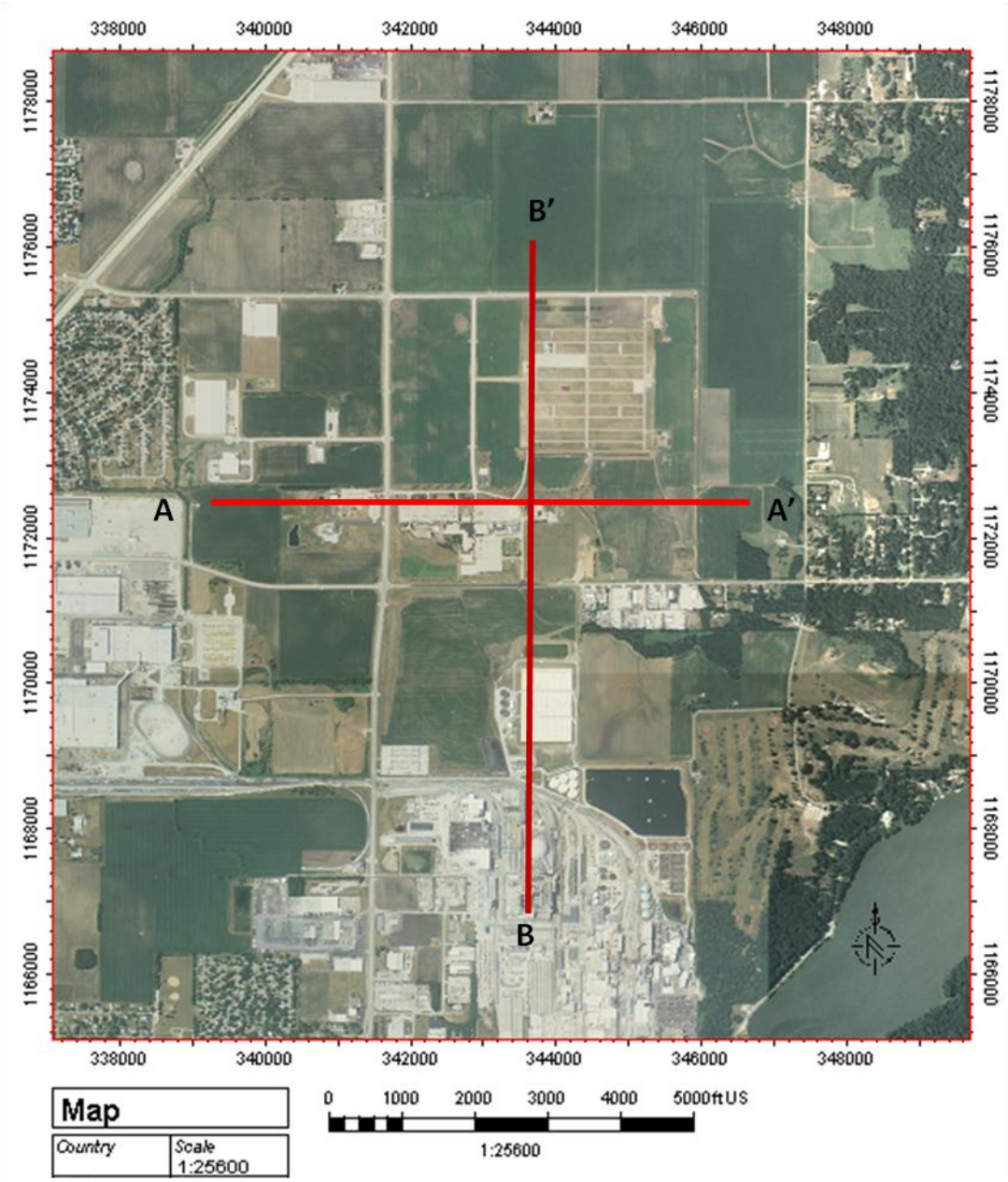


Figure 2-6: Cross section illustrating the geology along west (A) to east (A') direction (location given by Figure 2-5). Source: Smith, Schlumberger Carbon Services, 2011

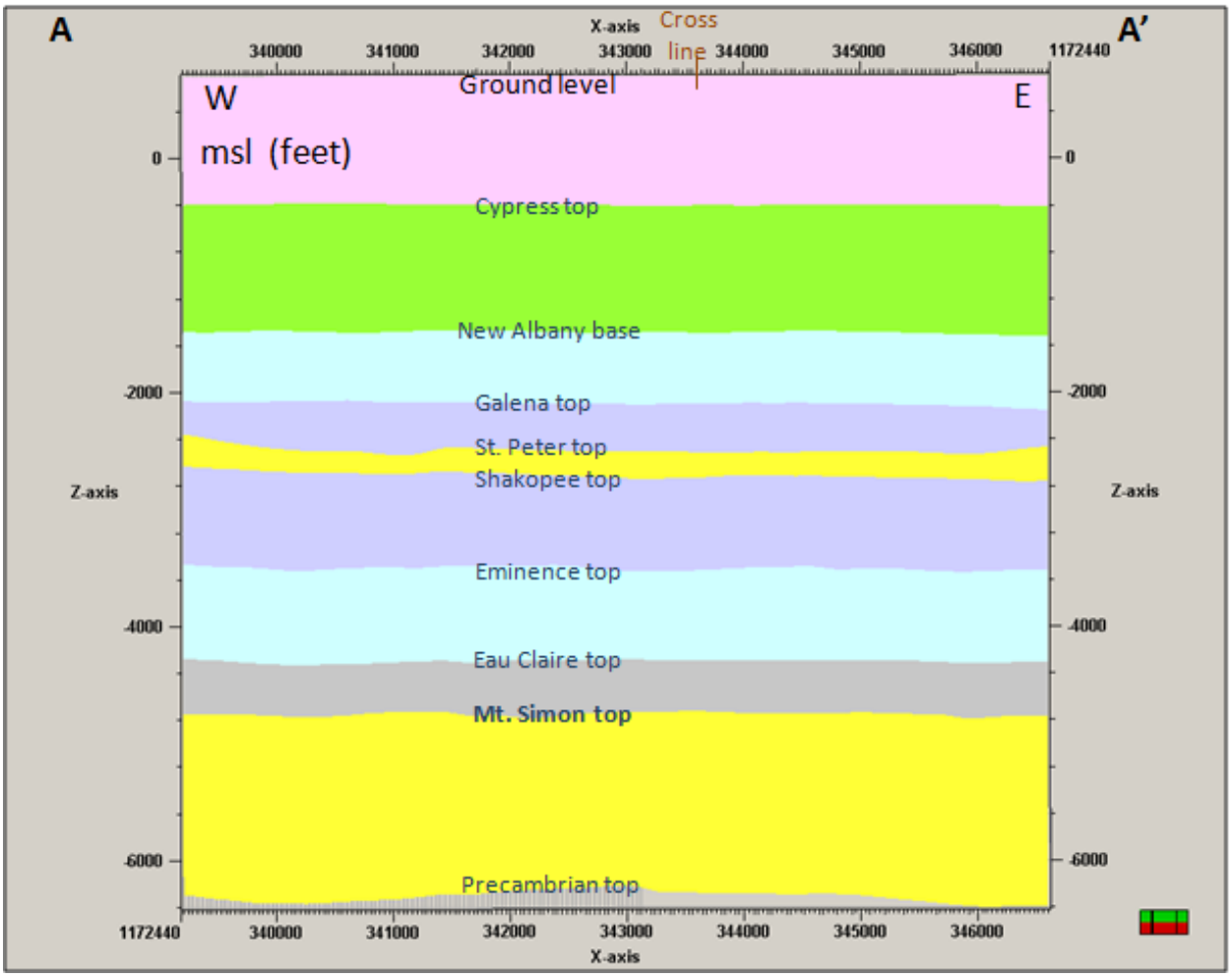


Figure 2-7: Cross section illustrating the geology along south (B) to north (B') direction (location given by Figure 2-5). Source: Smith, Schlumberger Carbon Services, 2011 .

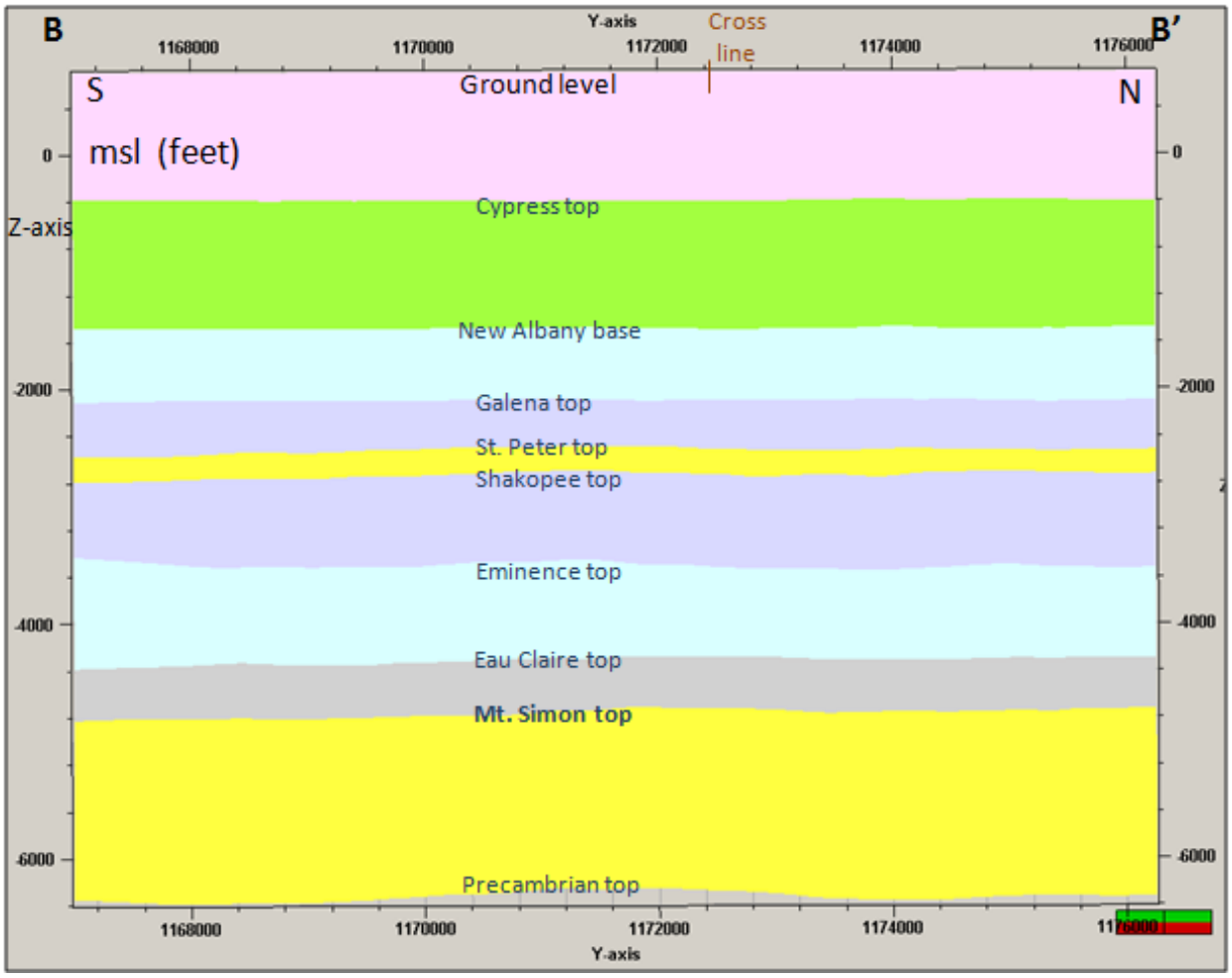


Figure 2-8: Stratigraphic column of Ordovician through Precambrian rocks in northern Illinois (Kolata, 2005). Arrows point to the formations discussed in this UIC permit application. Dr. Darriwillian; Dol, dolomite; Fm, formation; Ls, limestone; MAYS., Maysvillian; Mbr, Member; Sh, shale; WH., Whiterockian; Mya, million years ago; Ss, sandstone; Silts, siltstone.

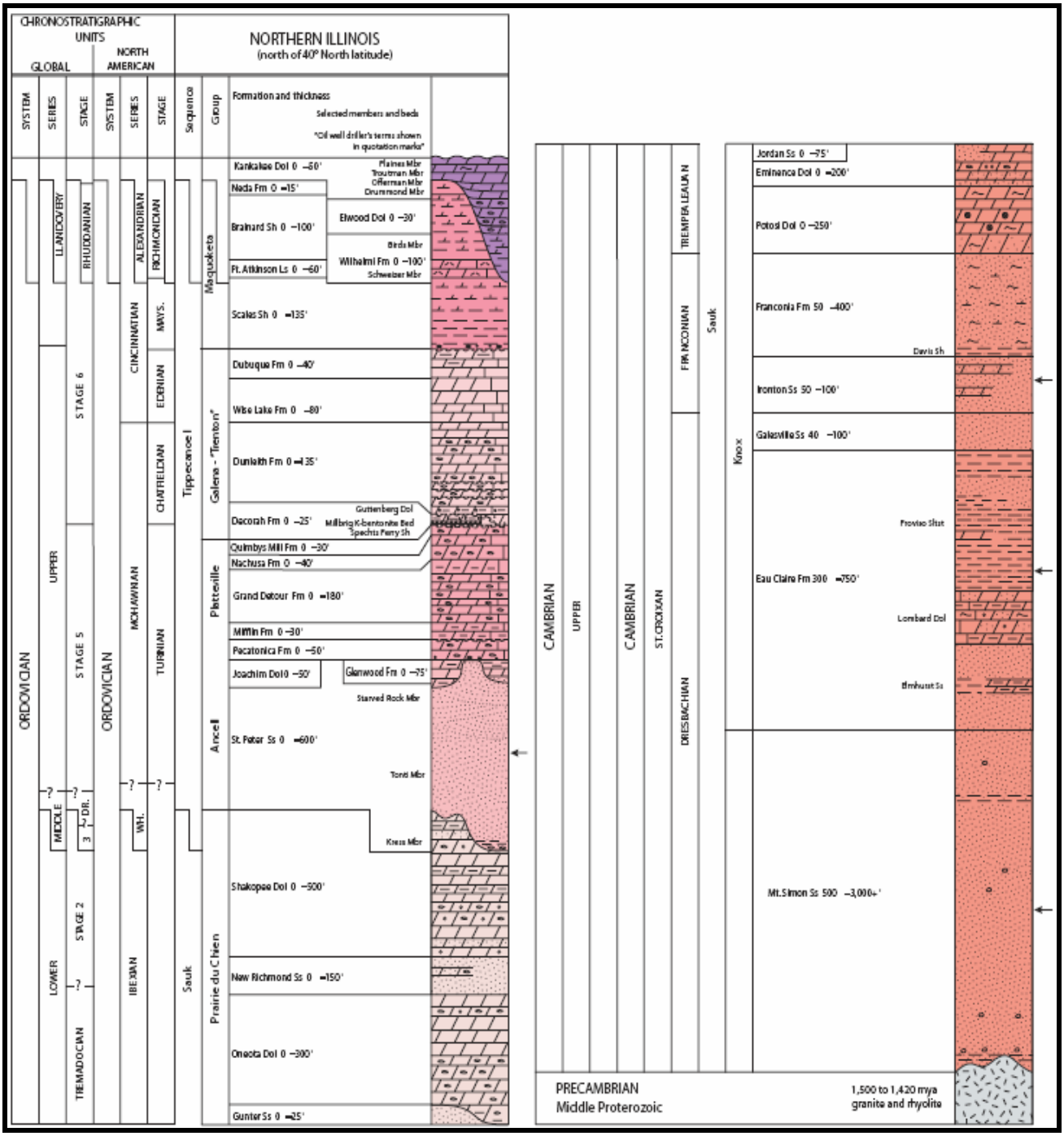


Figure 2-9: Stratigraphic cross section through the Weaber Horn #1, Harrison #1, CCS #1 and the Hinton #7 wells showing the Mt. Simon porosity. The red colored zones have porosity greater than 10% (Frommelt, 2010).

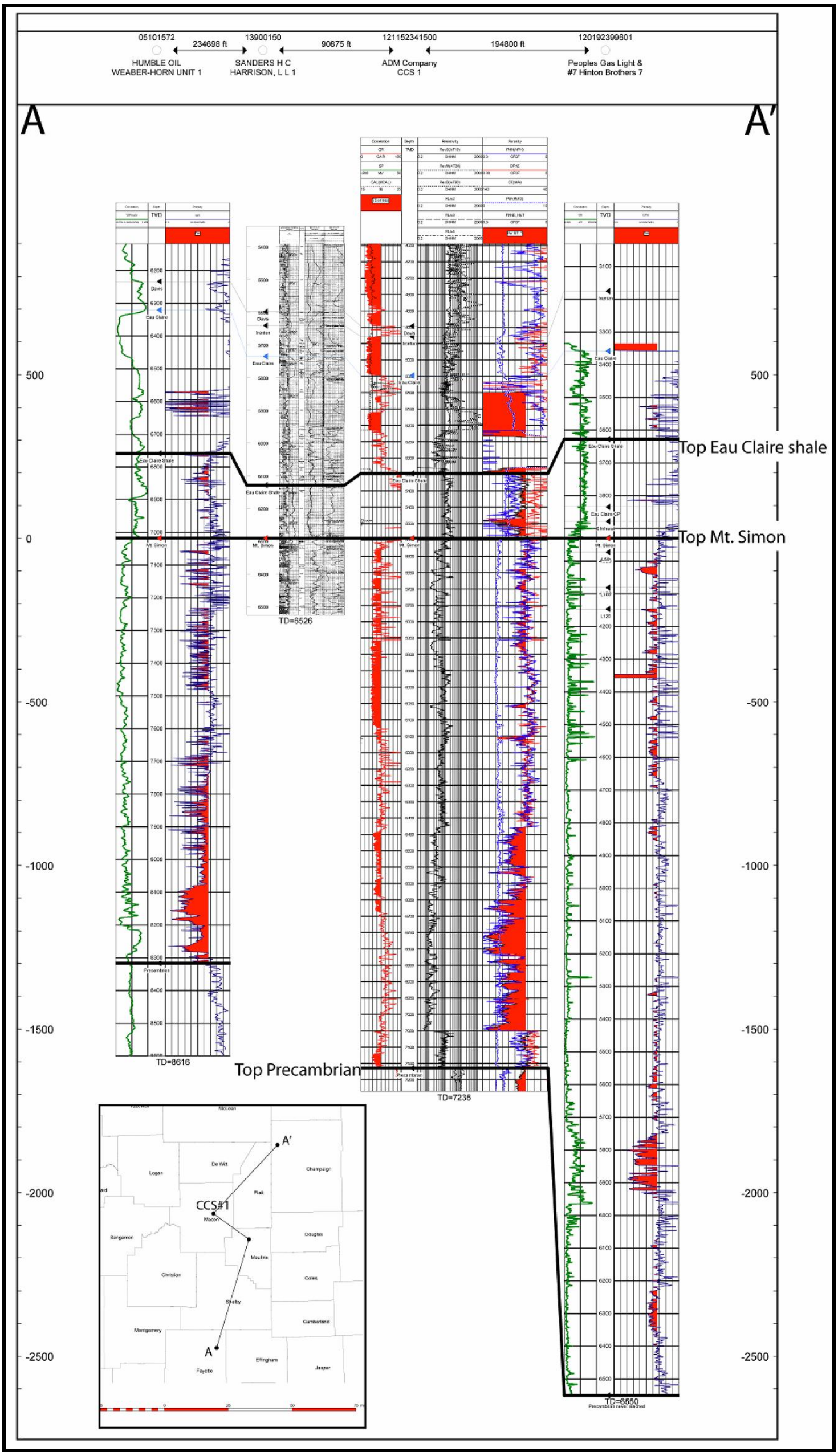


Figure 2-10: IBDP CCS #1 step-rate test with fracture propagation pressure of 4966 psig estimated from the intersection of the two lines. The first line (2-6 bpm) represents radial flow of the Mt. Simon; the second line 7-8 bpm represents flow into the Mt. Simon after a fracture has propagated. The perforated interval was 7,025 to 7,050 feet during this step-rate test. These results correspond to a fracture gradient of 0.715 psi/ft. Source: Frommelt, 2010.

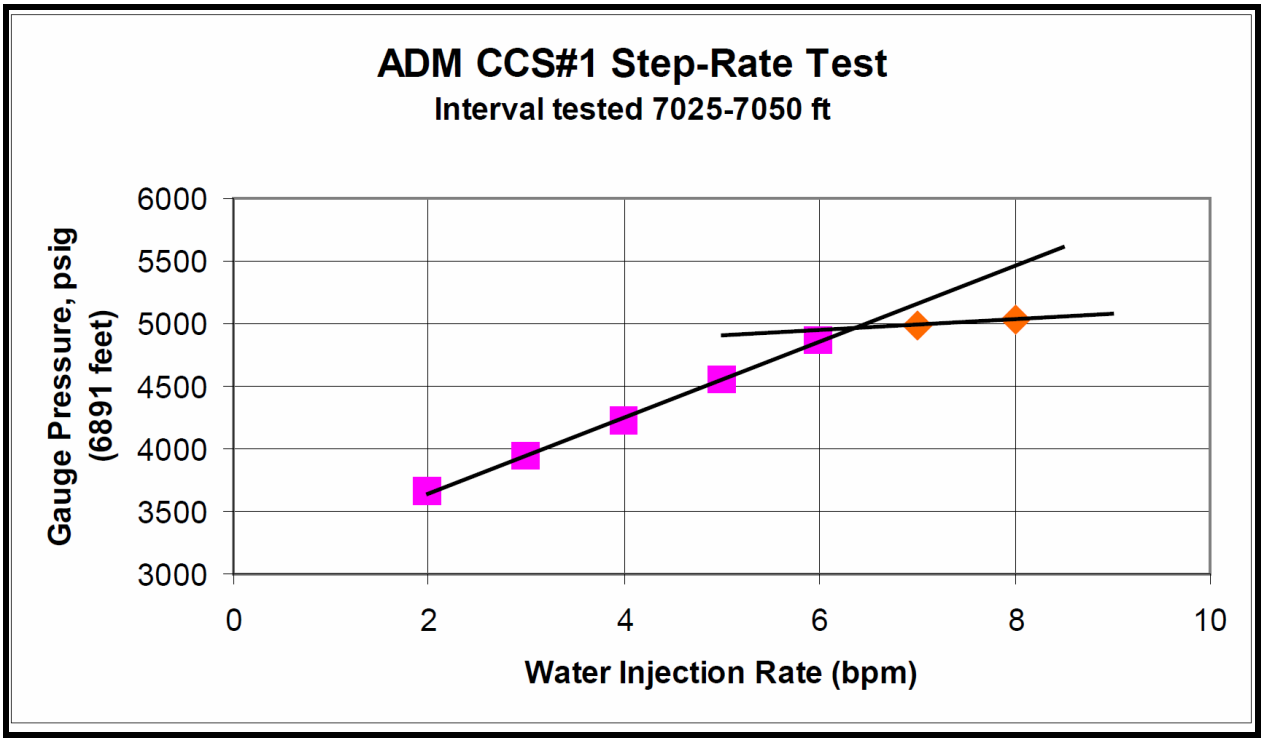


Figure 2-11: Crossplot of helium porosimeter and neutron-density data for CCS #1. The bold line through the data is the unit slope, showing very good correlation between the two types of porosity data. For the porosity data from the rotary sidewall core plugs and the neutron-density crossplot porosity at the interval of the core plug, the porosity compares relatively well such that total and effective porosity are very similar. Source: Frommelt, 2010.

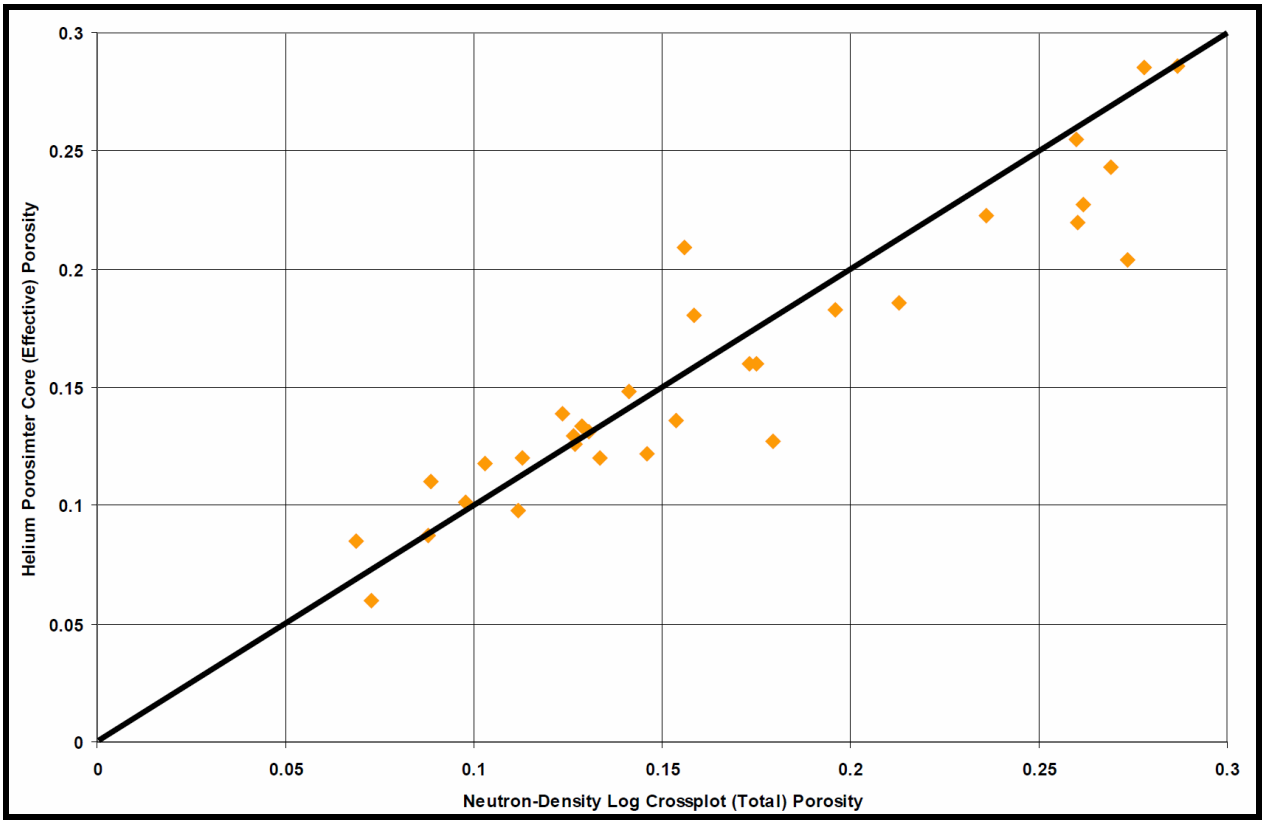


Figure 2-12. Crossplot of core permeability versus core porosity for CCS #1. Transforms were developed for three different grain sizes—fine grained, medium grained and coarse grained sandstone. Source: Frommelt, 2010.

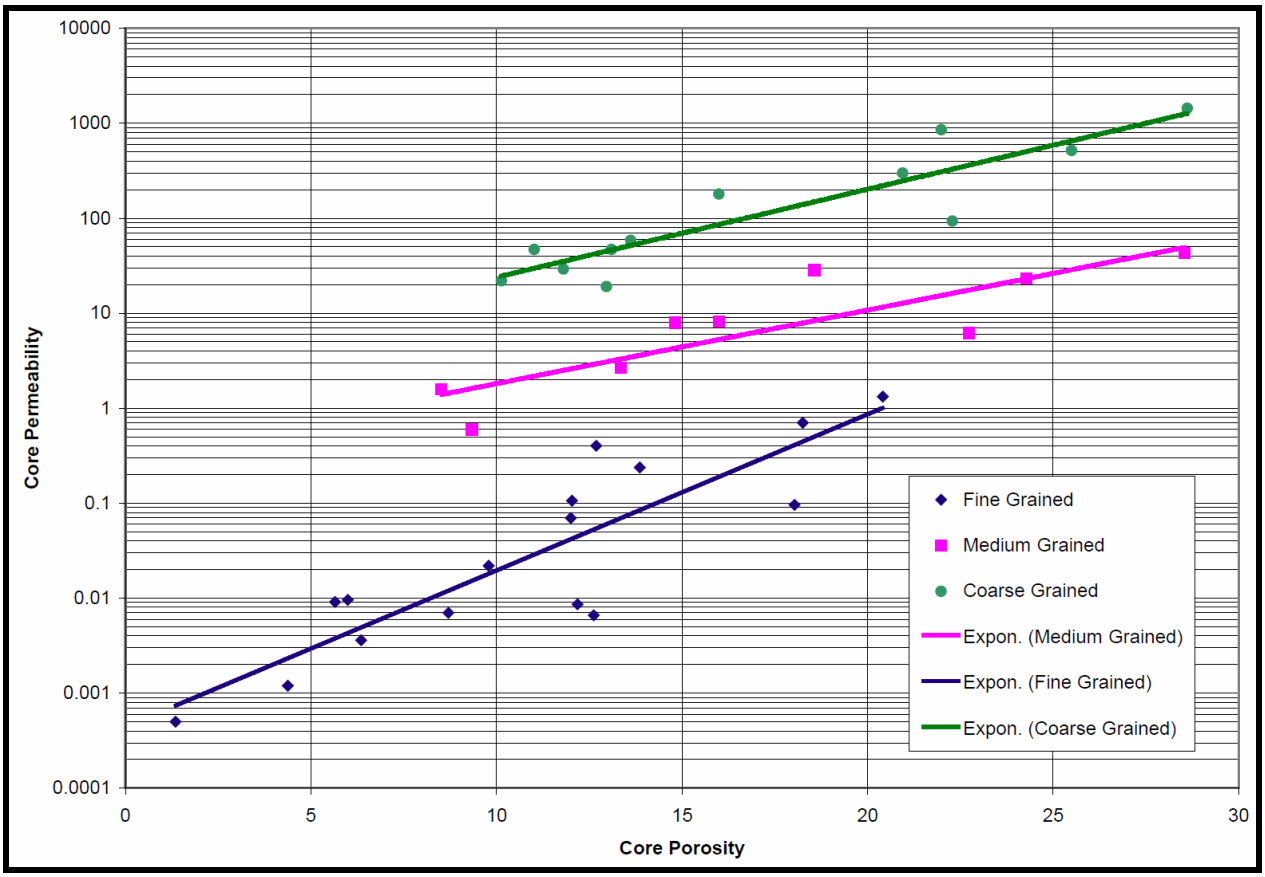


Figure 2-13: Qualitative derivative analyses of final pressure falloff test conducted in CCS #1. Radial pressure response is indicated by a horizontal derivative trend. Two periods were measured during this test between 0.1 and 1 hours (PPNSTB) and 20 to 100 hours (STABIL). The first period corresponds to radial flow across the perforated interval; the second period corresponds to the larger thickness that would be between two much lower permeability sub-units e.g, the less permeable arkose-rich interval at the base and a tighter interval above the perforated interval. The transition between the two radial responses (SPHERE) is a spherical flow period that is influenced by vertical permeability (or kv/kh). (The unit slope (UNIT SLP) indicating wellbore storage, identifies the end of wellbore storage influenced pressure data (ENDWBS) or pressure data that can be analyzed from reservoir properties.). Source: Frommelt, 2010.

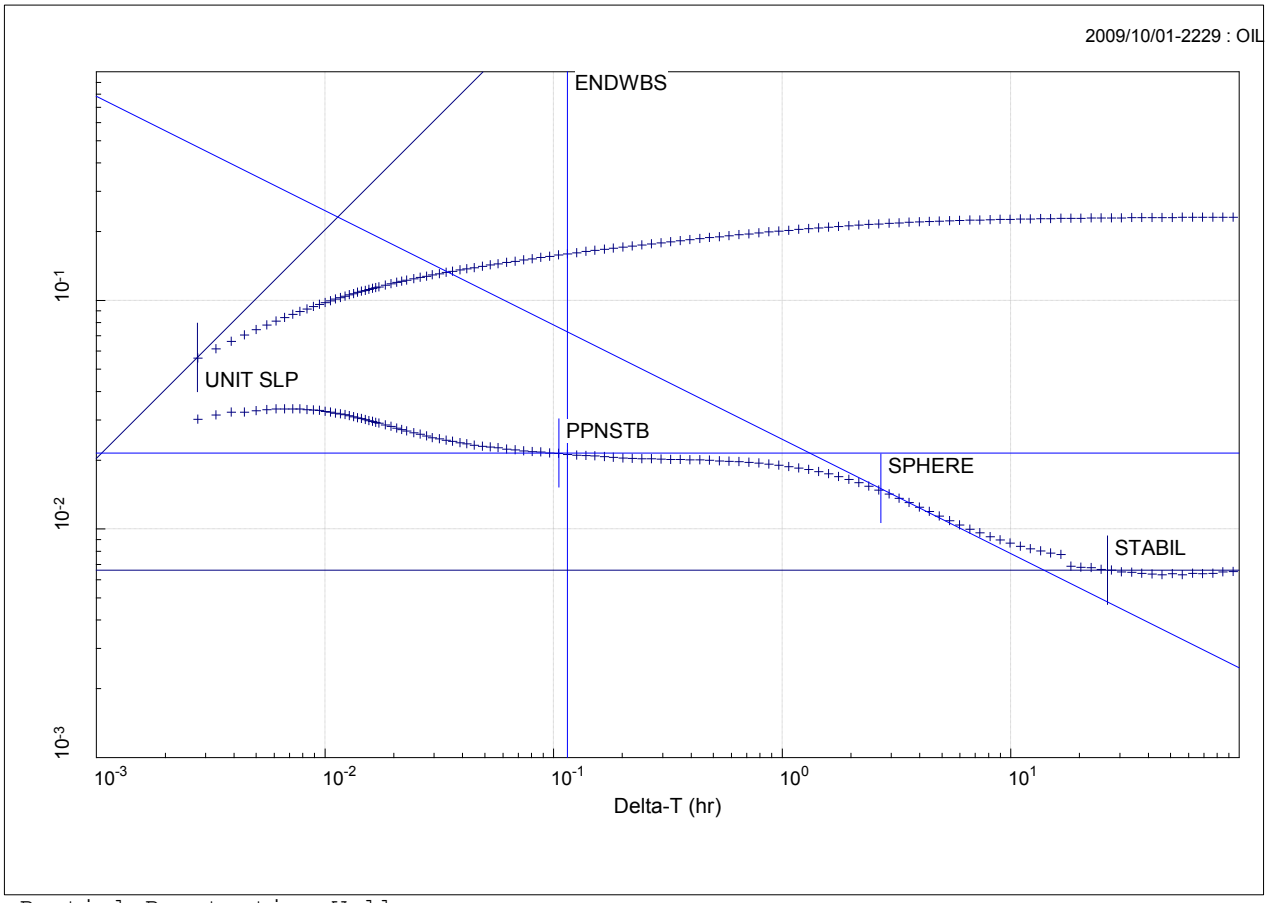


Figure 2-14: Overlay of pressure derivative of the three pressure falloff tests conducted in CCS #1. The Green curve (upper pressure curve and bell shaped derivative) is the first falloff which had perforated interval of 7025-7050 ft MD. The pink (lower derivative curve) is the second falloff in the same perforated interval which had a modest acid treatment prior to the falloff. The dark blue (lower pressure curve middle derivative curve) was the third falloff tests for the perforated intervals of 6982-7012 and 7025-7050 ft MD and a second acid treatment over both perforated intervals. The difference between the green curve and the pink curve in the first 6 minutes is a result of the improvement to flow due to the acid treatment. The upper curves show the pressure difference and the lower curves show the derivative. Source: Frommelt, 2010.

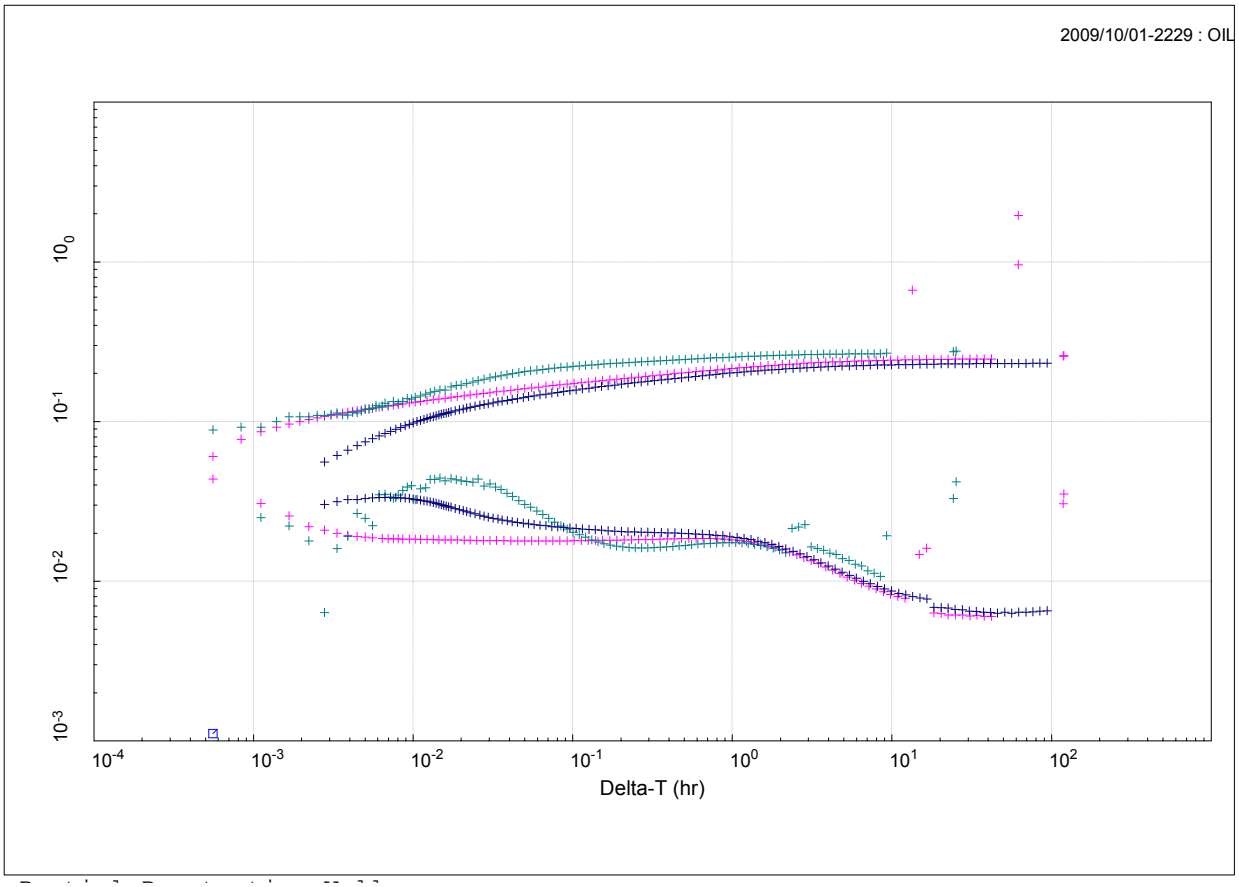
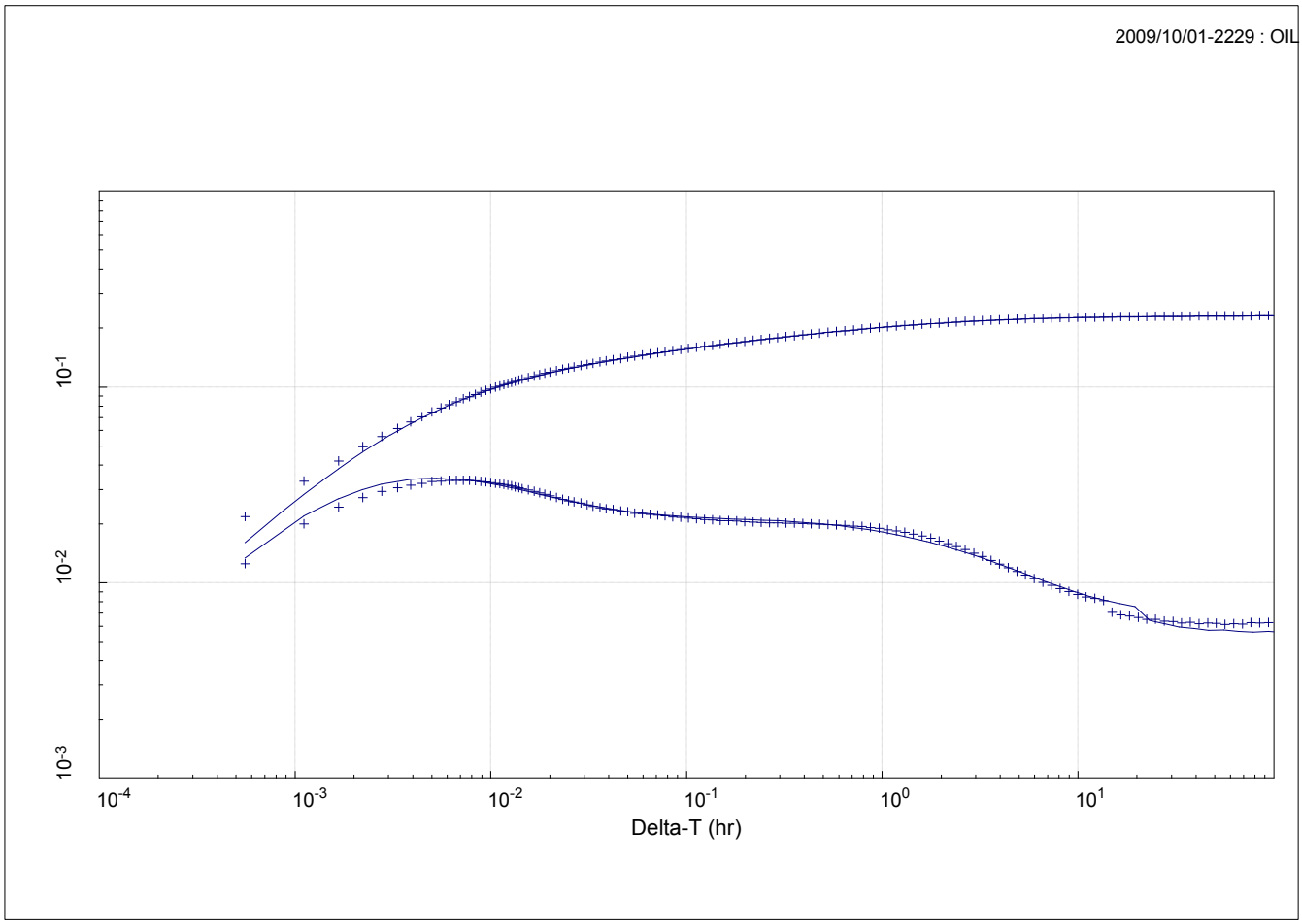


Figure 2-15: Nonlinear regression, or simulation history matching, of the of final pressure falloff test conducted in CCS #1. Test data shown as + symbols and simulated data shown as line. The upper curve is the pressure difference and the lower curve is the derivative. Source: Frommelt, 2010.



Partial Penetration Well

```
** Simulation Data **                    Type-Curve Model Static-Data
 well. storage  = 0.0011457 BBLS/PSI     Perf. Interval = 25.0 FEET
 Skin(mech.)    =  -0.85807
 permeability   =    184.58 MD          Static-Data and Constants
 Kv/Kh          =  0.013260             Volume-Factor  = 1.000 vol/vol
 Eff. Thickness =    75.000 FEET         Thickness      = 75.00 FEET
 Zp/Heff        =   0.83330             Viscosity      = 1.300 CP
 Skin(Global)   =    10.301             Total Compress = .1800E-04 1/PSI
 Perm-Thickness =    13843. MD-FEET      Rate           = -6100. STB/D
```

Figure 2-16: Observed head in the Mt. Simon sandstone. Groundwater flows from areas of higher head to lower head, along lines perpendicular to the head lines. Contour interval = 25 m. (modified from Gupta and Bair, 1997). At the CCS #1 well (red dot), the potentiometric surface was calculated to be 76 m above mean sea level.

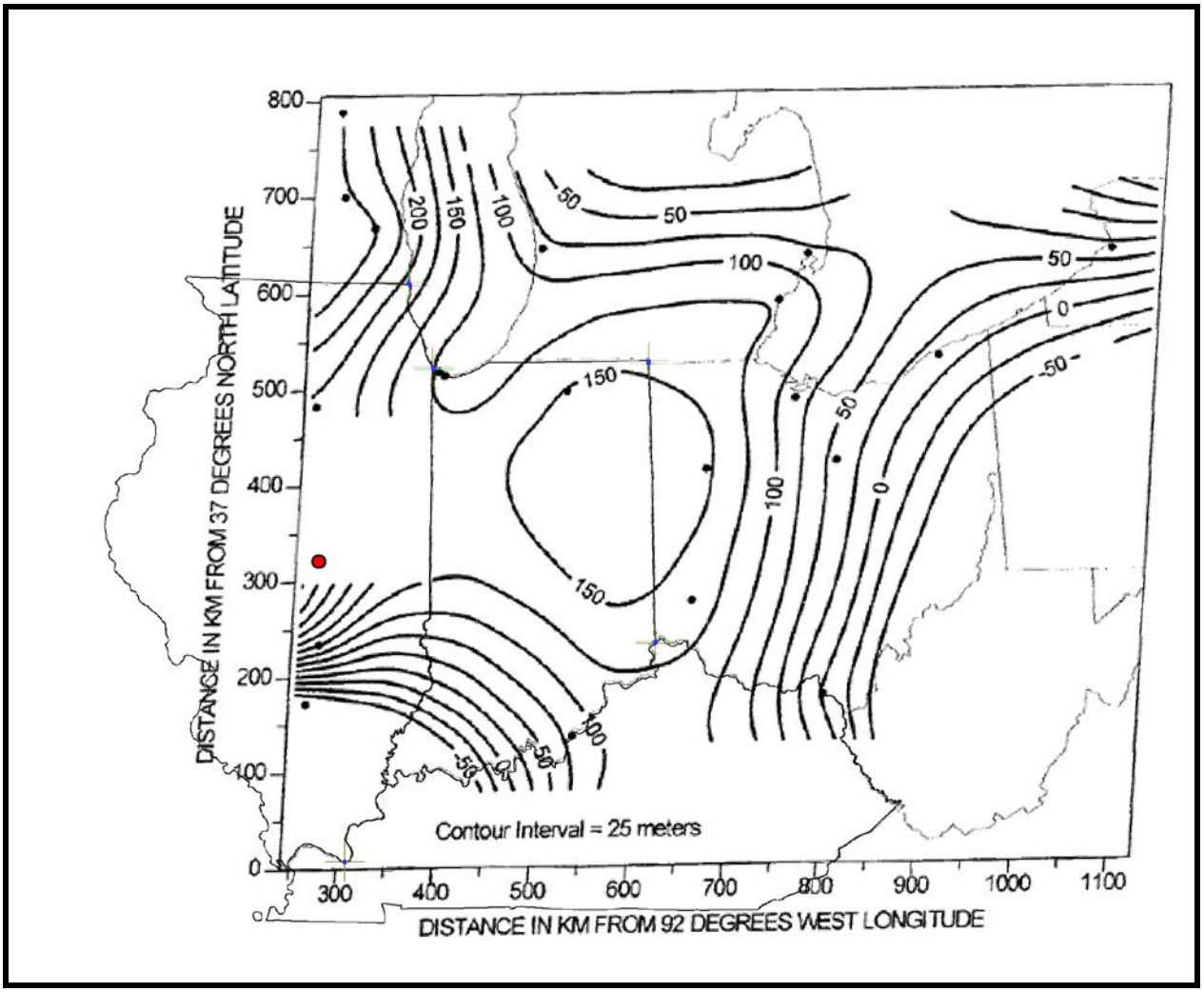


Figure 2-17: Observed vertical flow components in the Mt. Simon Sandstone around the Upper Midwest with the Michigan Basin based on Vugrinovich (1986), (from Gupta and Bair, 1997).

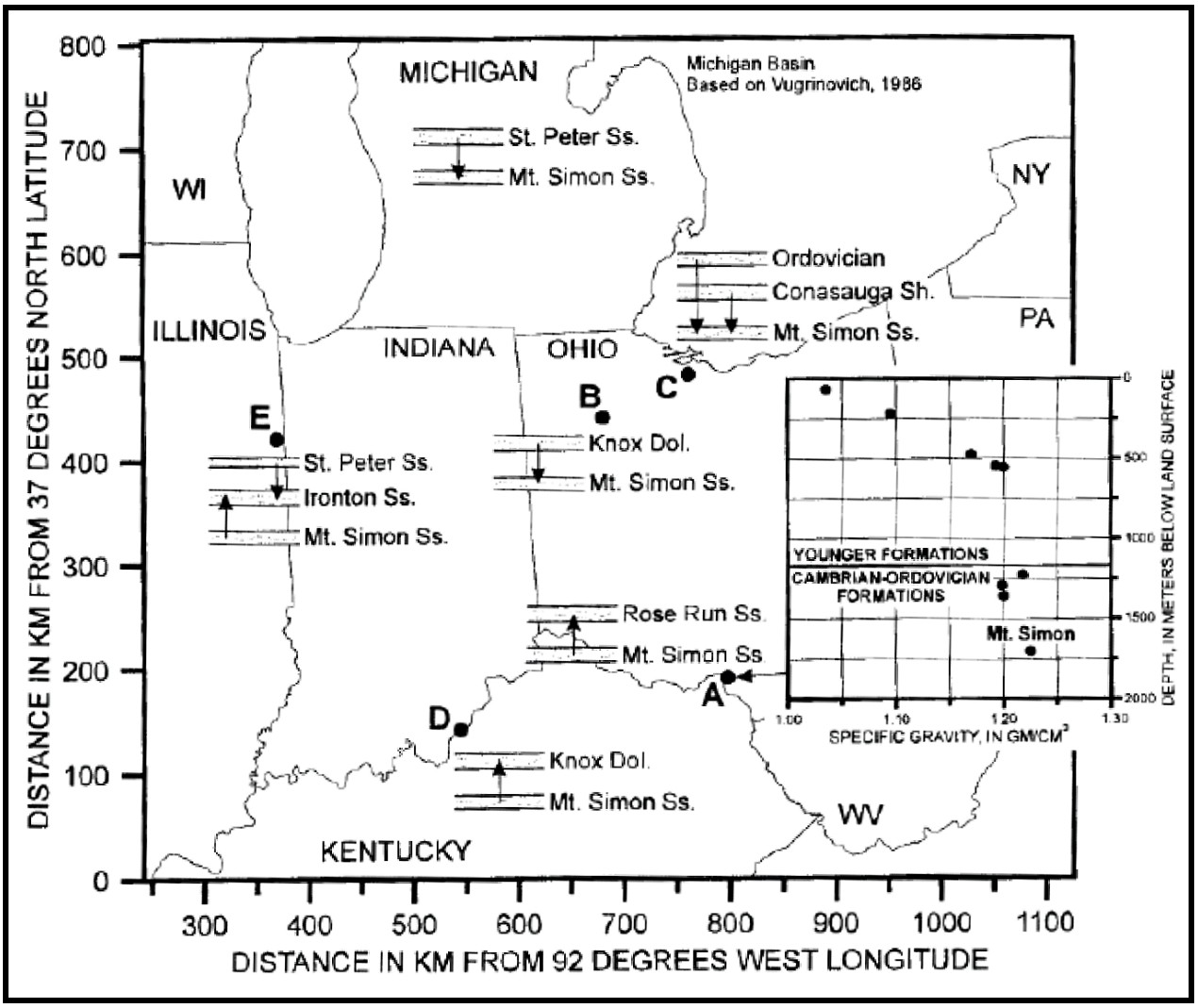


Figure 2-18: Relation between relative density and dissolved solids content of brines in deep aquifers of the Illinois Basin. Source: Bond (1972).

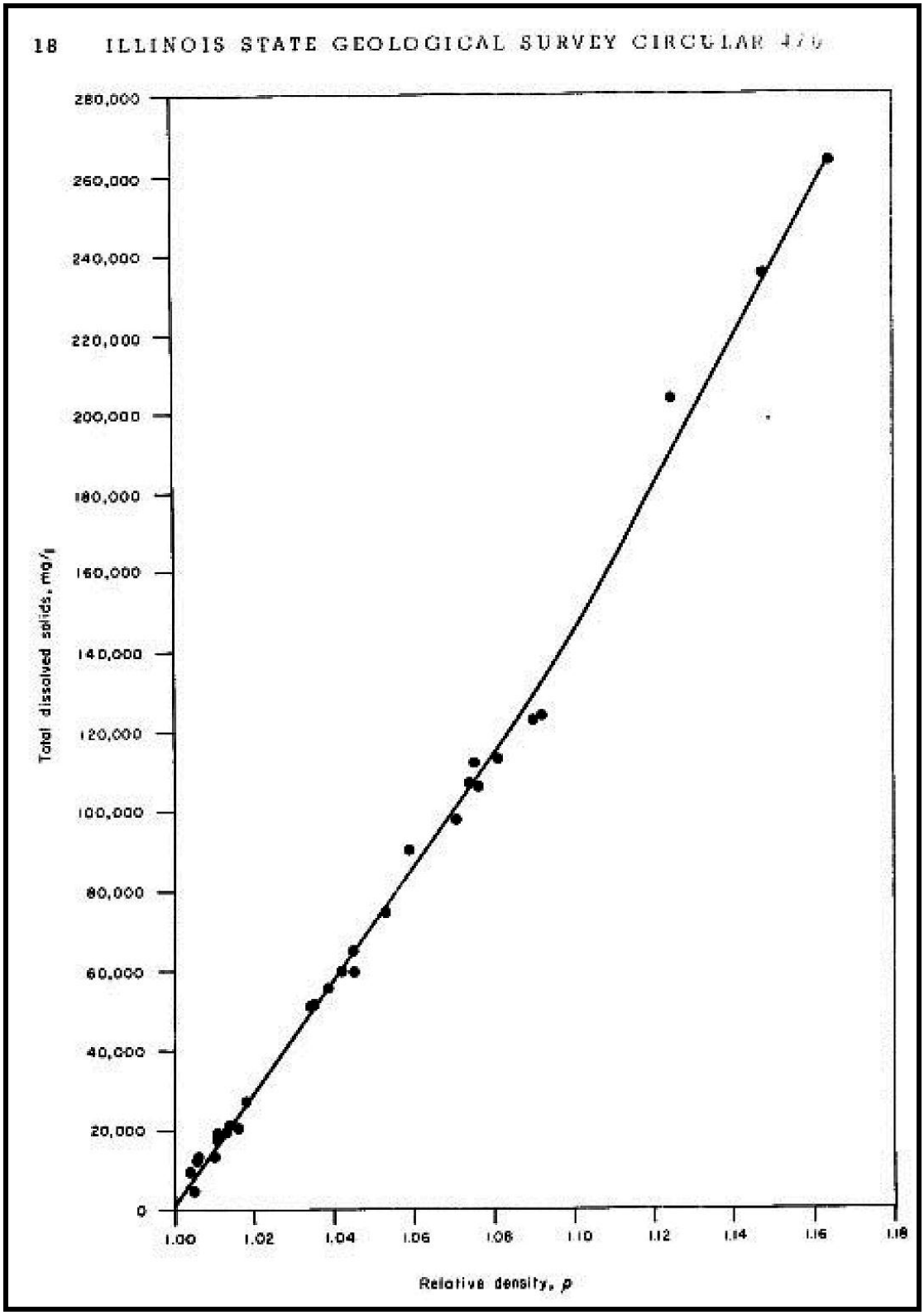


Figure 2-19: Total dissolved solids (TDS) within the formation water of the Mt. Simon Reservoir
Source: Modified from Finley, 2005.

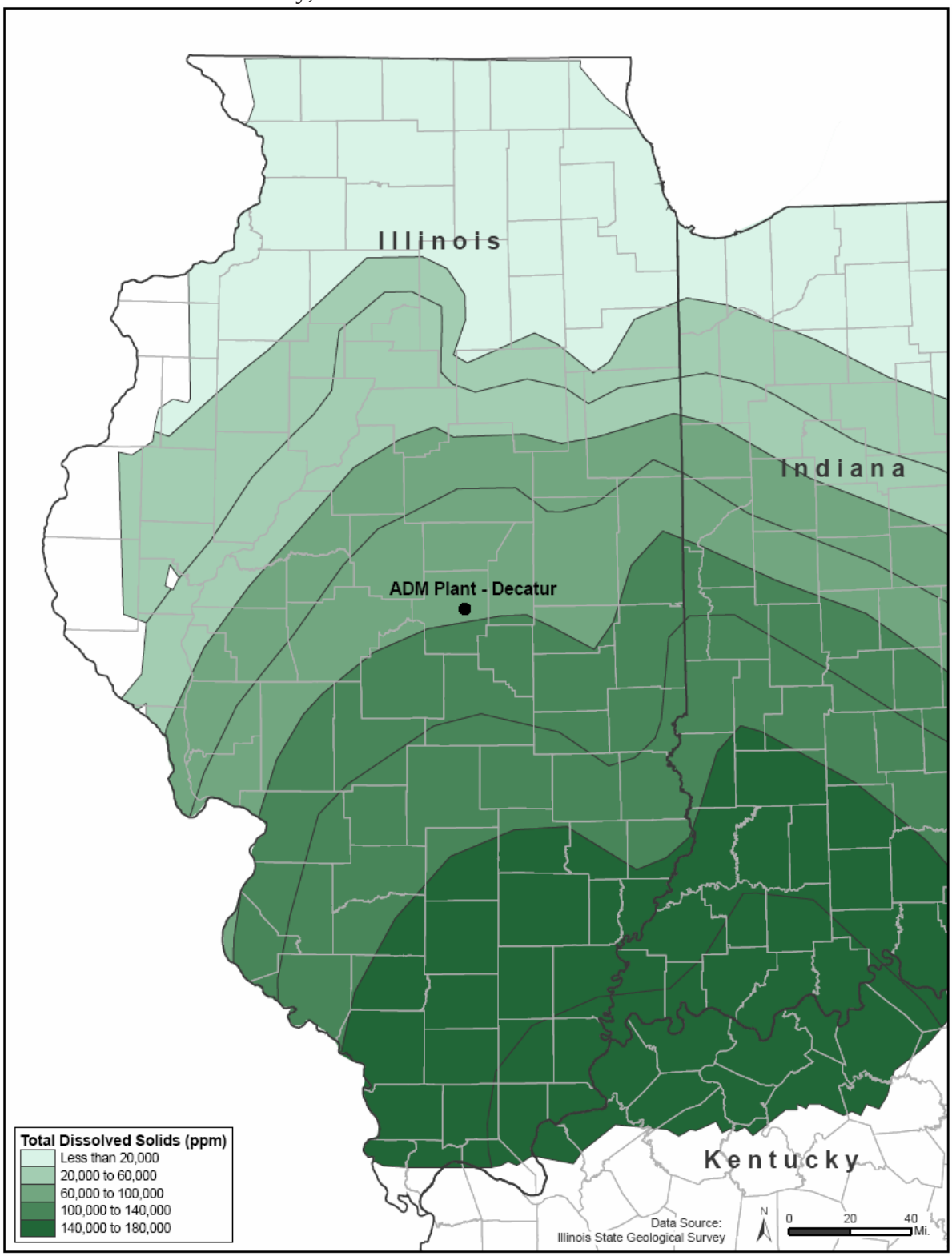


Figure 2-20: Diagrammatic cross section of the Cambrian System from northwestern to southeastern Illinois. The orange color shows the areas where the Eau Claire Formation is primarily shale and should be a good seal. Uncolored areas may behave as seals, but there is an enhanced risk for leakage because of fracturing (modified after Willman et. al., 1975).

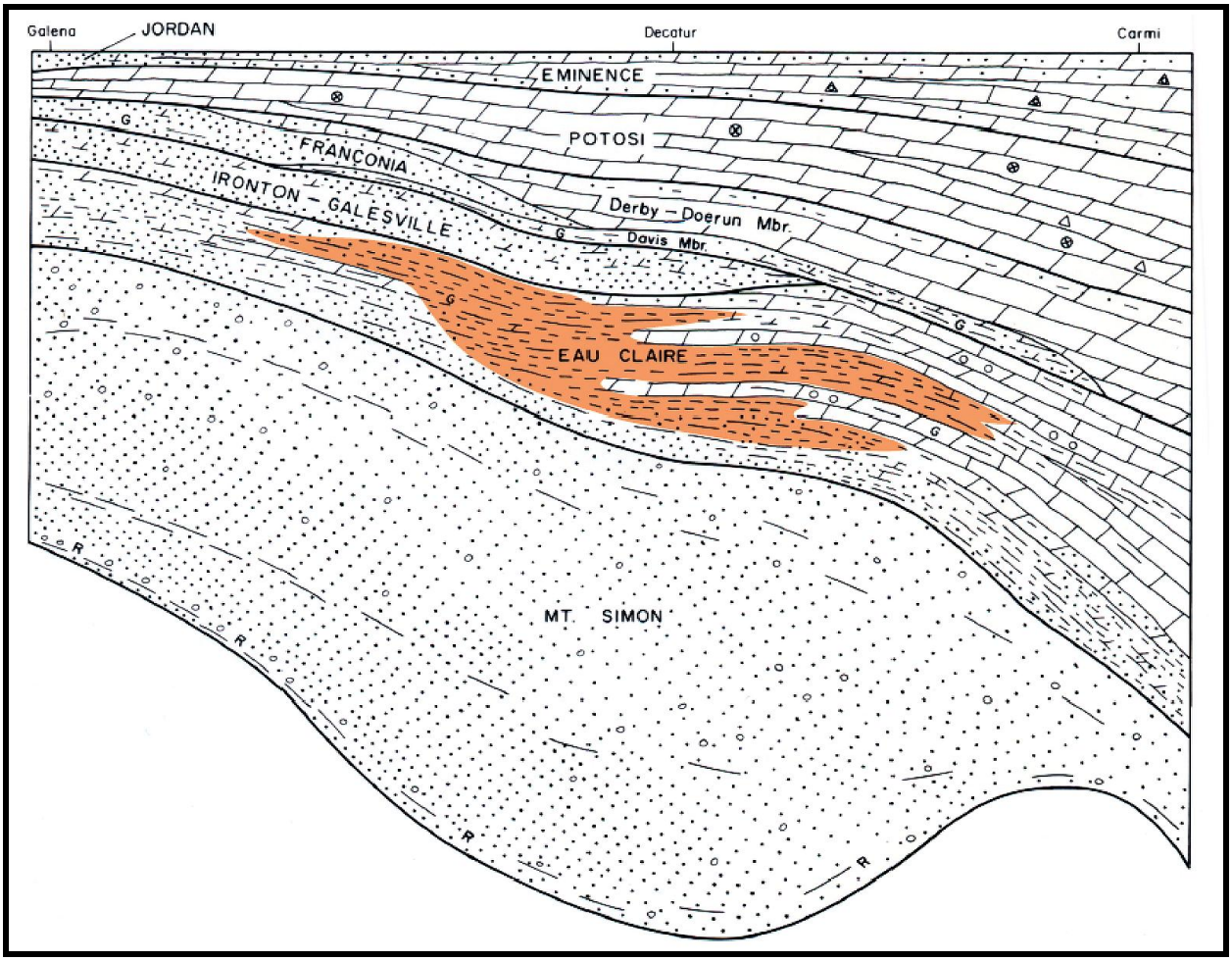


Figure 2-21: Thickness (feet) of the New Albany Shale.
Proposed injection well is near the center of Section 32 (shaded purple). Source: Leetaru, 2007.

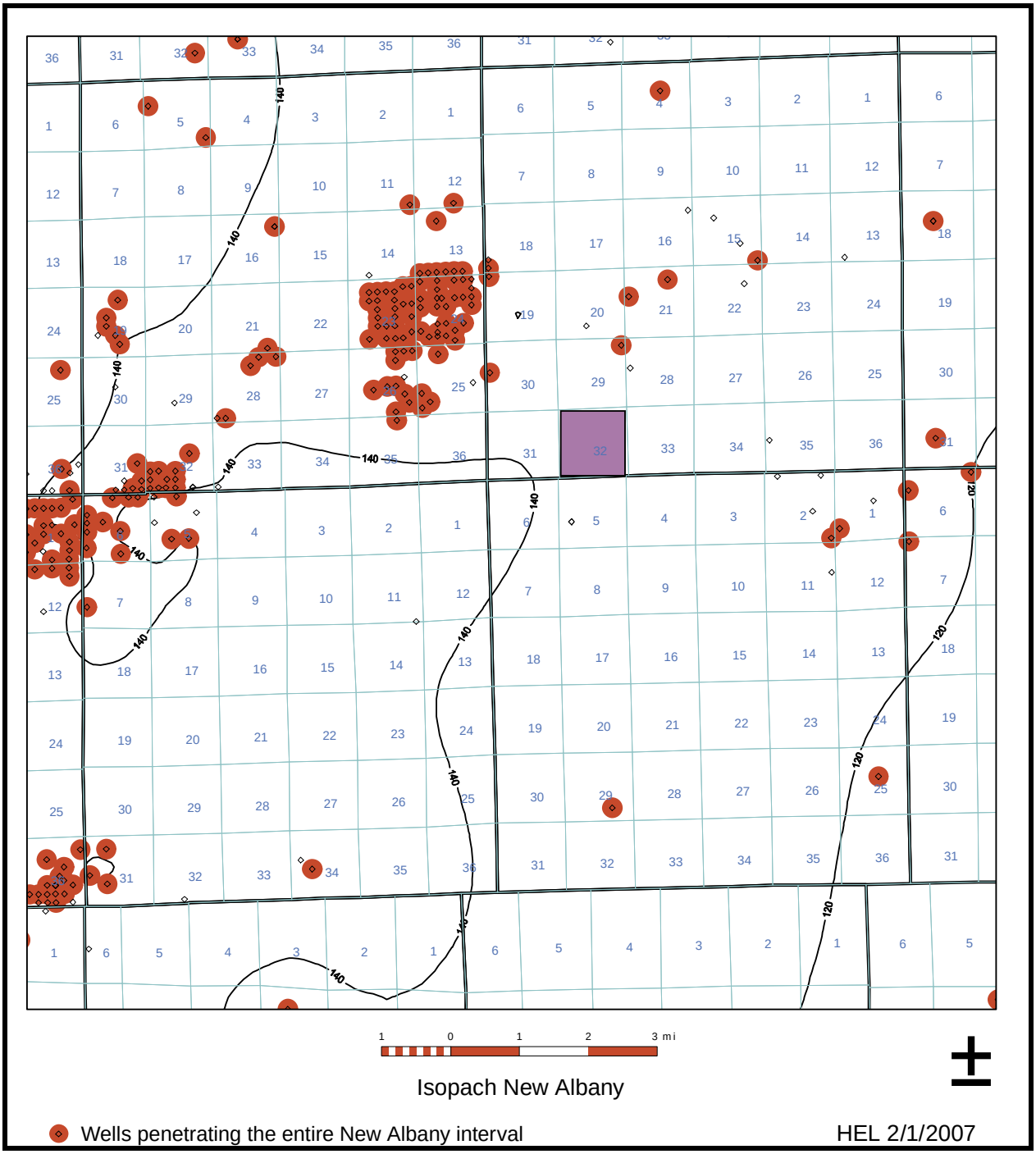


Figure 2-22: Isopach of the Ironton-Galesville Sandstone in Illinois. The orange line signifies the southern limit of the formation. There are no sandstone facies south of this line. (Willman, et al, 1975). The approximate site location is denoted by the red square.

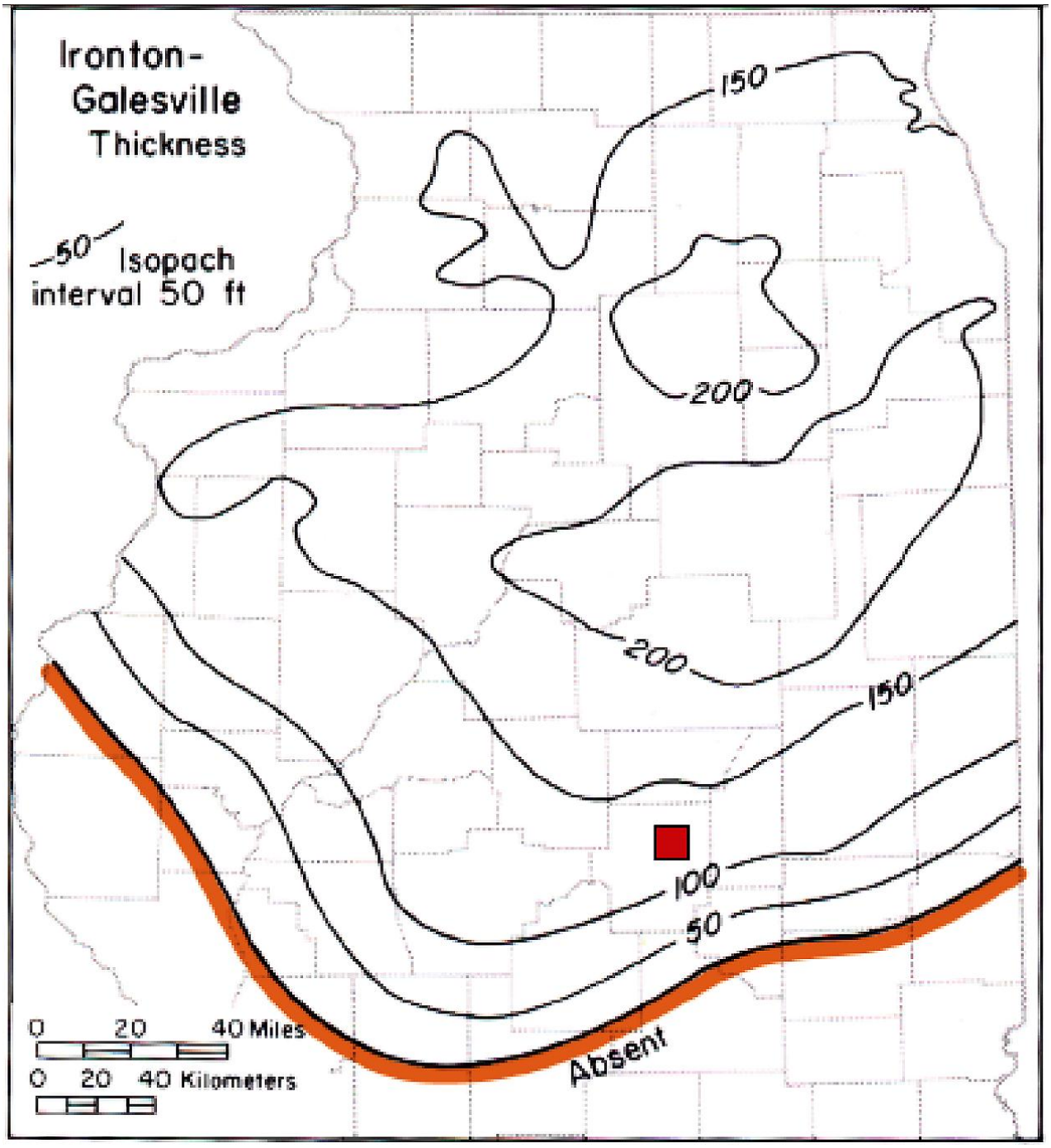


Figure 2-23: Regional map showing limits of fresh water in the Ironton-Galesville Sandstone. Proposed injection site should not encounter freshwater when drilling this formation. Source: Loyd, O,B. and W.L. Lyke, 1995, Ground Water Atlas of the United States, Segment 10: United States Geological Survey, 30 p. The red square denotes the relative location of the proposed injection site.

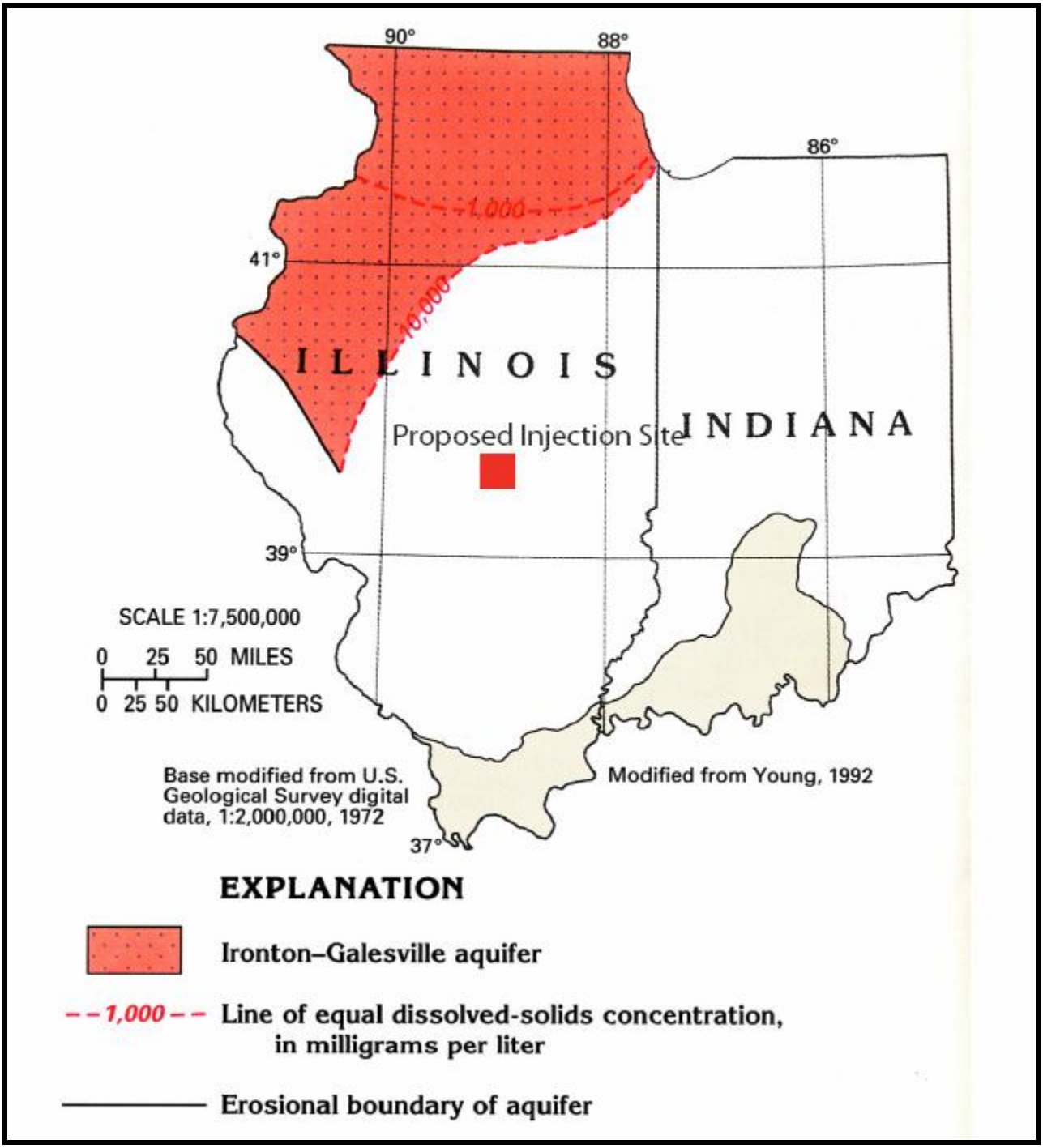


Figure 2-24: Regional Quaternary deposits near proposed IL-ICCS Injection Site, Decatur, IL. Source: ISGS Quarternary Deposits GIS Dataset, 1996.
http://www.isgs.illinois.edu/nsdihome/webdocs/st-geolq.html

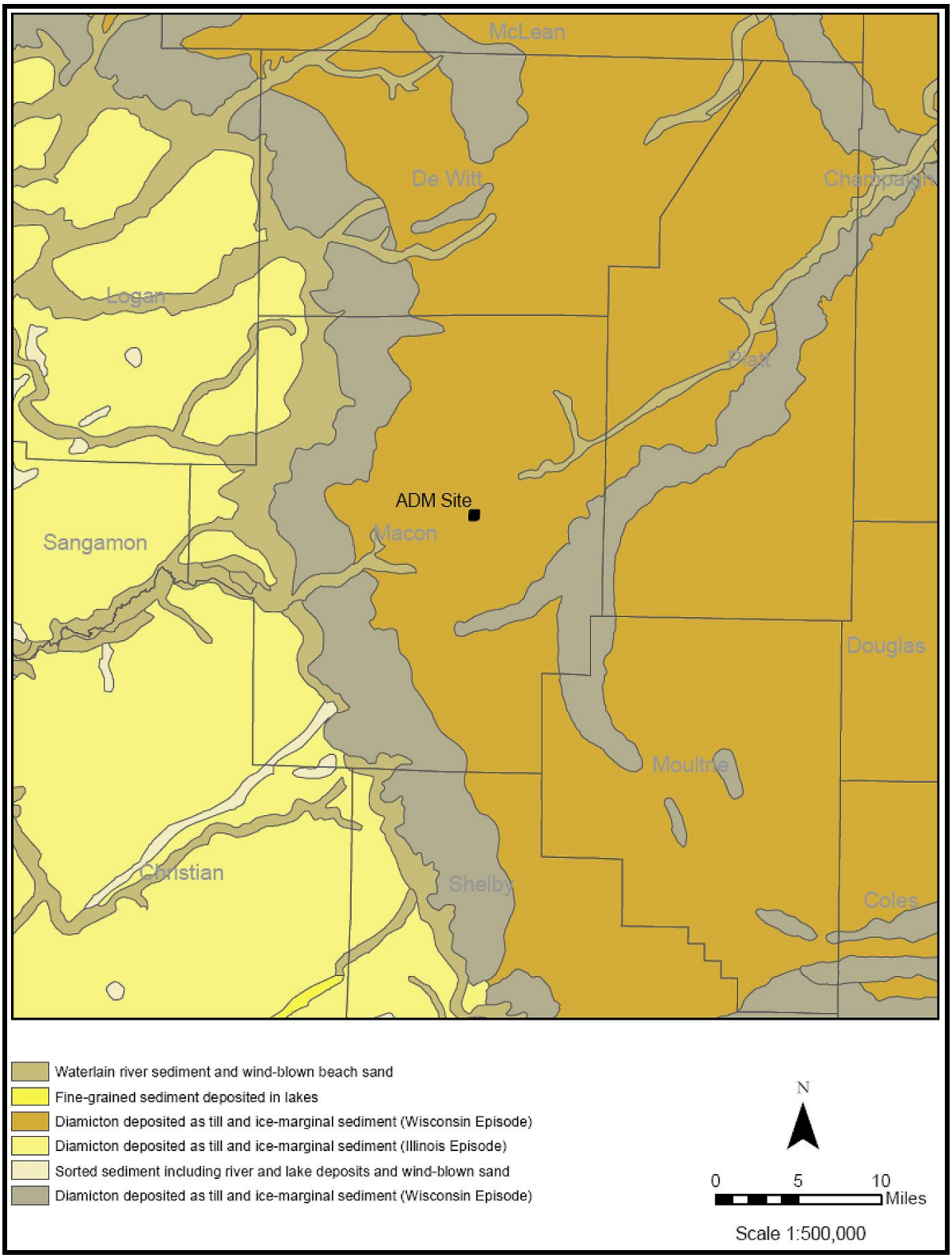


Figure 2-25: Schematic cross-section of aquifers within the Quaternary strata in the IL-ICCS area.

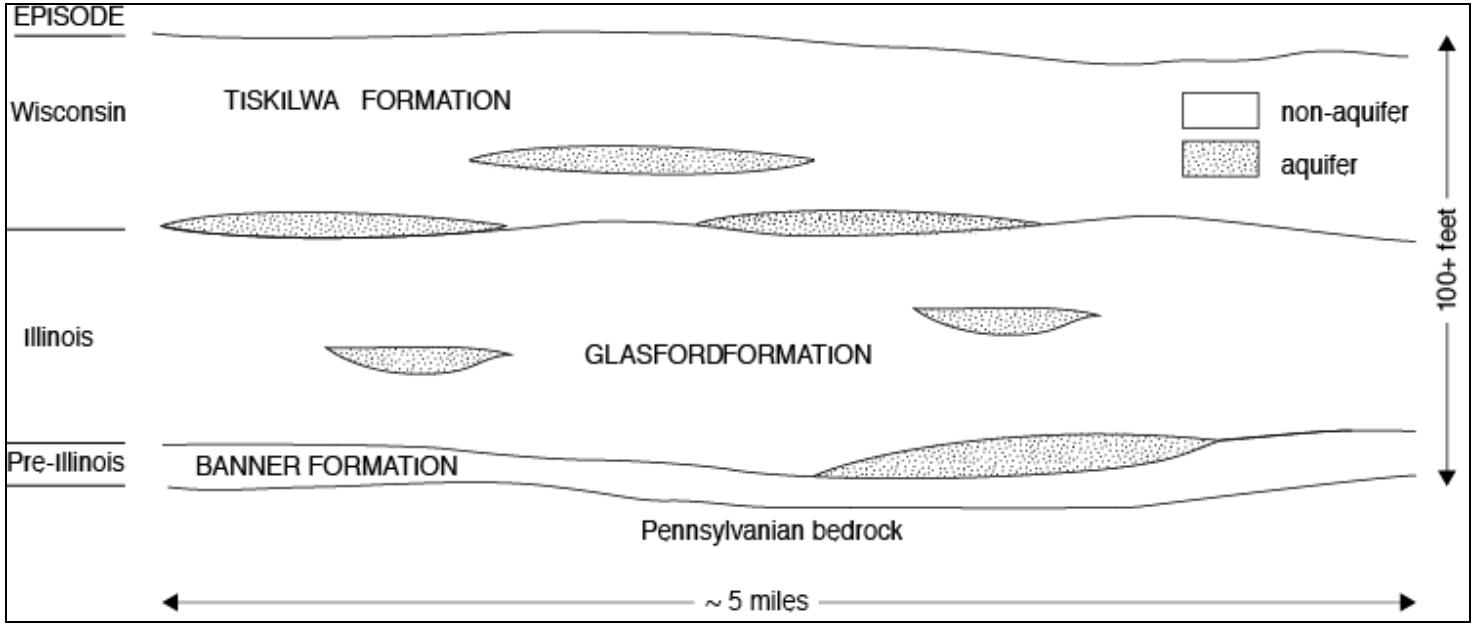


Figure 2-26: Depth to the top of the Mahomet aquifer (proposed injection well location in red) (Larson et al., 2003)

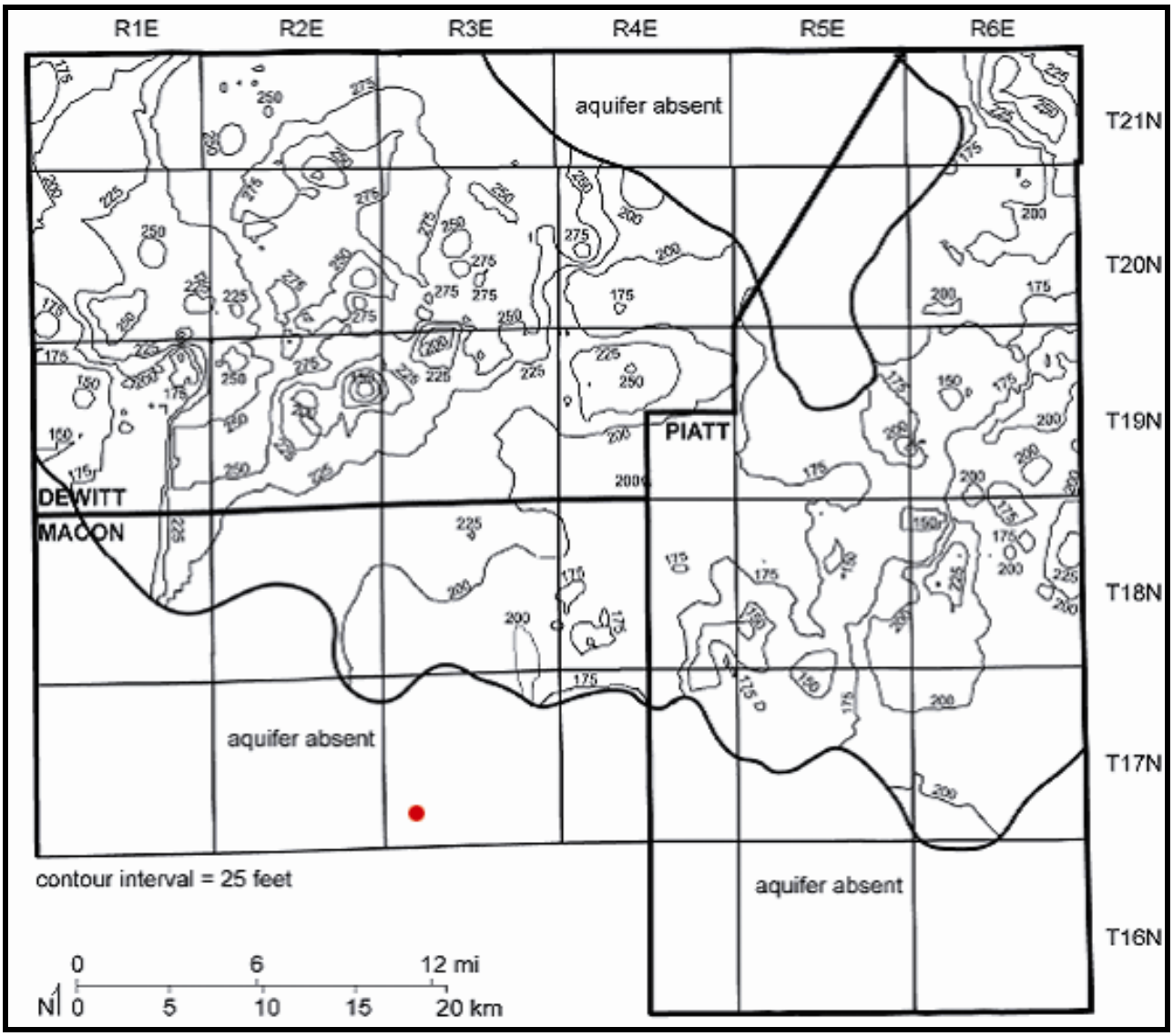


Figure 2-27: Thickness of the upper Banner aquifer (proposed injection well location in red) (Larson et al., 2003)

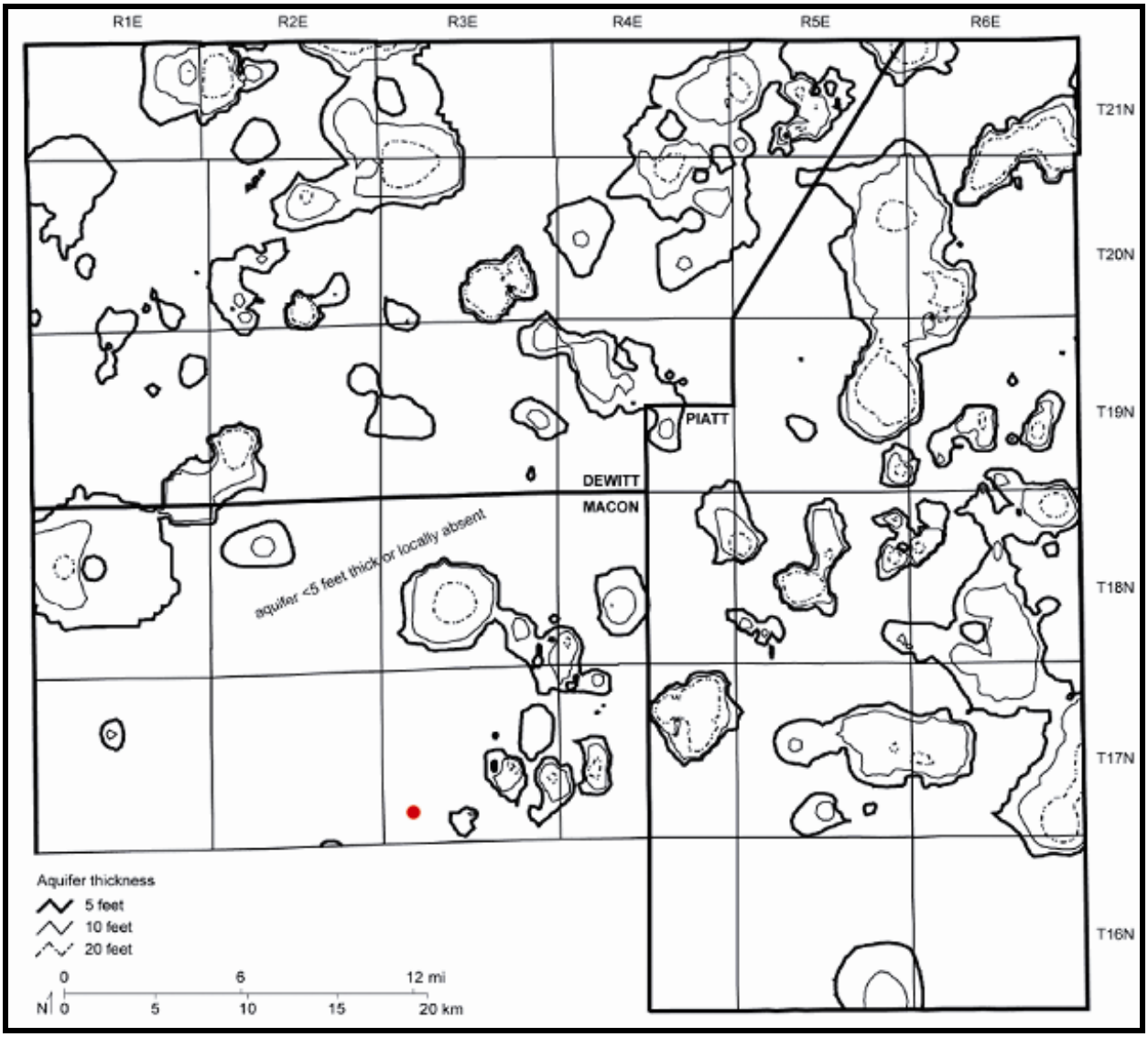


Figure 2-28: Thickness of the lower Glasford aquifer (proposed injection well location in red) (Larson et al., 2003)

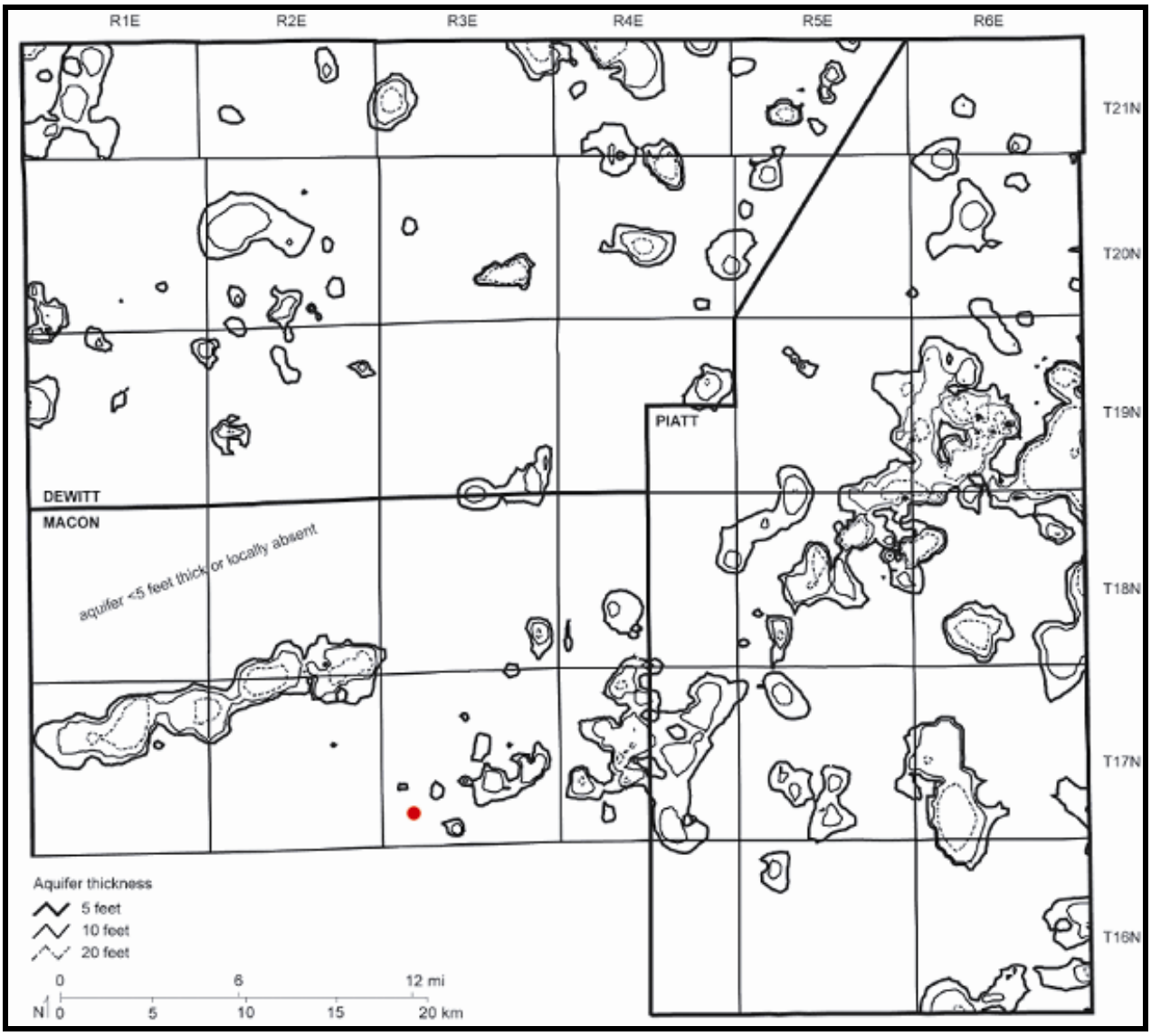


Figure 2-29: Thickness of the shallow sand aquifer (proposed injection well location in red) (Larson et al., 2003)

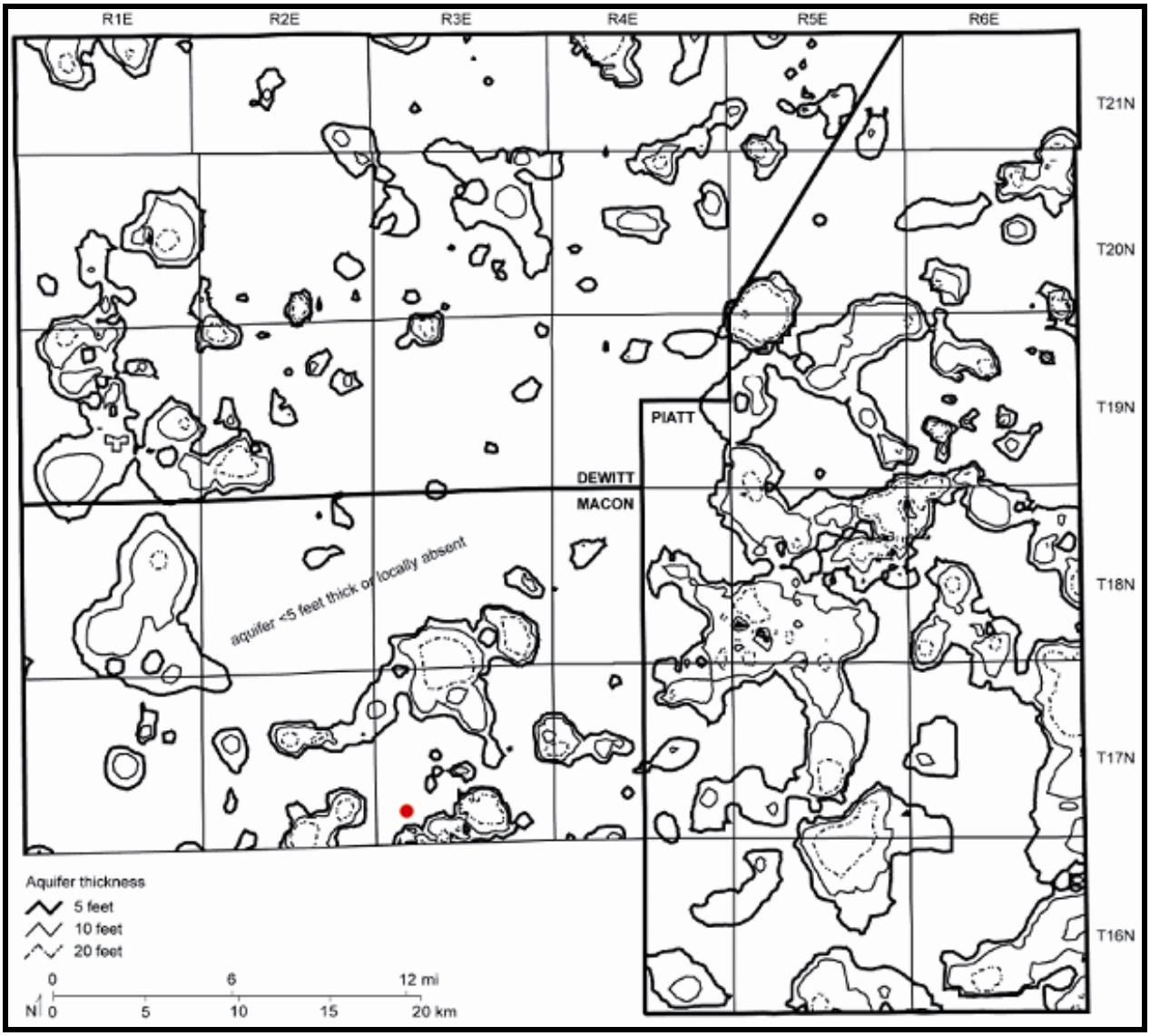


Figure 2-30: Thickness of the upper Glasford aquifer (proposed injection well location in red). (Larson et al., 2003)

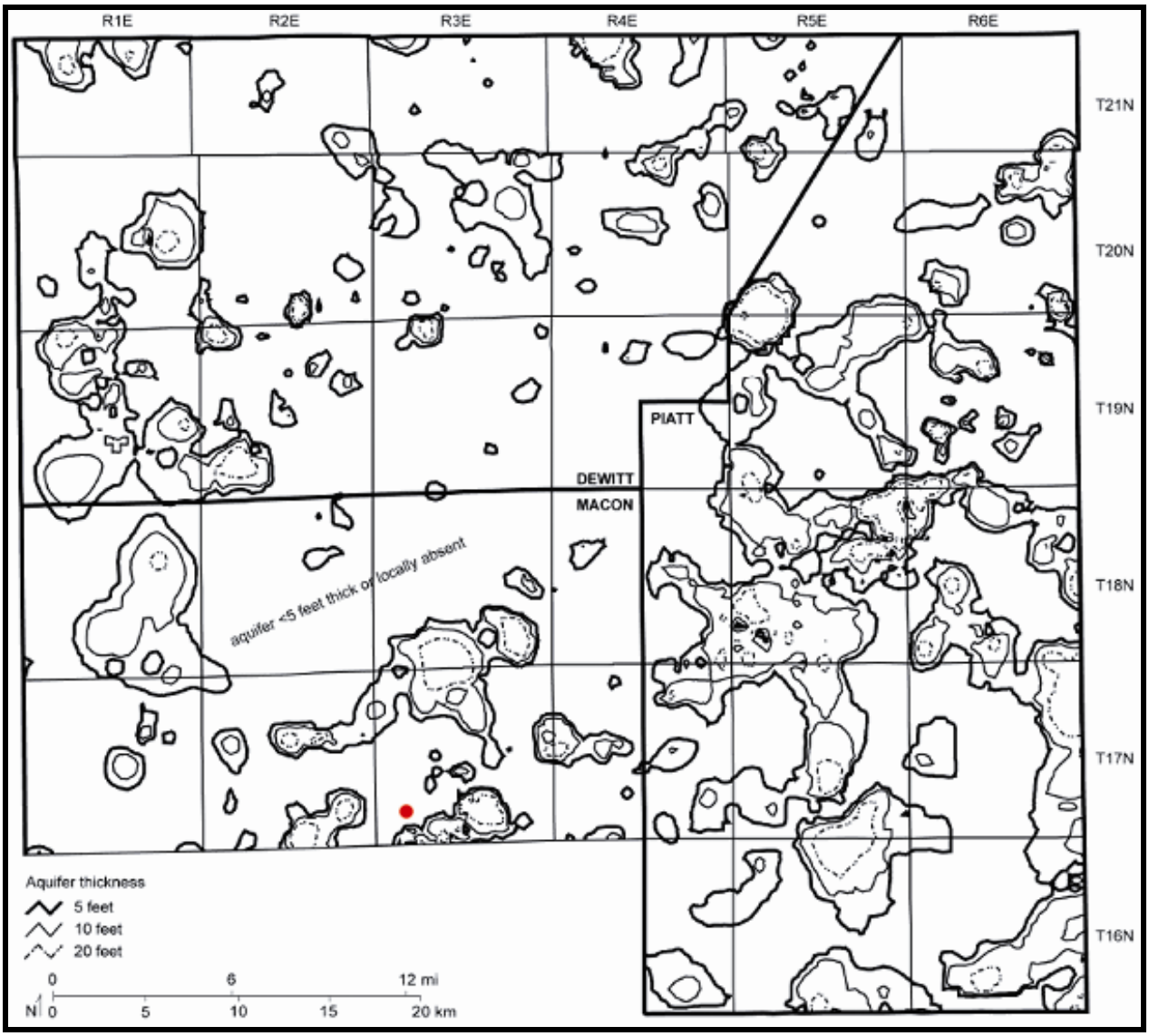


Figure 2-31: Regional bedrock geology near proposed IL-ICCS Injection Site, Decatur, IL. Source: ISGS Bedrock Geology GIS Dataset, 2005, http://www.isgs.illinois.edu/nsdihome/webdocs/st-geolb.html

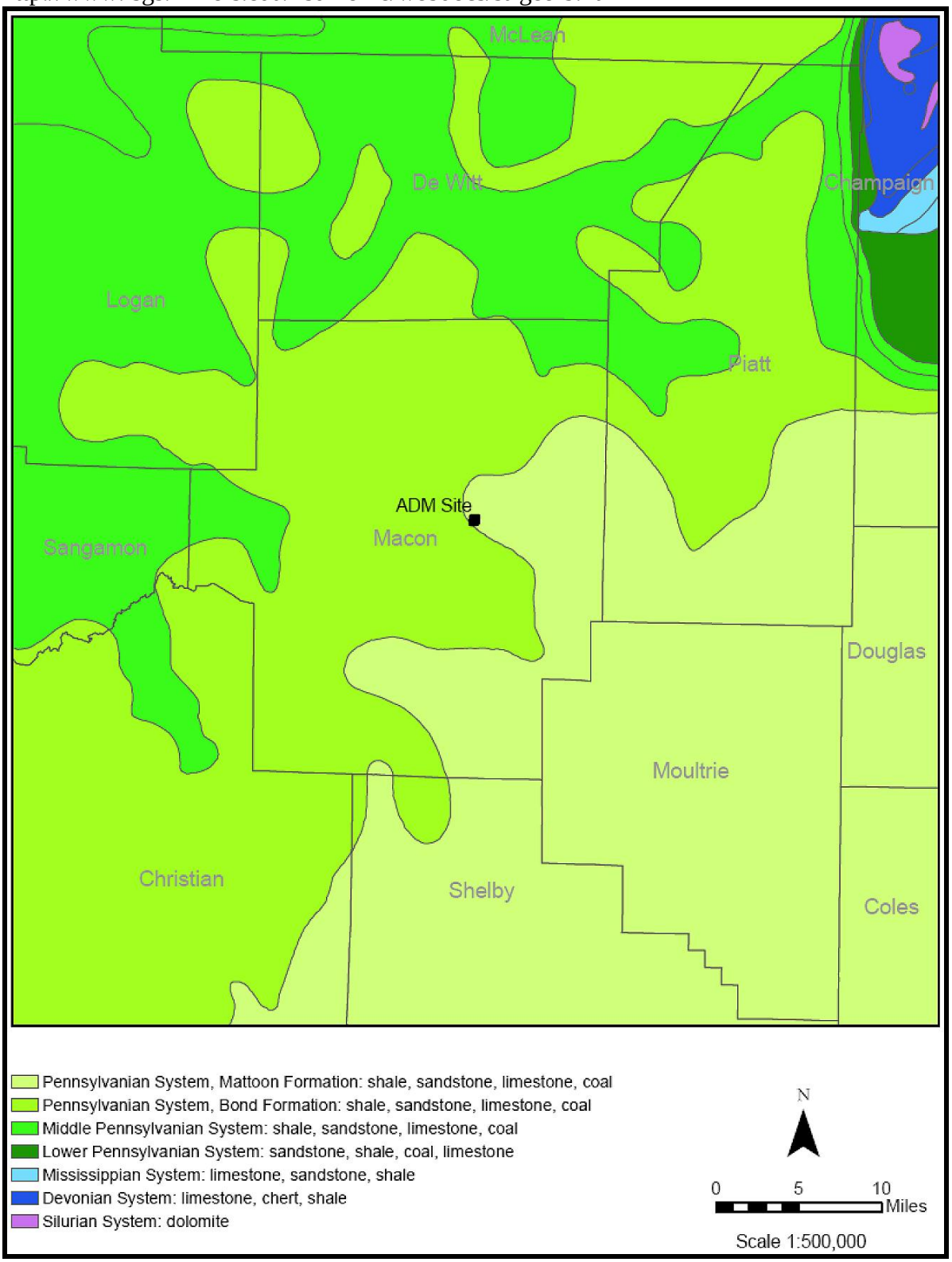


Figure 2-32: Map showing location of cross-section E-E' (modified from Vaiden, 1991).

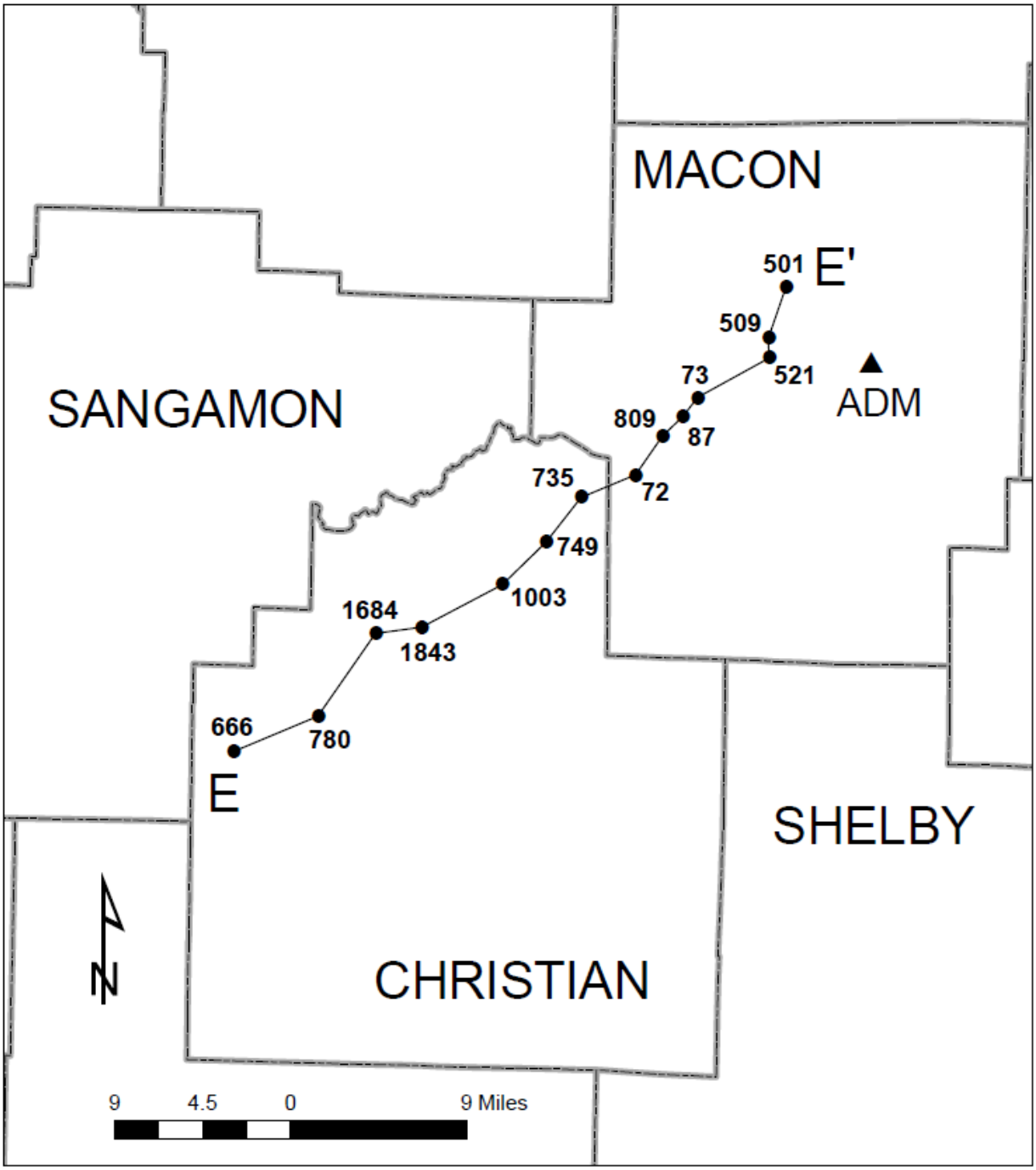
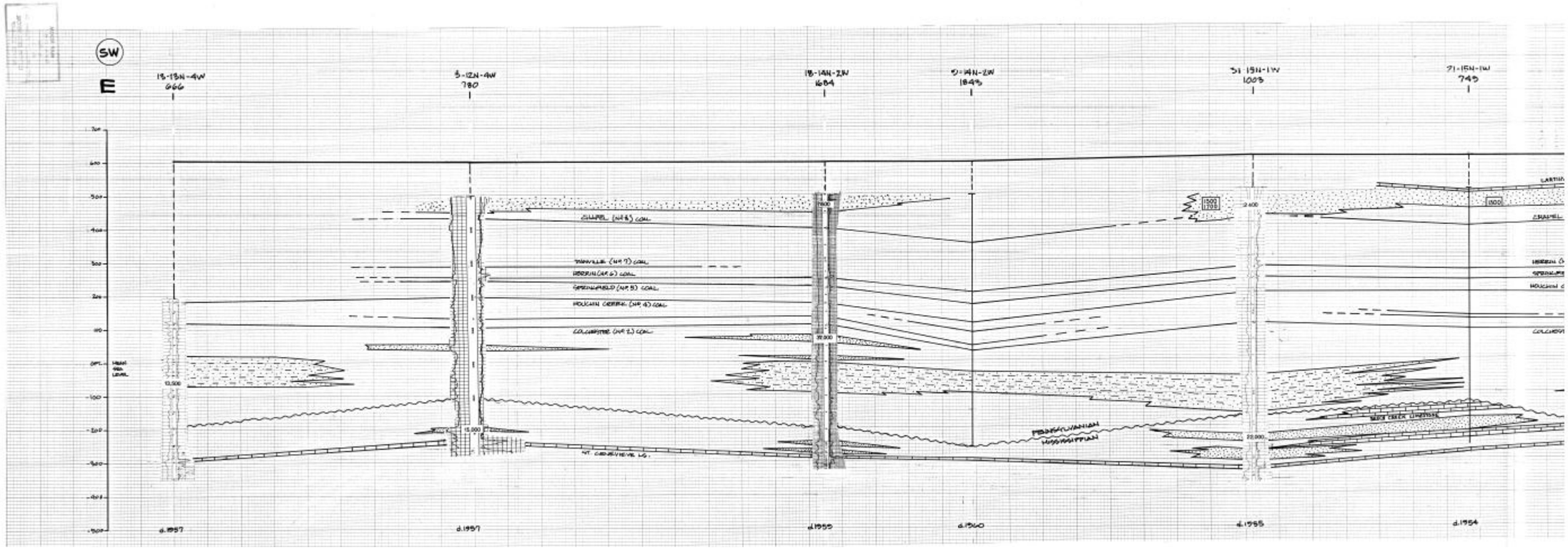


Figure 2-33: Pennsylvanian bedrock cross-section E-E' showing water quality data used to approximate the regional depth to USDW (Vaiden, 1991). Note that the location for well #780 (Section 3, T. 12 N., R. 4 W.) is incorrect. The correct location is Section 3, T. 13 N., R. 3 W.



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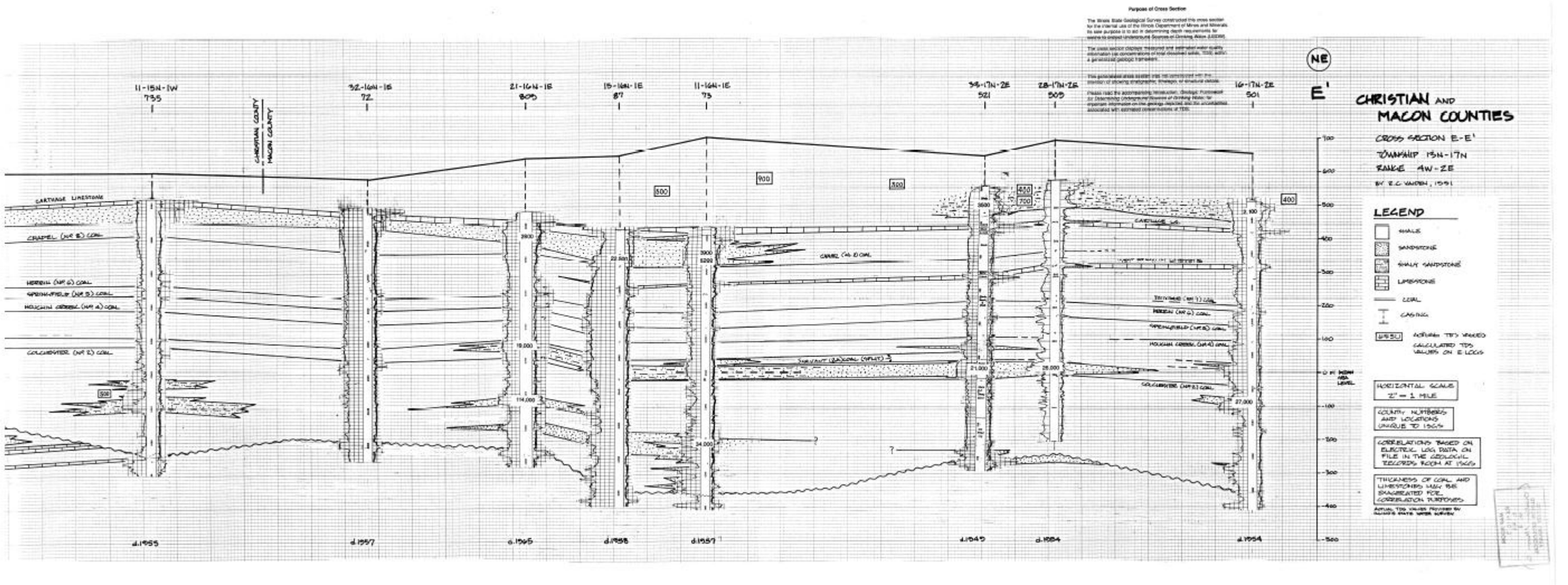
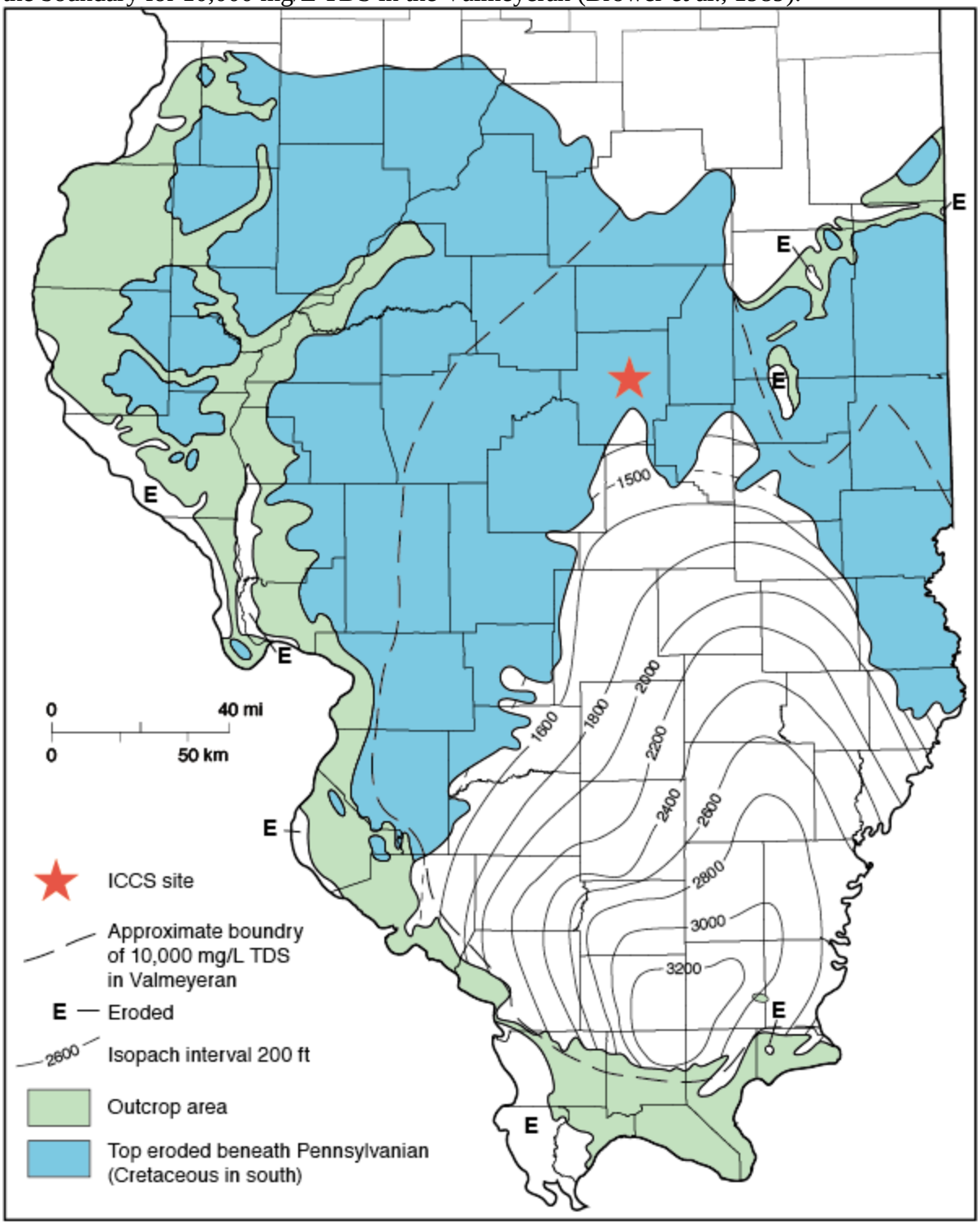
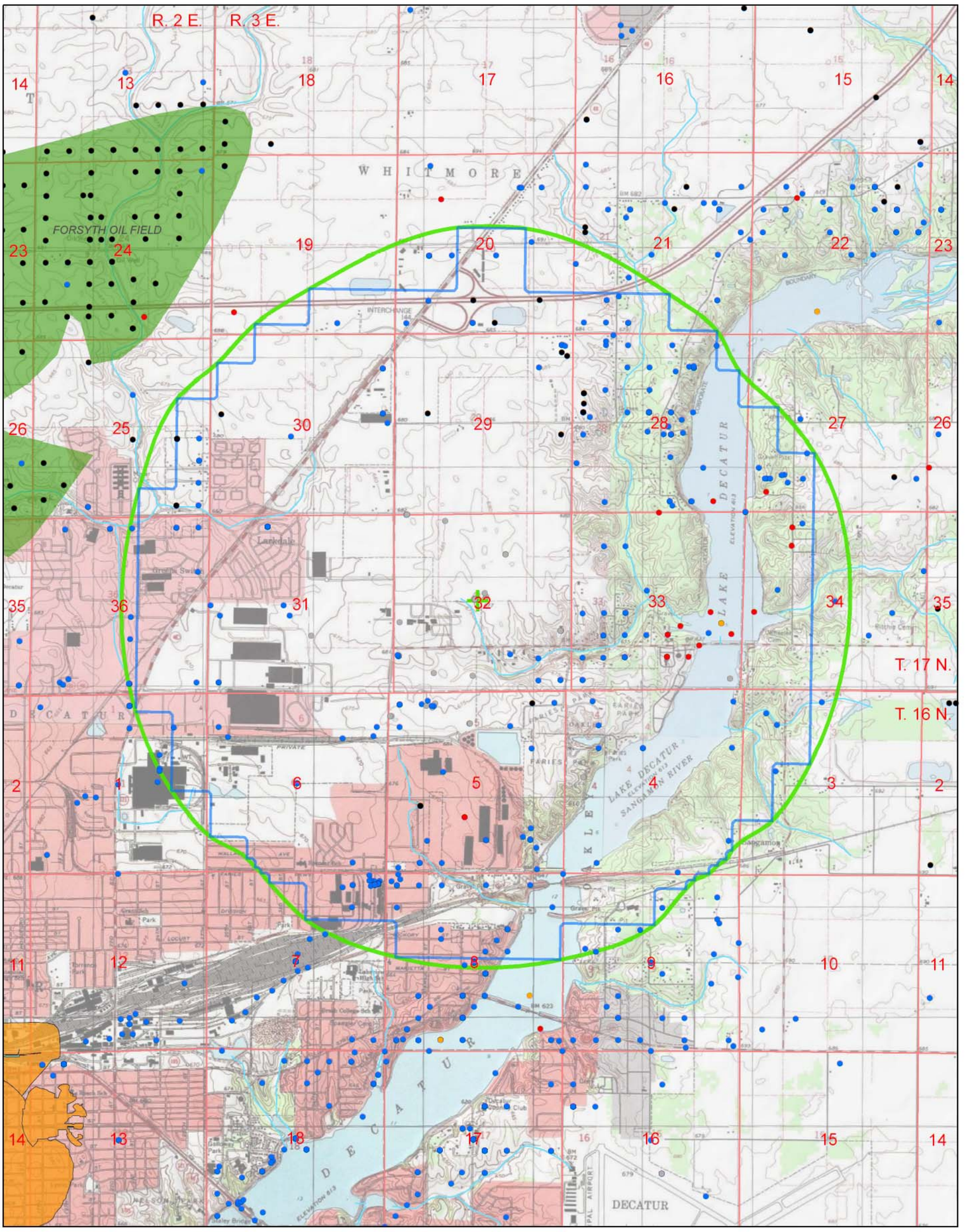


Figure 2-34: Thickness and distribution of the Mississippian System (Willman et al., 1975), and the boundary for 10,000 mg/L TDS in the Valmeyeran (Brower et al., 1989).





- Water Well
- Oil Well
- Stratigraphic Test
- Engineering Boring
- Other / Unknown
- Underground Coal Mine
- Generalized Oil Field Area
- Area of Review
- MESPOP Predicted by Computer Simulations
- Center of Area of Review

Base: United States Geological Survey (USGS) 7.5-Minute Topographic Quadrangle map imagery and intermediate-scale DLG streams data, rescaled to 1:36,000. Topographic contour intverval is 5 feet. Tiled topographic map imagery is sourced from scanned paper maps, and is provided by Esri's USGS Topographic Map Service (available at: http://goto.arcgisonline.com/maps/USA_Topo_Maps).

N

0 0.5 1 Miles

Original Printed Scale 1:36,000

Wells, borings, and other penetrations near the proposed IL-ICCS injection well at the ADM Site, Decatur, IL. Well data were obtained from ISGS and ISWS well databases as of May 10, 2011. The green circular feature shows the Area of Review. Updated January 19, 2012 to include drilled or planned ISGS/ICCS project wells.

SECTION 5 – AREA OF REVIEW

5.1 Radius of the Area of Review

A radius of approximately 3.2 kilometers (2.0 miles) was determined for the area of review (AoR).

5.2 Method of Radius Determination

The radius of the AoR is based on the *Maximum Extent of the Separate-phase Plume or Pressure-front (MESPOP)* methodology, as detailed in the relevant US EPA guidance document (USEPA, 2011). Information about the lowermost USDW and target injection zone obtained from the on-going efforts of the Illinois Basin-Decatur Project (IBDP) provided the input for the hydraulic head calculations specified in the guidance (Locke & Mehnert, 2011). Figure 5-1 illustrates the input values to these calculations and the graphical relationship between the hydraulic head in the lowermost USDW and that of the target injection interval of the lower Mt. Simon Sandstone. Results of these calculations indicate that the pressure front in the injection zone ($P_{i,f}$) is delineated by a pressure of 22.77 MPa (3302 psi), or a change in pressure of 1.27 MPa (184 psi) above the initial reservoir pressure. Based on computer modeling of the proposed 5-year injection and 50-year post-injection period, the MESPOP grows to a maximum extent of approximately 3.2 kilometers (2.0 miles) and is exclusively defined by the pressure front as the extent of the CO_2 plume remains inside this boundary throughout the entire 55 year simulated period. Figure 5-2 outlines the predicted extent of the pressure front within the injection interval over a topographic map of the immediate area around the project site. It should be noted that the jagged shape of the polygon outlined in blue is an artifact of the simulation grid and not physically realistic; therefore, the boundary of the AoR was extended to the green line circumscribing the blue polygon, which represents a more conservative and realistic delineation. Additional details of the model input parameters and results of the simulation are discussed in Section 5.4 below.

5.3 Area of Review Map

Well logs for all wells within the AoR were obtained from four databases. Records for water wells were obtained from the Illinois State Geological Survey (ISGS) ILWATER database and the Illinois State Water Survey (ISWS) water well database. Records for oil and gas wells were obtained from the ISGS ILOIL database. In addition, logs for coal stratigraphic tests were obtained from the ISGS Coal Section. The ISWS and ISGS are the repository for all well logs acquired since 1965; well logs filed prior to that year were submitted on a voluntary basis.

A total of 447 wells are known to be drilled within the AoR (Figure 5-2). The deepest well (excluding the IBDP injection, verification, and geophysical wells) is 762 m (2,500 ft). Fourteen wells within the AoR have been drilled to the depth range of 640 to 762 m (2,100 to 2,500 ft).

Within the AoR, the wells listed in the ISGS and ISWS databases were cross-checked to remove duplicates. The duplicates were identified by well owner, location, and/or well depth. Several wells identified only by a general location description (section, township, and range) were

assumed to be within the AoR, although it is possible these wells may actually be located beyond the AoR limits.

5.4 Description of Anticipated Injection Fluid Movement during the Life of the Project

5.4.1 Simulation Software Description and General Assumptions

Schlumberger Carbon Services (SCS) utilized ECLIPSE 300[1] reservoir simulation software with the CO2STORE module to estimate CO_2 plume migration and reservoir pressure behavior below the IL-ICCS site. ECLIPSE 300 is a compositional finite-difference solver that is commonly used to simulate hydrocarbon production and has various other applications including carbon capture and storage modeling. The CO2STORE module accounts for the thermodynamic interactions between three phases: an H_2O-rich phase (i.e. 'liquid'), a CO_2-rich phase (i.e. 'gas') and a solid phase, which is limited to several common salt compounds (e.g. NaCl, $CaCl_2$, and $CaCO_3$). Mutual solubilities and physical properties (e.g., density, viscosity, enthalpy, etc.) of the H_2O and CO_2 phases are calculated to match experimental results through a range of typical storage reservoir conditions, including temperatures ranging from 12-100°C and pressures up to 60 MPa. Details of the method can be found in Spycher and Pruess (Spycher & Pruess, 2005). Additional assumptions governing the phase interactions throughout the simulations are as follows:

- The salt components may exist in both the liquid and solid phases.
- The CO_2-rich phase (i.e., 'gas') density is obtained by an accurately tuned and modified (as described below) Redlich-Kwong equation of state (Redlich & Kwong, 1949).
- The brine density is first approximated by the pure water density and then corrected for salt and CO_2 effects by Ezrokhi's method (Zaytsev & Aseyev, 1992).
- The CO_2 gas viscosity is calculated per the method described by (Vesovic, Wakeham, Olchowy, Sengers, Watson, & Millat, 1990) and (Fenghour, Wakeham, & Vesovic, 1999).

The gas density was obtained using a cubic equation of state tuned to give the density of the compressed gas phase, following Spycher and Pruess. A modified Redlich-Kwong equation of state is used, where the attraction parameter is made temperature dependent:

$$P = \left(\frac{RT_K}{V - b_{mix}}\right) - \left(\frac{a_{mix}}{T_K^{1/2} V(V + b_{mix})}\right)$$

where V is the molar volume, P is the pressure, T_K the temperature in Kelvin, R is the universal gas constant and a_{mix} and b_{mix} are the attraction and repulsion parameters.

The transition between liquid CO_2 and gaseous CO_2 can lead to rapid density changes of the gas phase, the simulator use a narrow transition interval between the liquid and gaseous density to represent the two phase CO_2 region.

[1] Proprietary software of Schlumberger.

Initial simulation-based estimates of fluid conditions throughout the surface pipeline and wellbore indicated that the temperature of the injectate would be comparable to the formation temperature in the injection interval, with temperatures between 80°F and 120°F (Section 7.4.8). Therefore, the simulations were carried out under isothermal conditions. With respect to time step selection, the software algorithm optimizes the time step duration based on specific convergence criteria designed to minimize numerical artifacts. For these simulations, time step size ranged from 8.64×10^1 to 8.64×10^5 seconds or 0.001 to 10 days. In all cases the maximum solution change over a time step is monitored and compared with the specified target. Convergence is based on the pressure and saturation changes and being 'sufficiently small'. New time steps are chosen so that the predicted solution change is less than a specified target.

5.4.2 Site Specific Assumptions and Methodology

The 3D geologic model developed for the injection simulations is based on the interpretation of a diverse assemblage of geophysical data acquired throughout the construction of the IBDP injection well (herein referred to as CCS #1). Structurally, the model is based on the interpretation of both 2D and 3D seismic survey data in conjunction with dipmeter log data acquired after drilling CCS #1. Petrophysical and transport properties – based on the interpreted well log data and the analysis of core samples recovered from CCS #1 – were then distributed throughout each layer in the geocellular model in a homogeneous fashion. . [See Appendix K : ADM CCS #1 - Geophysical Log Descriptive Report]

Overall model dimensions are 48.3 km by 48.3 km (30 mi. by 30 mi.) in order to minimize artificial boundary effects. Both constant-pressure and no-flow boundary conditions were evaluated initially; however, little difference was observed due to the size of the model. Consequently, subsequent simulations were carried out with no-flow boundary conditions. An irregular grid pattern was chosen for the geocellular model in order to provide enhanced detail and improved accuracy near CCS #1 and the proposed IL-ICCS injection well, CCS #2. For example, grid cells in the vicinity of the injection wells are 15.25 m by 15.25 m (50 ft by 50 ft) in the horizontal plane, while grid cells near the edges of the model domain are 3.2 km by 3.2 km (2 mi. by 2 mi.) in the horizontal plane. Figure 5-3 illustrates the overall grid dimensions and geometry of the irregular gridding pattern used throughout the model.

The geologic model encompasses approximately the lower half of the Mt. Simon Sandstone: from the top of the basal arkosic zone up to a low-porosity, low-permeability interval that petrophysical analysis indicates will be a flow-limiting barrier over the course of the simulated time frame (refer to Figures 2-7 and 2-8 for a general stratigraphic sequence). These low permeability intervals within the Mt. Simon can be correlated on geophysical well logs acquired in CCS #1 and the more recently-drilled IBDP Verification Well #1, located approximately 300 meters to the north of CCS#1. In addition, the structural continuity of the Mt. Simon observed in the 2D and 3D seismic data acquired at both the IBDP and IL-ICCS sites, and described in

Section 2.3 of this application, suggests that these geologic features are present throughout the immediate project area. Regional extent of the macro-geologic features of the Mt. Simon throughout the Illinois Basin has been demonstrated through analysis of offset well log data, as described in Section 2.4; however, the regional continuity of the micro-geologic features, such as low-permeability layers within the Mt. Simon, will be better understood with the addition of future well log, core, and 3D seismic data associated with the IL-ICCS project.

Figure 5-4 shows the porosity and permeability values in the lower half of the Mt. Simon Sandstone represented by the upscaled well log of CCS #1 and the synthetic log of CCS #2. The upscaled values are based on porosity from CCS #1 well logs and permeability transformed from porosity, which are then averaged over the thickness of each modeled layer. Layering in the model is based upon trends in the petrophysical and facies characteristics observed in both well logs and core samples. The lower half of the Mt. Simon Sandstone was subdivided into 74 layers, which range from approximately 1.2 m (4 ft) to 10 m (33 ft) in thickness. Porosity and permeability within these layers range from 8 to 26% and from 0.03 to 117 millidarcies (mD), respectively. Based on core data, the ratio of vertical permeability to horizontal permeability (k_v/k_h) used in the model was 0.32. Temperature and pressure gradients of approximately 1.8°C/100-m (1°F/100-ft) and 10.2 MPa/km (0.45 psi/ft) – based on in-situ measurements made after drilling CCS #1 – were used in the model. The formation pressure gradient in the lower half of the Mt. Simon is slightly higher than a typical fresh water gradient due to the high salinity observed in this part of the reservoir, which ranges from 179,800 ppm to 228,000 ppm total dissolved solids (TDS) based on analysis of actual formation fluid samples recovered during the drilling of CCS #1 (Frommelt, 2010).

Based on the range of porosity and permeability values observed in log data and core samples obtained from CCS #1, a suite of proprietary relative permeability and capillary pressure curves were developed in collaboration with the CO_2 Sequestration Team at the Schlumberger-Doll Research Center in Cambridge, MA, USA. Figure 5-5 depicts the relative permeability curves which govern the multi-phase flow behavior of the CO_2-brine system during both drainage (i.e., displacement of wetting phase) and imbibition (i.e., re-entry of wetting phase). The red solid line represents permeability to CO_2 as a function of water saturation in the pores space during the CO_2 injection process (drainage – non-wetting phase replaces wetting phase in the pore space). Water saturation can be represented as "1-CO_2 saturation". As can be seen in the figure, relative permeability to CO_2 increases as we introduce more CO_2 into the pore space.

Similarly, the blue solid line in Figure 5-5 represents the relative permeability to water as a function of water saturation during the drainage process. As we increase the CO2 saturation in the pore space; in other words, as we decrease the water saturation, relative permeability to water decreases. During the drainage process, in the pore space we can reduce the amount of water to a certain saturation. In this case we assumed that, the water fraction that we cannot remove from the pore space was around 35%. The amount of water we cannot remove from the pore space is called irreducible water saturation.

The dashed lines in Figure 5-5 represent the relative permeabilities for the imbibition process where wetting phase replaces the non-wetting phase.

Similar to the irreducible water saturation concept, when water starts imbibing back, it can push CO_2 and reduce the amount of CO_2 to a certain degree. The amount of CO_2 that cannot be removed from pore space is defined as ”residual CO_2 saturation” and represented with the end point of red dashed line (relative permeability to CO_2 during imbibition).

The curves used for the modeling purposes and shown in Figure 5-5 were assumed since there was not measured data available, and are likely to be modified based on future results.

Figure 5-6 and
Figure **5-7** depict the capillary pressure behavior of the CO_2-brine system during drainage and imbibition, respectively, for four different classifications of lithology defined by intrinsic permeability. For example, Pc(1) represents the capillary pressure behavior for lithologies with intrinsic permeabilities less than 1 mD; Pc(2) for permeabilities between 1 mD and 10 mD; Pc(3) for permeabilities between 10 mD and 100 mD; and Pc(4) for permeabilities greater than 100 mD.

Another governing parameter used in the reservoir simulation was the fracture pressure gradient of the lower Mt. Simon Sandstone. The fracture pressure gradient in the lower Mt. Simon was demonstrated via step rate test in CCS #1 to be 16.2 MPa/km (0.715 psi/ft) (refer to Section 2.4.3.3 for description). For the purposes of the reservoir simulations, the bottomhole injection pressure in CCS #1 was allowed to operate up to 80% of this gradient, whereas the bottomhole injection pressure in CCS #2 was allowed to operate up to 90% on account of the higher injection rate.

During the course of the simulation, CO_2 was injected into CCS #1 for 1 year at 1,000 MT/day, followed by 2 years of dual injection – 1,000 MT/day into CCS #1 and 2,000 MT/day into CCS #2 – followed by 3 years of injection into CCS #2 at 3,000 MT/day with CCS #1 shut-in. Following a total of five years of injection into CCS #2, 50 years of shut-in were simulated in order to understand the long-term behavior of the CO_2 plume and the reservoir pressure within the injection zone. The injection of CO_2 was limited to the lower part of the Mt. Simon – just above the basal arkosic zone – since it is the most porous and permeable interval in the injection zone. In the case of CCS #1, the existing (‘as-completed’) perforated interval of 16.8 m (55 ft) was assumed for the simulations (Frommelt, 2010), whereas in the case of CCS #2, a perforated interval of 100 m (330 ft) was required to meet the maximum proposed injection rates.

5.4.3 Simulation Results

Based on simulation results, the maximum diameter of the CO_2 plume resulting from injection into CCS #2 is estimated to be 1800 m (5,900 ft) once injection ceases and is expected to interact with the CCS #1 plume. Since the injection interval is near the base of the Mt. Simon, CO_2 flows upward from the injection interval due to its buoyant rise through the denser native brine. As it rises, CO_2 saturation increases below the lower permeability intervals within the Mt. Simon. This, in turn, causes the CO_2 plume to gradually pool and spread laterally beneath these lower permeability strata which results in slow growth of the plume footprint to a maximum diameter of approximately 2235 m (7,333 ft) at the end of the 50-year post-injection period. Not coincidentally, it is these lower permeability strata within the Mt. Simon that also limit the

ultimate vertical migration through the injection zone, such that after five years of continuous injection through the IL-ICCS well and 50 years of shut-in, the CO_2 remains well within the lower half of the Mt. Simon. The development of and interaction between the CO_2 plumes resulting from injection into CCS #1 and CCS #2 is illustrated in cross-sectional view at various times in Figure 5-8. Figure 5-9 through Figure 5-21 depict map-view representations of the aggregate plume area at various times superimposed on a satellite image of the project area. Each figure is accompanied by an estimate of the aggregate area (in square kilometers) of the two plumes along with an equivalent circular radius. Also depicted in Figure 5-9 through Figure 5-21 is the development of the pressure front ($P_{i,f}$) boundary through simulated time. Each figure is accompanied by an estimate of the area encompassed by the pressure front (in square kilometers) along with an equivalent circular radius. Figure 5-22 and Figure 5-23 summarize this same information in graphical form for both the pressure front and CO_2 plume throughout the simulated time period.

It is noteworthy that the pressure front boundary continues to grow throughout the injection period (through Year 6) to a maximum equivalent radius of 3.2 km, after which point the reservoir pressure quickly decays. By Year 8, the pressure throughout the reservoir has dropped below the threshold pressure defined in Section 5.2 (i.e., $P_{i,f}$ = 22.77 MPa). One implication of this prediction is that after Year 7, the AoR is likely to be delineated exclusively by the footprint of the aggregate CO_2 plume rather than by pressure, which dramatically reduces the size of the AoR during the post-injection period. Another obvious feature in the pressure boundary is the jagged shape of the footprint. As described in Section 5.2, the jagged shape of the footprint is an artifact of the geocellular grid, which is comprised of small cells near the injection wells and progressively large cells beyond the immediate injection area. This transition is most notable between Figure 5-11 and Figure 5-12 as the pressure front boundary begins to grow larger than the area of fine grid cells and into the area of coarser grid cells. While this transition does impart an unnatural appearance to the pressure boundary, there is little impact on the accuracy of the resulting pressure estimate since these are areas of relatively low flux and very little change in fluid saturation.

Several additional interesting features can be identified in the sequence of images presented in Figure 5-8 through Figure 5-21. First, the shape of the CO_2 plume created by injection through CCS #1 is initially symmetrical during the first year of simulated injection due to the homogeneous nature of the geologic model. The symmetry of the plume is altered, however, once injection begins in CCS #2 and this effect becomes more dramatic throughout simulated time. This highlights the fact that, as a result of the pressure interference, the concurrent injections will influence each other even before the CO_2 plumes interact.

A second notable observation is that the brine displaced ahead of the advancing CO_2 plume created by the injection into CCS #2 not only distorts the shape of the plume around CCS #1, but also sweeps away mobile CO_2 from the nearest edges of the plume, leaving behind a 'shadow' of residually-trapped CO_2. This affect is most apparent when comparing the Year 3 and Year 7 cross-sectional views in Figure 5-8. The CO_2 that is residually trapped as a result of the encroaching brine is depicted in light-blue, or the 0.2 – 0.25 range in the CO_2 saturation color bar. This residually-trapped CO_2 is immobilized by capillary forces and can be seen to persist through the remaining cross-sectional images in Figure 5-8, suggesting long-term storage in the lower Mt. Simon.

A third notable observation is the difference in the size of the plumes. While dramatic, this size difference is easily explained by the difference in injection rates of CO_2 into the two wells: 1000 MT/day for three years into CCS #1 versus 2000 MT/day for two years and 3000 MT/day for three years into CCS #2. Furthermore, the perforated interval simulated in the two wells is dramatically different: 16.8 m in CCS #1 versus 100 m in CCS #2. This difference alone accounts for the majority of the difference in plume height observed in Figure 5-8.

Finally, a fourth notable observation is the continued vertical growth of the plumes throughout the simulated 50-year post-injection period. Although the CO_2 plumes do continue to grow vertically under buoyant forces after injection ceases, the vertical extent is ultimately limited by lower permeability intervals within the Mt. Simon. The cross-sectional profiles at various times depicted in Figure 5-8 illustrate how the CO_2 saturation increases below these lower permeability strata, which results in the lateral spreading of the CO_2 plume. While this does increase the footprint area of the plume, it retains the CO_2 well within the lower half of the Mt. Simon. Moreover, as can be seen in the Year 56 profile of Figure 5-8, the plume has not even reached the upper model boundary, which in this case, only extends to the low-porosity, low-permeability interval mid-way through the Mt. Simon Sandstone.

Geochemical Modeling. No compatibility problems are anticipated in the injection zone. Geochemical modeling was used to predict the effects of injecting supercritical CO_2 into a model Mt. Simon Sandstone (Berger, Mehnert, & Roy, 2009). Based on chemical and mineralogical data from the Manlove Gas Storage Field in Illinois, the geochemical modeling software package, Geochemist's Workbench (Bethke, 2006), was used to simulate geochemical reactions. As expected, the injected CO_2 decreased the pH of the formation brine to about pH 4.5. As the reaction was allowed to progress, the pH of the formation brine increased to pH 5.4.

In the geochemical simulations mentioned above, Berger et al (2009), it was predicted that illite and glauconite dissolved initially. As the reaction was allowed to proceed, kaolinite and smectite were predicted to precipitate. It was predicted that the volume of pore space would not be significantly altered (Berger, Mehnert, & Roy, 2009). Therefore, no compatibility problems, such as a major reduction in injection-formation permeability resulting from chemical precipitates, are expected.

Although the CO_2 is not expected to reach the Eau Claire within the post injection period, Geochemist's Workbench predicts that, if the CO_2 does come in contact with the Eau Claire, a geochemical reaction will occur. The modeling results indicated that illite and smectite would initially dissolve, but that the dissolved CO_2 could be precipitated as carbonates (Berger, Mehnert, & Roy, 2009). This dissolution and precipitation process would not be expected to affect the caprock integrity.

5.5 Wells within the Area of Review

5.5.1 Tabulation of Well Data Within the AoR

A total of 447 wells are located within the area of review. Water wells (371 of 447 wells) are the most common well type. The domestic water wells have depths of less than 60 m (200 ft).

Other wells include stratigraphic test holes, other water wells, and oil and gas wells. Appendix D provides a full size map of the wells within the AoR and a listing of these wells with their API number, well owner, well location, well type, and well depth identified (if known). All wells within the 4 townships surrounding the proposed injection well site were also identified (total of 3,761 wells). Information regarding these wells is provided as a supplement to this permit application (available in electronic format).

Ten oil and gas wells are located within approximately 2.4 km (1.5 miles) from the proposed injection well location. The closest well is located in the northeast quarter of Section 5, T16N, R3E. This well (API number 121150061800) was drilled as a gas well in 1933 and was 27 m (88 ft) deep. There is no record of this well being plugged. This well was likely collecting naturally occurring methane from the Quaternary sediments. The other 9 wells are located in Section 5, T16N, R3E or Section 28 and Section 29, T17N, R3E. The deepest of these oil wells is API number 121150054700, located in the northwest quarter of Section 28. This well was drilled into the Lower Devonian and was 714 m (2,344 ft) deep.

Like other areas with humid climates (Freeze and Cherry, 1979), the water table in central Illinois is expected to reflect the elevation of the land surface. Steady-state groundwater flow modeling for the IBDP site indicates that shallow groundwater flows toward the east and southeast toward the Sangamon River and Lake Decatur.

5.5.2 Number of Wells within the AoR Penetrating the Uppermost Injection Zone

With the exception of the IBDP injection and verification wells, there are no known wells within the area of review that penetrate deeper than 762 m (2,500 ft). The depth to the top of the injection zone (Mt. Simon Sandstone) is 1690 m (5,545 ft). Therefore, there are only two known wells that penetrate the uppermost injection zone.

Properly Plugged and Abandoned: No wells deeper than 762 m (2,500 ft) are known to have been plugged and abandoned within the AoR.

Temporarily Abandoned: No wells deeper than 762 m (2,500 ft) are known to have been temporarily abandoned within the AoR.

Operating: Two wells penetrating the uppermost injection zone (IBDP injection and verification wells, CCS #1 and Verification Well #1) are known to be in use within the AoR. The IBDP injection well began injection in November 2011.

No plugging affidavits are provided, as the IBDP wells are currently in use.

5.5.3 Proposed Corrective Action for Unplugged Wells Penetrating the Injection Zone

No wells have been found that are believed to require corrective action. The AoR will be re-evaluated periodically (see Section 5.6 below) to verify whether corrective actions may be necessary in the future.

5.6 Area of Review Re-Evaluation & Corrective Action Plan

This section is intended to satisfy the requirements of 40 CFR 146.84.

AoR Re-Evaluation.
In accordance with Federal regulations for Class VI (geologic sequestration) injection wells, the AoR will be re-evaluated on a 5-year basis following issuance of the UIC permit. During each re-evaluation, the following will be performed:

- New wells within the AoR that exceed a depth of 305 m (1,000 ft) will be identified;
- Wells exceeding a depth of 305 m (1,000 ft) within the AoR that have been plugged & abandoned will be identified;
- Monitoring and operational data from the injection well (CCS#2), other surrounding wells, and other sources will be analyzed to assess whether the predicted CO_2 plume migration is consistent with actual data. An AOR Corrective Plan flowchart is shown in Figure 5-24. A table which summarizes key monitoring and operational data is shown in Table 5-1.

If data are inconsistent with model predictions, ADM will assess whether the inconsistency is related to unanticipated conditions within the Mt. Simon Sandstone, heterogeneity within the injection formation, or uncertainty within the model itself. If the inconsistency suggests that location(s) within the AoR may be subject to CO_2 leakage.

Monitoring and operational data will be analyzed on a frequent (likely annual) basis by ADM and/or its partners in the IL-ICCS project. If data suggest that a significant change in the size or shape of the actual CO_2 plume as compared to the predicted CO_2 plume is occurring, or if the actual reservoir pressures are significantly different than predicted pressures, ADM will initiate an AoR re-evaluation, prior to the 5-year re-evaluation period.

Re-Evaluation Report.
Following each AoR re-evaluation, a report will be prepared documenting the AoR re-evaluation process, data evaluated, any corrective actions determined necessary, and the schedule for any corrective actions to be performed. The report will be submitted to the regulatory agency for approval within a timeframe specified by permit.

If no changes result from the AoR re-evaluation, the report will include the data and results demonstrating that no changes are necessary. The original AoR evaluation and all submitted re-evaluation reports shall be retained by ADM until 10 years after site closure.

Corrective Action.
If corrective actions are warranted based on the AoR re-evaluation, ADM will take the following actions:

- Identify all wells within the AoR that may require corrective action (e.g., plugging),
- Identify the appropriate corrective action for the well(s),
- Prioritize corrective actions to be performed, and

- Conduct corrective actions in an expedient manner to minimize risk of CO_2 leakage to a USDW.

Based on the information obtained for the ICCS project permit application, no corrective actions are believed to be necessary within the area of review.

State, Tribe, and Territory Contact Information.
In accordance with 40 CFR 146.82(a)(20), the State of Illinois is the only State, Tribe, or Territory identified to be within the area of review. Contact information for the State of Illinois will be directed through:

Illinois Environmental Protection Agency (IEPA)
Mr. Kevin Lesko, UIC Permit Engineer, Bureau of Land
1021 N. Grand Avenue East
Springfield, IL 62794-9276
Phone: (217) 524-3271
Kevin.Lesko@illinois.gov

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Vesovic, V., Wakeham, W. A., Olchowy, G. A., Sengers, J. V., Watson, J. T., & Millat, J. (1990). The Transport Properties of Carbon Dioxide. *J. Phys. Chem. Ref. Data , 19* (3).

Zaytsev, I. D., & Aseyev, G. G. (1992). *Properties of Aqueous Solutions of Electrolytes.* Boca Raton, FL: CRC Press.

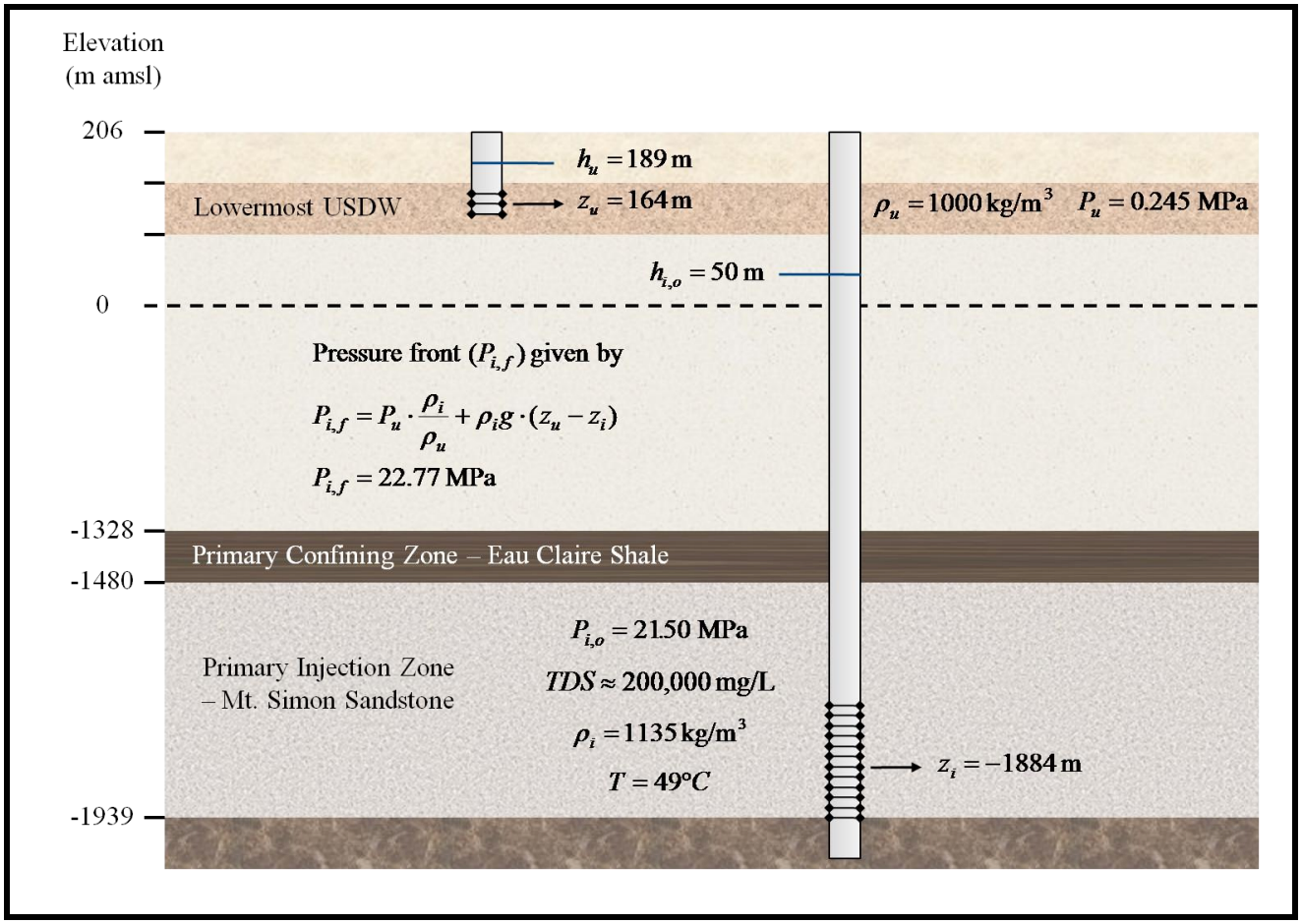


Figure 5-1: Illustration of pressure front delineation calculation based on data from IL-ICCS site.

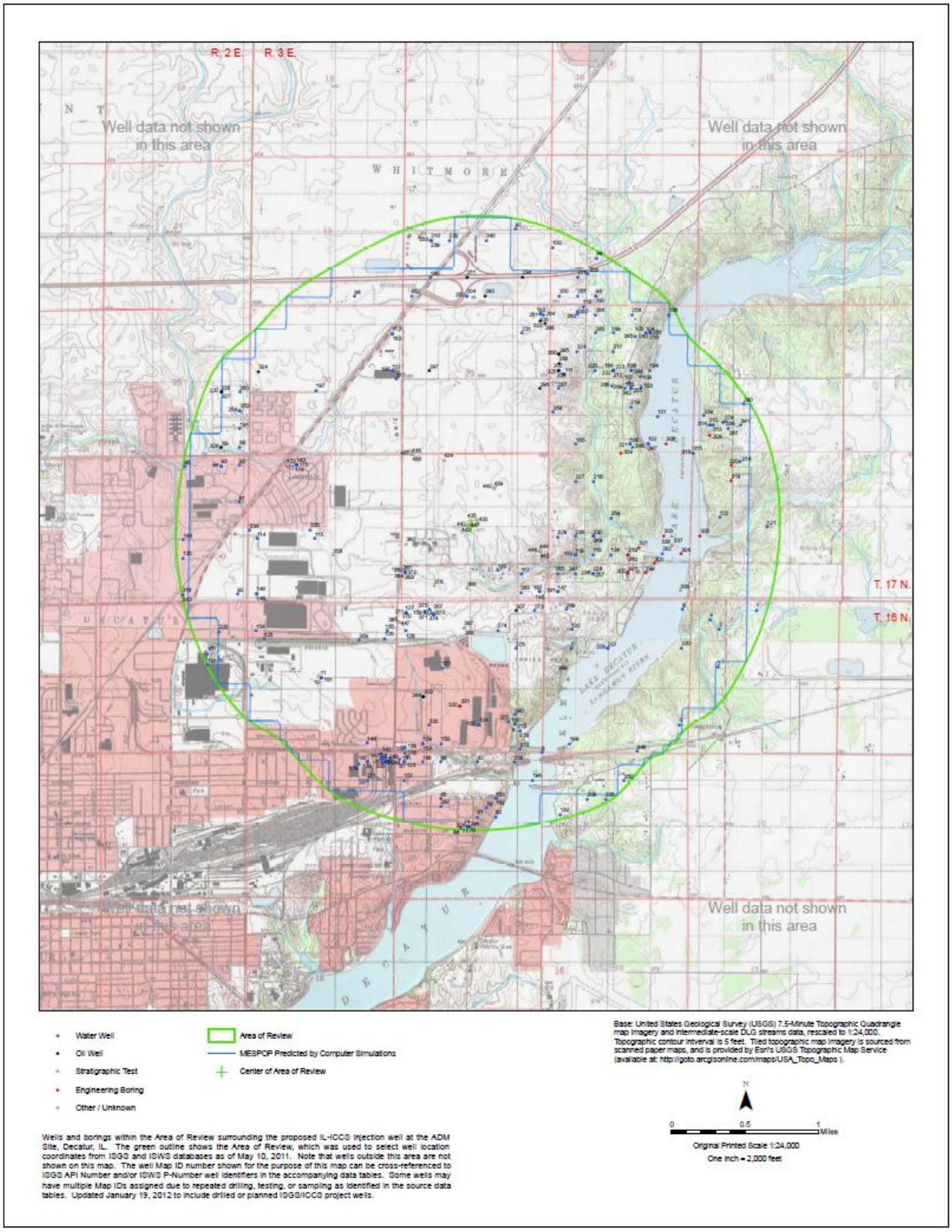


Figure 5-2: Well Penetrations within approximately 3.2 km (2.0 mile) radius of site.
Source: ISWS and ISGS databases, data current as of January 1, 2012.
Note: *A larger scale map is found in Appendix D.*

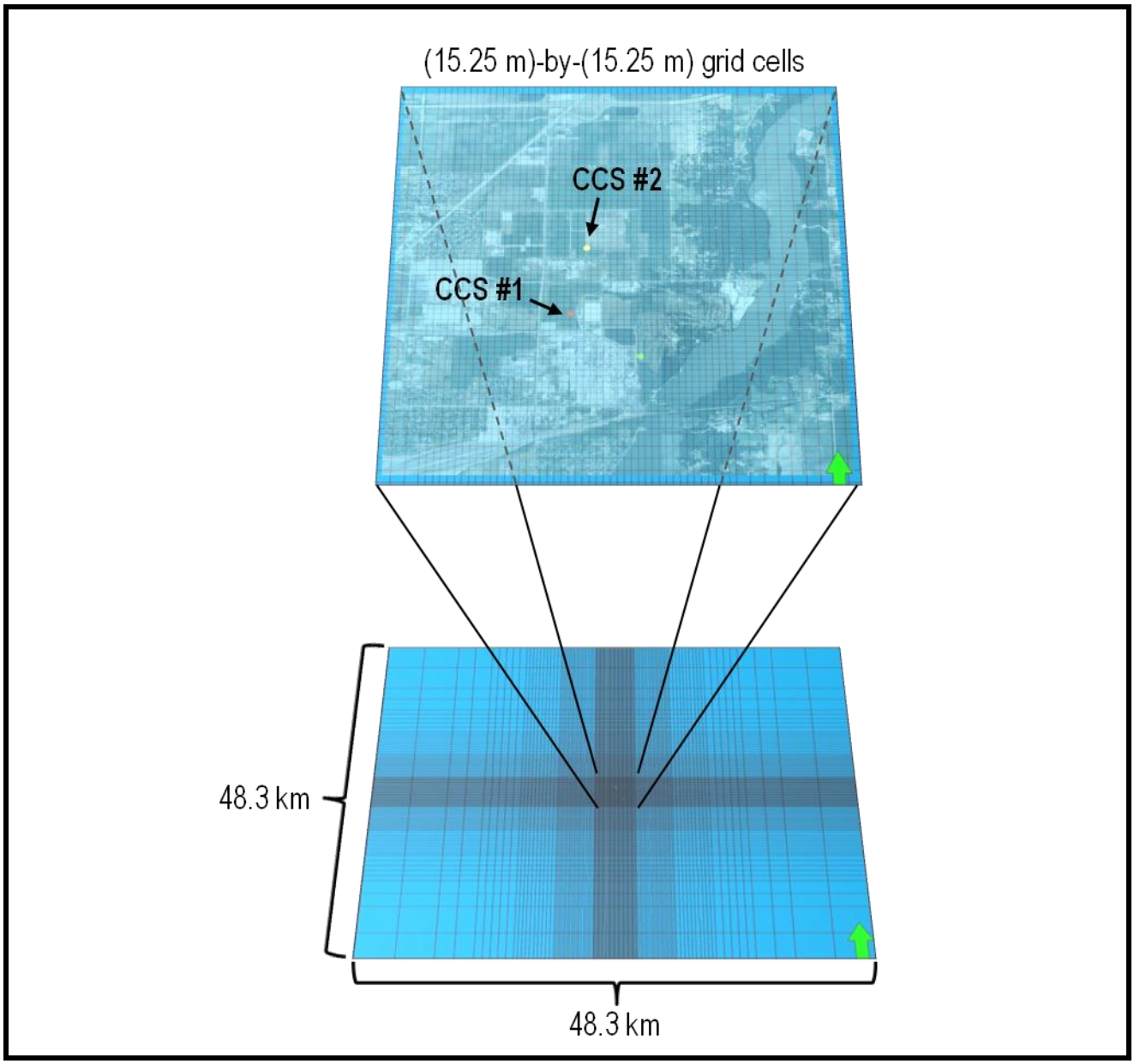


Figure 5-3: Depiction of irregular gridding pattern and dimensions of geocellular model used in reservoir simulations.

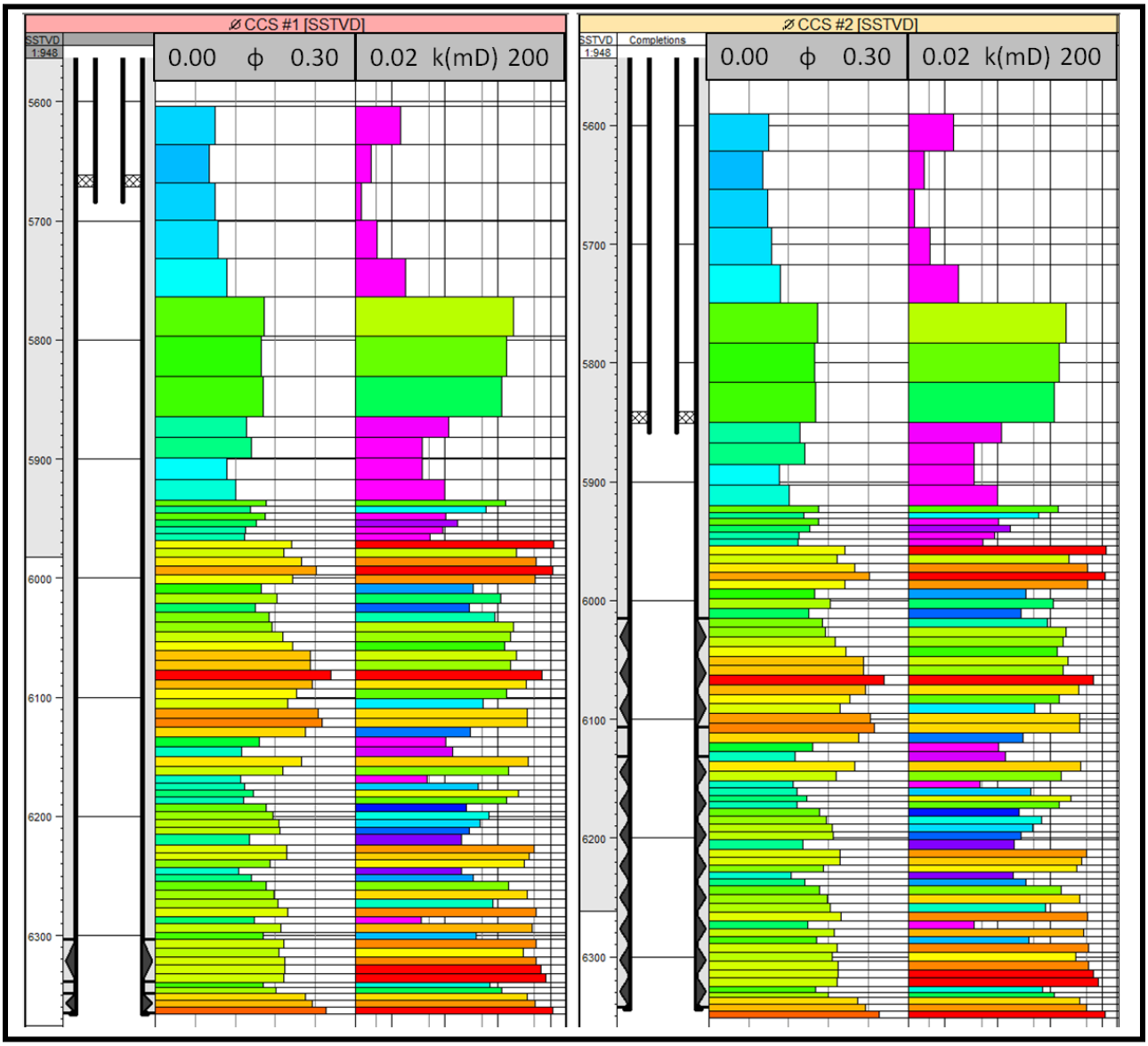


Figure 5-4: Upscaled well logs with respect to sub-surface true vertical depth (SSTVD) in feet of porosity and permeability (mD) from CCS #1 and proposed IL-ICCS injection well. (Warmest color indicates relative highest values and cool color indicates relative lower values). For example, the red intervals in the permeability track exhibit approximately 100 millidarcies of permeability. Porosity and permeability within these layers range from 8 to 26% and from 0.03 to 117 millidarcies (mD), respectively.

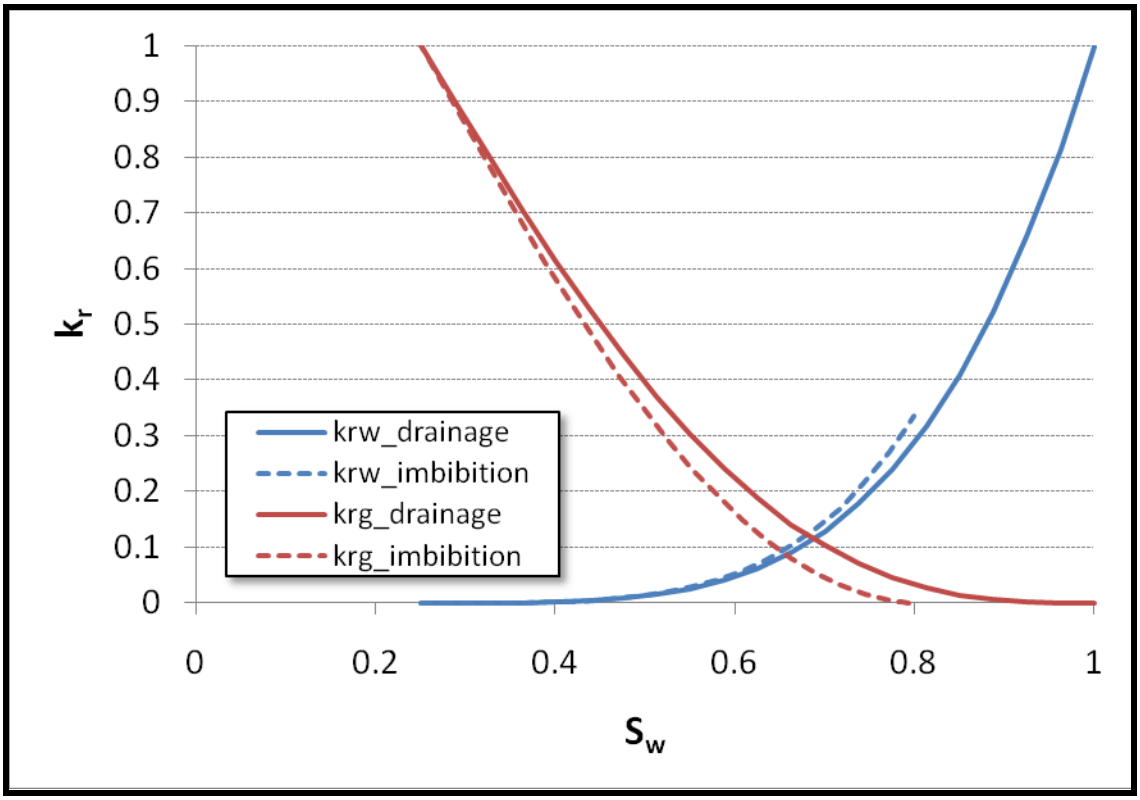


Figure 5-5: Relative permeability curves of the CO_2-brine system during drainage and imbibition with respect to brine saturation (S_w). Where: krw_drainage represents the relative permeability of brine during drainage, krw_imbibition represents the relative permeability of brine during imbibition, krg_drainage represents the relative permeability of CO_2 during drainage, and krg_imbibition represents the relative permeability of CO_2 during imbibition. S_{wi} (irreducible water saturation) is approximately 35% as assumed in the reservoir simulation. Note: Drainage is defined as CO_2 replacing brine in the pores. Imbibition is defined as brine replacing CO_2 in the pores.

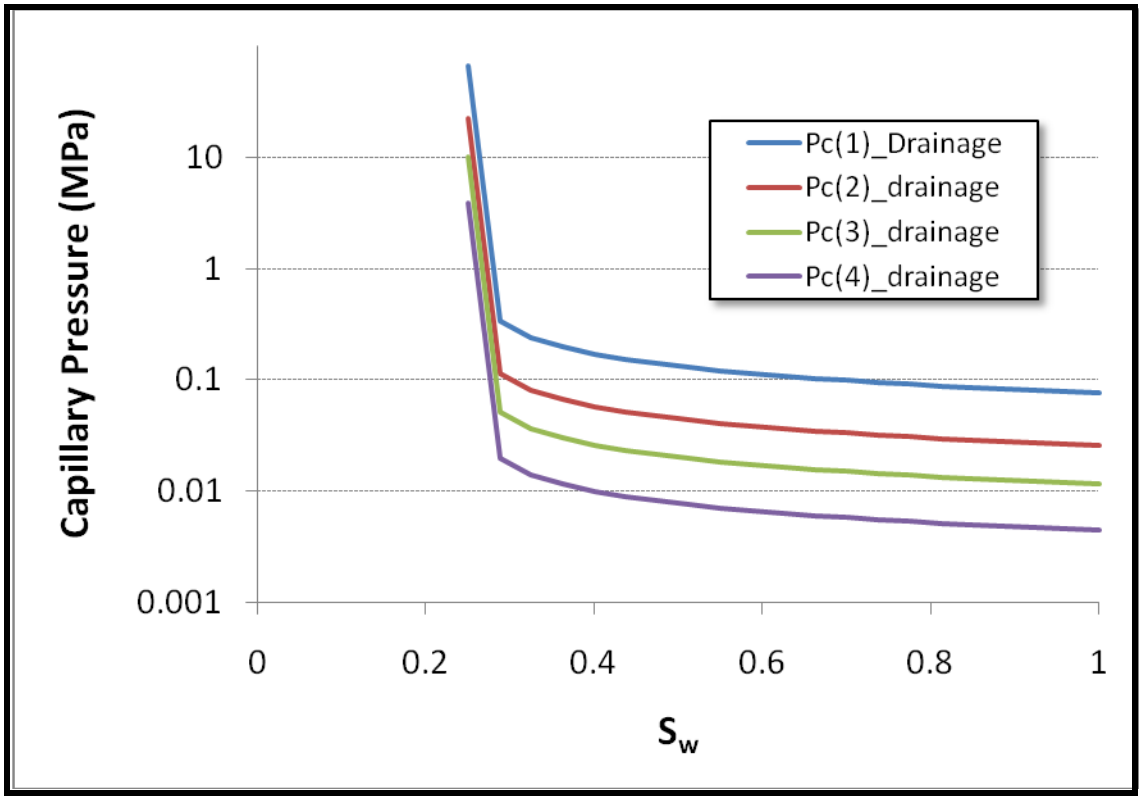


Figure 5-6: Capillary pressure behavior of the CO_2-brine system during drainage. The horizontal Access represents S_w (Water Saturation). Pc(1) represents the capillary pressure behavior for lithologies with intrinsic permeabilities less than 1 mD; Pc(2) for permeabilities between 1 mD and 10 mD; Pc(3) for permeabilities between 10 mD and 100 mD; and Pc(4) for permeabilities greater than 100 mD.

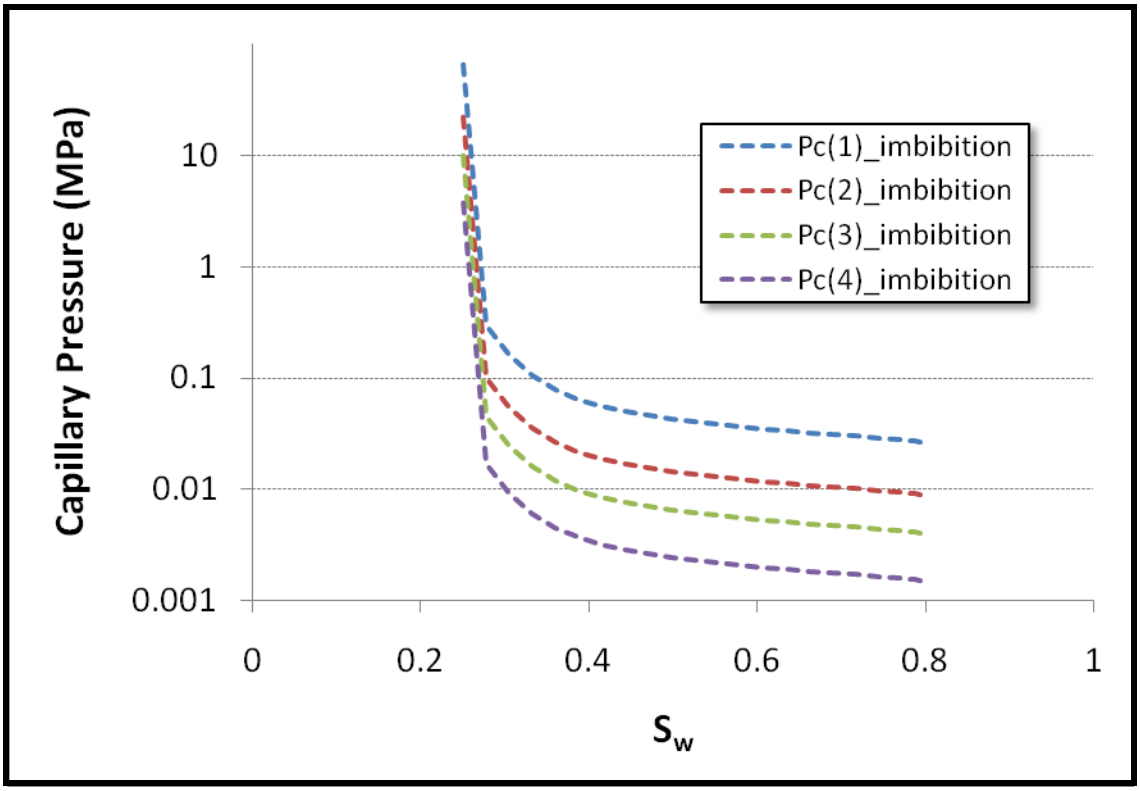


Figure 5-7: Capillary pressure behavior of the CO_2-brine system during imbibition. The horizontal Access represents S_w (Water Saturation). Pc(1) represents the capillary pressure behavior for lithologies with intrinsic permeabilities less than 1 mD; Pc(2) for permeabilities between 1 mD and 10 mD; Pc(3) for permeabilities between 10 mD and 100 mD; and Pc(4) for permeabilities greater than 100 mD.

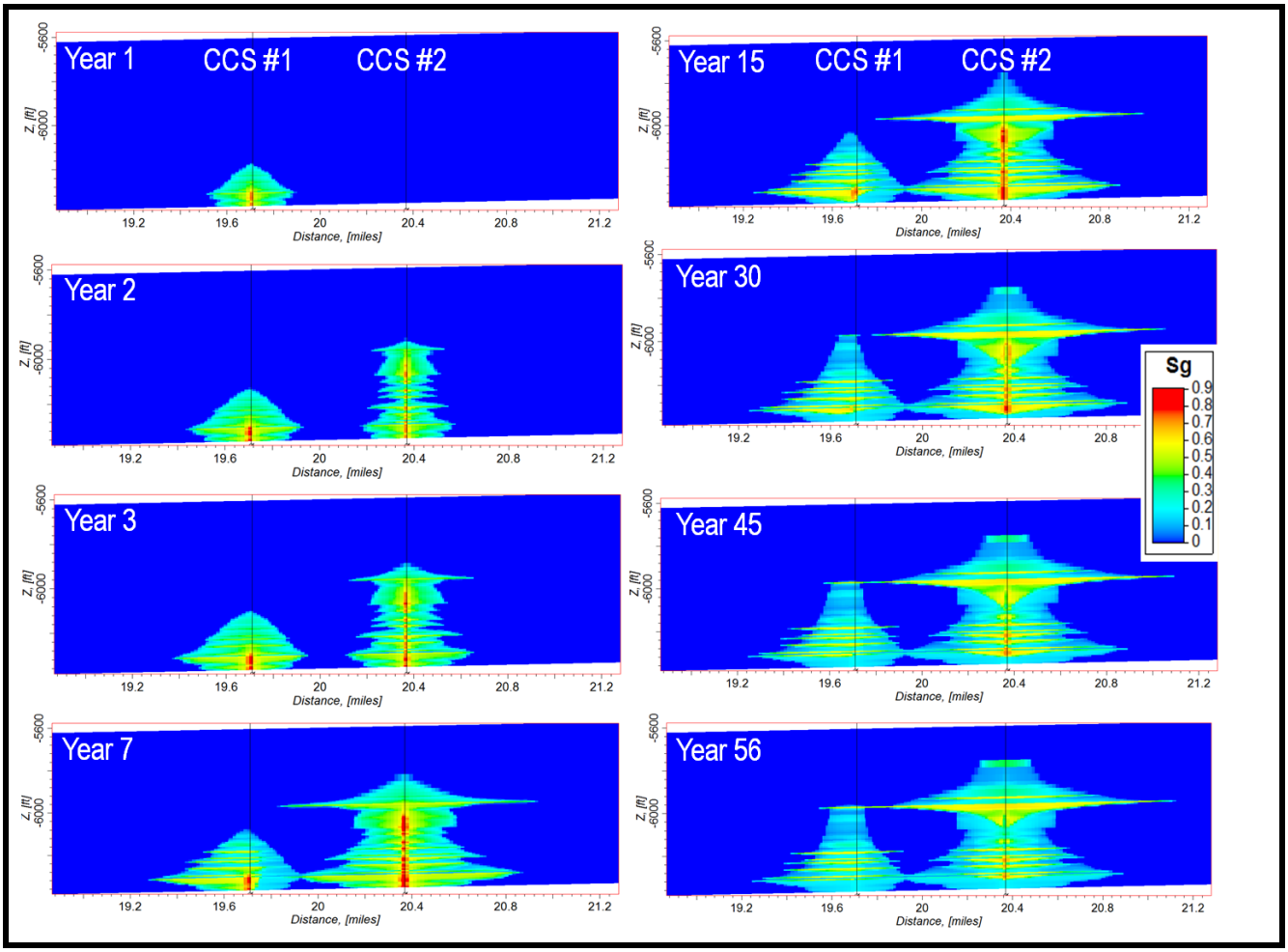


Figure 5-8: Cross-sectional views of CO_2 plumes (represented by gas saturation, Sg, ranging from 0 to 1) at various time steps during simulation.

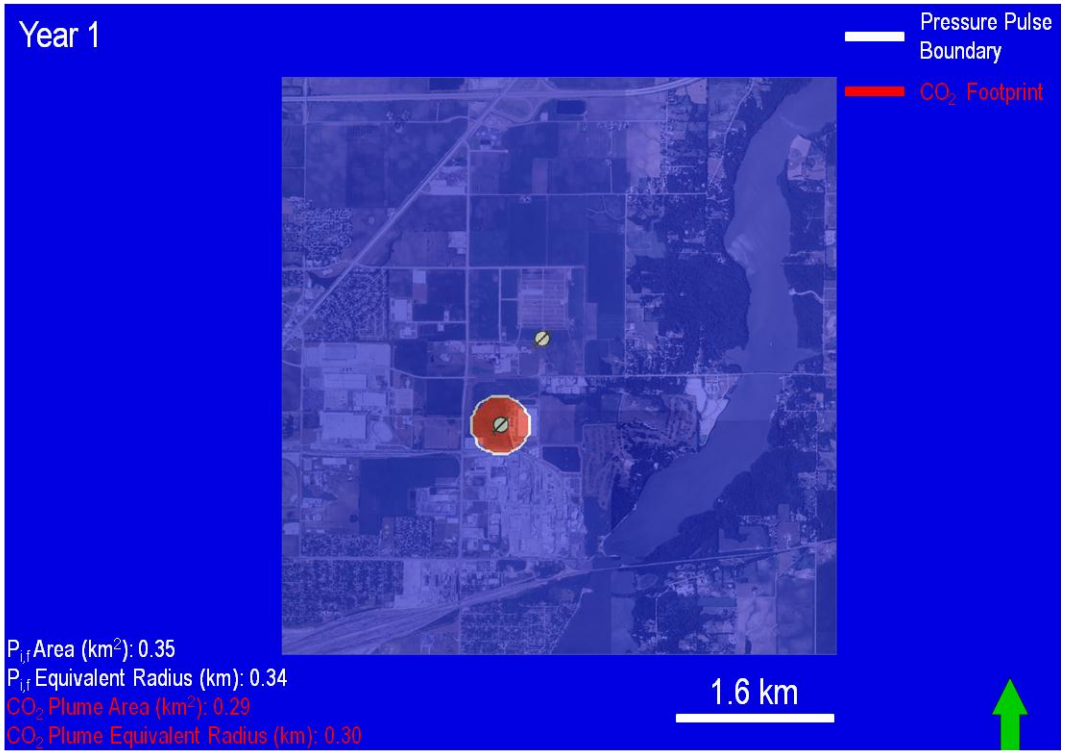


Figure 5-9: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 1.

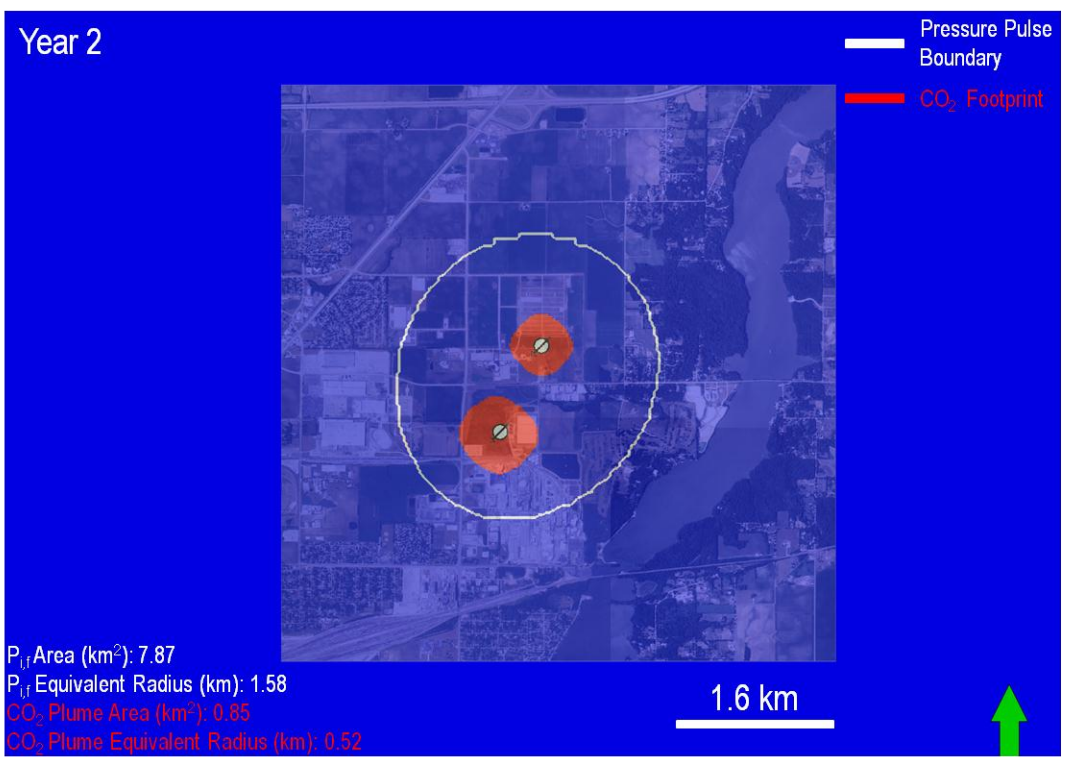


Figure 5-10: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 2.

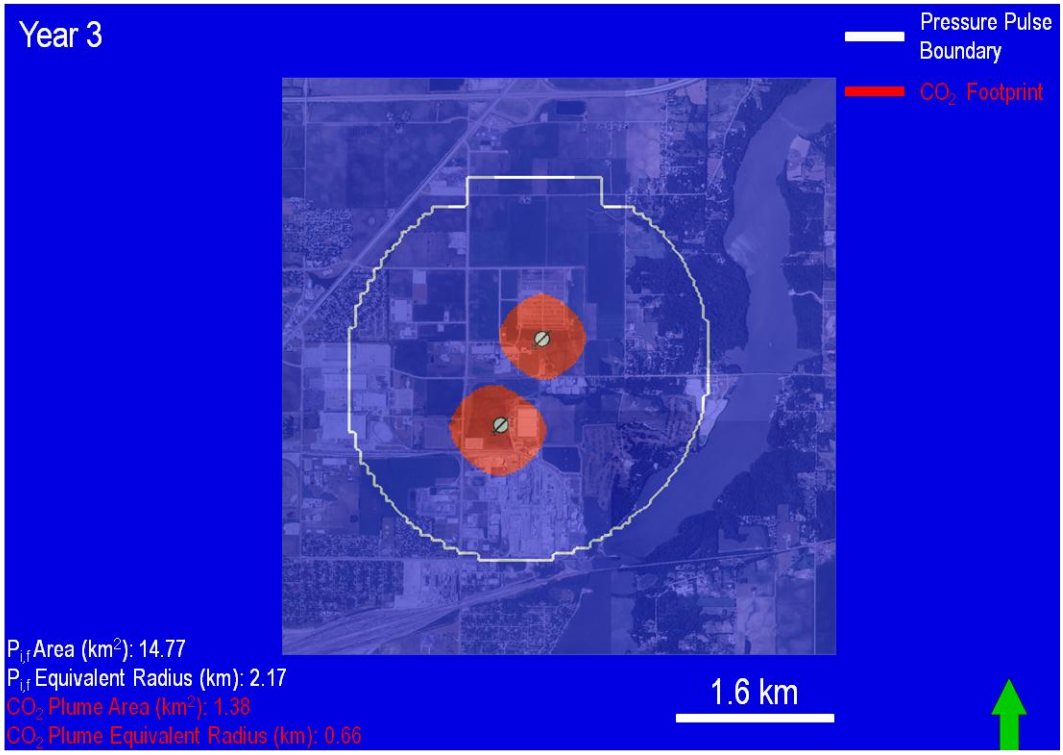


Figure 5-11: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 3.

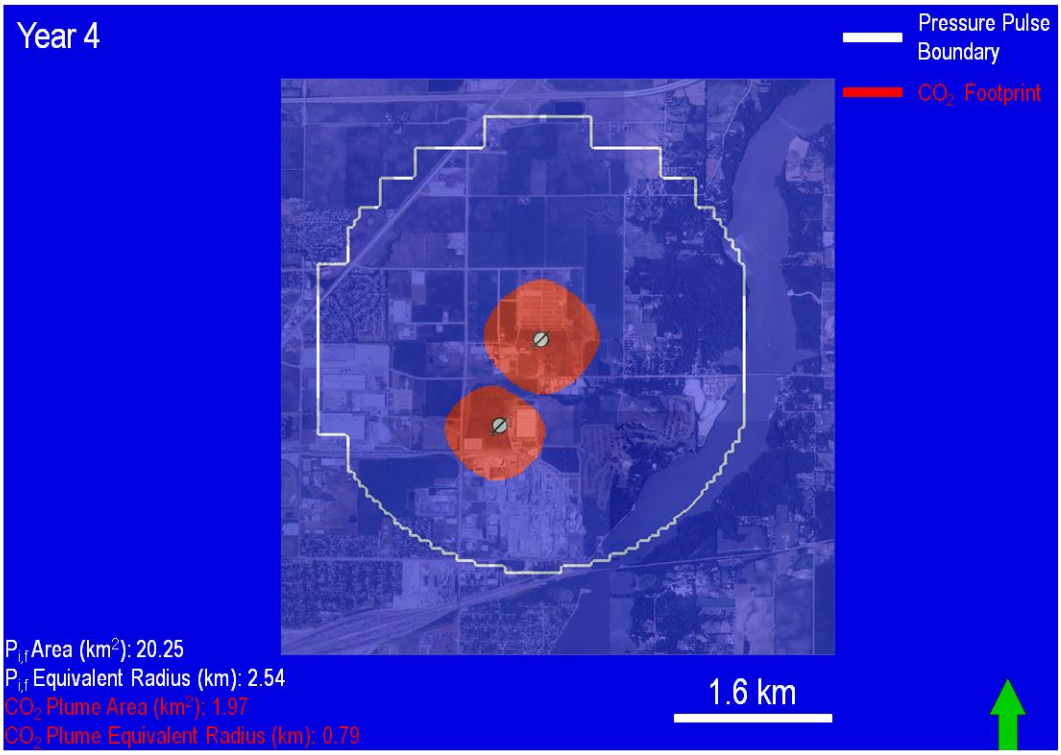


Figure 5-12: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 4.

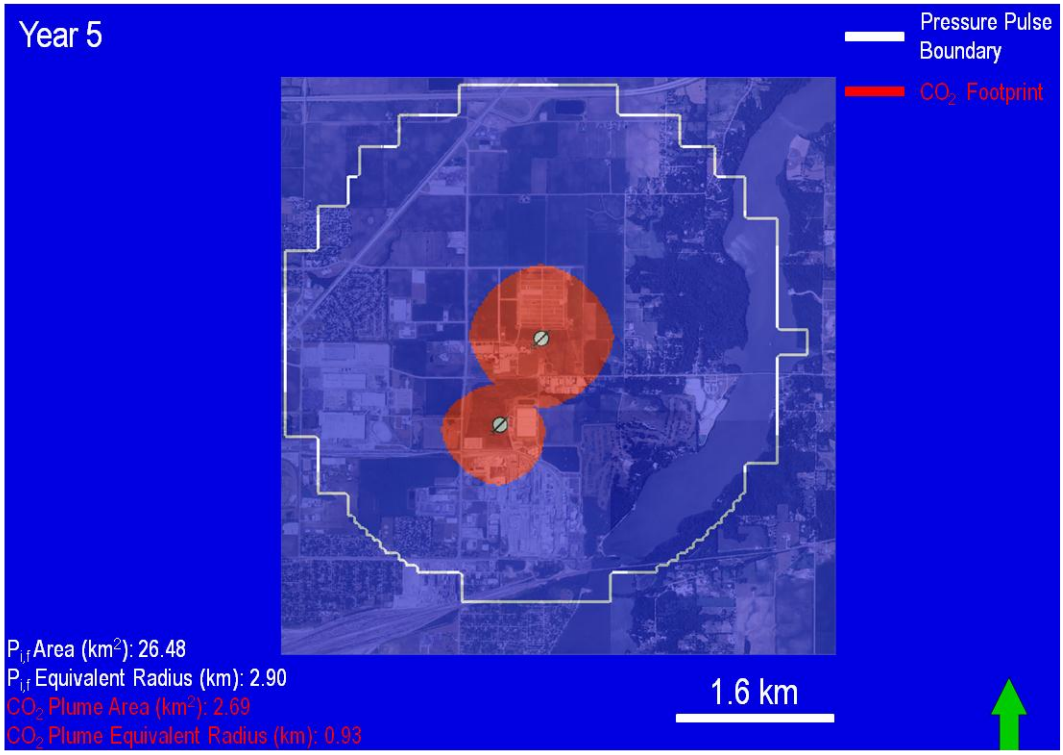


Figure 5-13: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 5.

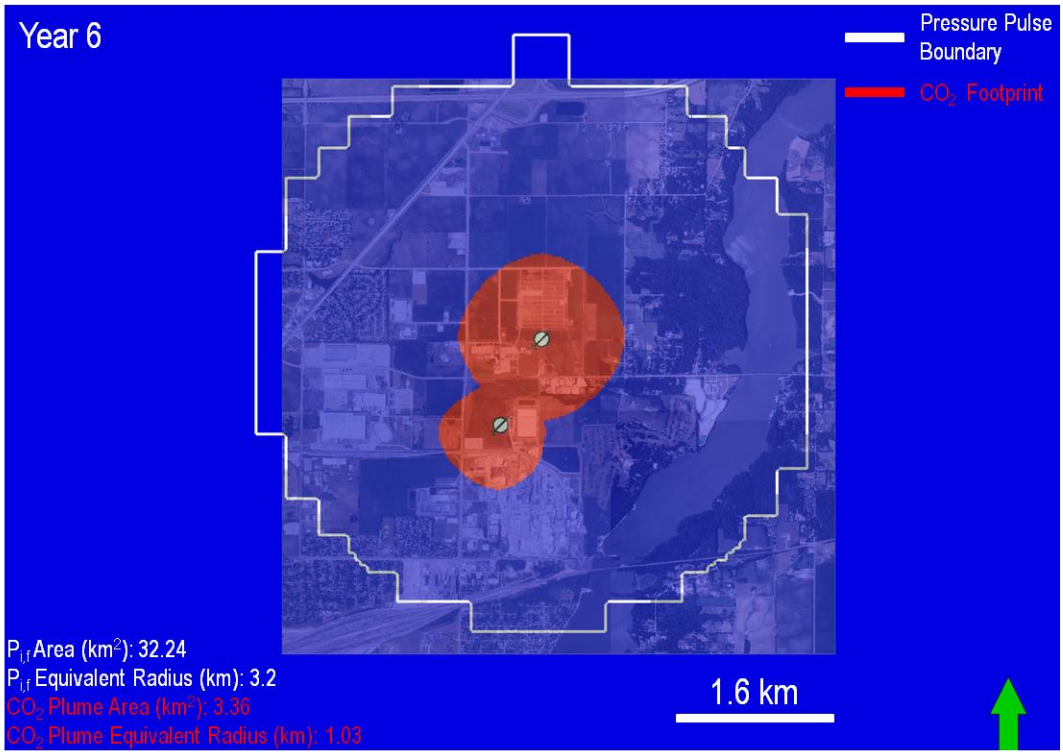


Figure 5-14: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 6.

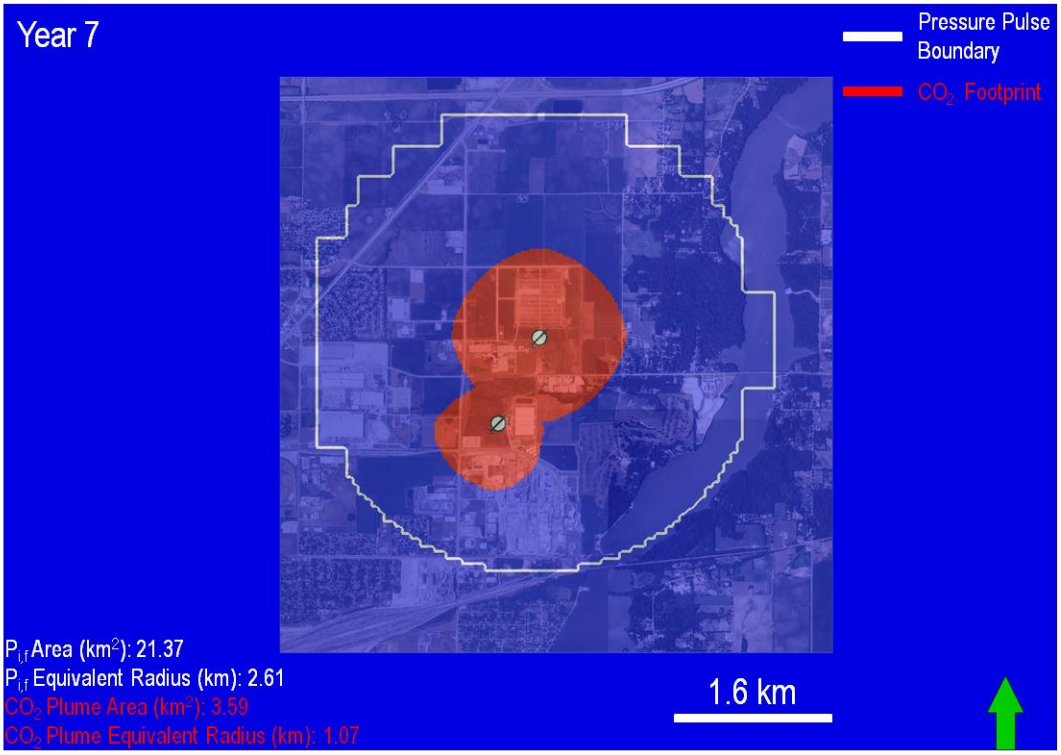


Figure 5-15: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 7.

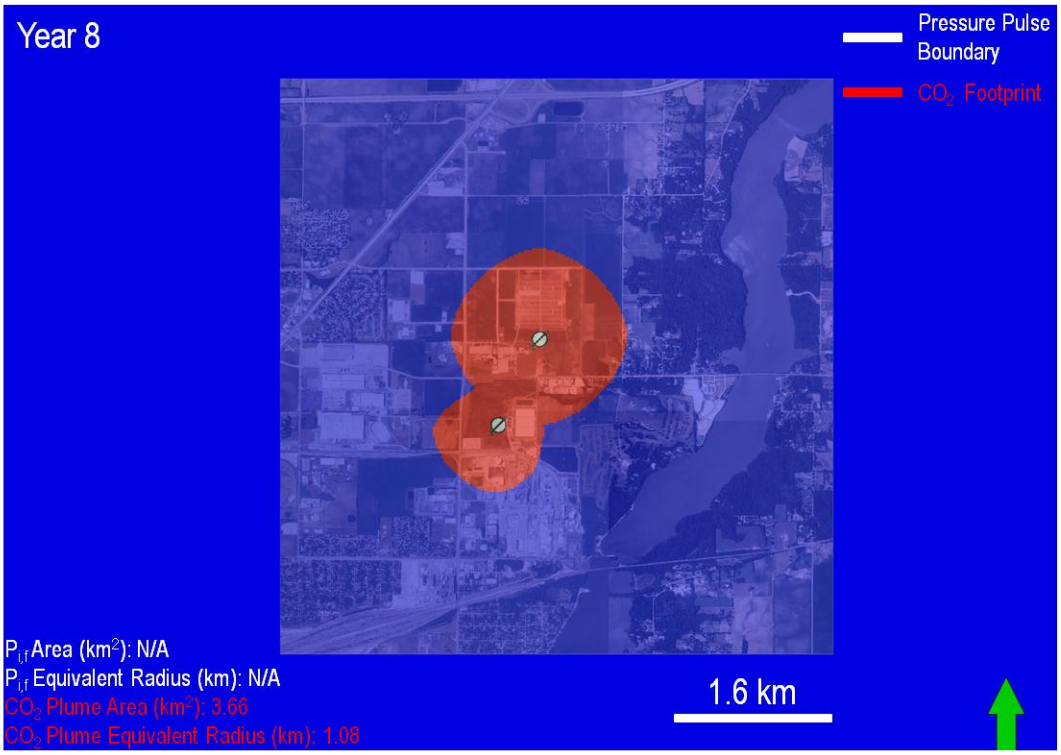


Figure 5-16: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 8. **Note:** The pressure in the injection formation is below the minimum value for delineation of a pressure pulse boundary, so no pressure pulse boundary is shown.

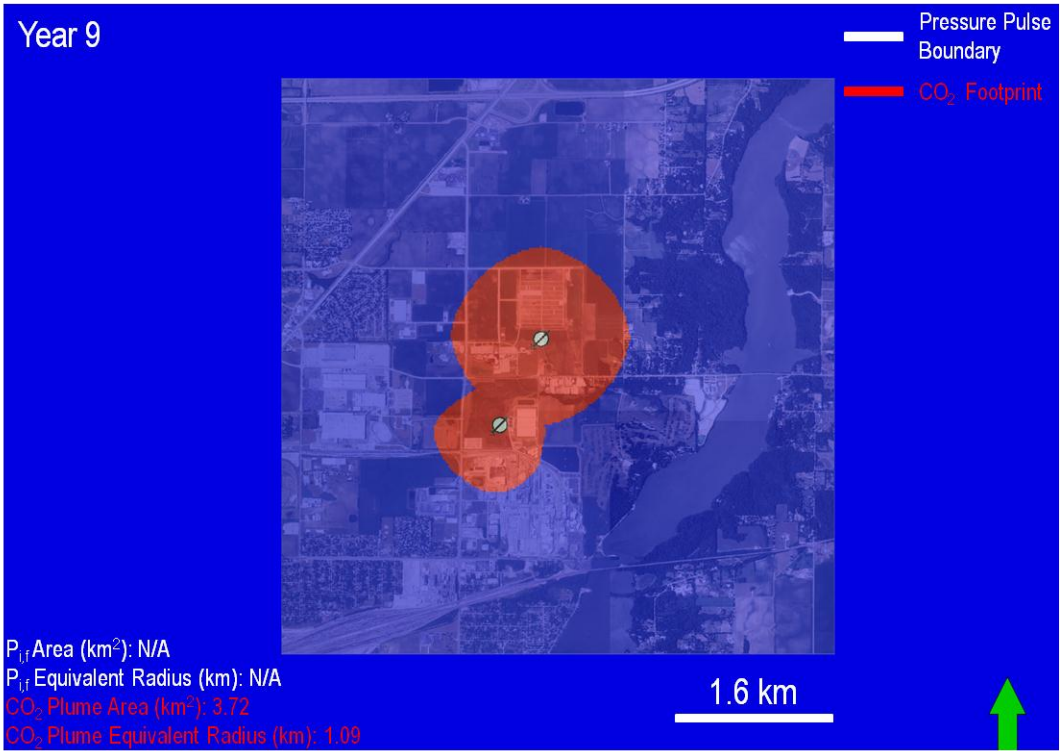


Figure 5-17: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 9. **Note:** The pressure in the injection formation is below the minimum value for delineation of a pressure pulse boundary, so no pressure pulse boundary is shown.

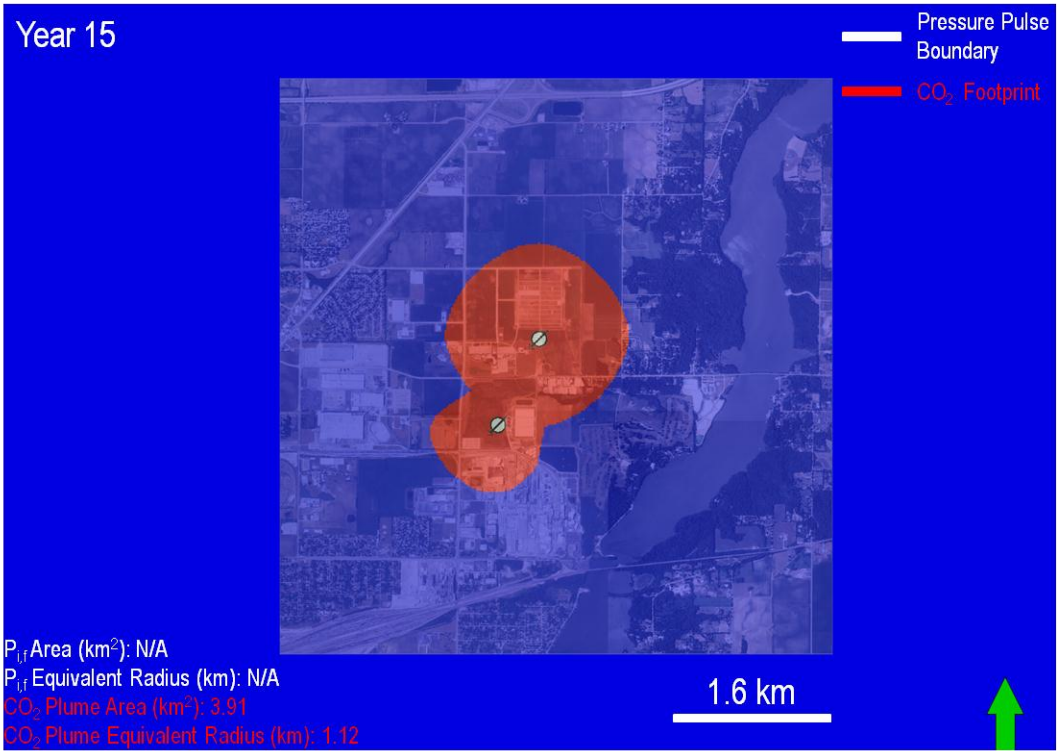


Figure 5-18: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 15. **Note:** The pressure in the injection formation is below the minimum value for delineation of a pressure pulse boundary, so no pressure pulse boundary is shown.

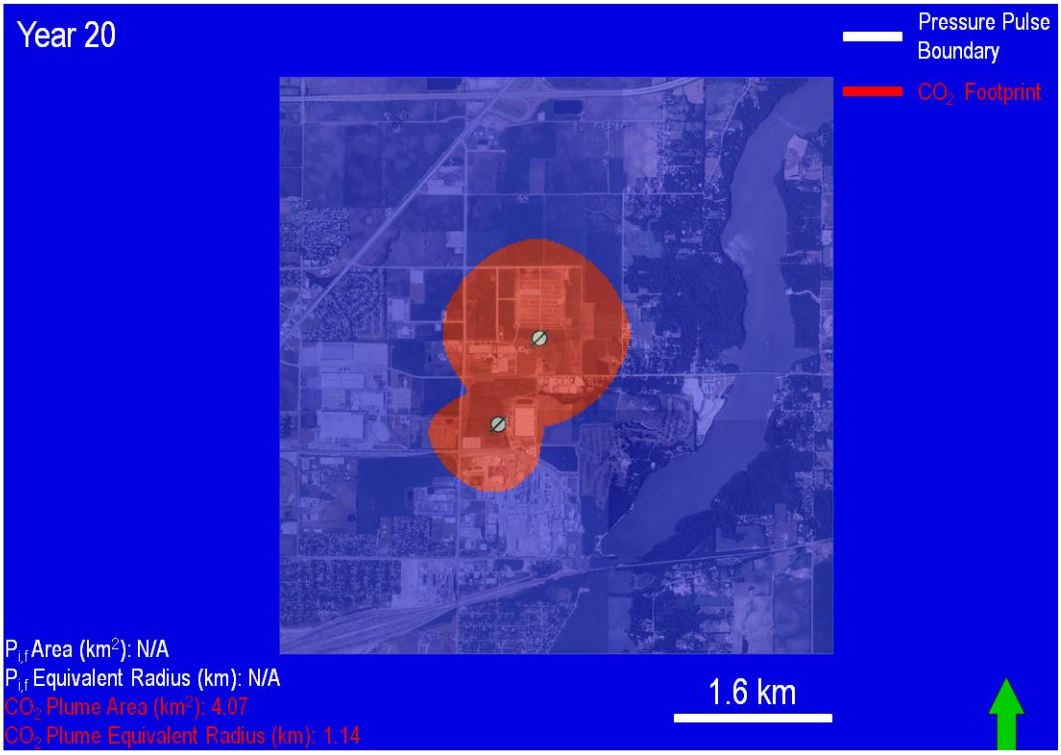


Figure 5-19: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 20. **Note:** The pressure in the injection formation is below the minimum value for delineation of a pressure pulse boundary, so no pressure pulse boundary is shown.

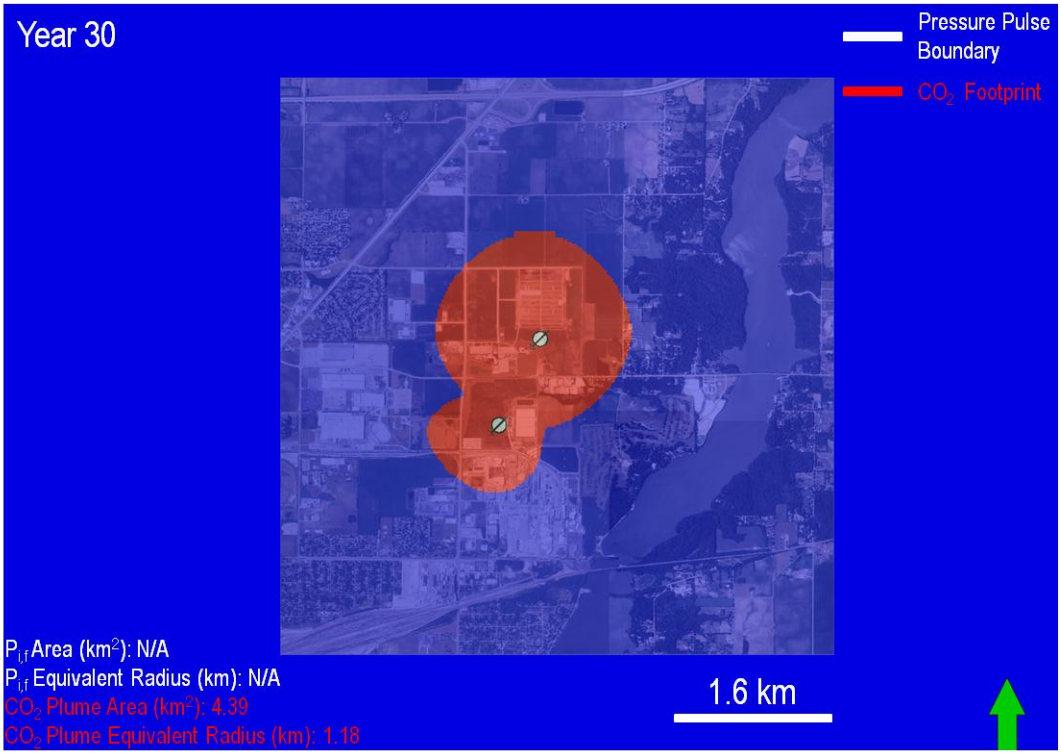


Figure 5-20: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 30. **Note:** The pressure in the injection formation is below the minimum value for delineation of a pressure pulse boundary, so no pressure pulse boundary is shown.

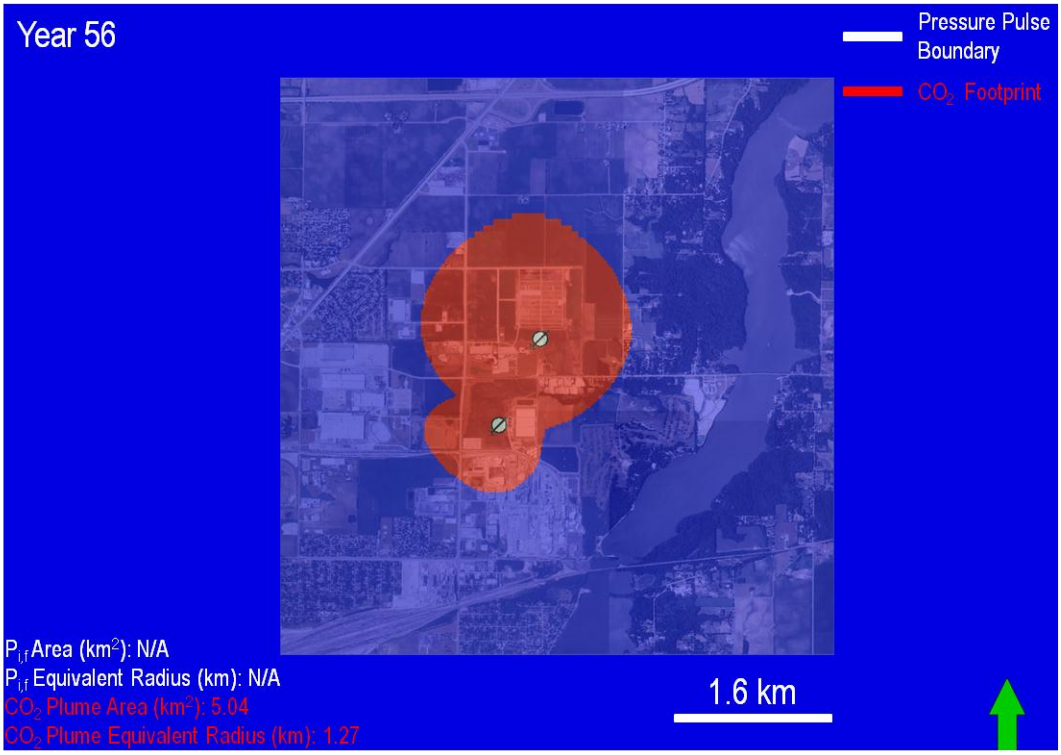


Figure 5-21: Map-view of pressure front ($P_{i,f}$) and CO_2 plume footprints after simulated Year 56. **Note:** The pressure in the injection formation is below the minimum value for delineation of a pressure pulse boundary, so no pressure pulse boundary is shown.

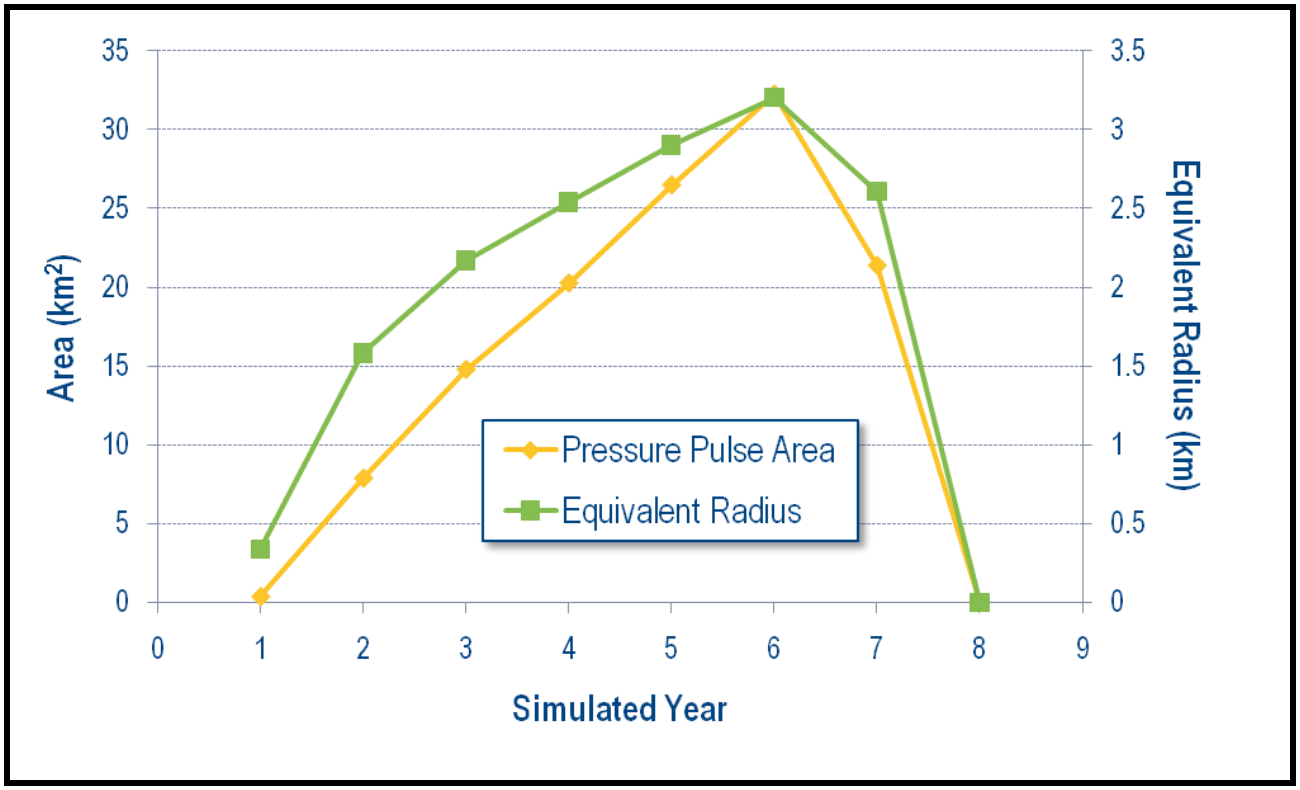


Figure 5-22: Graph of pressure front ($P_{i,f}$) area and equivalent radius throughout simulated time.

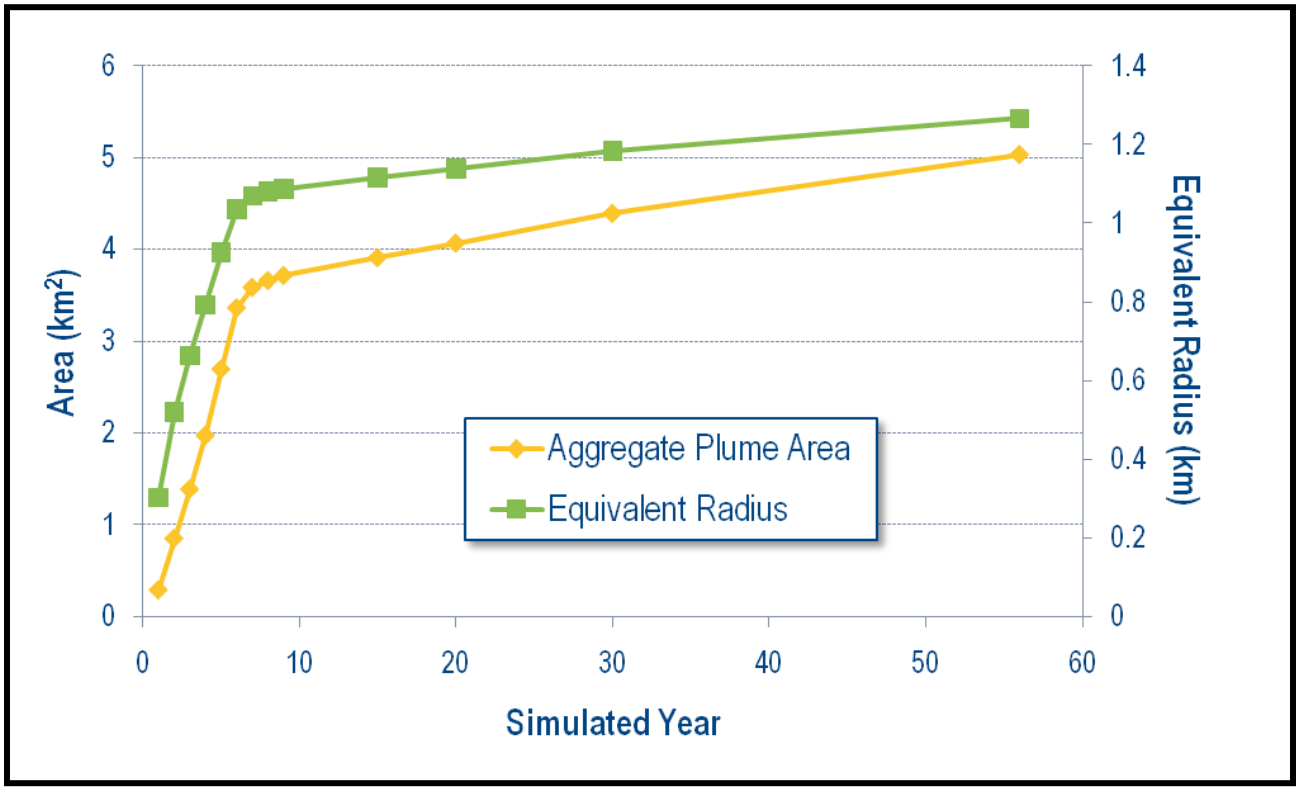


Figure 5-23: Graph of CO_2 plume area and equivalent radius throughout simulated time.

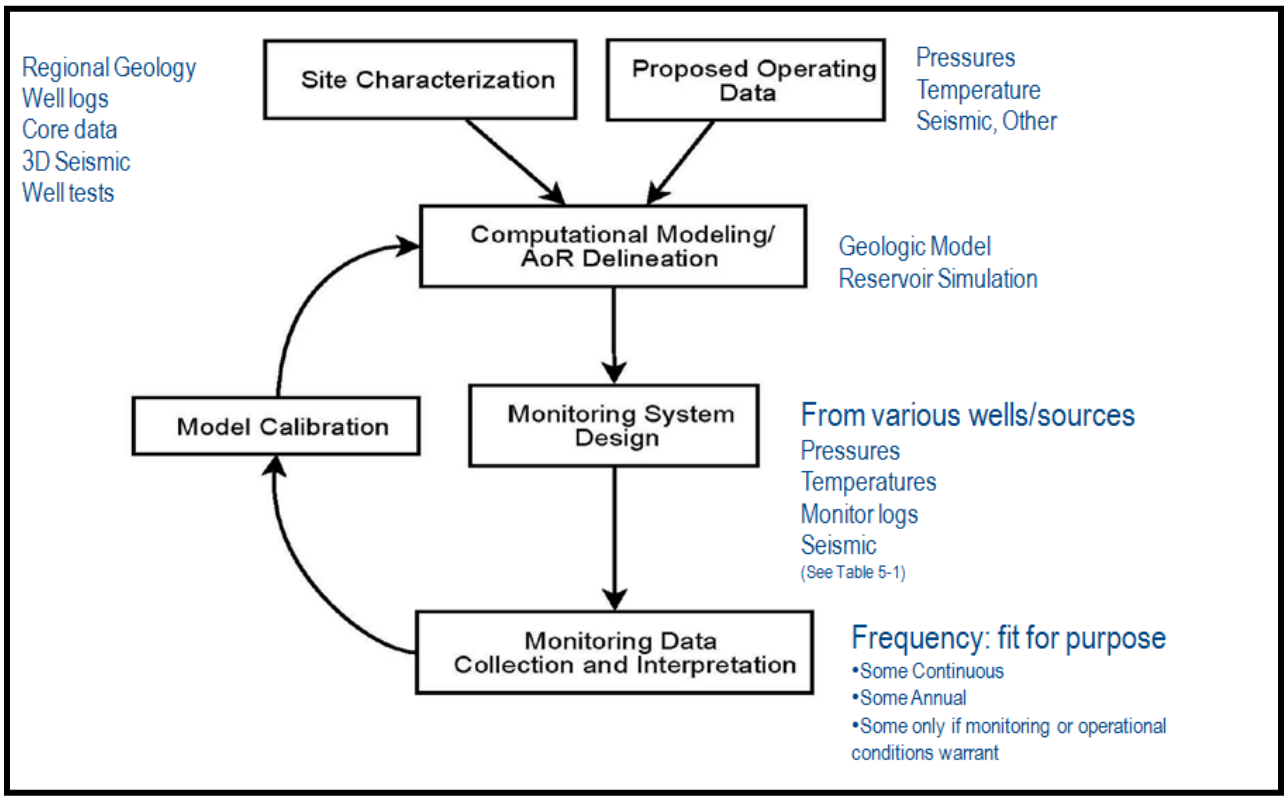


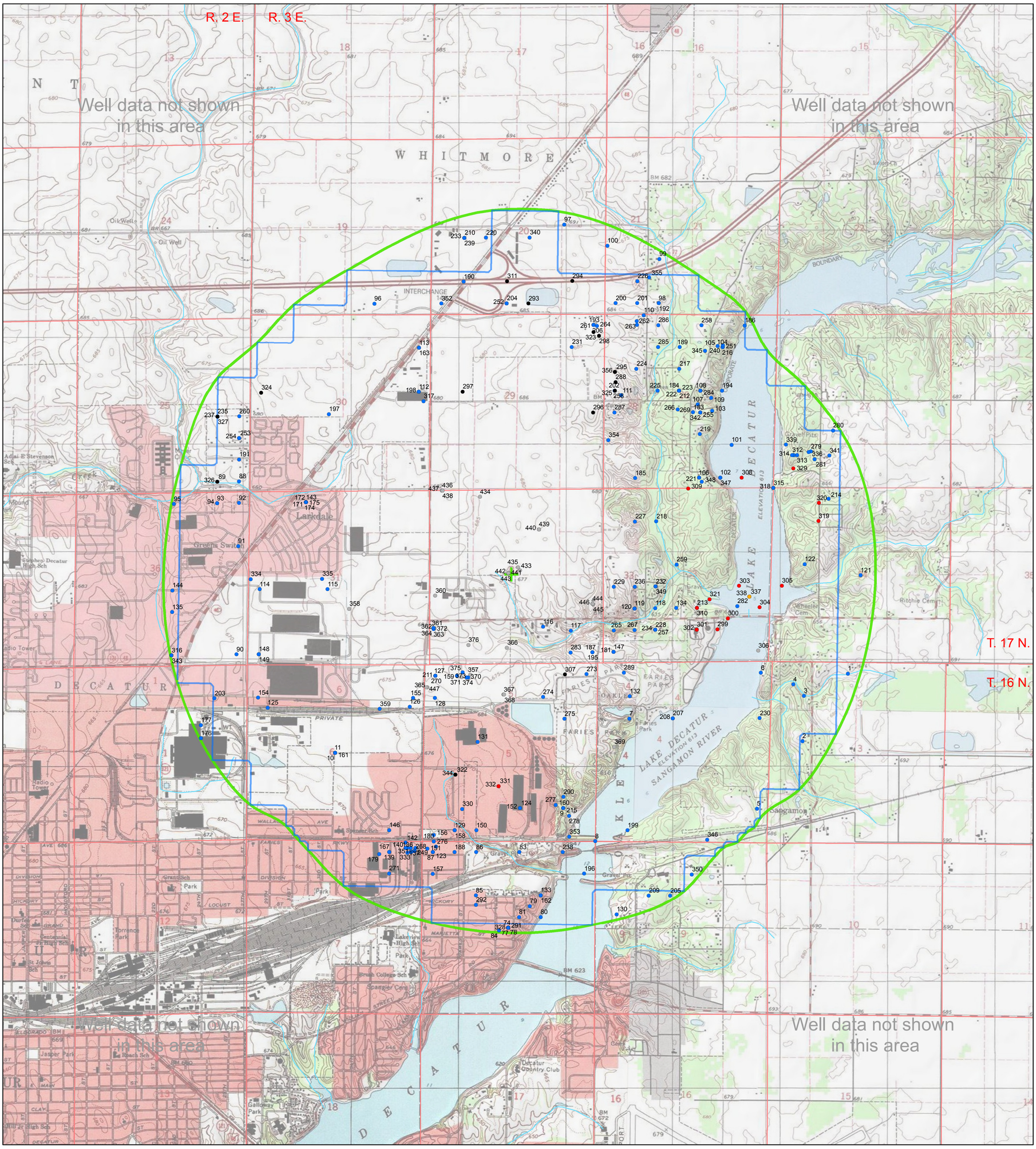
Figure 5- 24: AOR Corrective Action Plan Flowchart (Reference: Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators, US EPA 2011)

	IL ICCS Wells			IL IBDP Wells		
	CCS #2	VW #2	GM #2	CCS#1	VW#1	GW#1
Approx. Depth (ft)	7200	7200	3500	7200	7200	3500
Approx. Distance from CCS#2 (ft)	0	3000	300	3950	2950	4050
Capable of obtaining:						
Mt. Simon pressure(s)/temperature(s)	yes	yes	no	yes	yes	no
Mt. Simon fluid sampling	no	yes	no	no	yes	no
Ironton Galesville pressure/temperature	no	no	no	no	yes	no
Ironton Galesville sampling	no	no	no	no	yes	no
St. Peter pressure/temperature	no	no	yes	no	no	no
St. Peter fluid sampling	no	no	yes	no	no	no
RST Logging (near wellbore CO_2 detection)	yes	yes	yes	yes	yes	yes
Seismic Imaging of CO_2 plume	no	no	yes	no	no	yes
Annulus Pressure at surface	yes	yes	yes	yes	yes	yes
Injection Pressure at surface	yes	no	no	yes	no	no

* Deeper formations only. Shallow USDW monitoring not included in this table

Table 5-1: Monitoring System Capability for IL-ICCS Injection Site.

APPENDIX D – Area of Review and Well Data



- Water Well
- Oil Well
- Stratigraphic Test
- Engineering Boring
- Other / Unknown

- Area of Review
- MESPOP Predicted by Computer Simulations
- Center of Area of Review

Base: United States Geological Survey (USGS) 7.5-Minute Topographic Quadrangle map imagery and intermediate-scale DLG streams data, rescaled to 1:24,000. Topographic contour intverval is 5 feet. Tiled topographic map imagery is sourced from scanned paper maps, and is provided by Esri's USGS Topographic Map Service (available at: http://goto.arcgisonline.com/maps/USA_Topo_Maps).

N

0 0.5 1 Miles

Original Printed Scale 1:24,000

One inch = 2,000 feet

Wells and borings within the Area of Review surrounding the proposed IL-ICCS injection well at the ADM Site, Decatur, IL. The green outline shows the Area of Review, which was used to select well location coordinates from ISGS and ISWS databases as of May 10, 2011. Note that wells outside this area are not shown on this map. The well Map ID number shown for the purpose of this map can be cross-referenced to ISGS API Number and/or ISWS P-Number well identifiers in the accompanying data tables. Some wells may have multiple Map IDs assigned due to repeated drilling, testing, or sampling as identified in the source data tables. Updated January 19, 2012 to include drilled or planned ISGS/ICCS project wells.

Appendix D - Tabulation of Well Data Within the AoR

PERMIT MAP ID	API NUMBER	ISWSPNUM	DD_N83_X	DD_N83_Y	SECTION	TWP	TDIR	RNG	RDIR	owner	well number	driller	status	elev	ELEV REF	depth total last known	water from	depth open interval top	depth open interval bottom	cr pumping gpm	U16_X	U16_Y	abandoned	plugged	well type	date sealed	well use	ISWS well	inside_AoR
1		88163	-88.851988	39.878055	3	16N		03E		ADOLPH DODDEK						10							n	n	wd		DO	y	Y
2	121152109200	88164	-88.856777	39.872323	3	16	N	3	E	Melvin, David		Beasley	WATER	0		37	sand and gravel	22	25	0	341206.269	4415236.29			wd				Y
3		88165	-88.856742	39.876124	3	16N		03E		SAMUEL L MOORE						14							n	n	wd		DO	y	Y
4	121150033400	88166	-88.857915	39.877063	3	16	N	3	E	Brewer, Fred R.		Lentz Tony	WATER	0		94		0	0	0	341119.882	4415764.45			wd				Y
5		88167	-88.861586	39.866567	4	16N		03E		RALPH MILLER													n	n	wd		DO	y	Y
6		88168	-88.861461	39.877974	4	16N		03E		VICK ANDERSON		T R HANKS				70							n	n	wd		DO	y	Y
7		88169	-88.875676	39.873907	4	16N		03E		DR WOLFE		MASHBURN BROS				65							n	n	wd		DO	y	Y
8	121150033700	88177	-88.879117	39.863561	5	16	N	3	E	Starr, Louise		Lentz Tony	WATER	0		64		0	0	0	339275.15	4414303.67			wd				Y
9		88178	-88.882674	39.866299	5	16N		03E		DECATUR PARK DIST (GOLF COURSE		G C MASHBURN				101							n	n	x		IR	y	Y
10		88179	-88.907625	39.87052	6	16N		03E		C M BLANKENSHIP		LENTZ				75							n	n	wd		DO	y	Y
11		88180	-88.907625	39.87052	6	16N		03E		JIM SHONDEL		LENTZ				78							n	n	wd		DO	y	Y
12		88197	-88.888397	39.856152	8	16N		03E		DAVID L HOPKINS		LENTZ				55							n	n	wd		DO	y	Y
13		88203	-88.888397	39.856152	8	16N		03E		CHAS N DUNCAN		TONY LENTZ				84							n	n	wd		DO	y	Y
14		88204	-88.888397	39.856152	8	16N		03E		CHAS M DUNCAN		LENTZ				49							n	n	wd		DO	y	Y
15	121150037400	88205	-88.888397	39.856152	8	16	N	3	E	Sullivan, Helen Ward		Lentz Tony	WATER	0		75		0	0	0	338463.982	4413498.02			wd				Y
16	121150037100	88206	-88.888397	39.856152	8	16	N	3	E	Raiford, T. S.		Lentz Tony	WATER	0		92		0	0	0	338463.982	4413498.02			wd				Y
17		88207	-88.888397	39.856152	8	16N		03E		ROY CARR		TONY LENTZ				87							n	n	wd		DO	y	Y
18	121150035800	88208	-88.888397	39.856152	8	16	N	3	E	Blacet, Roy		Lentz Tony	WATER	0		84		0	0	0	338463.982	4413498.02			wd				Y
19		88209	-88.888397	39.856152	8	16N		03E		RUSSELL K SHAFFER		TONY LENTZ				110							n	n	wd		DO	y	Y
20		88210	-88.888397	39.856152	8	16N		03E		J E NICHOLS		LENTZ				60							n	n	wd		DO	y	Y
21		88212	-88.888397	39.856152	8	16N		03E		CHARLES DUNCAN		LENTZ				52							n	n	wd		DO	y	Y
22		88214	-88.888397	39.856152	8	16N		03E		E F LANGLEY		LENTZ				45							n	n	wd		DO	y	Y
23	121150037200	88216	-88.888397	39.856152	8	16	N	3	E	Rhodes, Howard		Lentz Tony	WATER	0		98		0	0	0	338463.982	4413498.02			wd				Y
24	121150036300	88217	-88.888397	39.856152	8	16	N	3	E	Gunter, John H.		Lentz Tony	WATER	0		90		0	0	0	338463.982	4413498.02			wd				Y
25	121150035700	88218	-88.888397	39.856152	8	16	N	3	E	Adams, Richard L.		Lentz Tony	WATER	0		90		0	0	0	338463.982	4413498.02			wd				Y
26		88220	-88.888397	39.856152	8	16N		03E		LESTER GEER		TONY LENTZ				85							n	n	wd		DO	y	Y
27		88221	-88.888397	39.856152	8	16N		03E		JAMES H SCHUERMAN		LENTZ				90							n	n	wd		DO	y	Y
28		88222	-88.888397	39.856152	8	16N		03E		CLAUDE THOMPSON		TONY LENTZ				110							n	n	wd		DO	y	Y
29		88223	-88.888397	39.856152	8	16N		03E		MARIAN GODWIN		TONY LENTZ				74							n	n	wd		DO	y	Y
30		88224	-88.888397	39.856152	8	16N		03E		MARION GODWIN		LENTZ				72							n	n	wd		DO	y	Y
31		88225	-88.888397	39.856152	8	16N		03E		MARION GODWIN		LENTZ				84							n	n	wd		DO	y	Y
32		88226	-88.888397	39.856152	8	16N		03E		BEN KING		LENTZ				73							n	n	wd		DO	y	Y
33		88227	-88.888397	39.856152	8	16N		03E		BEN KING		LENTZ				90							n	n	wd		DO	y	Y
34		88228	-88.888397	39.856152	8	16N		03E		BEN KING		LENTZ				83							n	n	wd		DO	y	Y
35		88229	-88.888397	39.856152	8	16N		03E		HILL		LENTZ				81							n	n	wd		DO	y	Y
36		88230	-88.888397	39.856152	8	16N		03E		BEN KING		LENTZ				83							n	n	wd		DO	y	Y
37		88232	-88.888397	39.856152	8	16N		03E		BEN KING		LENTZ				87							n	n	wd		DO	y	Y
38		88233	-88.888397	39.856152	8	16N		03E		ROARICK		LENTZ				35							n	n	wd		DO	y	Y
39		88234	-88.888397	39.856152	8	16N		03E		MARION GODWIN		LENTZ				85							n	n	wd		DO	y	Y
40		88235	-88.888397	39.856152	8	16N		03E		BEN KING		LENTZ				70							n	n	wd		DO	y	Y
41		88236	-88.888397	39.856152	8	16N		03E		JACK RUSS		LENTZ				85							n	n	wd		DO	y	Y
42		88237	-88.888397	39.856152	8	16N		03E		BEN KING		LENTZ				52							n	n	wd		DO	y	Y
43		88238	-88.888397	39.856152	8	16N		03E		MARION GODWIN		LENTZ				87							n	n	wd		DO	y	Y
44		88239	-88.888397	39.856152	8	16N		03E		MATTIOTA		LENTZ				80							n	n	wd		DO	y	Y
45		88240	-88.888397	39.856152	8	16N		03E		BEN KING		LENTZ				75							n	n	wd		DO	y	Y
46		88241	-88.888397	39.856152	8	16N		03E		MARION GODWIN		SPANGLER HTS				87							n	n	wd		DO	y	Y
47		88242	-88.888397	39.856152	8	16N		03E		J C VOGEL		LENTZ				73							n	n	wd		DO	y	Y
48		88243	-88.888397	39.856152	8	16N		03E		MARION GODWIN		LENTZ				79							n	n	wd		DO	y	Y
49		88244	-88.888397	39.856152	8	16N		03E		MARION GODWIN		LENTZ				79							n	n	wd		DO	y	Y
50		88245	-88.888397	39.856152	8	16N		03E		MARION GODWIN		LENTZ				85							n	n	wd		DO	y	Y
51		88246	-88.888397	39.856152	8	16N		03E		MARION GODWIN		LENTZ				74							n	n	wd		DO	y	Y
52		88247	-88.888397	39.856152	8	16N		03E		CARL T GEORGE		LENTZ				61							n	n	wd		DO	y	Y
53		88248	-88.888397	39.856152	8	16N		03E		RAY LITTLE		LENTZ				95							n	n	wd		DO	y	Y
54		88249	-88.888397	39.856152	8	16N		03E		KOSSIECK		LENTZ				82							n	n	wd		DO	y	Y
55		88250	-88.888397	39.856152	8	16N		03E		SUFFERN		LENTZ				82							n	n	wd		DO	y	Y
56		88251	-88.888397	39.856152	8	16N		03E		SPANGLER		LENTZ				85							n	n	wd		DO	y	Y
57		88252	-88.888397	39.856152	8	16N		03E		TOMMY THOMPSON		LENTZ				104							n	n	wd		DO	y	Y

PERMIT MAP ID	API NUMBER	ISWSPNUM	DD_N83_X	DD_N83_Y	SECTION	TWP	TDIR	RNG	RDIR	owner	well number	driller	status	elev	ELEV REF	depth total last known	water from	depth open interval top	depth open interval bottom	cr pumping gpm	U16_X	U16_Y	abandoned	plugged	well type	date sealed	well use	ISWS well	inside_AoR
58		88253	-88.888397	39.856152	8	16N		03E		M GODWIN		LENTZ				86							n	n	wd		DO	y	Y
59		88254	-88.888397	39.856152	8	16N		03E		MARION GODWIN		LENTZ				88							n	n	wd		DO	y	Y
60		88255	-88.888397	39.856152	8	16N		03E		ED STOLLY		LENTZ				84							n	n	wd		DO	y	Y
61		88256	-88.888397	39.856152	8	16N		03E		WILLARD JENKINS		LENTZ				75							n	n	wd		DO	y	Y
62		88257	-88.888397	39.856152	8	16N		03E		ERNEST E SPINNER		LENTZ				60							n	n	wd		DO	y	Y
63		88258	-88.888397	39.856152	8	16N		03E		HANKS		LENTZ											n	n	wd		DO	y	Y
64		88259	-88.888397	39.856152	8	16N		03E				LENTZ				45							n	n	wd		DO	y	Y
65		88260	-88.888397	39.856152	8	16N		03E		DON DEFOREST		LENTZ				64							n	n	wd		DO	y	Y
66		88261	-88.888397	39.856152	8	16N		03E		WILLIAM N MALONE		LENTZ				76							n	n	wd		DO	y	Y
67		88262	-88.888397	39.856152	8	16N		03E		WAYNE & GENE CAMPBELL		LENTZ				80							n	n	wd		DO	y	Y
68		88263	-88.888397	39.856152	8	16N		03E		ILLINI REALTY		LENTZ				58							n	n	wd		DO	y	Y
69		88264	-88.888397	39.856152	8	16N		03E		THOMAS HALL		LENTZ				93							n	n	wd		DO	y	Y
70		88265	-88.888397	39.856152	8	16N		03E		DON ETNIER		LENTZ				83							n	n	wd		DO	y	Y
71		88266	-88.888397	39.856152	8	16N		03E		RUSSELL OBRIEN		LENTZ				48							n	n	wd		DO	y	Y
72		88267	-88.888397	39.856152	8	16N		03E		COLE		LENTZ				76							n	n	wd		DO	y	Y
73		88268	-88.888397	39.856152	8	16N		03E		GEORGE M PRUST		LENTZ				52							n	n	wd		DO	y	Y
74		88269	-88.888397	39.856152	8	16N		03E		GLEN STEWART		LENTZ				76							n	n	wd		DO	y	Y
75		88270	-88.888397	39.856152	8	16N		03E		DOYLE WILLIAMS		LENTZ				40							n	n	wd		DO	y	Y
76		88271	-88.888397	39.856152	8	16N		03E		YORK		LENTZ				102							n	n	wd		DO	y	Y
77		88272	-88.888397	39.856152	8	16N		03E		CARL GEORGE		LENTZ				74							n	n	wd		DO	y	Y
78		88273	-88.888397	39.856152	8	16N		03E		DURBIN						38							n	n	wd		DO	y	Y
79	121150086400	88274	-88.886074	39.858003	8	16	N	3	E	Scammahorn, W. W.	1	Hanks, T. R.	WATER	0		84	sand and gravel	79	84	25	338667.043	4413699.28			wd				Y
80		88277	-88.884882	39.857119	8	16N		03E		J F WILMETH		T R HANKS				60							n	n	wd		DO	y	Y
81		88282	-88.887235	39.857079	8	16N		03E		HARRY BOUCH		L R BURT				74							n	n	wd		DO	y	Y
82	121150036800	88283	-88.888397	39.856152	8	16	N	3	E	Penn, Thomas		Lentz Tony	WATER	0		40		0	0	0	338463.982	4413498.02			wd				Y
83		88284	-88.887338	39.862511	8	16N		03E		N CARNELL		MASHBURN BROS				102							n	n	wd		DO	y	Y
84	121150036900	88296	-88.889387	39.85592	8	16	N	3	E	Perkins, Donald D.		Lentz Tony	WATER	0		93		0	0	0	338378.746	4413474.06			wd				Y
85		88300	-88.89198	39.858806	8	16N		03E		J HANKS		TONY LENTZ				80							n	n	wd		DO	y	Y
86		88301	-88.892045	39.862431	8	16N		03E		GLACKEN		T R HANKS				228							n	n	wd		DO	y	Y
87	121150037000	88311	-88.896752	39.862347	8	16	N	3	E	Powell, Doc.		Woollen Brothers	WATER	0		108	sand and gravel	104	108	8	337763.831	4414200.79			wd				Y
88		89002	-88.918714	39.893105	25	17N		02E		JOHN HARRISON		ASHMORE				81							n	n	wd		DO	y	Y
89		89003	-88.921072	39.893037	25	17N		02E		BENSHAW SCHOOL						82							n	n	x		SC	y	Y
90		89400	-88.918583	39.878592	36	17N		02E		EDGAR ALEXANDER						23							n	n	wd		DO	y	Y
91		89401	-88.918655	39.887662	36	17N		02E		J F BURDINE						40							n	n	wd		DO	y	Y
92		89402	-88.918682	39.891289	36	17N		02E		JOSEPH BLOIR		WEBB				18							n	n	wd		DO	y	Y
93		89403	-88.921044	39.891224	36	17N		02E		JOHN ALBERTS						18							n	n	wd		DO	y	Y
94		89404	-88.921044	39.891224	36	17N		02E		BILL MASON		MASHBURN BROS				85							n	n	wd		DO	y	Y
95		89405	-88.92576	39.891087	36	17N		02E		O E SLOAN						13							n	n	wd		DO	y	Y
96	121152194500	89447	-88.904385	39.908234	19	17	N	3	E	Duncan, Tim	1	Mashburn, Grover C. Jr.	WATER	0		127	sand	120	127	15	337219.51	4419308.09			wd				Y
97	121152191300	89450	-88.883907	39.915219	20	17	N	3	E	Swearingen, Rick	1	Mashburn, Bruce E.	WATER	640 GL		134	sand & gravel	129	134	15	338986.377	4420046.28			wd				Y
98	121152116900	89453	-88.873433	39.908788	21	17	N	3	E	Dickey, Jack		Beasley	WATER	0		40	gravel	15	32	0	339866.644	4419313.6			wd				Y
99		89455	-88.873461	39.912492	21	17N		03E		D H NIXON		MASHBURN BROS				96							n	n	wd		DO	y	Y
100	121152124900	89459	-88.879154	39.913524	21	17	N	3	E	Varner, Cecil	1	Mashburn Brothers	WATER	0		121	sand	110	121	15	339388.672	4419849.57			wd				Y
101	121152191500	89497	-88.865171	39.897033	28	17	N	3	E	Smalley, Gary	1	Mashburn, Grover C. Jr.	WATER	0		105	sand	96	105	10	340545.634	4417994.02			wd				Y
102	121152124800	89498	-88.866325	39.894279	28	17	N	3	E	Radleng, Tom		Beasley	WATER	0		78	gravel	24	74	0	340440.583	4417690.39			wd				Y
103	121150102100	89499	-88.867367	39.899868	28	17	N	3	E	Taylor, George	1	Hanks, T. R.	WATER	0		86	sand & gravel	77	80	15	340364.466	4418312.63			wd				Y
104		89500	-88.866362	39.905214	28	17N		03E		R E KINZER 1		WOOLLEN BROS				103							n	n	wd		DO	y	Y
105	121150100200	89501	-88.866906	39.905286	28	17	N	3	E	Kinzer, R. E.	2	Woollen Earl D	WATER	0		91	sand	84	91	10	340416.452	4418913.19			wd				Y
106		89502	-88.86864	39.894231	28	17N		03E		RONALD C ALSTAD						112							n	n	wd		DO	y	Y
107	121150103500	89503	-88.868947	39.900365	28	17	N	3	E	Klingler, Herb	1	Hanks, T. R.	WATER	0		82	sand	74	77	6	340230.542	4418370.62			wd				Y
108		89504	-88.868686	39.901531	28	17N		03E		HAROLD CONWAY 1		T R HANKS				105							n	n	wd		DO	y	Y
109	121150100700	89505	-88.867519	39.90094	28	17	N	3	E	Conway, Harold	1	Hanks, T. R.	WATER	670 TM		103	sand and gravel	94	98	25	340353.959	4418431.89			wd				Y
110	121150093200	89506	-88.87503	39.907745	28	17	N	3	E	Federal Housing	1	Mashburn, B.E.	WATER	655 GL		125	sand & gravel	118	125	12	339727.699	4419200.7			wd				Y
111	121150096400	89507	-88.877294	39.901	28	17	N	3	E	Conway, M. D.	1	Hanks, T. R.	WATER	0		110	gray sand	105	108	10	339518.424	4418456.07			wd				Y
112	121150010200	89508	-88.899348	39.900935	30	17N		03E		RAY H CRISTIAN		T R HANKS				113							n	n	wd		DO	y	Y
113	121150092800	89509	-88.899427	39.904631	30	17	N	3	E	Rockhold, Max		Dement Ray Well Co	WATER	0		112	sand	107	112	6	337634.822	4418899.13			wd				Y
114		89510	-88.916216	39.884093	31	17N		03E		MAX ROCKHOLD		RAY DEMENT				115							n	n	wd		DO	y	Y
115		89511	-88.908824	39.88423	31	17N		03E		MAX ROCKHOLD		RAY DEMENT				117							n	n	wd		DO	y	Y
116		89512	-88.885283	39.881461	32	17N		03E		CLARK		LENTZ				71							n	n	wd		DO	y	Y

PERMIT MAP ID	API NUMBER	ISWSPNUM	DD_N83_X	DD_N83_Y	SECTION	TWP	TDIR	RNG	RDIR	owner	well number	driller	status	elev	ELEV REF	depth total last known	water from	depth open interval top	depth open interval bottom	cr pumping gpm	U16_X	U16_Y	abandoned	plugged	well type	date sealed	well use	ISWS well	inside_AoR
117		89513	-88.882264	39.881173	32	17N		03E		ACE DROLL		MASHBURN BROS				45							n	n	wd		DO	y	Y
118		89515	-88.873103	39.883211	33	17N		03E		GILBERT GRUBBS		MASHBURN BROS				80							n	n	wd		DO	y	Y
119		89516	-88.875368	39.88316	33	17N		03E		CAMPBELL		MASHBURN				98							n	n	wd		DO	y	Y
120		89517	-88.875368	39.88316	33	17N		03E		JAMES NEESE		MASHBURN BROS				84							n	n	wd		DO	y	Y
121		89518	-88.850844	39.886326	34	17N		03E		BOONE		LENTZ				95							n	n	wd		DO	y	Y
122		89522	-88.856945	39.887168	34	17N		03E		HERM BOEHM (ROBERTA RUPERT)		MASHBURN BROS				55							n	n	wd		DO	y	Y
123		89763	-88.896752	39.862347	8	16N		03E		AMERICAN BAKERY		BRUCE MASHBURN				98							n	n	wc		IC	y	Y
124		89773	-88.887381	39.86621	5	16N		03E		ARCHER DANIELS MIDLAND CO		MASHBURN BROS				111							n	n	wc		IC	y	Y
125	121152241700	89792	-88.915063	39.874175	6	16	N	3	E	Caterpiller Tractor TH	1	Burt, Luther	WTST	0		110		0	0	0	336225.66	4415547.09	y		wc				Y
126	121152241800	89793	-88.899596	39.874528	6	16	N	3	E	Caterpiller Tractor T	2	Burt, Luther	WTST	0		125		0	0	0	337549.304	4415558.03	y		wc				Y
127		89813	-88.896904	39.87715	5	16N		03E		DECATUR BOTTLING CO		G C MASHBURN				70							n	n	wc		IC	y	Y
128		89814	-88.896888	39.875295	5	16N		03E		DECATUR BOTTLING CO		MASHBURN BROS				71							n	n	wc		IC	y	Y
129		89815	-88.894422	39.86422	5	16N		03E		DECATUR BOTTLING CO		MASHBURN				70							n	n	wc		IC	y	Y
130	121150037700	89854	-88.876613	39.85747	9	16	N	3	E	Decatur Park District		Woollen Brothers	WATER	0		78		0	0	0	339475.138	4413623.08			wc				Y
131	121152180200	89859	-88.892142	39.871694	5	16	N	3	E	Ecoff Trucking, Inc.		Reynolds, Joseph R.	WATER	0		70	sandy clay & sa	10	70	0	337986.823	4415846.24			wc				Y
132		89869	-88.875688	39.875784	4	16N		03E		DECATUR PARK DIST						102							n	n	x		PK	y	Y
133		89875	-88.884916	39.85893	8	16N		03E		DISABLED VETERANS		MASHBURN BROS				37							n	n	wd		DO	y	Y
134		89905	-88.870835	39.883263	33	17N		03E		HIGH COOK CAN CO		MASHBURN BROS				77							n	n	wc		IC	y	Y
135		89921	-88.925688	39.882014	36	17N		02E		I & S DRY WALL		MASHBURN BROS				17							n	n	wc		IC	y	Y
136	121150034000	89932	-88.898651	39.862674	7	16	N	3	E	Spencer Kellogg & Sons,	1	Burt, Luther R.	WATER	0		97		0	0	440	337602.163	4414240.54			wc				Y
137	121150034100	89933	-88.899185	39.862672	7	16	N	3	E	Spencer Kellogg & Sons,Inc.	2	Burt, Luther R.	WATER	0		96		0	0	0	337556.481	4414241.29			wc				Y
138	121150034500	89934	-88.899543	39.862668	7	16	N	3	E	Spencer Kellogg & Sons,Inc.	6	Burt, Luther R.	WATER	0		88		0	0	0	337525.849	4414241.49			wc				Y
139		89935	-88.901512	39.8623	7	16N		03E		SPENCER KELLOGG & SONS INC						87							n	n	wc		IC	y	Y
140	121150034200	89936	-88.899722	39.862666	7	16	N	3	E	Spencer Kellogg & Sons,Inc.	3	Burt, Luther R.	WATER	0		97		0	0	350	337510.532	4414241.6			wc				Y
141	121150034300	89937	-88.899536	39.862254	7	16	N	3	E	Spencer Kellogg & Sons,Inc.	4	Burt, Luther R.	WTST	0		115		0	0	0	337525.471	4414195.53	y		wc				Y
142	121150034400	89938	-88.899733	39.863108	7	16	N	3	E	Spencer Kellogg & Sons,Inc.	5	Burt, Luther R.	WATER	0		99		0	0	0	337510.635	4414290.68			wc				Y
143		89944	-88.911382	39.891452	31	17N		03E		LARKDALE SWIM CLUB		MASHBURN BROS				98							n	n	x		IR	y	Y
144		89976	-88.925705	39.883827	36	17N		02E		MORGAN SASH & DOOR		T R HANKS				122				10.00			n	n	wc		IC	y	Y
145		90047	-88.899123	39.862318	7	16N		03E		SHELLSBARGER GRAIN PROD CO		L R BURT				95							n	n	wc		IC	y	Y
146		90112	-88.90154	39.864127	6	16N		03E		VET ADMIN		DEMENT				54							n	n	wd		DO	y	Y
147		90113	-88.877539	39.879467	33	17N		03E		VET ADMIN		DEMENT				85							n	n	wd		DO	y	Y
148		90129	-88.916165	39.878647	31	17N		03E		W S O Y RADIO STATION		LEONARD NEWBERRY				37							n	n	wc		IC	y	Y
149		90130	-88.916165	39.878647	31	17N		03E		W S O Y RADIO STATION		LEONARD NEWBERRY				87							n	n	wc		IC	y	Y
150	121152218000	190939	-88.892069	39.864264	5	16	N	3	E	Morris, Jerry		Reynolds, Joseph R.	WATER	0		62		0	0	0	338168.917	4414405.08			wd				Y
151	121150084600	200880	-88.897358	39.862662	8	16	N	3	E	American Bakery	2	Mashburn, B.E.	WATER	640 GL		98	sand and gravel	82	98	12	337712.737	4414236.86			wc				Y
152		200906	-88.887381	39.86621	5	16N		03E		ARCHER DANIELS MIDLAND CO		LENTZ				111							n	n	wc		IC	y	Y
153		200918	-88.888397	39.856152	8	16N		03E		BAUER AUTO WRECKING		LENTZ				93							n	n	wc		IC	y	Y
154		200958	-88.916131	39.874992	6	16N		03E		CATERPILLAR TRACTOR CO TEST		BURT				110							n	n	wc		IC	y	Y
155		200959	-88.899267	39.87525	6	16N		03E		CATERPILLAR TRACTOR CO TEST		BURT				125							n	n	wc		IC	y	Y
156	121152211100	200979	-88.896697	39.863807	5	16	N	3	E	Decatur Bottling Co (Rest. 4)	1	Mashburn, Grover C. Jr.	WATER	0		70	sand	0	70	60	337771.976	4414362.75			wc				Y
157		200980	-88.896721	39.860536	8	16N		03E		DECATUR BOTTLING						71							n	n	wc		IC	y	Y
158		200981	-88.894422	39.86422	5	16N		03E		DECATUR BOTTLING (NEW TESTWELL						70							n	n	wc		IC	y	Y
159		201021	-88.894554	39.877207	5	16N		03E		ENCOFF TRUCKING		REYNOLDS				70							n	n	wc		IC	y	Y
160		201036	-88.882674	39.866299	5	16N		03E		DECATUR PARK DIST FARIES PARK		MASHBURN				98							n	n	x		PK	y	Y
161		201042	-88.907625	39.87052	6	16N		03E		DECATUR SAND GRAVEL TEST						92							n	n	wc		IC	y	Y
162		201045	-88.884916	39.85893	8	16N		03E		DISABLED VETERANS		MASHBURN				37							n	n	wc		NC	y	Y
163	121152126500	201095	-88.899427	39.904631	30	17	N	3	E	Glatz Truck & Trailer		Reynolds, Joseph	WATER	0		60	sand & gravel	56	60	0	337634.822	4418899.13			wc				Y
164		201188	-88.899123	39.862318	7	16N		03E		SPENCER KELLOG CO		BURT				97							n	n	wc		IC	y	Y
165		201189	-88.899123	39.862318	7	16N		03E		SPENCER KELLOG CO		BURT				94							n	n	wc		IC	y	Y
166		201190	-88.899123	39.862318	7	16N		03E		SPENCER KELLOG CO		BURT				88							n	n	wc		IC	y	Y
167		201191	-88.901512	39.8623	7	16N		03E		SPENCER KELLOG CO RETURN WELL						87							n	n	wc		IC	y	Y
168		201192	-88.899123	39.862318	7	16N		03E		SPENCER KELLOG CO SUPPLY WELL4		BURT				97							n	n	wc		IC	y	Y
169		201199	-88.911382	39.891452	31	17N		03E		LARKDALE SWIM CLUB DRY HOLE		MASHBURN				80							n	n	wc		NC	y	Y
170		201200	-88.911382	39.891452	31	17N		03E		LARKDALE SWIM CLUB TEST HOLES		MASHBURN				85							n	n	wc		NC	y	Y
171		201201	-88.911382	39.891452	31	17N		03E		LARKDALE SWIM CLUB TEST HOLES		MASHBURN				83							n	n	wc		NC	y	Y
172		201202	-88.911382	39.891452	31	17N		03E		LARKDALE SWIM CLUB TEST HOLES		MASHBURN				95							n	n	wc		NC	y	Y
173		201203	-88.911382	39.891452	31	17N		03E		LARKDALE SWIM CLUB TEST HOLES		MASHBURN				80							n	n	wc		NC	y	Y
174		201204	-88.911382	39.891452	31	17N		03E		LARKDALE SWIM CLUB TEST HOLES		MASHBURN				120							n	n	wc		NC	y	Y
175		201205	-88.911382	39.891452	31	17N		03E		LARKDALE SWIM CLUB TEST HOLES		MASHBURN				30							n	n	wc		NC	y	Y

PERMIT MAP ID	API NUMBER	ISWSPNUM	DD_N83_X	DD_N83_Y	SECTION	TWP	TDIR	RNG	RDIR	owner	well number	driller	status	elev	ELEV REF	depth total last known	water from	depth open interval top	depth open interval bottom	cr pumping gpm	U16_X	U16_Y	abandoned	plugged	well type	date sealed	well use	ISWS well	inside_AoR
176	121150018800	201360	-88.922267	39.871492	1	16	N	2	E	Ralston Purina Co Test	2	Layne Western Co., Inc.	WTST	0		112		0	0	0	335603.131	4415262.51	y		wc				Y
177	121150018900	201362	-88.922297	39.872594	1	16	N	2	E	Ralston Purina Co Test	3	Layne Western Co., Inc.	WTST	0		114		0	0	0	335603.197	4415384.89	y		wc				Y
178		201380	-88.899123	39.862318	7	16N		03E		SHELLBARGER GRAIN PROD		BURT				95							n	n	wc		IC	y	Y
179	121150035600	201476	-88.902578	39.862093	7	16	N	3	E	A. E. Staley Mfg. Co. test	29	Griffy, Cecil D.	WTST	0		96		0	0	0	337264.879	4414183.19	y		wc				Y
180	121150037300	201478	-88.896691	39.863255	8	16	N	3	E	A. E. Staley Mfg. Co. test	30	Griffy, Cecil D.	WTST	0		109		0	0	0	337771.189	4414301.47	y		wc				Y
181		201542	-88.877539	39.879467	33	17N		03E		VET ADMIN		DEMENT				85							n	n	wc		NC	y	Y
182	121152203300	210125	-88.871019	39.901494	28	17	N	3	E	Smalley, Gary	1	Mashburn, Grover C. Jr.	WATER	0		110	sand	100	110	10	340056.029	4418499.65			wd				Y
183	121152205300	210153	-88.868673	39.899707	28	17	N	3	E	Grigg, Ron	1	Mashburn, Grover C. Jr.	WATER	0		121	sand	108	121	15	340252.439	4418297.09			wd				Y
184	121152220800	210385	-88.871019	39.901494	28	17	N	3	E	Allen, Raymond E.	1	Mashburn, Grover C. Jr.	WATER	0		105	sand	99	105	15	340056.029	4418499.65			wd				Y
185	121152220900	218728	-88.875586	39.894088	28	17	N	3	E	Vahlkamp, Steve		Luttrell, Gerald Dean	WATER	0		82	fine sand	75	82	0	339648.328	4417685.78			wd				Y
186	121152221000	218721	-88.864016	39.907065	28	17	N	3	E	Wahlkamp, Frederick		Luttrell, Gerald Dean	WATER	0		73		0	0	0	340667.629	4419105.5			wd				Y
187	121152221200	218729	-88.87985	39.879411	32	17	N	3	E	Sebens, Gary		Luttrell, Gerald Dean	WATER	0		38	yellow sand	12	17	0	339249.468	4416064.32			wd				Y
188	121152218100	221433	-88.894399	39.862388	8	16	N	3	E	Anchor Inn		Luttrell, Gerald Dean	WATER	0		54	sand & gravel	48	54	0	337965.202	4414201.07			wc				Y
189	121152228700	229739	-88.87105	39.905149	28	17	N	3	E	Doty, Bob		Mashburn, Grover C. Jr.	WATER	0		86	sand	81	86	0	340061.881	4418905.4			wd				Y
190		231047	-88.894731	39.910252	20	17N		03E		WILLIAM BROWN		LUTTRELL				62							n	n	wd		DO	y	Y
191	121152219200	231496	-88.918756	39.894925	25	17	N	2	E	Woodroff, Herb		Luttrell, Gerald Dean	WATER	0		60		0	0	0	335959.296	4417857.1			wd				Y
192	121152220300	231497	-88.873433	39.908788	21	17	N	3	E	Meier, Emery	1	Luttrell, Gerald Dean	WATER	0		78	sand	71	78	15	339866.644	4419313.6			wd				Y
193	121152236400	243223	-88.880475	39.906846	29	17	N	3	E	Hanna, William H.	1	Ready, Dale	WATER	0		136		0	0	10	339260.144	4419110.7			wd				Y
194	121152236300	243225	-88.866349	39.901568	28	17	N	3	E	Smalley, Gary	1	Mashburn, Grover C. Jr.	WATER	0		101	sand	96	101	12	340455.441	4418499.51			wd				Y
195	121152236600	261218	-88.87985	39.879411	32	17	N	3	E	Stiles, Anna		Luttrell, Gerald Dean	WATER	0		56	gray sand & gra	51	56	0	339249.468	4416064.32			wd				Y
196	121152252700	275751	-88.88024	39.860824	8	16	N	3	E	Price, Lee		Mashburn, Robert	WATER	0		91	sand	47	91	12	339172.698	4414001.89			wd				Y
197	121152221100	280757	-88.909091	39.898892	30	17	N	3	E	Schwarze, R.D.		Luttrell, Gerald Dean	WATER	0		33		0	0	0	336795.057	4418279.73			wd				Y
198	121152236500	285488	-88.899348	39.900935	30	17	N	3	E	Jan-San Supply		Luttrell, Gerald Dean	WATER	0		48	yellow sand	40	48	0	337632.848	4418488.73			wc				Y
199	121152258400	289868	-88.875623	39.864528	4	16	N	3	E	Kiger, Dave		Luttrel, James	WATER	0		30		0	0	0	339576.271	4414404.73			wd				Y
200	121152268900	293158	-88.87814	39.908727	21	17	N	3	E	Hawthorne Homes Inc.		Luttrell, James	WATER	0		70		0	0	0	339464.141	4419315.28			wc				Y
201	121152269000	297600	-88.875788	39.908756	21	17	N	3	E	Lane, Richard E.		Luttrell, James	WATER	0		61		0	0	0	339665.261	4419314.28			wd				Y
202	121152269200	297602	-88.878026	39.901382	28	17	N	3	E	Kelly, Franklin Jr.		Luttrell, James	WATER	0		82		0	0	0	339456.736	4418499.79			wd				Y
203	121152198100	297743	-88.920871	39.874869	1	16	N	2	E	Sams, Lloyd		Luttrell, Gerald Dean	WATER	0		65	sand	44	47	0	335730.588	4415634.79			wd				Y
204	121152264600	299527	-88.889979	39.908508	20	17	N	3	E	Shur Co.		Mashburn, Robert	WATER	0		145	dry	0	0	0	338451.611	4419312.33			wc				Y
205	121152271600	303144	-88.870833	39.85912	9	16	N	3	E	Russell, Florence		Luttrell, James	WATER	0		45		0	0	0	339973.423	4413795.86			wd				Y
206	121152273800	303944	-88.880475	39.906846	29	17	N	3	E	Smalley, Gary		Mashburn, Robert	WATER	0		101	sand	98	101	12	339260.144	4419110.7			wd				Y
207	121152273200	304871	-88.87095	39.873995	4	16	N	3	E	Beck, Mathew A.		Luttrell, James	WATER	0		19		0	0	0	339997.987	4415447.17			wd				Y
208	121152273300	304872	-88.87095	39.873995	4	16	N	3	E	Bliefnick, Amy		Luttrell, James	WATER	0		43		0	0	0	339997.987	4415447.17			wd				Y
209	121152279600	309131	-88.873175	39.859097	9	16	N	3	E	Kopetz Mfg., Inc.		Reynolds Well Drilling	WATER	0		69	sand gravel	65	69	0	339773.028	4413797.5			wc				Y
210	121152281100	311493	-88.89476	39.913928	20	17	N	3	E	Omni Erection, Inc./Reynolds		Mashburn, Robert	WATER	0		136	sand	120	136	12	338055.692	4419922.61			wc				Y
211	121152283500	312842	-88.896904	39.87715	5	16	N	3	E	Acher Daniels Midland	3 East	Dowell, S.L.	WATER	0		130		0	0	1000	337785.714	4415844.18			wc				Y
212	121152284500	314763	-88.871019	39.901494	28	17	N	3	E	Kostenski, Robert		Mashburn, Robert	WATER	0		110	sand	100	110	15	340056.029	4418499.65			wd				Y
213	121152284600	314787	-88.86857	39.883314	33	17	N	3	E	Yaegel, Carl		Gaza, John Edward	WATER	0		98	top of casing	67	98	15	340223.172	4416477.31			wd				Y
214	121152284700	314790	-88.854497	39.892669	34	17	N	3	E	Maples, Henry		Gaza, John Edward	WATER	0		92	top of casing	60	92	15	341448.157	4417490.62			wd				Y
215	121152283400	319507	-88.882674	39.866299	5	16	N	3	E	Archer Daniels Midland	4	Dowell, S.L.	WATER	0		120		0	0	1000	338977.295	4414613.99			wc				Y
216	121152287400	322494	-88.866362	39.905214	28	17	N	3	E	Meador, James & Susan	1	Sims, R. Marc Jr.	WATER	0		107	sand	99	107	10	340462.789	4418904.23			wd				Y
217	121152287500	323334	-88.871035	39.903321	28	17	N	3	E	Grubbs, Curtis		Gaza, John Edward	WATER	0		83	top of casing	40	83	18	340058.911	4418702.47			wd				Y
218	121152287700	323336	-88.873217	39.89049	33	17	N	3	E	Walker, Tim		Gaza, John Edward	WATER	0		55	top of casing	30	55	15	339842.499	4417282.16			wd				Y
219	121152291200	325421	-88.868661	39.89788	28	17	N	3	E	Cheatham, Arthur & Gloria		Gaza, John Edward	WATER	0		112	top of casing	58	112	10	340249.22	4418094.28			wd				Y
220	121152290200	326095	-88.892394	39.913979	20	17	N	3	E	Oasis Truckstop		Mashburn, Robert	WATER	0		134	sand	118	134	20	338258.046	4419923.98			wc				Y
221	121152290000	326575	-88.86864	39.894231	28	17	N	3	E	Radley, Alvira M.		Balding, Shane	WATER	0		102	top of casing	57	102	10	340242.54	4417689.2			wd				Y
222	121152296300	331769	-88.871019	39.901494	28	17	N	3	E	McCarty, Ron		Luttrell, James	WATER	0		95		0	0	0	340056.029	4418499.65			wd				Y
223	121152297100	334269	-88.871019	39.901494	28	17	N	3	E	McCarty, Ron		Mashburn, Robert	DRYP	0		140	dry hole	0	0	0	340056.029	4418499.65	y	y	wd				Y
224	121152298000	334337	-88.875716	39.90325	28	17	N	3	E	Critchelow, Frank		Mashburn, Robert	WATER	0		97	sand	94	97	12	339658.576	4418702.99			wd				Y
225	121152298300	334340	-88.873356	39.901457	28	17	N	3	E	Brelsford, Stanley		Balding, Shane	WATER	0		104	top of casing	60	104	18	339856.152	4418499.73			wd				Y
226	121152298800	334884	-88.875804	39.910608	21	17	N	3	E	Williams, Robert & Sheri		Mashburn, Robert	WATER	0		123	sand	117	123	12	339668.213	4419519.88			wd				Y
227	121152303200	336745	-88.875518	39.890442	33	17	N	3	E	Reidelberger, Bruce		Balding, Shane	WATER	0		82	sand	77	82	30	339645.642	4417280.96			wd				Y
228	121152307200	342220	-88.873073	39.88139	33	17	N	3	E	Kerwood, Don	1	S & J Well Drilling	WATER	0		60	sand	50	60	40	339833.629	4416271.81			wd				Y
229	121152307300	342222	-88.877681	39.88493	33	17	N	3	E	Klepzig, Aaron	1	S & J Well Drilling	WATER	0		105	sand	95	105	25	339447.834	4416673.02			wd				Y
230	121152307400	342223	-88.861502	39.874171	4	16	N	3	E	Beck, Matthew	1	S & J Well Drilling	WATER	0		40	sand	25	40	40	340806.43	4415449.83			wd				Y
231	121152306700	342505	-88.88281	39.904962	29	17	N	3	E	Smalley, Jeff	1	Mashburn, Robert	WATER	0		102	sand	96	102	15	339056.129	4418905.78			wd				Y
232	121152306000	343558	-88.87313	39.88503	33	17	N	3	E	Ball, David		S & J Well Drilling	WATER	0		82	sand	72	82	12	339837.228	4416675.95			wd				Y
233	121152304000	344361	-88.89476	39.913928	20	17	N	3	E	TCR Systems		Mashburn, Robert	WATER	0		121	sand	117	121	12	338055.692	4419922.61			wc				Y
234	121152308700	345167	-88.873073	39.88139	33	17	N	3	E	Schaub, Jerry & Donna	1	Mashburn, Robert	WATER	0		91	sand	72	91	12	339833.629	4416271.81			wd				Y

PERMIT MAP ID	API NUMBER	ISWSPNUM	DD_N83_X	DD_N83_Y	SECTION	TWP	TDIR	RNG	RDIR	owner	well number	driller	status	elev	ELEV REF	depth total last known	water from	depth open interval top	depth open interval bottom	cr pumping gpm	U16_X	U16_Y	abandoned	plugged	well type	date sealed	well use	ISWS well	inside_AoR
235	121152311200	347854	-88.921195	39.898492	25	17	N	2	E	Ricker, Greg & Tonya		S & J Well Drilling	DRYP	0		120	dry hole	0	0	0	335759.282	4418257.52	y	y	wd				Y
236	121152312700	348705	-88.875405	39.884979	33	17	N	3	E	Ball, Larry & Rebecca		S & J Well Drilling	WATER	0		104	sand	74	104	15	339642.571	4416674.37			wd				Y
237	121152313000	348706	-88.921195	39.898492	25	17	N	2	E	Ricker, Greg & Tawnya	1	Skinner, Todd	WATER	0		39	sand & gravel	15	17	0	335759.282	4418257.52			wd				Y
238	121152312600	348708	-88.882631	39.862594	8	16	N	3	E	Pugh, Brad		S & J Well Drilling	WATER	0		40	sand	8	40	60	338972.309	4414202.66			wd				Y
239	121152313200	349760	-88.89476	39.913928	20	17	N	3	E	McLeod Express	1	Mashburn, Robert	WATER	0		135	sand	131	135	30	338055.692	4419922.61			wc				Y
240	121152315200	349899	-88.866362	39.905214	28	17	N	3	E	Ewing, David		Mashburn, Robert	WATER	0		105	sand	100	105	7	340462.789	4418904.23			wd				Y
241		352640	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				24							y	y	x	12/23/2002		y	Y
242		352641	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				17							y	y	x	12/23/2002		y	Y
243		352642	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				23							y	y	x	12/23/2002		y	Y
244		352643	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				26							y	y	x	12/23/2002		y	Y
245		352644	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				21							y	y	x	12/23/2002		y	Y
246		352645	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				30							y	y	x	12/23/2002		y	Y
247		352646	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				28							y	y	x	12/23/2002		y	Y
248		352647	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				13							y	y	x	12/23/2002		y	Y
249		352648	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				17							y	y	x	12/23/2002		y	Y
250		352649	-88.898761	39.86241	7	16N		03E		ARCHER DANIELS MIDLAND CO.		ANDREW L. WIESENHOFER				17							y	y	x	12/23/2002		y	Y
251		354403	-88.866343	39.905361	28	17N		03E		DAVID EWING		ROBERT MASHBURN				104							y	y	wd	6/30/2003	DO	y	Y
252	121152265000	355542	-88.889979	39.908508	20	17	N	3	E	Shur Company		Luttrell, James	WATER	0		25		0	0	0	338451.611	4419312.33			wc				Y
253	121152317100	358056	-88.918798	39.896741	25	17	N	2	E	Trostle, Lisa	1	Skinner, Todd	WATER	0		45	sand & gravel	11	23	0	335960.036	4418058.75			wd				Y
254	121152317000	358273	-88.918798	39.896741	25	17	N	2	E	Trostle, Lisa		Mashburn, Robert	DRYP	0		125	dry hole	0	0	0	335960.036	4418058.75	y	y	wd				Y
255	121152316500	359986	-88.868673	39.899707	28	17	N	3	E	Elliot, John		S & J Well Drilling	WATER	0		115	sand	100	115	0	340252.439	4418297.09			wd				Y
256	121152316600	359987	-88.878026	39.901382	28	17	N	3	E	McCarty, Ronald W.		S & J Well Drilling	WATER	0		78	sand	70	78	5	339456.736	4418499.79			wd				Y
257	121152319300	361043	-88.873073	39.88139	33	17	N	3	E	Morris, Steve		S & J Well Drilling	WATER	0		62	sand	50	62	20	339833.629	4416271.81			wd				Y
258	121152318300	361730	-88.868719	39.907005	28	17	N	3	E	Traughber, William	2	Sims, R. Marc Jr.	WATER	0		108	sand	104	108	6	340265.461	4419107.24			wd				Y
259	121152321900	365451	-88.870877	39.886901	33	17	N	3	E	Johnson, Matt		S & J Well Drilling	WATER	0		90	sand	70	90	40	340034.234	4416879.59			wd				Y
260	121152319400	367211	-88.918841	39.898557	25	17	N	2	E	New Day Community Church	1	Skinner, Todd	WATER	0		80	sand & gravel	66	70	0	335960.692	4418260.41			wc				Y
261	121152323000	370672	-88.880475	39.906849	29	17	N	3	E	Smalley, Jeff		Mashburn, Robert	WATER	0		102	sand	99	102	12	339260.151	4419111.03			wd				Y
262	121152323300	370676	-88.875765	39.906918	28	17	N	3	E	Thornton, Bill	2	Mashburn, Robert	WATER	0		102	sand	99	102	7	339662.941	4419110.22			wd				Y
263		370750	-88.875788	39.907233	28	17N		03E		BILL THORNTON		ROBERT MASHBURN				102							y	y	wd	5/21/2005	DO	y	Y
264		371827	-88.880103	39.90677	29	17N		03E		JEFF SMALLEY		ROBERT MASHBURN				45							y	y	wd	7/9/2005	DO	y	Y
265	121152325500	372368	-88.877584	39.881289	33	17	N	3	E	Klepzig, Aaron		S & J Well Drilling	WATER	0		97	sand	90	98	15	339447.633	4416268.7			wd				Y
266		372894	-88.871122	39.899921	28	17N		03E		MIKE CAMPBELL		ROBERT MASHBURN				81							y	y	wd	9/9/2005	DO	y	Y
267	121152329100	374988	-88.875327	39.881341	33	17	N	3	E	Walker, Cody		S & J Well Drilling	WATER	0		95	sand	85	95	0	339640.763	4416270.41			wd				Y
268		375852	-88.898761	39.86241	7	16N		03E		ADM - WEST PLANT		ROBERT MASHBURN				85							y	y	wc	11/21/2005	IC	y	Y
269	121152332900	383584	-88.869444	39.899722	28	17	N	3	E	Allen, D. Scott		S & J Well Drilling	WATER			112	sand	98	112	15	340186.559	4418300.14			wd				Y
270	121152206800	402770	-88.896904	39.87715	5	16	N	3	E	ADM Corn Sweeteners	5	Grosch, Wayne A.	WATER	0		90					337785.714	4415844.18			wc				Y
271	121152207200	402771	-88.901478	39.860489	7	16	N	3	E	ADM Corn Sweeteners		Grosch, Wayne A.	WATER	0		125		0	0	0	337355.184	4414003.15			wc				Y
272	121152207100	402772	-88.899123	39.862318	7	16	N	3	E	ADM Corn Sweeteners		Grosch, Wayne A.	WATER	0		94		0	0	0	337560.949	4414201.88			wc				Y
273	121152207000	402773	-88.880433	39.877551	5	16	N	3	E	ADM Corn Sweeteners	1	Grosch, Wayne A.	WATER	0		110		0	0	0	339195.265	4415858.91			wc				Y
274	121152207400	402775	-88.885122	39.875574	5	16	N	3	E	ADM Corn Sweeteners	2	Grosch, Wayne A.	WATER	0		114		0	0	0	338789.63	4415647.92			wc				Y
275	121152206900	402777	-88.882748	39.873762	5	16	N	3	E	ADM Corn Sweeteners	3	Grosch, Wayne A.	WATER	0		80		0	0	0	338988.422	4415442.51			wc				Y
276		402779	-88.896436	39.862829	8	16N		03E		DECATUR BOTTLING CO													n	n	x			y	Y
277	121150093400	402781	-88.883496	39.866526	5	16	N	3	E	Decatur Park Dist		Mashburn Brothers	WATER	675	GL	98	sand and gravel	92	98	30	338907.517	4414640.67			wc				Y
278	121152185700	402785	-88.882028	39.865652	5	16	N	3	E	Decatur Park District	2	Mashburn, Grover C. Jr.	WATER	0		101	sand & gravel	64	101	150	339031.038	4414541.01			wc				Y
279		405494	-88.856543	39.896608	27	17N		03E		LONG CREEK TOWNSHIP		SHADOW MANUFACTURING				104							n	n	x		-1	y	Y
280		407634	-88.854161	39.898416	27	17N		03E		LONG CREEK TOWNSHIP		ALBRECHT WELL DRLG		660		94							n	n	x		-1	y	Y
281	121152113100	407635	-88.856105	39.895971	27	17	N	3	E	Long Creek, Township of	1	Layne Western Co., Inc.	WATER	662	GL	107	sand and gravel	59	105	305	341318.289	4417859.99			wc				Y
282		411204	-88.864187	39.883522	33	17N		03E		ADM CORN SWEETENERS													n	n	x			y	Y
283	121152203900	428754	-88.882215	39.879351	32	17	N	3	E	Sebens, Gary		Luttrell, Gerald Dean	WATER	0		55	gray sand & gra	48	51	0	339047.078	4416061.92			wd				Y
284	121152203200	428880	-88.868686	39.901531	28	17	N	3	E	Leevy, Warren	1	Mashburn, Grover C. Jr.	WATER	0		108	sand	101	108	20	340255.564	4418499.58			wd				Y
285	121152206100	428881	-88.873395	39.905117	28	17	N	3	E	Garratt, Gerald	2	Wiesenhofer, Andrew	WATER	0		155	gray sand	105	106	0	339861.342	4418906.06			wd				Y
286	121152208700	428882	-88.873418	39.906947	28	17	N	3	E	Jones, Vernie		Link, Harold F.	WATER	0		40	gravel	13	24	0	339863.638	4419109.23			wd				Y
287	121152207900	428883	-88.877995	39.899547	28	17	N	3	E	Smalley, Gary	1	Mashburn, Grover C. Jr.	WATER	0		118	sand	113	118	15	339455.103	4418296.05			wd				Y
288	121150000600		-88.877962	39.902091	28	17	N	3	E	Rhodes, Wm.	1	Eureka Oil Corp	DA	687	DF	2248					339463.863	4418578.37	y		o				Y
289	121150033500		-88.876394	39.877753	4	16	N	3	E	Decatur Gun Club		No Company	WATER	675	TM	75		0	0	0	339541.152	4415874.07			wc				Y
290	121150033600		-88.882684	39.867231	5	16	N	3	E	Archer-Daniel-Midland Co.		Lentz Tony	WATER	0		108		0	0	0	338978.62	4414717.46			wc				Y
291	121150036000		-88.888397	39.856152	8	16	N	3	E	Burks, A. B.		Woollen Brothers	WATER	656	GL	66		0	0	0	338463.982	4413498.02			wd				Y
292	121150036400		-88.891962	39.858022	8	16	N	3	E	Hank, J.		Lentz Tony	WATER	0		80		0	0	0	338163.401	4413712.04			wd				Y
293	121150053900		-88.887617	39.90854	20	17	N	3	E	Kuny	1	Myers, Theodore F.	DAP	688	KB	2226					338653.594	4419311.61	y	y	o				Y

PERMIT MAP ID	API NUMBER	ISWSPNUM	DD_N83_X	DD_N83_Y	SECTION	TWP	TDIR	RNG	RDIR	owner	well number	driller	status	elev	ELEV REF	depth total last known	water from	depth open interval top	depth open interval bottom	cr pumping gpm	U16_X	U16_Y	abandoned	plugged	well type	date sealed	well use	ISWS well	inside_AoR
294	121150054000		-88.882891	39.910499	20	17	N	3	E	Stout, Bertha	1	Robinson, H. F., Inc.	DAOP	689	DF	2239					339062.167	4419520.53	y	y	o				Y
295	121150054700		-88.878037	39.902947	28	17	N	3	E	Clements, Belle	1	Davis, C. G.	DAO	678	DF	5					339459.45	4418673.52			o				Y
296	121150054800		-88.880339	39.899509	29	17	N	3	E	Boyd	1	Davis, C. G.	DA	686	DF	2282					339254.618	4418296.05	y		o				Y
297	121150054900		-88.894578	39.901021	29	17	N	3	E	Boyd, A. T.	1	Welker Oil Co., Ltd.	OILP	680	GL	2240					338040.845	4418489.62	y	y	o				Y
298	121150055000		-88.879867	39.905957	29	17	N	3	E	McKee, John H., Sr.	1	Costello Leonard J	DA	0		2251					339310.04	4419010.92	y		o				Y
299	121150055100		-88.8663	39.881547	33	17	N	3	E	Oakley Damsite T.H.	1	U S Engineering Dept	ENG	643	GL	43		0	0	0	340413.189	4416277.11			e				Y
300	121150055200		-88.86517	39.882482	33	17	N	3	E	Oakley Damsite T.H.	2	U S Engineering Dept	ENG	621	GL	45		0	0	0	340511.988	4416378.88			e				Y
301	121150055300		-88.868558	39.881495	33	17	N	3	E	Oakley Damsite T.H.	3	U S Engineering Dept	ENG	652	GL	53		0	0	0	340219.975	4416275.38			e				Y
302	121150055400		-88.868558	39.881495	33	17	N	3	E	Oakley Damsite T.	. 4	U S Engineering Dept	ENG	640	GL	45		0	0	0	340219.975	4416275.38			e				Y
303	121150055500		-88.864031	39.885233	33	17	N	3	E	Oakley Damsite T.H.	5	U S Engineering Dept	ENG	618	GL	55		0	0	0	340615.761	4416682.2			e				Y
304	121150055600		-88.861772	39.883465	33	17	N	3	E	Oakley Damsite T.H.	6	U S Engineering Dept	ENG	620	GL	55		0	0	0	340804.839	4416481.93			e				Y
305	121150055700		-88.859398	39.885321	34	17	N	3	E	Oakley Damsite T. H.	7	U S Engineering Dept	ENG	632	GL	40		0	0	0	341012.135	4416683.71			e				Y
306	121150055800		-88.861798	39.87983	33	17	N	3	E	Reas Bridge Park	1	Pearcy Ed B	UNK	0		35		0	0	0	340794.206	4416078.49			wc				Y
307	121150061800		-88.882787	39.877494	5	16	N	3	E	Rowe		Burt, Luther R.	GAS	675	GL	88		0	0	0	338993.817	4415856.82			o				Y
308	121150073300		-88.86401	39.894324	28	17	N	3	E		CO-534	U. S. Army Corps of Eng.	ENG	608	GL	114		0	0	0	340638.618	4417691.25			e				Y
309	121150073400		-88.869792	39.893296	33	17	N	3	E		CO-514	U S Army Corp Of Eng	ENG	604	GL	123		0	0	0	340141.872	4417587.48			e				Y
310	121150073500		-88.86857	39.883314	33	17	N	3	E		CO-509	U S Army Corp Of Eng	ENG	652	GL	160		0	0	0	340223.172	4416477.31			e				Y
311	121150073900		-88.889992	39.910357	20	17	N	3	E	Roos-Kuny	1	Atkins and Hale	DAP	683	KB	2229					338454.845	4419517.59	y	y	o				Y
312	121150080700		-88.858381	39.896281	27	17	N	3	E	Long Creek Water District T	1	Baker, E. C. & Sons	WTST	0		115	sand and gravel	99	109	5	341124.414	4417898.45	y		wc				Y
313	121150081000		-88.858022	39.896287	27	17	N	3	E	Long Creek Water District T	2	Baker, E. C. & Sons	WTST	0		101	sand and gravel	86	96	5	341155.121	4417898.47	y		wc				Y
314	121150081100		-88.85856	39.896277	27	17	N	3	E	Long Creek Pub Water Dist T	3	Baker, E. C. & Sons	WTST	0		121	sand and gravel	100	121	150	341109.1	4417898.32	y		wc				Y
315	121150082900		-88.860538	39.893489	33	17	N	3	E		CO-539	U S Army Corp Of Eng	ENG	612	GL	62		0	0	0	340933.54	4417592.38			e				Y
316	121150089500		-88.92566	39.878384	36	17	N	2	E	SBI 48 bridge	3	IL Dept. of Transportation	ENG	681	GL	41		0	0	0	335329.424	4416033.77			e				Y
317	121150102000		-88.898806	39.900165	30	17	N	3	E	Christian, Ray H.	1	Hanks, T. R.	WATER	0		113	sand	108	113	25	337677.367	4418402.28			wd				Y
318	121152107800		-88.860538	39.893489	27	17	N	3	E	Long Creek Township	D	Layne Western Co., Inc.	WTST	0		121		0	0	0	340933.54	4417592.38	y		wc				Y
319	121152115800		-88.85555	39.890806	34	17	N	3	E	Oakley Dam	618	Engineers, Corp. of	ENG	666	GL	145		0	0	0	341353.828	4417285.7			e				Y
320	121152115900		-88.855536	39.892324	34	17	N	3	E	Oakley Dam	619	Engineers, Corp. of	ENG	660	GL	149		0	0	0	341358.525	4417454.17			e				Y
321	121152116000		-88.867224	39.884038	33	17	N	3	E	Oakley Dam	T.H.C.	Engineers, Corp. of	ENG	614	GL	112		0	0	0	340339.953	4416555.26			e				Y
322	121152133800		-88.894475	39.868894	5	16	N	3	E	A.D.M.	1	Archer Daniels Midland	DAOP	682	KB	2315					337974.012	4414923.37	y	y	o				Y
323	121152138100		-88.880462	39.90625	29	17	N	3	E	French	1	Davis, C. G.	DAP	693	KB	2294					339259.862	4419044.52	y	y	o				Y
324	121152149400		-88.916509	39.900583	30	17	N	3	E	Schwarze, R. D.	1	Triple G Oil Company Ltd.	DAP	684	KB	2187					336164.892	4418481.01	y	y	o				Y
325	121152152400		-88.878011	39.901374	28	17	N	3	E	Cundiff	1	Davis, C. G.	DAP	689	KB	2285					339458	4418498.88	y	y	o				Y
326	121152165000		-88.921076	39.89304	25	17	N	2	E	Harrison-Oliver Community	1	Triple G Oil Company Ltd.	DAP	656	GL	2500					335756.437	4417652.13	y	y	o				Y
327	121152185200		-88.921199	39.898497	25	17	N	2	E	Batthauer Community	1	Triple G Oil Company Ltd.	OILP	676	KB	2223					335758.952	4418258.08	y	y	o				Y
328	121152225100		-88.888397	39.856152	8	16	N	3	E	Durbin	1		WATER	0		0		0	0	0	338463.982	4413498.02			wd				Y
329	121152238700		-88.858384	39.895177	27	17	N	3	E	Oakley Damsite	612	Baker, E. C. & Sons	ENG	629	GL	93					341121.607	4417775.91			e				Y
330	121152241400		-88.893672	39.866038	5	16	N	3	E	Archer Daniels Midland Co	2	Layne-Western	WTST	0		90		0	0	0	338035.975	4414604.9			wc				Y
331	121152241500		-88.889755	39.868025	5	16	N	3	E	Grove Rd.@ Sand Cr. Boring	2	Baker, E. C. & Sons	ENG	0		36		0	0	0	338375.679	4414818.36			e				Y
332	121152241600		-88.889755	39.868025	5	16	N	3	E	Grove Rd. @ Sand Cr. Boring	3	Baker, E. C. Baker & Sons	ENG	0				0	0	0	338375.679	4414818.36			e				Y
333	121152241900		-88.899123	39.862318	7	16	N	3	E	West Plant Addition	2	Baker, E. C. & Sons	ENG	0				0	0	0	337560.949	4414201.88			e				Y
334	121152243900		-88.917219	39.884926	31	17	N	3	E	Caterpiller Tractor T	3	Burt, Luther	WTST	0		0		0	0	0	336066.881	4416744.4	y		wc				Y
335	121152244000		-88.909451	39.885072	31	17	N	3	E	Caterpiller Tractor TH	4	Burt, Luther	WTST	0		117		0	0	0	336731.48	4416746.37	y		wc				Y
336	121152246400		-88.856765	39.896581	27	17	N	3	E	Long Creek PWS	TH 1-94	Layne-Western Co.	WTST	650	GL	105		0	0	0	341263.269	4417928.87	y		wc				Y
337	121152260900		-88.8629	39.884349	33	17	N	3	E	Lake Decatur Sediments		IL State Water Survey	STRAT	0		45					340710.427	4416582.06			s				Y
338	121152261000		-88.8629	39.884349	33	17	N	3	E	Lake Decatur Sediments		IL State Water Survey	STRAT	0		2					340710.427	4416582.06			s				Y
339	121152262700		-88.859254	39.89715	27	17	N	3	E	Long Creek, Town of	2	Albrecht, S. Dean	WATER	0		0					341051.783	4417996.46			wc				Y
340	121152301600		-88.887658	39.914079	20	17	N	3	E	Oasis Truck Stop			WATER	0		0		0	0	0	338663.09	4419926.51			wc				Y
341	121152301700		-88.854514	39.896312	27	17	N	3	E	Long Creek Township PWS	2		WATER	0		86		0	0	0	341455.101	4417895.01			wc				Y
342	121152301800		-88.868673	39.899707	28	17	N	3	E	Whitmore Park			WATER	0		0		0	0	0	340252.439	4418297.09			wd				Y
343	121152443600		-88.92566	39.878384	36	17	N	2	E	Cities Service	1	Lentz, Neil Drilling	WTST	0		0		0	0	0	335329.424	4416033.77	y		wc				Y
344	1711521338000C		-88.894475	39.868894	5	16	N	3	E			ARCHER DANIALS MIDLAND CO.	COALSEC	679		906					337974	4414923			c				Y
345	121152345600	450826	-88.868283	39.904883	28	17	N	3	E	Rhodes, John	2	Mashburn, Robert	WATER			103	sand	98	103	12								N	Y
346	121152342800	447202	-88.866944	39.863889	4	16	N	3	E	Big Brothers Big Sisters		S & J Well Drilling	DRYP	662		90	dry											N	Y
347	121152343000	447198	-88.866323	39.894279	28	17	N	3	E	McCarty, Ronald Jr.		S & J Well Drilling	DRY			107												N	Y
348	121152342000	445303	-88.868333	39.893889	28	17	N	3	E	McCarty, Ronald W.	1	Skinner, Todd	WATER	749		45	silty sand	34	45									N	Y
349	121152342100	445259	-88.873129	39.885032	33	17	N	3	E	Moore, Timothy		S & J Well Drilling	WATER			95	sand	81	95	15								N	Y
350	121152341900	445201	-88.868539	39.860951	9	16	N	3	E	Steve's Trucking Inc		Mashburn, Robert	DRY			135	dry											N	Y
351	121152340700	442072	-88.899121	39.862319	7	16	N	3	E	ADM West Refinery		S & J Well Drilling	WATER			106	sand	86	106	130								N	Y
352	121152340800	442066	-88.897085	39.90837	20	17	N	3	E	Pressley, Jerry		S & J Well Drilling	WATER			113	sand	109	113	10								N	Y

PERMIT MAP ID	API NUMBER	ISWSPNUM	DD_N83_X	DD_N83_Y	SECTION	TWP	TDIR	RNG	RDIR	owner	well number	driller	status	elev	ELEV REF	depth total last known	water from	depth open interval top	depth open interval bottom	cr pumping gpm	U16_X	U16_Y	abandoned	plugged	well type	date sealed	well use	ISWS well	inside_AoR
353	121152338100	437333	-88.881944	39.863889	5	16	N	3	E	ADM	TW1	S & J Well Drilling	WATER	647		99	sand	55	99									N	Y
354	121152337200	433210	-88.878611	39.897222	33	17	N	3	E	Crain, Mark D.		S & J Well Drilling	WATER	667		105	sand	95	105	20								N	Y
355	121152335700	430498	-88.874533	39.910933	21	17	N	3	E	Marlowe, Harold		Mashburn, Robert	WATER			112	sand & gravel	106	112	15								N	Y
356	121150054700		-88.878037	39.902947	28	17	N	3	E	Clements, Belle	1	Davis, C. G.	DAO	678	DF	2344												N	Y
357	121152337800		-88.893100	39.877291	5	16	N	3	E	Archer Daniels Midland	MMV-01B	Illinois State Geological Survey	CONF	675	TM	201												N	Y
358	121152339000		-88.906438	39.88261	31	17	N	3	E	ADM	MMV-02S	Illinois State Geological Survey	CONF			28												N	Y
359	121152339100		-88.902868	39.874274	6	16	N	3	E	Decatur, City of	1 well	IL State Geological Survey	WATER															N	Y
360	121152339200		-88.897096	39.883867	32	17	N	3	E	ADM	MMV-03S	Illinois State Geological Survey	CONF			24												N	Y
361	121152339300		-88.897136	39.881135	32	17	N	3	E	ADM	MMV-04S	Illinois State Geological Survey	CONF			28												N	Y
362	121152339400		-88.89712	39.881118	32	17	N	3	E	ADM	MMV-04UG	Illinois State Geological Survey	CONF			67												N	Y
363	121152339500		-88.897099	39.88109	32	17	N	3	E	ADM	MMV-04P	Illinois State Geological Survey	CONF			99												N	Y
364	121152339600		-88.897184	39.881084	32	17	N	3	E	ADM	MMV-04B	Illinois State Geological Survey	MONIT	861		504												N	Y
365	121152339700		-88.897721	39.876167	5	16	N	3	E	ADM	MMV-07UG	Illinois State Geological Survey	CONF			75												N	Y
366	121152339800		-88.889172	39.879638	5	16	N	3	E	ADM	MMV-05S	Illinois State Geological Survey	CONF			22												N	Y
367	121152339900		-88.889442	39.875701	5	16	N	3	E	ADM	MMV-08UG	Illinois State Geological Survey	CONF			60												N	Y
368	121152340000		-88.889384	39.87569	5	16	N	3	E	ADM	MMV-08S	Illinois State Geological Survey	CONF			25												N	Y
369	121152340100		-88.877254	39.871505	4	16	N	3	E	ADM	MMV-09S	Illinois State Geological Survey	CONF			24												N	Y
370	121152341500		-88.893410	39.876963	5	16	N	3	E	ADM	CCS-1	Archer Daniels Midland	CONF	690	KB	7236												N	Y
371	121152343800		-88.894041	39.877082	5	16	N	3	E	ADM/Geophone	CCS-1	Pioneer Oil Co., Inc.	CONF	690	KB	3500												N	Y
372	121152344300		-88.897207	39.881162	32	17	N	3	E	ADM	G104	IL State Geological Survey	WATER															N	Y
373	121152344400		-88.893303	39.877072	5	16	N	3	E	ADM	G101	Illinois State Geological Survey	WATER															N	Y
374	121152344500		-88.893491	39.877077	5	16	N	3	E	ADM	G102A	Illinois State Geological Survey	DRYP															N	Y
375	121152344600		-88.893942	39.877486	5	16	N	3	E	ADM	G103	Illinois State Geological Survey	WATER															N	Y
376	121152346000		-88.893353	39.879785	5	16	N	3	E	ADM Verification Well	1	Pioneer Oil Co., Inc.	CONF			7250												N	Y
377		88170			5	16N		03E		CLISSOLD C PIERCE		LENTZ				81							n	n	wd		DO	y	Y
378		88171			5	16N		03E		GEORGE NOLEN		LENTZ				62							n	n	wd		DO	y	Y
379		88172			5	16N		03E		QUERREY		LENTZ				60							n	n	wd		DO	y	Y
380		88173			5	16N		03E		MILLINGER		LENTZ				86							n	n	wd		DO	y	Y
381		88174			5	16N		03E		KEMP		LENTZ				100							n	n	wd		DO	y	Y
382		88175			5	16N		03E		FLOYD KENNEY		LENTZ				76							n	n	wd		DO	y	Y
383		88176			5	16N		03E		PAUL MONSKA		LENTZ				85							n	n	wd		DO	y	Y
384		88183			7	16N		03E		A LONGSTREET		LENTZ				85							n	n	wd		DO	y	Y
385		88184			8	16N		03E		LOUIS GOOD						33							n	n	wd		DO	y	Y
386		88186			7	16N		03E		H L SCARBER		LENTZ				84							n	n	wd		DO	y	Y
387		88187			7	16N		03E		TOLLE		LENTZ				85							n	n	wd		DO	y	Y
388		88188			7	16N		03E		WAKEFIELD & WILBUR		WOOLLEN BROS				84							n	n	wd		DO	y	Y
389		88189			7	16N		03E		WILBUR GILLIBRAND		LENTZ				91							n	n	wd		DO	y	Y
390		88219			8	16N		03E		CLARENCE A CHAPMAN		LENTZ				78							n	n	wd		DO	y	Y
391		88231			8	16N		03E		MARION GODWIN		LENTZ				68							n	n	wd		DO	y	Y
392		89454			21	17N		03E		CECIL VARNER		MASHBURN BROS				105							n	n	wd		DO	y	Y
393	121152195800	89514			33	17N		03E		LARRY SMALLEY		G C MASHBURN				90							n	n	wd		DO	y	Y
394		89771			5	16N		03E		ARCHER DANIELS MIDLAND CO		TONY LENTZ				92							n	n	wc		IC	y	Y
395		89772			5	16N		03E		ARCHER DANIELS MIDLAND CO		LENTZ				116							n	n	wc		IC	y	Y
396		89778			5	16N		03E		BAUER AUTO WRECKING		LENTZ				93							n	n	wc		IC	y	Y
397		89861			5	16N		03E		FARIES PARK						20							n	n	x		PK	y	Y
398		89862			5	16N		03E		FARIES PARK						25							n	n	x		PK	y	Y
399		89863			5	16N		03E		FARIES PARK						42							n	n	x		PK	y	Y
400		89864			5	16N		03E		FARIES PARK						35							n	n	x		PK	y	Y
401		89865			5	16N		03E		FARIES PARK						56							n	n	x		PK	y	Y
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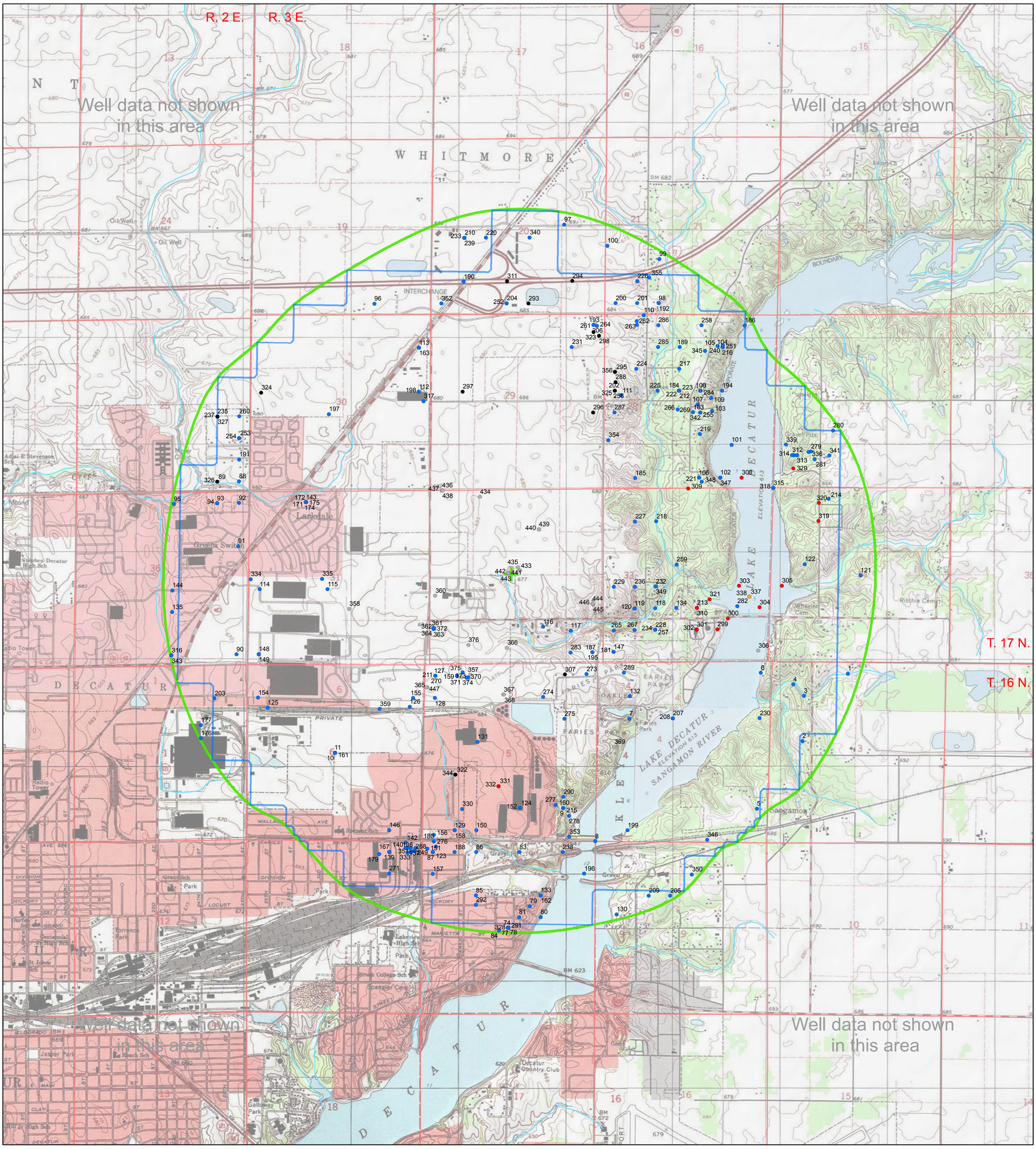
403		89867			5	16N		03E		FARIES PARK						35							n	n	x		PK	y	Y
404		89868			5	16N		03E		FARIES PARK						12							n	n	x		PK	y	Y
405		89870			4	16N		03E		DECATUR PARK DIST		LENTZ				50							n	n	x		PK	y	Y
406		89871			5	16N		03E		DECATUR PARK DIST		MASHBURN BROS				98							n	n	x		PK	y	Y
407		89902			1	16N		02E		HEINKLE PACKING CO		LENTZ				88							n	n	wc		IC	y	Y
408		89966			1	16N		02E		MCBRIDES TRUCK REPAIR		T R HANKS				67							n	n	wc		IC	y	Y
409		200896			5	16N		03E		ARCHER DANIELS MIDLAND CO						123							n	n	wc		IC	y	Y
410		200899			5	16N		03E		ARCHER DANIELS MIDLAND CO						116							n	n	wc		IC	y	Y
411		200901			5	16N		03E		ARCHER DANIELS MIDLAND CO		LENTZ				109							n	n	wc		IC	y	Y

PERMIT MAP ID	API NUMBER	ISWSPNUM	DD_N83_X	DD_N83_Y	SECTION	TWP	TDIR	RNG	RDIR	owner	well number	driller	status	elev	ELEV REF	depth total last known	water from	depth open interval top	depth open interval bottom	cr pumping gpm	U16_X	U16_Y	abandoned	plugged	well type	date sealed	well use	ISWS well	inside_AoR
412		200904			5	16N		03E		ARCHER DANIELS MIDLAND CO		LENTZ				116							n	n	wc		IC	y	Y
413		201025			5	16N		03E		DECATUR PARK DIST FARIES PARK						20							n	n	x		PK	y	Y
414		201026			5	16N		03E		DECATUR PARK DIST FARIES PARK						42							n	n	x		PK	y	Y
415		201028			5	16N		03E		DECATUR PARK DIST FARIES PARK						56							n	n	x		PK	y	Y
416		201030			5	16N		03E		DECATUR PARK DIST FARIES PARK						25							n	n	x		PK	y	Y
417		201031			5	16N		03E		DECATUR PARK DIST FARIES PARK						35							n	n	x		PK	y	Y
418		201032			4	16N		03E		DECATUR PARK DIST FARIES PARK						102							n	n	x		PK	y	Y
419		201034			4	16N		03E		DECATUR PARK DIST FARIES PARK		LENTZ				50							n	n	x		PK	y	Y
420		201120			1	16N		02E		HEINKLE MEAT MARKET		LENTZ				67							n	n	wc		IC	y	Y
421		201122			1	16N		02E		HEINKLE MEAT MARKET		LENTZ				29							n	n	wc		IC	y	Y
422		201123			1	16N		02E		HEINKLE MEAT MARKET		LENTZ				32							n	n	wc		IC	y	Y
423		201124			1	16N		02E		HEINKLE MEAT MARKET		LENTZ				33							n	n	wc		IC	y	Y
424		201126			1	16N		02E		HEINKLE MEAT MARKET		LENTZ				88							n	n	wc		IC	y	Y
425		201128			1	16N		02E		HEINKLE MEAT MARKET DRY HOLE		LENTZ				42							n	n	wc		IC	y	Y
426		201134			33	17N		03E		HIGH COOK CAN CO		MASHBURN				77							n	n	wc		IC	y	Y
427		375851			7	16N		03E		ADM - WEST PLANT		ROBERT MASHBURN				97							y	y	wc	11/21/2005	IC	y	Y
428	121152207500	402774			5	16N		03E		ADM CORN SWEETENERS		GROSCH IRRIGATION CO		673		103							y	y	x	2005		y	Y
429		428841			28	17N		03E		KENNETH DAVIS #1		TODD SKINNER				81.5	SAND	63.00	68.00	40.00			n	n	wd		DO	y	Y
430		428878			28	17N		03E		KEITH & DANA CHAPMAN		UNKNOWN				103							n	n	wd		DO	y	Y
431		428879			28	17N		03E		FRED STOLLEY		UNKNOWN				60							n	n	wd		DO	y	Y
432		428913			28	17N		03E		TERRY WOLPERT		SHANE BALDING		7.8		115	SAND	108.00	115.00	18.00			n	n	wd		DO	y	Y
433	Planned		-88.887922	39.88613	32	17	N	3	E	ADM	CCS-2		Planned															N	Y
434	Planned		-88.892447	39.892232	32	17	N	3	E	ADM Verification Well	2		Planned															N	Y
435	Planned		-88.88814	39.886396	32	17	N	3	E	ADM/GeophysicalMonitor	2		Planned															N	Y
436	121152350100		-88.896577	39.892695	32	17	N	3	E	Richland Community College	MVA-10B	Illinois State Geological Survey	CONF	659		140												N	Y
437	121152350200		-88.896604	39.892695	32	17	N	3	E	Richland Community College	MVA-10LG	Illinois State Geological Survey	CONF	657		101												N	Y
438	121152349600		-88.896539	39.892697	32	17	N	3	E	Richland Community College	MVA-10UG	Illinois State Geological Survey	CONF	659		65												N	Y
439	121152349000		-88.88595	39.889612	32	17	N	3	E	ADM	MVA-11LG	Illinois State Geological Survey	CONF	706		135												N	Y
440	121152349100		-88.885956	39.889591	32	17	N	3	E	ADM	MVA-11UG	Illinois State Geological Survey	CONF	705		74												N	Y
441	121152350300		-88.889191	39.885849	32	17	N	3	E	ADM	MVA-12B	Illinois State Geological Survey	CONF	657		150												N	Y
442	121152350500		-88.889151	39.885908	32	17	N	3	E	ADM	MVA-12LG	Illinois State Geological Survey	CONF	656		95												N	Y
443	121152350400		-88.88918	39.885868	32	17	N	3	E	ADM	MVA-12S	Illinois State Geological Survey	CONF	656		30												N	Y
444	121152349500		-88.879952	39.88346	32	17	N	3	E	ADM	MVA-13B	Illinois State Geological Survey	CONF	680		145												N	Y
445	121152349300		-88.879888	39.883453	32	17	N	3	E	ADM	MVA-13LG	Illinois State Geological Survey	CONF	682		140												N	Y
446	121152349400		-88.879946	39.88346	32	17	N	3	E	ADM	MVA-13UG	Illinois State Geological Survey	CONF	678		46												N	Y
447			-88.897856	39.876169	5	16	N	3	E	ADM	MMV-07S	Illinois State Geological Survey	CONF	682		32												N	Y



- Water Well
- Oil Well
- Stratigraphic Test
- Engineering Boring
- Other / Unknown

- Area of Review
- MESPOP Predicted by Computer Simulations
- Center of Area of Review

Base: United States Geological Survey (USGS) 7.5-Minute Topographic Quadrangle map imagery and intermediate-scale DLG streams data, rescaled to 1:24,000. Topographic contour intverval is 5 feet. Tiled topographic map imagery is sourced from scanned paper maps, and is provided by Esri's USGS Topographic Map Service (available at: http://goto.arcgisonline.com/maps/USA_Topo_Maps).

N

0 0.5 1 Miles

Original Printed Scale 1:24,000

One inch = 2,000 feet

Wells and borings within the Area of Review surrounding the proposed IL-ICCS injection well at the ADM Site, Decatur, IL. The green outline shows the Area of Review, which was used to select well location coordinates from ISGS and ISWS databases as of May 10, 2011. Note that wells outside this area are not shown on this map. The well Map ID number shown for the purpose of this map can be cross-referenced to ISGS API Number and/or ISWS P-Number well identifiers in the accompanying data tables. Some wells may have multiple Map IDs assigned due to repeated drilling, testing, or sampling as identified in the source data tables. Updated January 19, 2012 to include drilled or planned ISGS/ICCS project wells.

APPENDIX H – Lower USDW Letter from Frommelt (2009)

Archer Daniels Midland Company
4666 Faries Parkway
Decatur, IL 62526
T 217.424.5200

September 29, 2009 **Via Overnight Service**

Ms. Terri Blake Meyers, L.P.G
Illinois Environmental Protection Agency
Manager, RCRA - Groundwater Assistance Unit, Permit Section, Bureau of Land
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, IL 62794-9276

Subject: Lowermost Underground Source of Drinking Water (USDW)
Archer Daniels Midland Company – UIC Permit UIC-012-ADM

Dear Ms. Blake-Meyers:

On July 27, 2009, ADM submitted via email a draft permit amendment for its UIC Permit for carbon sequestration. Included with that email was a final copy of a report summarizing the investigation results to determine the lowermost USDW and a proposal for monitoring the lowermost USDW.

ADM is hereby re-submitting this final report in hardcopy for your review. Once you have had a chance to review, please let me know as we would like to schedule a meeting to discuss.

If you have questions regarding this submittal please contact me at (217) 451-6330.

Sincerely,

Dean Frommelt
Division Environmental Manager
Archer Daniels Midland – Corn Processing

cc: Kevin Lesko, IEPA
Mark Burau, ADM
Mark Carroll, ADM
Rob Finely, ISGS
Sallie Greenburg, ISGS

Last revised: June 23, 2009
RJF Review July 20, 2009

Summary

Data regarding the Lowermost Underground Source of Drinking Water at the Illinois Basin Decatur Project

Introduction

Field investigations were conducted at the ADM ethanol plant in Decatur to determine the lowermost underground source of drinking water (USDW). A USDW is defined based on its hydraulic conductivity (K >$1x10^{-4}$ cm/sec) and its water quality (total dissolved solids <10,000 mg/L). Available data indicated that USDWs may be present in the Pennsylvanian bedrock and the upper St. Peter Sandstone (Ordovician age bedrock). To identify these USDWs, the following investigations were conducted:

1) Drill stem testing, water sampling, and logging of the St. Peter Sandstone in ADM CCS No. 1
2) Geophysical logging of bedrock formations in groundwater monitoring well
3) Coring, packer testing and water sampling of Pennsylvanian bedrock in groundwater monitoring well

Results from these investigations are summarized. Details regarding the methods used and results are described in several attachments. This summary concludes with a proposal for monitoring the lowermost USDW.

Testing of the St. Peter Sandstone

During drilling of ADM's CCS #1 well, a drill stem test (DST) was conducted in the upper 30 feet of the 210 ft thick St. Peter Sandstone. This DST provided data to calculate the hydraulic conductivity and a water sample to test total dissolved solids (TDS). TDS was determined by two labs. For the sample collected in the DST sample chamber, Prairie Analytical Systems (Springfield, IL) determined TDS to be 4,540 mg/L while the ISGS determined it to be 5,420 mg/L. Thus, water in the upper section of the St. Peter is below the USDW definition.

Using the DST data, the permeability of the St. Peter Sandstone was estimated to range from 41.5 to 144 millidarcies (mD), with a best estimate of 100 mD. Values of permeability (k) can be converted to hydraulic conductivity ($K= k\rho g/\mu$) if the fluid viscosity (μ) and density (ρ) are known. Available algorithms to estimate brine viscosity provide a range of values—0.70 to 0.84 centipoise. For ρ= 1000 kg/m^3 and μ= 0.70 centipoise or $7.0x10^{-4}$ kg/m sec, 100 mD converts to $1.38x10^{-4}$ cm/sec. For ρ= 1000 kg/m^3 and μ= 0.84 centipoise or $8.4x10^{-4}$ kg/m sec, 100 mD converts to $1.15x10^{-4}$ cm/sec. These estimates of hydraulic conductivity are slightly greater than the USDW definition. The range of permeability values (41.5 to 144 mD) converts to $5.7x10^{-5}$ to $2.0x10^{-4}$ cm/sec assuming a fluid viscosity of 0.70 centipoise.

Other Geophysical Logging

During drilling of ADM's CCS #1 well, the borehole was logged prior to the installation of the steel casing. This open-hole logging included Schlumberger's Platform Express (PEX), which includes neutron and density logs to determine porosity and fluid type and several resistivity logs (depth of investigation ranged from borehole to 90 inches) to determine fluid salinity. Based on

these and other logs, the porewater over the entire 210 ft interval in the St. Peter was estimated using the Archie equation (assumed cementation factor, m= 1.85) to have salinity ranging from 7,900 to 12,600 mg/L (NaCl equivalent). Salinity was lowest in the shallower portion of the St. Peter and highest in the deeper portion of the St. Peter. On a pore volume weighted basis, the mean salinity was estimated to be 11,300 mg/L NaCl equivalent, which means all the salinity was due to sodium (Na) and chloride (Cl) in solution.

Table 1. Summary of TDS estimates based on DST sample results

Interval (feet below ground surface)	Salinity estimated from geophysical logs (mg/L)	TDS, lab 1 (mg/L)	TDS, lab 2 (mg/L)	TDS estimate, lab 1 (mg/L)	TDS estimate, lab 2 (mg/L)
3252-3262	7,947	4,540	5,420	4,540	5,420
3262-3366	10,701			6,113	7,298
3366-3454	12,598			7,197	8,592

Lab 1= Prairie Analytical, Springfield, IL
Lab 2= ISGS, Champaign, IL

This NaCl-equivalent salinity can be converted to TDS using published conversion factors or estimated using brine geochemistry. The TDS values were estimated for three intervals using TDS values from the DST sample (Table 1), which was collected from a depth of 3239 to 3284 feet below ground surface. TDS values from a single water sample were determined by two labs. These values were used to convert salinity to TDS assuming that the salinity of the first interval was equivalent to the lab-determined TDS value. The TDS estimates for deeper intervals were adjusted using a linear correction (TDS2= Sal2/Sal1 * TDS1). Both estimates of TDS are below the 10,000 mg/L limit for USDWs.

Testing of the Pennsylvanian Bedrock

Geologic materials and water samples were collected in MMV-04B to a depth of 504 feet below ground surface. This well is located approximately 1,850 feet northwest of CCS #1. HQ-sized core were collected from a depth of 146 to 504 feet, allowing the lithology and stratigraphy to be identified. Pennsylvanian bedrock was recovered from this borehole and included fine-grained sandstone, limestone, siltstone, shale and some coal. None of the rock appeared to be capable of producing much water. Seven packer tests were conducted in the borehole. These packer tests were run at depths from 162 to 454 feet and indicated that the Pennsylvanian bedrock had a maximum hydraulic conductivity of $3x10^{-6}$ cm/sec and a minimum K $<10^{-8}$ cm/sec. Thus, this bedrock K is less than the value in the USDW definition.

Water quality sampling and geophysical logging indicated a sharp interface between fresh groundwater and “brine” at a depth of 310 to 320 feet. A groundwater sample collected at a depth of 300 feet had a TDS concentration of 1,550 mg/L, while a sample collected at a depth of 380 feet had a TDS concentration of 25,300 mg/L.

A monitoring well was completed in MMV-04B this borehole at a total depth of 295 feet. This well was screened from 275 to 295 feet and had a sand pack from 265 to 295 feet. The monitoring well was developed, but sampling results are pending.

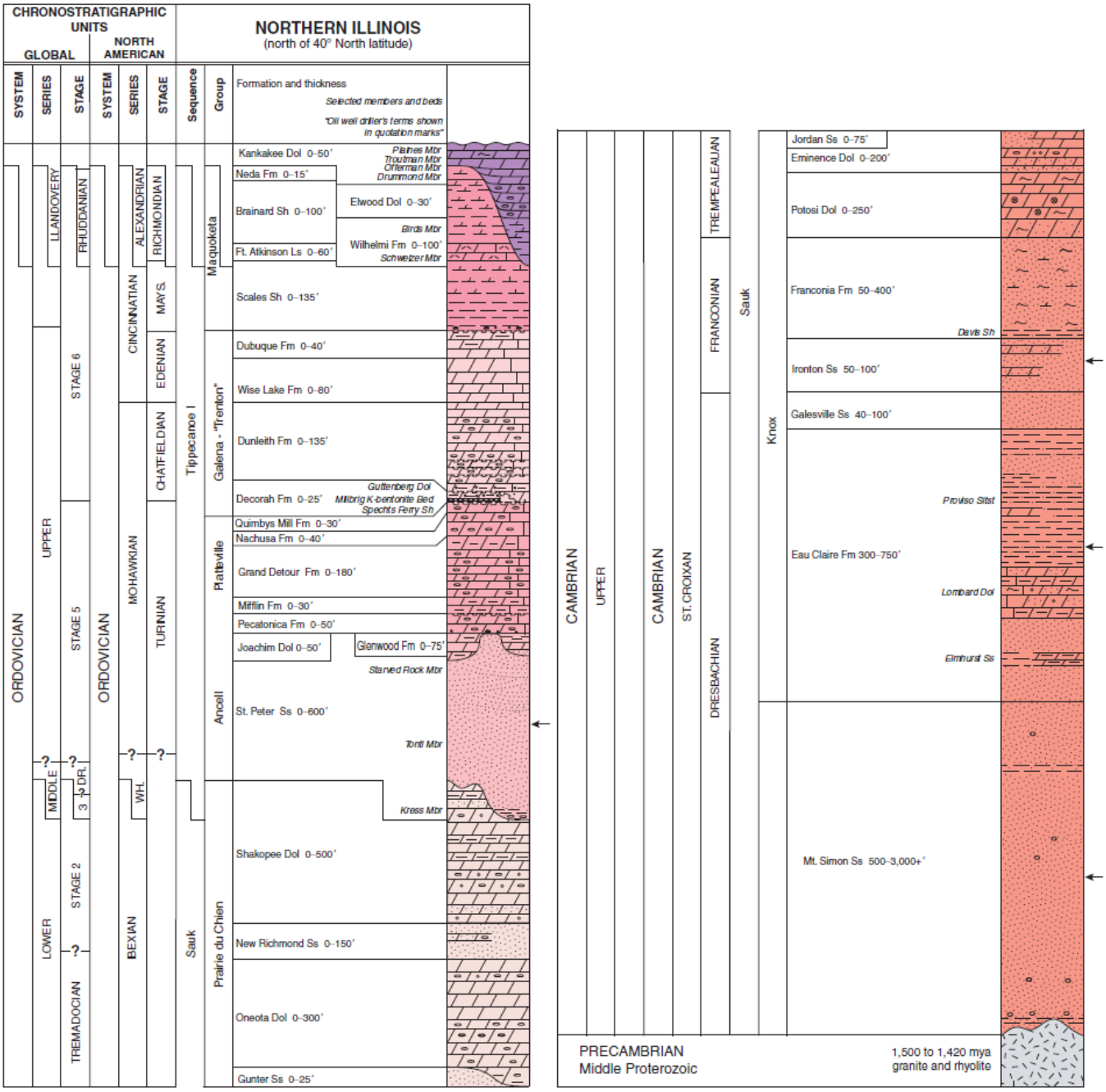
Summary and Proposed Monitoring for the Lowermost USDW

Data collected at the site demonstrate that some of the Pennsylvanian bedrock has groundwater with TDS less than 10,000 mg/L, but its hydraulic conductivity is below 10^{-4} cm/sec. The St. Peter Sandstone also has groundwater with TDS less than 10,000 mg/L, but its hydraulic conductivity is slightly greater than 10^{-4} cm/sec.

Although the Pennsylvanian bedrock does not meet both elements of the USDW definition, we propose to monitor groundwater in the Pennsylvanian bedrock because of its potential for domestic use. Groundwater in the Pennsylvanian bedrock can be monitored using wells completed like MMV-04B. A total of three wells can be installed surrounding the CO_2 injection well. Three wells should be adequate to define any seasonal variations in the shallow bedrock groundwater and to detect any leaked CO_2.

The USDW present in the St. Peter Sandstone can be protected by monitoring the first aquifer above the Mt. Simon Sandstone, the Ironton-Galesville (Figure 1), using the verification well. Monitoring the Ironton-Galesville is expected to detect any CO_2 leaked from the Mt. Simon Sandstone faster than directly monitoring in the St. Peter Sandstone. In other words, early detection of CO_2 in the Ironton-Galesville may better protect the St. Peter from out-of-zone CO_2 migration through early detection and opportunity for mitigation before actual CO_2 entry into the St. Peter. Because these formations are so deeply buried, monitoring with a single well is adequate to detect any changes in geochemistry. In addition, borehole logging with the reservoir saturation tool (RST) in the verification well should provide additional data to verify that no CO_2 is leaking from the Mt. Simon Sandstone. RST uses pulsed neutron techniques to determine reservoir saturation, lithology, porosity, and borehole fluid profiles. Additional information about this tool can be found in UIC Form 4E. In summary, the verification well can be used to monitor groundwater quality and formation pressure in the Ironton-Galesville and collect RST data from the Mt. Simon Sandstone through the St. Peter Sandstone. These data will help us determine if any CO_2 moves from the Mt. Simon Sandstone and into any overlying formations above the primary Eau Claire shale seal.

Figure 1. Stratigraphic column of the Ordovician through Precambrian bedrock in northern Illinois (from Kolata, 2005. Bedrock Geology of Illinois, Illinois Map 14**)**



Appendices

A. **Detailed Report— Drill Stem Test of the St. Peter Sandstone-- Geochemical Results**
B. **Detailed Report—Drill Stem Test Report**
C. **Detailed Report-- Analysis of DST-1 ADM – CCS #1**
D. **Detailed Report— Interpretation of Wireline Log Data in the St. Peter Sandstone**
E. **Detailed Report— Testing of the Pennsylvanian Bedrock**

Drill Stem Test of the St. Peter Sandstone—Geochemical Results

Ivan G. Krapac, ISGS Draft: May 20, 2009

Introduction

A drill stem test (DST) was conducted at the Illinois Basin Decatur Project CO_2 injection well on March 6 and 7, 2009. The primary goal of the test was to collect a water sample from the St. Peter to determine if the total dissolved solids (TDS) would exceed the USDW criteria of 10,000 mg/L TDS. In addition, a pressure fall-off test was conducted to determine the hydraulic conductivity of the St. Peter.

Trilobite Testing Inc. (Hays, Kansas) ran a conventional bottomhole DST. The test interval was 3255 to 3300 feet below the Kelly Block (KB) or 3239 to 3284 feet below ground surface. The test was conducted in an 8.75 inch diameter borehole, which had a total depth of 3,300 feet (KB). The tested interval represents the lower portion of the Galena-Platteville limestone and the upper portion of the St. Peter Sandstone (top of St. Peter at 3270 feet). The packer was set in the Galena-Platteville to enable sealing of the mechanical packer. Because the porosity and permeability of the Galena-Platteville is considered to be much lower than the St. Peter, it was believed that water collected during the DST would flow from the St. Peter. During the DST, 1,772 gallons of water was recovered. This water rose 3,000 feet into the drill pipe. The recovered water was described as follows: 147 gallons of muddy water and 1,625 gallons of water. These data indicate that the St. Peter was not heavily damage by the drilling process and that the hydraulic head in the St. Peter is approximately 250 feet below ground surface. The downhole temperature probe in the DST tool recorded the fluid temperature at 97.5 °F.

Geochemical Methods

As the DST was conducted, water flowed through the DST tool into the drill string. As the DST tool was brought to surface, water samples were collected in five gallon buckets as each joint of a 30 or 60 foot drill string was broken. Field parameters such as pH, EC, temperature, and alkalinity were attempted to be measured for each bucket. An oily film present on the surface of the water caused the electrodes to foul and inhibited field measurements to be conducted. It was concluded that the oily material was likely an artifact of the pipe thread lubricant used in the drilling operation.

A water sample was collected and analyzed from the last drill string located immediately above the DST tool and is identified as DST-10 in this report. This sample was collected because it was thought to be somewhat representative of the St. Peter formation water because it was the last water that flowed from the St. Peter formation and through the DST tool. This sample also served as a backup sample if the DST tool failed to collect an adequate water sample. The water sample collected from the DST tool sample chamber is identified as DST-1. This sample was collected directly from the sample chamber and placed directly in the appropriate sample bottles and filter assembly. Alkalinity, pH, temperature and EC were measured on DST-1

The samples for anions, cations, and alkalinity were filtered through 0.45 μm filters on site and preserved as required. All samples were kept on ice in the field and refrigerated at 4°C in the laboratory until analyzed. Electrical conductivity, pH, and temperature were determined in the field using electrodes according to standard methods (American Public Health Association [APHA], 1992).

The water samples were submitted for cation, anion, and TDS analysis to laboratories within the Illinois State Geological Survey, the Illinois State Water Survey, and Prairie Analytical Systems, Incorporated (Table 1). Anion concentrations were determined by ion chromatography (O'Dell et al., 1984, method EPA300.0), and cation concentrations by inductively coupled argon plasma spectrophotometry (ICP- method EPA 200.7 and APHA, 1992) or ICP-MS (method EPA 200.8). TDS was determined according to APHA (1992).

Data Quality

There was good agreement between the concentration data measured by the various laboratories with relative differences between laboratories generally less than 20%. Anion and cation equivalents and calculated TDS were determined using Geochemist's Workbench (Bethke and Yeakle, 2007) based on input data presented in Table 1. Anion-cation balance and the difference between calculated and measured TDS for each of the data sets were within quality control limits set by APHA (1992) and are presented in Table 1.

Discussion

Constituent concentrations in sample DST-1 and DST-10 were comparable for most constituents. Comparison of constituent concentrations determined in samples DST-1 and DST-10 to primary and secondary drinking water standards suggested that, with the exception of Fe, Mn, Pb, SO_4, and TDS, sample concentrations were less than the drinking water standard concentrations. Lead (Pb) was detected at a greater concentration than the drinking standard in sample DST-10 but not in DST-1, which may be due to the use of a lead based lubricant in the drilling process.

Iron, manganese, and sulfate concentrations, although exceeding secondary drinking water standards, would likely not impact human health but rather affect the aesthetics of the water by likely causing staining on plumbing fixtures. TDS was greater than the secondary drinking water standard but less than the 10,000 mg/L USDW limit. Chemical concentrations in the DST water samples would suggest that the St. Peter sand could be considered a USDW.

References

American Public Health Association, 1992. *Standard Methods for the Examination of Water and Wastewater*- 18th Edition, American Public Health Association.

Bethke, C.M. and S. Yeakel, 2007, The Geochemist's Workbench Release 7.0: Reaction Modeling Guide: Urbana, University of Illinois Urbana-Champaign, 84 p. [http://www.geology.uiuc.edu/Hydrogeology/hydro_gwb.htm]

O'Dell, J.W., J.D. Psass, M.E. Gales, and G.D. McKee, 1984. *Test Method- The Determination of Inorganic Anions in Water by Ion Chromatography- Method 300*, U.S. Environmental Protection Agency, EPA-600/4-84-017.

Wood, W.W., 1976. Guidelines for collection and field analysis of groundwater samples for selected unstable constituents, in US Geological Survey, Techniques for Water Resources Investigations, Chapter D-2, 24 p.

Table 1. Chemical composition of drill stem test water samples collected from the St. Peter Sandstone at Archer Daniels Midland well (CCS #1), Decatur IL. DST-1 was collected directly from the DST water sample chamber. DST-10 was collected from drill pipe immediately above the DST sample chamber.

Constituent	**DST-1 Prairie Analytical (mg/L)**	**DST-1 ISWS/ISGS (mg/L)**	**DST-10 Prairie Analytical (mg/L)**	**DST-10 ISWS/ISGS (mg/L)**	**Drinking Water Standard (mg/L)**
Al	ND	<0.037	ND	<0.037	NA
As	<0.0050	<0.108	<0.0050	<0.108	0.010
As (graphic furnace)	ND	<0.00095	ND	ND	0.010
B	ND	2.86	ND	2.86	NA
Ba	0.162	0.163	0.164	0.212	2
Be	<0.0040	<0.00055	<0.0040	<0.00055	0.004
Ca	128	134	146	148	NA
Cd	<0.0010	<0.012	<0.0010	<0.012	0.005
Co	ND	<0.013	ND	<0.013	NA
Cr	ND	<0.0058	ND	<0.0058	NA
Cu	<0.0050	<0.00079	<0.0050	<0.00079	1.3
Fe	4.40	4.90	<0.100	0.520	0.3
K	40.4	56.3	41.6	57.8	NA
Li	<0.0100	1.34	<0.0100	2.07	NA
Mg	49.4	55.5	52.9	57.6	NA
Mn	1.17	1.10	1.14	1.12	0.05
Mo	ND	0.159	ND	0.026	NA
Na	1490	1672	1510	1650	NA
Ni	ND	0.036	ND	0.026	NA
P	ND	<0.063	ND	<0.063	NA
Pb	<0.0050	<0.041	0.0922	<0.041	0.015
S	ND	134	ND	122	NA
Sb	ND	<0.059	ND	<0.059	NA
Se	ND	<0.131	ND	<0.131	NA
Si	ND	6.59	ND	6.66	NA
Sn	ND	<0.086	ND	<0.086	NA
Sr	ND	7.49	ND	8.31	NA
Ti	ND	<0.00056	ND	<0.00056	NA
Tl	<0.0020	0.023	<0.0020	0.024	0.002
V	ND	<0.047	ND	<0.047	NA
Zn	0.0292	0.0611	0.112	0.0657	5
F	ND	3.03	ND	3.31	2
Br	11.4	13.0	11.7	13.1	NA
Cl	2400	2384	2330	2403	NA
SO_4	295	404	287	394	250
SO_4 by cal. of S	ND	401	ND	366	NA
pH	ND	6.97	ND	ND	6.5-8.5
EC (Ms/cm)	ND	11.5	ND	9.8	NA
DO	ND	1.5	ND	ND	NA
Alkalinity (mg/L as $CaCO_3$)	ND	268	ND	266	NA
TDS (measured)	4540	5420	4620	5240	500/10,000
TDS (calculated)	4420	5144	4381	5142	NA
TDS difference	1.0[a]	1.1[a]	1.1[a]	1.0[a]	NA
Temperature (C)	ND	26.5	ND	28.7	NA
Anion/Cation Balance (%)	+1.7[a]	+2.8[a]	+4.5[a]	+2.5[a]	NA

ND= not determined

NA= not applicable or no standard

[a] = Within acceptable criteria for correctness of analyses (APHA. 1992. p.1-12)

TRILOBITE TESTING, INC.

DRILL STEM TEST REPORT

Prepared For: **ADM Co**

PO Box 1470
Decatur IL 62525

ATTN: Chuck Wiles

5-16N-3E Macon IL

CCS #1

TEST REPORT

TRILOBITE TESTING, INC.

DRILL STEM TEST REPORT

Prepared For: **ADM Co**

PO Box 1470
Decatur IL 62525

ATTN: Chuck Wiles

5-16N-3E Macon IL

CCS #1

Start Date: 2009.03.06 @ 20:39:02

End Date: 2009.03.07 @ 07:58:30

Job Ticket #: 32384 DST #: 1

Trilobite Testing, Inc

PO Box 1733 Hays, KS 67601

ph: 785-625-4778 fax: 785-625-5620

DRILL STEM TEST REPORT

TRILOBITE TESTING, INC

ADM Co
PO Box 1470
Decatur IL 62525

ATTN: Chuck Wiles

CCS #1

5-16N-3E Macon IL

Job Ticket: 32384 **DST#: 1**

Test Start: 2009.03.06 @ 20:39:02

GENERAL INFORMATION:

Formation: **St Peter**
Deviated: No Whipstock: ft (KB)
Time Tool Opened: 00:34:45
Time Test Ended: 07:58:30

Test Type: Conventional Bottom Hole
Tester: Jack Fox
Unit No: 29

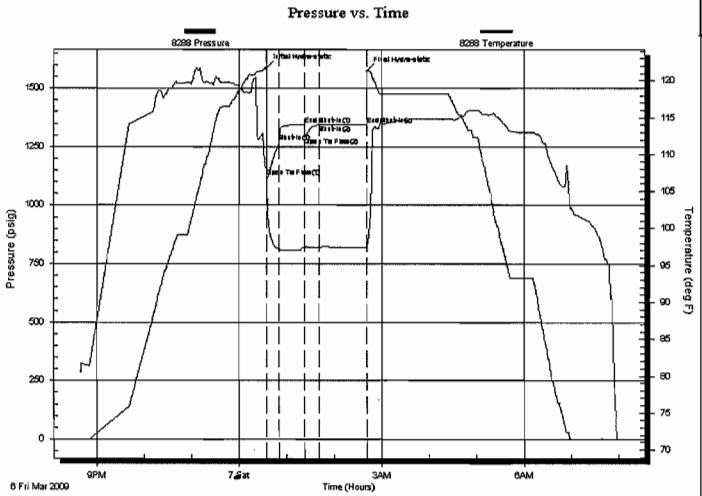
Interval: 3255.00 ft (KB) To 3300.00 ft (KB) (TVD)
Total Depth: 3300.00 ft (KB) (TVD)
Hole Diameter: 8.75 inches Hole Condition: Fair

Reference Elevations: 690.00 ft (KB)
675.00 ft (CF)
KB to GR/CF: 15.00 ft

Serial #: 8288 **Inside**

Press@RunDepth:	1342.96 psig @	3294.01 ft (KB)		Capacity:	7000.00 psig
Start Date:	2009.03.06	End Date:	2009.03.07	Last Calib.:	2007.07.16
Start Time:	20:39:02	End Time:	07:58:30	Time On Btm:	2009.03.07 @ 00:34:30
				Time Off Btm:	2009.03.07 @ 02:41:15

TEST COMMENT: IF BOB in 1 mn Very Strong blow
FF BOB ASAO dying back to surface in 20 mn



PRESSURE SUMMARY

Time (Min.)	Pressure (psig)	Temp (deg F)	Annotation
0	1585.96	108.26	Initial Hydro-static
1	1119.57	108.03	Open To Flow (1)
17	1271.97	97.16	Shut-In(1)
49	1343.82	97.39	End Shut-In(1)
50	1289.99	97.37	Open To Flow (2)
67	1342.96	97.47	Shut-In(2)
127	1344.95	97.41	End Shut-In(2)
127	1572.88	97.49	Final Hydro-static

Recovery

Length (ft)	Description	Volume (bbl)
2759.00	Water	38.70
248.00	Muddy Water	3.48

Gas Rates

	Choke (inches)	Pressure (psig)	Gas Rate (Mcf/d)

DRILL STEM TEST REPORT

TOOL DIAGRAM

TRILOBITE TESTING, INC

ADM Co

PO Box 1470
Decatur IL 62525

ATTN: Chuck Wiles

CCS #1

5-16N-3E Macon IL

Job Ticket: 32384 **DST#: 1**

Test Start: 2009.03.06 @ 20:39:02

Tool Information

Drill Pipe:	Length:	3236.00 ft	Diameter:	3.80 inches	Volume:	45.39 bbl	Tool Weight:		2500.00 lb
Heavy Wt. Pipe:	Length:	0.00 ft	Diameter:	0.00 inches	Volume:	0.00 bbl	Weight set on Packer:		30000.00 lb
Drill Collar:	Length:	0.00 ft	Diameter:	0.00 inches	Volume:	0.00 bbl	Weight to Pull Loose:		75000.00 lb
					Total Volume:	45.39 bbl	Tool Chased		0.00 ft
Drill Pipe Above KB:		10.00 ft					String Weight:	Initial	58000.00 lb
Depth to Top Packer:		3255.00 ft						Final	72000.00 lb
Depth to Bottom Packer:		ft							
Interval between Packers:		45.02 ft							
Tool Length:		74.02 ft							
Number of Packers:		2	Diameter:	7.50 inches					

Tool Comments:

Tool Description	Length (ft)	Serial No.	Position	Depth (ft)	Accum. Lengths	
Shut In Tool	5.00			3231.00		
Sampler	3.00			3234.00		
Hydraulic tool	5.00			3239.00		
Jars	5.00			3244.00		
Safety Joint	2.00			3246.00		
Packer	5.00			3251.00	29.00	Bottom Of Top Packer
Packer	4.00			3255.00		
Stubb	1.00			3256.00		
Perforations	5.00			3261.00		
Change Over Sub	0.50			3261.50		
Blank Spacing	32.00			3293.50		
Change Over Sub	0.50			3294.00		
Recorder	0.01	8288	Inside	3294.01		
Recorder	0.01	6773	Outside	3294.02		
Perforations	3.00			3297.02		
Bullnose	3.00			3300.02	45.02	Bottom Packers & Anchor
Total Tool Length:	**74.02**					

DRILL STEM TEST REPORT

FLUID SUMMARY

TRILOBITE TESTING, INC

ADM Co

PO Box 1470
Decatur IL 62525

ATTN: Chuck Wiles

CCS #1

5-16N-3E Macon IL

Job Ticket: 32384 **DST#: 1**

Test Start: 2009.03.06 @ 20:39:02

Mud and Cushion Information

Mud Type:	Gel Chem	Cushion Type:		Oil API:	deg API
Mud Weight:	9.00 lb/gal	Cushion Length:	ft	Water Salinity:	7000 ppm
Viscosity:	80.00 sec/qt	Cushion Volume:	bbl		
Water Loss:	6.80 in³	Gas Cushion Type:			
Resistivity:	ohm.m	Gas Cushion Pressure:	psig		
Salinity:	ppm				
Filter Cake:	inches				

Recovery Information

Recovery Table

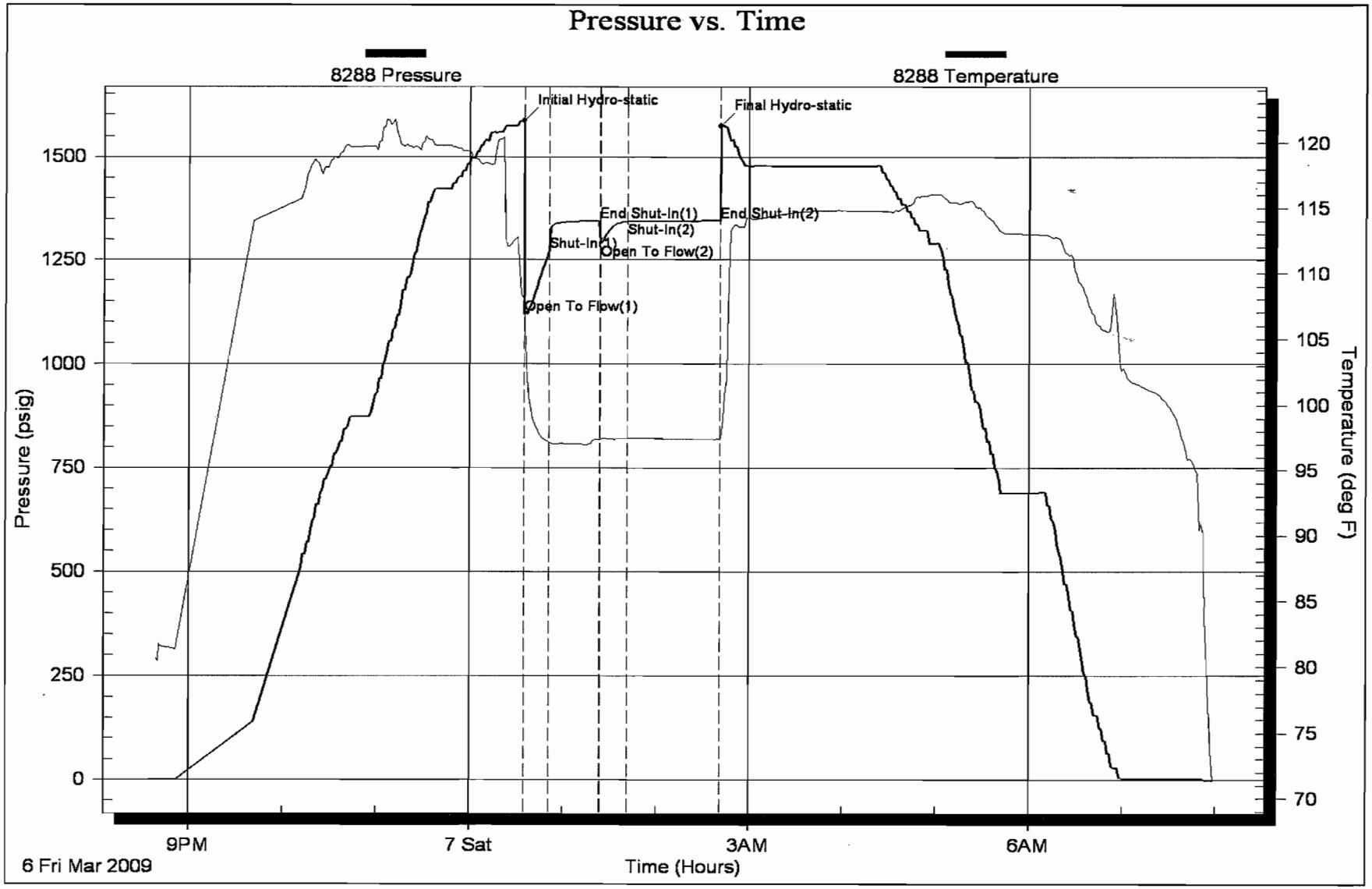
Length ft	Description	Volume bbl
2759.00	Water	38.702
248.00	Muddy Water	3.479

Total Length: 3007.00 ft Total Volume: 42.181 bbl

Num Fluid Samples: 0 Num Gas Bombs: 0 Serial #:

Laboratory Name: Laboratory Location:

Recovery Comments:


Pressure vs. Time
8288 Pressure
8288 Temperature
Initial Hydro-static
Final Hydro-static
End Shut-In(1)
End Shut-In(2)
Shut-In(2)
Shut-In(1)
Open To Flow(2)
Open To Flow(1)
Pressure (psig)
1500
1250
1000
750
500
250
0
Temperature (deg F)
120
115
110
105
100
95
90
85
80
75
70
9PM
7 Sat
3AM
6AM
6 Fri Mar 2009
Time (Hours)

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Houston, Texas 77042
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gary@welltestsolutions.com

Analysis of DST-1 ADM – CCS No.1

By
Gary E. Crawford
June 5, 2009

Summary

An open-hole Drill Stem Test (DST) was conducted on the ADM CCS No.1 on March 6, 2009. The test consisted of an initial flow period of 16 minutes, an initial shut-in of 30 minutes, a final flow of approximately 17 minutes during which the well essentially killed itself, and a final shut-in of one hour. Figure 1 shows the pressure and rate history recorded during the DST. The well was completed in the top of the St Peter formation with the packer set at 3255 ft MD (bottom of sealing element) and a total depth of approximately 3300 ft MD. The top of the St Peters formation is estimated to be at 3170 ft but logs suggest that the entire open interval could have contributed to flow (although I am not an expert log analyst). Because there is uncertainty in the actual contributing interval, the analysis assumes the entire 45 feet were contributing to flow. Analyses were conducted using productive intervals from 30 to 110 feet to show the sensitivity of the model parameters (permeability, kv/kh and skin) to this uncertainty although the analysis based on the actual 45 foot interval is considered the most appropriate.

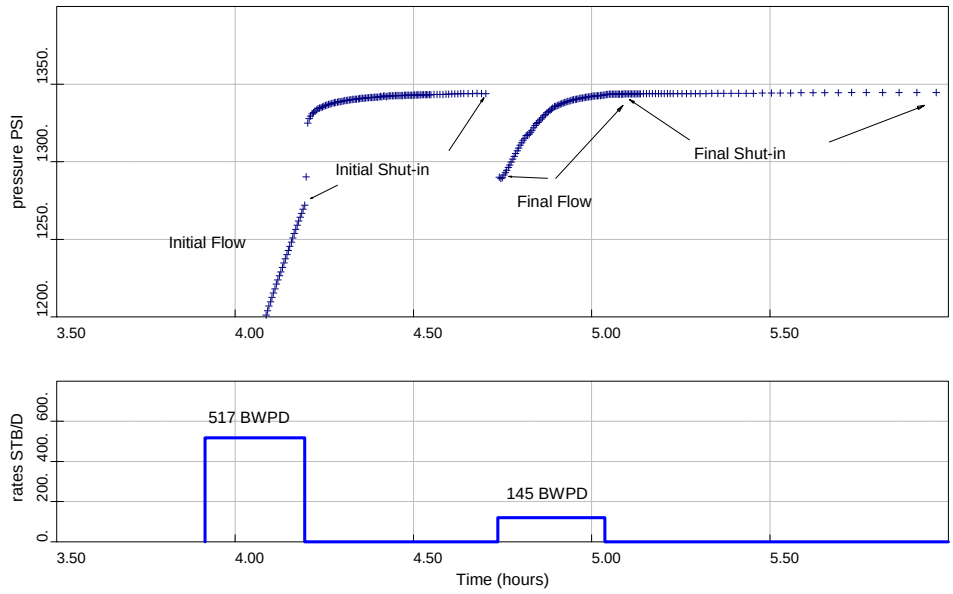


Figure 1 – Pressure and rate history of ADM CCS No.1 recorded during the March 6, 2009 DST of the interval 3270 – 3300 ft MD.

Analysis results are based on the initial shut-in period since it has a well defined shut-in as compared to the final shut-in. The test response shown in Figure 2 (the derivative plot) suggests a partial penetration model, which is appropriate since the St. Peter formation is approximately 200 feet thick and only the upper 45 feet were open to flow. The data are quite noisy near the end of the buildup (The downward trend in the derivative is characteristic of a limited entry (partial penetration) completion. The response in Figure 2 is shown compared to the partial penetration model summarized in Table 1 in order to emphasize the downward turn.

Figure 3 is an expanded pressure plot showing the undulations in the pressure during the shut-in periods. The initial shut-in contains reasonably good data with two questionable regions. There is a pressure shift about 13.5 minutes after shut-in and an upward swing about 11 minutes later. This last ten minutes of the initial buildup cannot be match with a diffusion model (pressure transient theory) and is excluded from the data used in my analysis. The final shut-in is seen to have significant pressure shifts and upward curvature which are indicative of wellbore or mechanical problems during the period. The partial penetration model summarized in Table 1 is plotted as the red line on Figure 3 and matches the overall pressure response of both shut-in periods quite well. The derivative plot is very sensitive to these shift and pressure variations thus the final shut-in derivative cannot be used for analysis. The pressure match obtained from the initial shut-in analysis is well within the uncertainties indicated by the observed variations in the data.

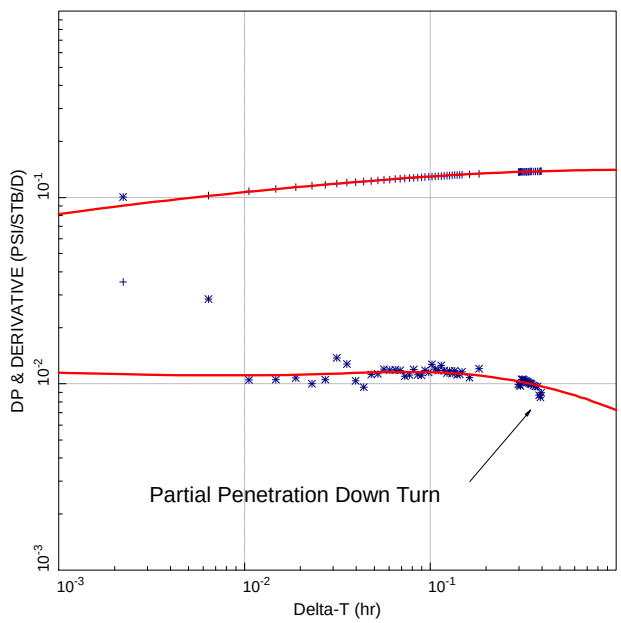


Figure 2 – The derivative response of the initial buildup recorded during DST-1 of ADM CCS No. 1 March 6, 2009. Data are compared to the model predictions of the partial penetration model summarized in Table 1.

Table 1 – Summary of the analysis results of DST-1 based on the partial penetration model assuming 45 ft of producing interval located at the top of the St. Peters formation

Property	**Initial Shut-in**
Permeability (md)	100.3
k_v/k_h	0.1
Permeability-Thickness (md-ft) based on 200 ft of net pay	20061
Completion interval (ft)	45
Total Formation Thickness (ft)	200
Distance of Center of open interval to the top of the formation (ft)	23
Skin	0.6
Wellbore Storage (RB/psi)	$1x10^{-5}$
Formation Pressure (psig)	1345.4
Depth of Pressure Gauge (ft MD)	3294

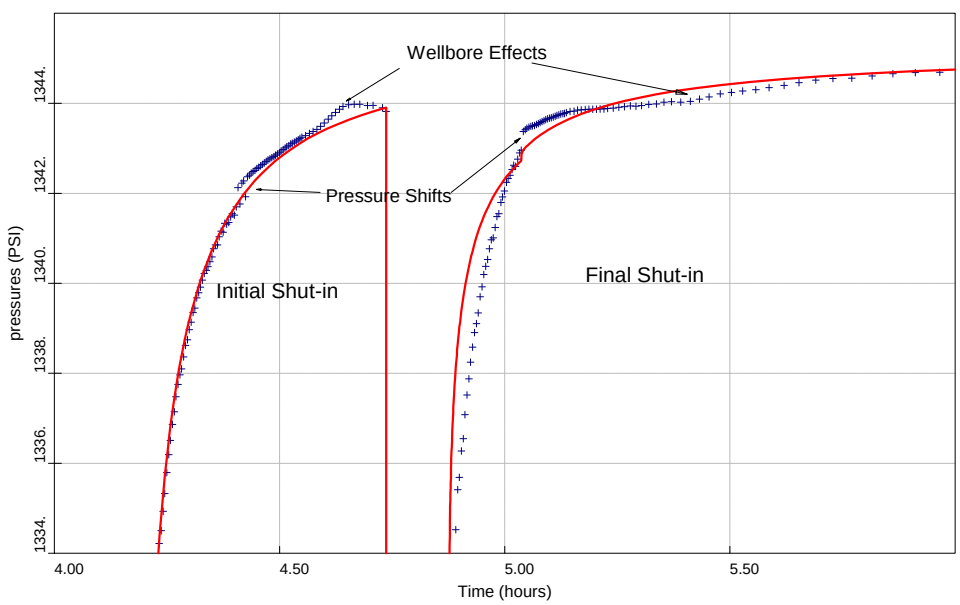


Figure 3 – Expanded pressure plot showing the variations in pressure during the initial and final shut-ins. Upward curvature indicates wellbore effects or mechanical problems and cannot be explained by pressure transient theory.

Analysis

During the second flow period the well essentially killed itself as it loaded up with water. When this happens it is difficult to pick the exact point of shut-in and the difference between the final flowing pressure and the shut-in pressures are very small. The uncertainty in shut-in time along with the variations in pressure shown in the final shut-in (Figure 3) cause significantly more noise in the data during the final shut-in. This is evident from the comparison of the derivatives of the initial and final shut-ins in Figure 4. The derivative of the initial buildup is very well behaved compared to the scatter observed in the final shut-in (Green points). For this reason the analysis is based on the initial shut-in. Data were further conditioned by removing areas where sudden pressure shifts occurred and when the first derivative increased.

Figure 2 shows the derivative of the initial buildup compared to the partial penetration model with 45 ft open to flow. The downward turn in the derivative is not well defined by the data but this feature is picked up by the optimizer in PIE, the pressure transient analyses software used in this analysis. Initial estimates of model parameters were made using straight line analysis of the derivative then these values were improved using the optimizer. The resulting parameters are summarized in Table 1. The partial penetration model is compared to the data in the superposition plot and the pressure history plot in Figures 5 and 6, respectively.

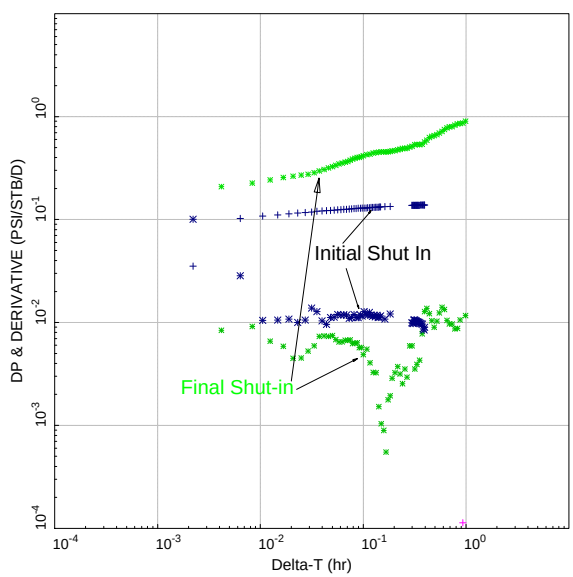


Figure 4 – Comparison of the derivatives of the initial and final shut-in periods of DST-1

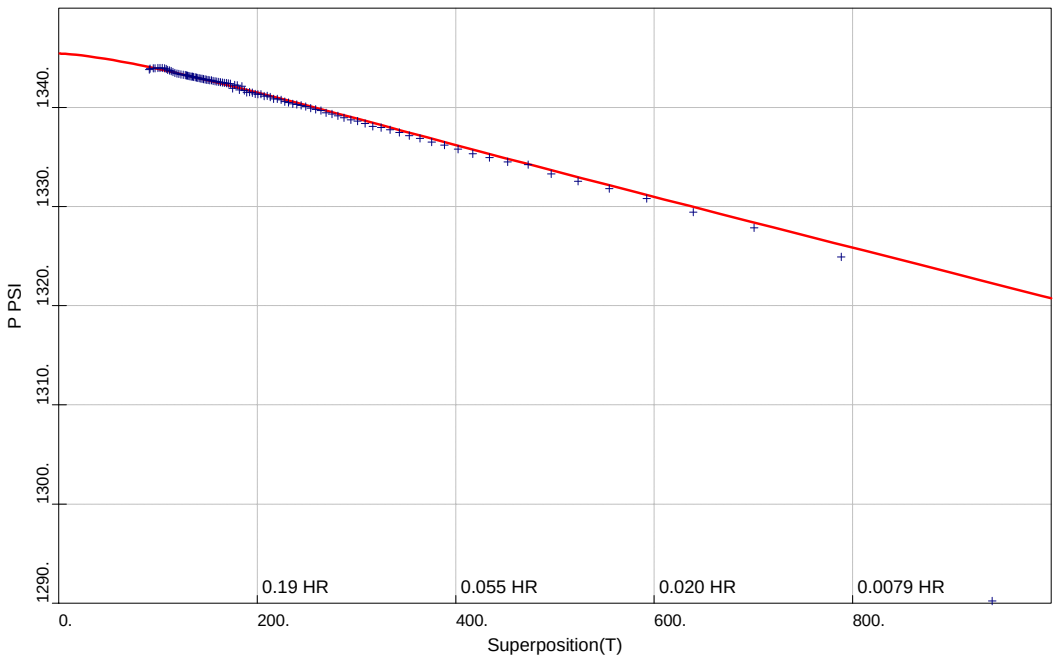


Figure 5 - Comparison of the predictions of the partial penetration model summarized in Table 1 compared to the superposition plot of the initial shut-in of DST-1

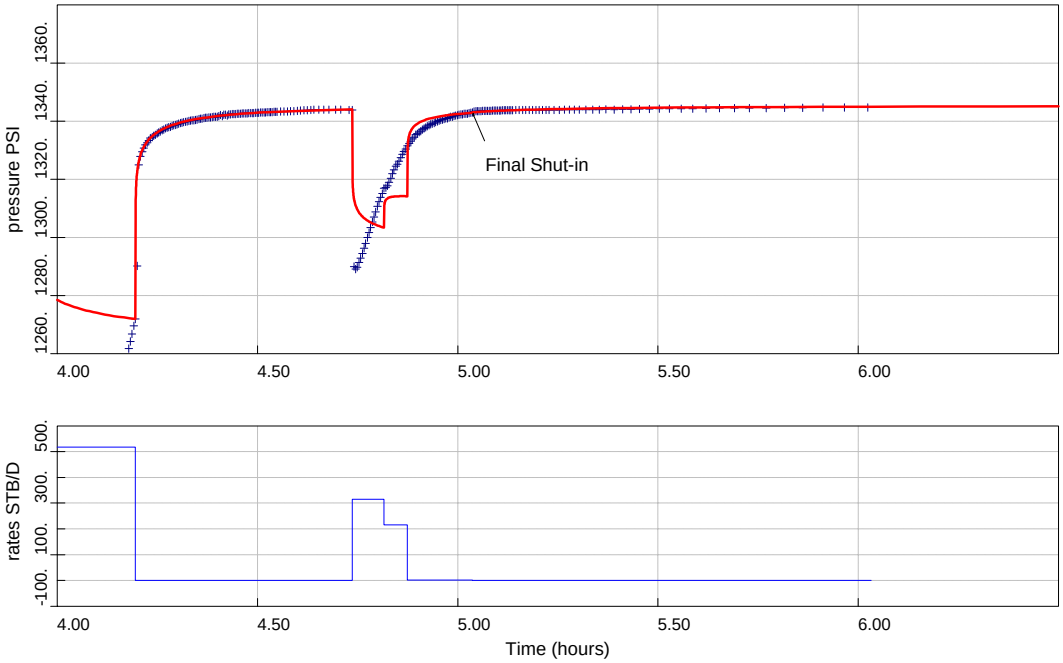


Figure 6 – Comparison of the partial penetration model summarized in Table 1 with the pressure history recorded during DST-1

Sensitivity Study

Since there is uncertainty in the interval contributing to flow during the DST, analyses were made assuming different intervals contributing to early radial flow as shown in Table 2. The 45 feet was the open hole under the packer. However, the estimated top of the St. Peter formation is 3270 ft MD (based on wire line measurements). Using these measurements the productive interval would be 30 feet. Depending on the vertical permeability a greater thickness could be contributing to the early radial flow regime. It is also possible that the drilling resulted in connection below the drilled interval (small fractures) or that the vertical permeability in the contributing layers is high. The interpretations for various effective flow intervals summarized in Table 2 provide an estimate of the uncertainty in the average permeability of the upper St Peter formation. Effective flow interval is defined in this context as the vertical interval which is contributing to the early radial flow regime in the partial penetration model. The entire 200 feet of St Peter formation in included in the model in each case. The intervals listed were provided to me by ISGS staff.

Matches to the data are essentially the same as those shown in Figures 3 – 6 for all of the cases. The appendix shows the derivative match for each of the cases listed in Table 2 along with the input parameters and results. Based on the results the average tested formation permeability ranges from 41.5 to 144 md with the most likely value being 100 md (the actual open interval below the packer). Vertical permeability ratios are reasonable for most of the cases but are seen to increase as the effective productive interval increases. Mechanical skin also increases with completion interval.

Table 2 – Comparison of results of varying the completion interval in the analysis of DST-1 of ADM CCS No.1. The 45 foot Open interval represents the measured open hole below the packer during the test.

Model Parameter	**45 ft Open**	**30 ft Open**	**40 ft Open**	**60 ft Open**	**110 ft Open**
Permeability (md)	**100.3**	144	110	75	41.5
k_v/k_h	**0.10**	0.04	0.1	0.3	1.4
Permeability-Thickness (md-ft) based on 200 ft of net pay	**20,061**	28,868	22,000	15,000	8,300
Completion interval (ft)	**45**	30	40	60	110
Distance of Center of open interval to the top of the formation (ft)	**23**	16	21	31	56
Skin	**0.6**	-0.4	0.4	0.7	1.1
Wellbore Storage (RB/psi)	**$1x10^{-5}$**	$1x10^{-5}$	$1x10^{-5}$	$1x10^{-5}$	$1x10^{-5}$
Formation Pressure (psig)	**1345.4**	1345.1	1345.1	1345.1	1345.3
Depth of Pressure Gauge (ft MD)	**3294**				

Conclusions

Analysis of the data recorded during DST-1 on ADM CCS No.1 results in the following conclusions:

- Data recorded during the initial buildup provided an analyzable response. This response was matched using the limited entry completion (partial penetration) model resulting in average formation permeability for the zone tested of 100 md. The skin and formation pressure determined by the test were 0.6 and 1345.4 psi respectively.
- The well was allowed to load up and kill itself during the final flow period which rendered the final buildup all but useless for pressure transient analysis. Impulse analysis was attempted but this method very seldom results in a satisfactory interpretation.
- Analyses performed with a number of open interval thicknesses resulted in very good matches to the data. These results place the permeability in the range of 41.5 md to 144 md with the most likely value of 100 md. Note that pressure transient analysis determines the transmissivity (kh/μ). Permeability is based on assumed values of thickness, h, and viscosity, μ, from other sources.

Recommendations

In future tests, especially when pressure transient analysis is an objective, it is recommended that the flow periods be conducted to avoid having the well kill itself.

It is also recommended that the service company provide a record of surface activity during the entire test. This should be provided even if no activities are being conducted.

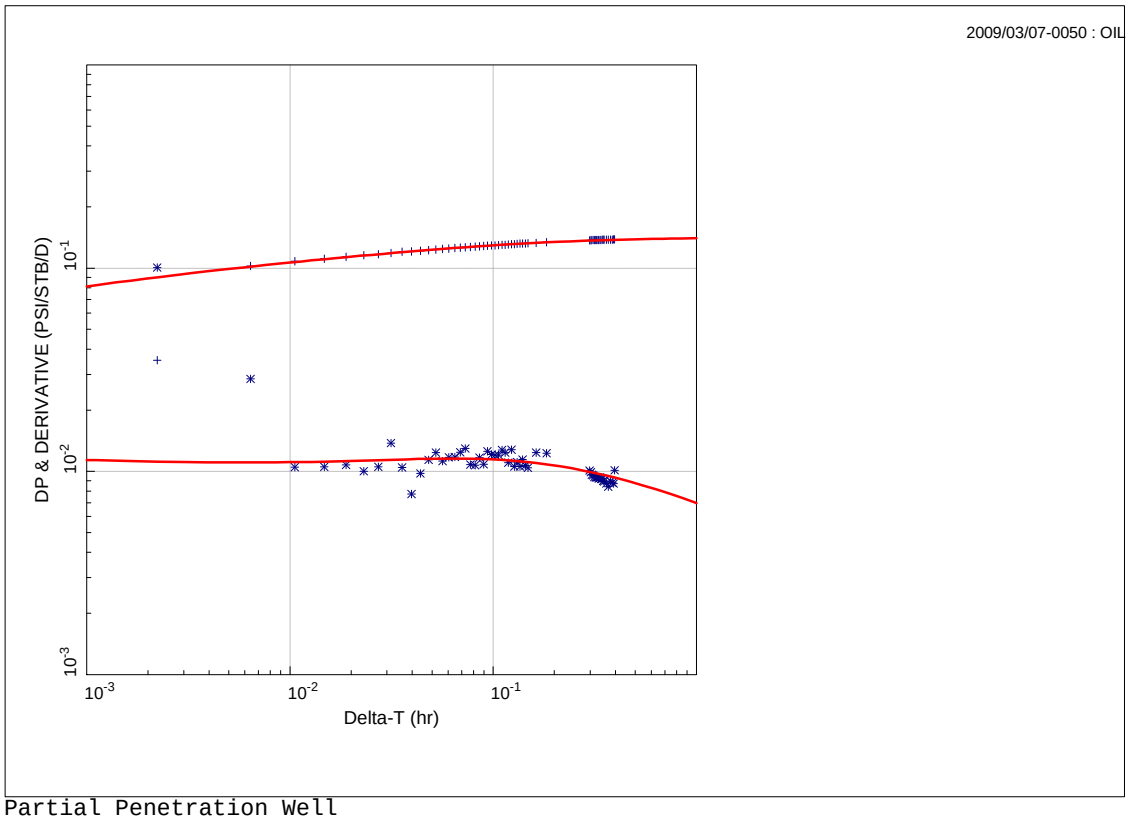
Disclaimer

The analyses presented here are based on the data provided by the client (oral and written) that may or may not be complete. Results are based on these data and the assumptions stated.

Analysis of pressure transients is an inverse problem which by its very nature is non-unique. Other interpretations may exists which provide acceptable matches to the recorded responses.

Appendix

Limited Entry Model with 45 Feet Open



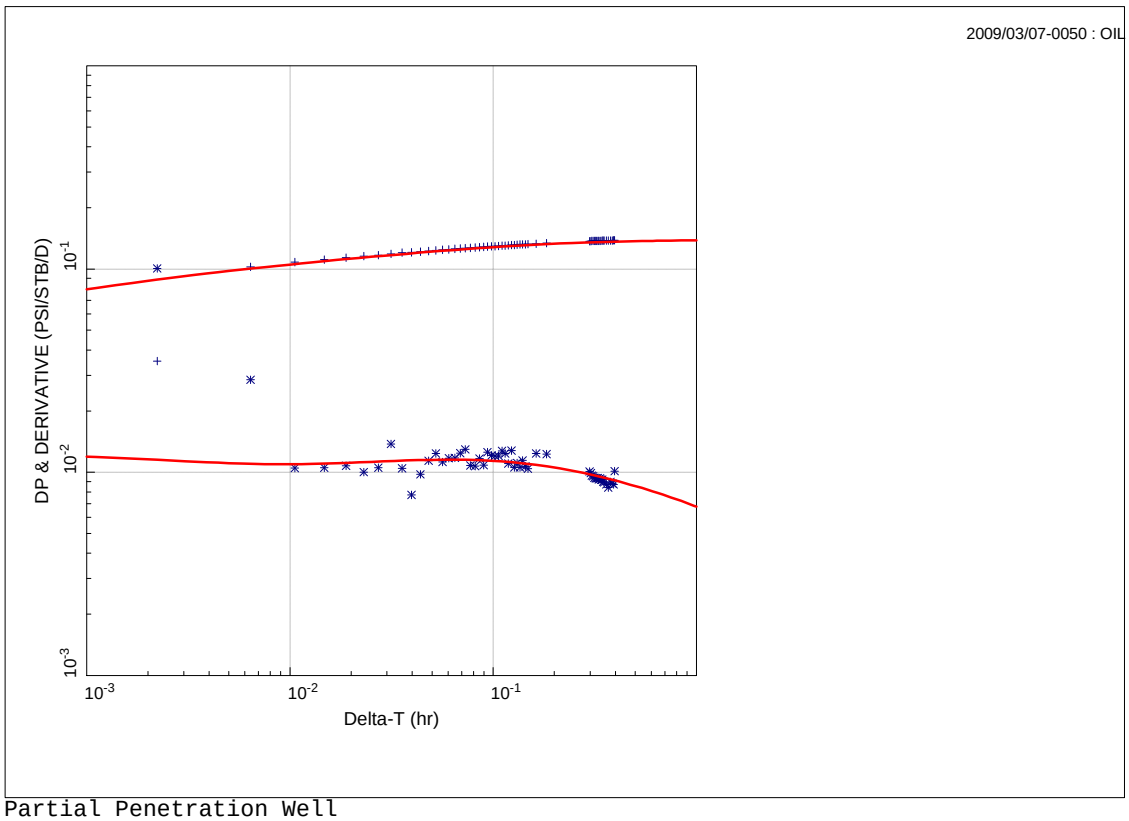

```
Partial Penetration Well
** Simulation Data **
 well. storage  = .7373E-05 BBLS/PSI
 Skin(mech.)    =   0.58857
 permeability   =    100.31 MD
 Kv/Kh          =   0.11733
 Eff. Thickness =    200.00 FEET
 Zp/Heff        =   0.11500
 Skin(Global)   =    23.478
 Perm-Thickness =    20061. MD-FEET
 Initial Press. =   1345.17 PSI
 Smoothing Coef = 0.020,0.
```

```
Type-Curve Model Static-Data
Perf. Interval = 45.0 FEET

Static-Data and Constants
Volume-Factor  = 1.030 vol/vol
Thickness      = 200.0 FEET
Viscosity      = 0.7000 CP
Total Compress = .9270E-05 1/PSI
Rate           = 517.0 STB/D
Storivity      = 0.0003152 FEET/PSI
Diffusivity    = 23980. FEET^2/HR
Gauge Depth    = 3294. FEET
Perf. Depth    = N/A FEET
Datum Depth    = N/A FEET
Analysis-Data  ID: GEC3
Based on Gauge ID: ALL
PFA Starts: 2009-03-07 00:34:30
PFA Ends  : 2009-03-07 01:23:15
```

Figure A1 – Input parameters and analysis results for the limited entry model assuming 45 feet open to the well. Parameters listed under the plot are summarized in Table 1.

Limited Entry Model with 30 Feet Open



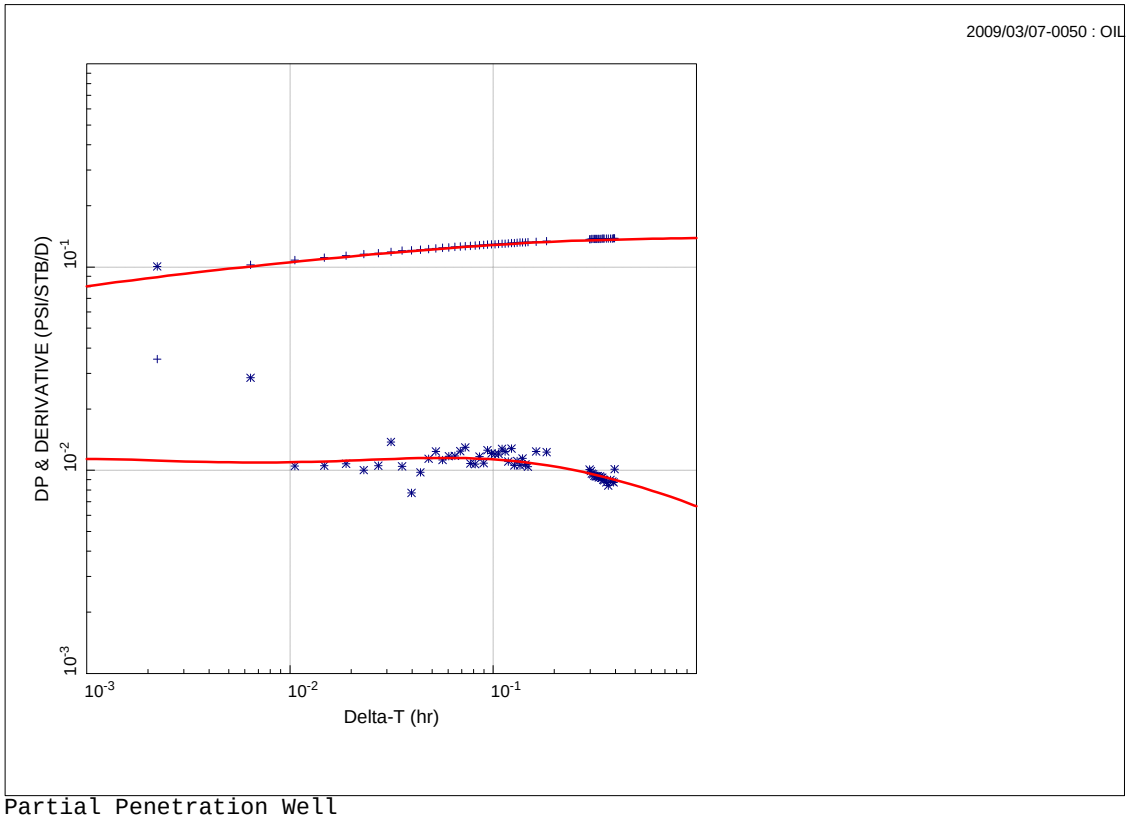

```
Partial Penetration Well
** Simulation Data **
 well. storage  = .1000E-04 BBLS/PSI
 Skin(mech.)    =   0.19309
 permeability   =    144.34 MD
 Kv/Kh          =  0.042344
 Eff. Thickness =    200.00 FEET
 Zp/Heff        =  0.080000
 Skin(Global)   =    36.242
 Perm-Thickness =    28868. MD-FEET
 Initial Press. =   1345.08 PSI
 Smoothing Coef = 0.020,0.
```

```
Type-Curve Model Static-Data
Perf. Interval = 30.0 FEET

Static-Data and Constants
Volume-Factor  = 1.030 vol/vol
Thickness      = 200.0 FEET
Viscosity      = 0.7000 CP
Total Compress = .9270E-05 1/PSI
Rate           = 517.0 STB/D
Storivity      = 0.0003152 FEET/PSI
Diffusivity    = 34500. FEET^2/HR
Gauge Depth    = 3294. FEET
Perf. Depth    = N/A FEET
Datum Depth    = N/A FEET
Analysis-Data  ID: GEC3
Based on Gauge ID: ALL
PFA Starts: 2009-03-07 00:34:30
PFA Ends  : 2009-03-07 01:23:15
```

Figure A2 – Input parameters and analysis results for the limited entry model assuming 30 feet open to the well. Parameters listed under the plot are summarized in Table 2.

Limited Entry Model with 40 Feet Open



Partial Penetration Well

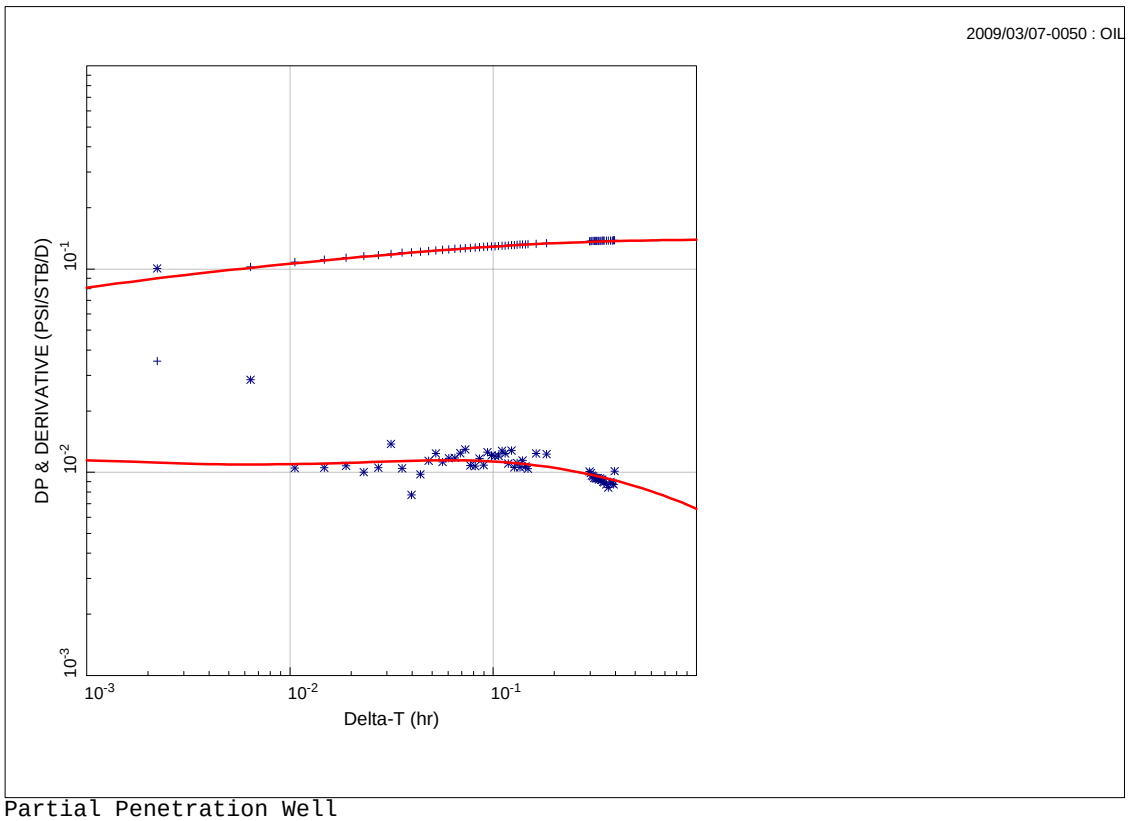
```
** Simulation Data **
 well. storage  = .1000E-05 BBLS/PSI
 Skin(mech.)    =   0.40000
 permeability   =    110.00 MD
 Kv/Kh          =  0.099975
 Eff. Thickness =    200.00 FEET
 Zp/Heff        =   0.10500
 Skin(Global)   =    25.913
 Perm-Thickness =    22000. MD-FEET
 Initial Press. =   1345.10 PSI
 Smoothing Coef = 0.020,0.
```

```
Type-Curve Model Static-Data
Perf. Interval = 40.0 FEET

Static-Data and Constants
Volume-Factor  = 1.030 vol/vol
Thickness      = 200.0 FEET
Viscosity      = 0.7000 CP
Total Compress = .9270E-05 1/PSI
Rate           = 517.0 STB/D
Storivity      = 0.0003152 FEET/PSI
Diffusivity    = 26300. FEET^2/HR
Gauge Depth    = 3294. FEET
Perf. Depth    = N/A FEET
Datum Depth    = N/A FEET
Analysis-Data  ID: GEC3
Based on Gauge ID: ALL
PFA Starts: 2009-03-07 00:34:30
PFA Ends  : 2009-03-07 01:23:15
```

Figure A3 – Input parameters and analysis results for the limited entry model assuming 40 feet open to the well. Parameters listed under the plot are summarized in Table 2.

Limited Entry Model with 60 Feet Open



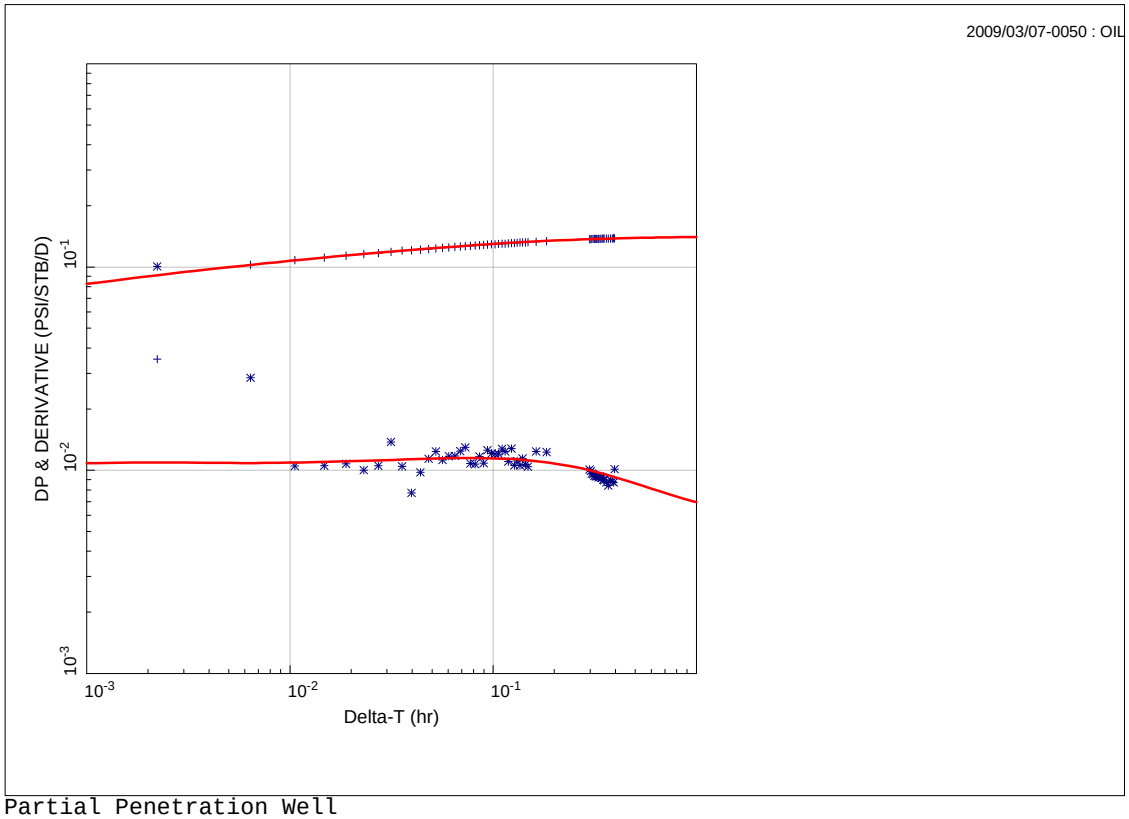

```
Partial Penetration Well
** Simulation Data **
 well. storage  = .1000E-04 BBLS/PSI
 Skin(mech.)    =   0.71010
 permeability   =    75.000 MD
 Kv/Kh          =   0.30000
 Eff. Thickness =    200.00 FEET
 Zp/Heff        =   0.15500
 Skin(Global)   =    15.742
 Perm-Thickness =    15000. MD-FEET
 Initial Press. =   1345.10 PSI
 Smoothing Coef = 0.020,0.
```

```
Type-Curve Model Static-Data
Perf. Interval = 60.0 FEET

Static-Data and Constants
Volume-Factor  = 1.030 vol/vol
Thickness      = 200.0 FEET
Viscosity      = 0.7000 CP
Total Compress = .9270E-05 1/PSI
Rate           = 517.0 STB/D
Storivity      = 0.0003152 FEET/PSI
Diffusivity    = 17930. FEET^2/HR
Gauge Depth    = 3294. FEET
Perf. Depth    = N/A FEET
Datum Depth    = N/A FEET
Analysis-Data  ID: GEC3
Based on Gauge ID: ALL
PFA Starts: 2009-03-07 00:34:30
PFA Ends  : 2009-03-07 01:23:15
```

Figure A4 – Input parameters and analysis results for the limited entry model assuming 60 feet open to the well. Parameters listed under the plot are summarized in Table 2.

Limited Entry Model with 110 Feet Open



Partial Penetration Well

```
** Simulation Data **
 well. storage  = .1000E-05 BBLS/PSI
 Skin(mech.)    =    1.1000
 permeability   =    41.500 MD
 Kv/Kh          =    1.4000
 Eff. Thickness =    200.00 FEET
 Zp/Heff        =   0.28000
 Skin(Global)   =    6.3398
 Perm-Thickness =    8300.0 MD-FEET
 Initial Press. =   1345.34 PSI
 Smoothing Coef = 0.020,0.
```

```
Type-Curve Model Static-Data
Perf. Interval = 110. FEET

Static-Data and Constants
Volume-Factor  = 1.030 vol/vol
Thickness      = 200.0 FEET
Viscosity      = 0.7000 CP
Total Compress = .9270E-05 1/PSI
Rate           = 517.0 STB/D
Storivity      = 0.0003152 FEET/PSI
Diffusivity    = 9920. FEET^2/HR
Gauge Depth    = 3294. FEET
Perf. Depth    = N/A FEET
Datum Depth    = N/A FEET
Analysis-Data  ID: GEC3
Based on Gauge ID: ALL
PFA Starts: 2009-03-07 00:34:30
PFA Ends  : 2009-03-07 01:23:15
```

Figure A5 – Input parameters and analysis results for the limited entry model assuming 110 feet open to the well. Parameters listed under the plot are summarized in Table 2.

Interpretation of Wireline Log Data in the St. Peter Sandstone
ADM Company – CCS Well #1

Prepared by Robert J. Butsch, Schlumberger Carbon Services, Sugar Land, TX
Edited by Edward Mehnert, Illinois State Geological Survey, Champaign, IL

Summary

Openhole wireline logs were run in the ADM CCS #1 well in Decatur, Macon County, Illinois. One of the primary purposes of the logs was to determine the salinity of the water in the St. Peter Sandstone.

Based on the analysis of the wireline logs, the salinity of the water in the St. Peter Sandstone appears to be increasing with depth from about 7,900 mg/L NaCl (equivalent) at the top of the formation to about 12,600 mg/L NaCl (equivalent) at the bottom of the formation. The change in salinity in the formation is likely due to gravity segregation with the denser, higher salinity water settling to the bottom of the formation. The formation and fluid properties resulting from the analysis over selected intervals within the St. Peter are listed in Table 1, as well as average values calculated for the entire zone which is 202 feet thick. Figure 1 is a graphical view of this analysis.

Table 1. Summary of salinity calculations for the St. Peter fluids from CCS #1

Formation	Top (ft)	Bottom (ft)	Thickness (ft)	Av Phi (--)	Av Vcl (--)	Av Sal2 (mg/L)	Av Sal185 (mg/L)
St. Peter top	3268	3278	10.5	0.206	0.144	10,239	7,947
St. Peter middle	3278	3382	103.5	0.209	0.067	13,796	10,701
St. Peter lower	3382	3470	88.0	0.168	0.059	16,856	12,598
Thickness weighted average						14,944	11,384
Pore volume weighted average						14,769	11,274

Notes:
1) Top and Bottom depths are given with respect to the Kelly Block, which was set at elevation 689.85 ft. The ground elevation was 674.22 ft.
2) Abbreviations used: Av Phi – Average porosity, Av Vcl – Average volume of shale, Av Sal2 – Average salinity using m=2.0, Av Sal185 – Average salinity using m=1.85
3) Thickness weighted average= Σ(thickness*salinity)/ Σ thickness
4) Pore volume weighted average= Σ(thickness*porosity*salinity)/ Σ(thickness*porosity)

The Logging Program

The logging program consisted of a single run of the Platform Express (PEX). These logs were run March 9, 2009 in an open borehole (i.e., no casing in the borehole). The PEX is actually a combination of several tools that make up what is commonly referred to as a Triple Combo. The three main tools that are contained in this logging tool combination are the resistivity, the density, and the neutron tools. Several other tools and measurements are also included in the normal tool string and Table 2 lists the tools (measurements) and their common use in the analysis. A brief explanation of the various logs appears in Figure 1 and 2.

Table 2. Logging Tools Run

Logging Run	Logging tools	Data Used For:
PEX (Platform Express)	GR – Gamma Ray	Correlation and Volume of Shale
	SP – Spontaneous Potential	Correlation and Volume of Shale
	Caliper	Hole size
	Resistivity	Correlation, Saturations / Salinity
	Density	Density Porosity, Fluid Type
	Neutron	Neutron Porosity, Fluid Type

Interpretation of the data

The interpretation of the data was based on the Archie formula and the following steps were taken:

1. Data QC to verify all data are good and on depth with all other data.
2. Compute volume of shale using GR, SP, and Density/Neutron cross plot.
3. Compute porosity using Density/Neutron cross plot
4. Use Pickett plot to select value for "m" in Archie formula.
5. Compute Apparent Water Resistivity (Rwa) using Archie formula assuming formation contains all water or Sw=100%
6. Compute salinity NaCl (equivalent) from the resulting Rw.

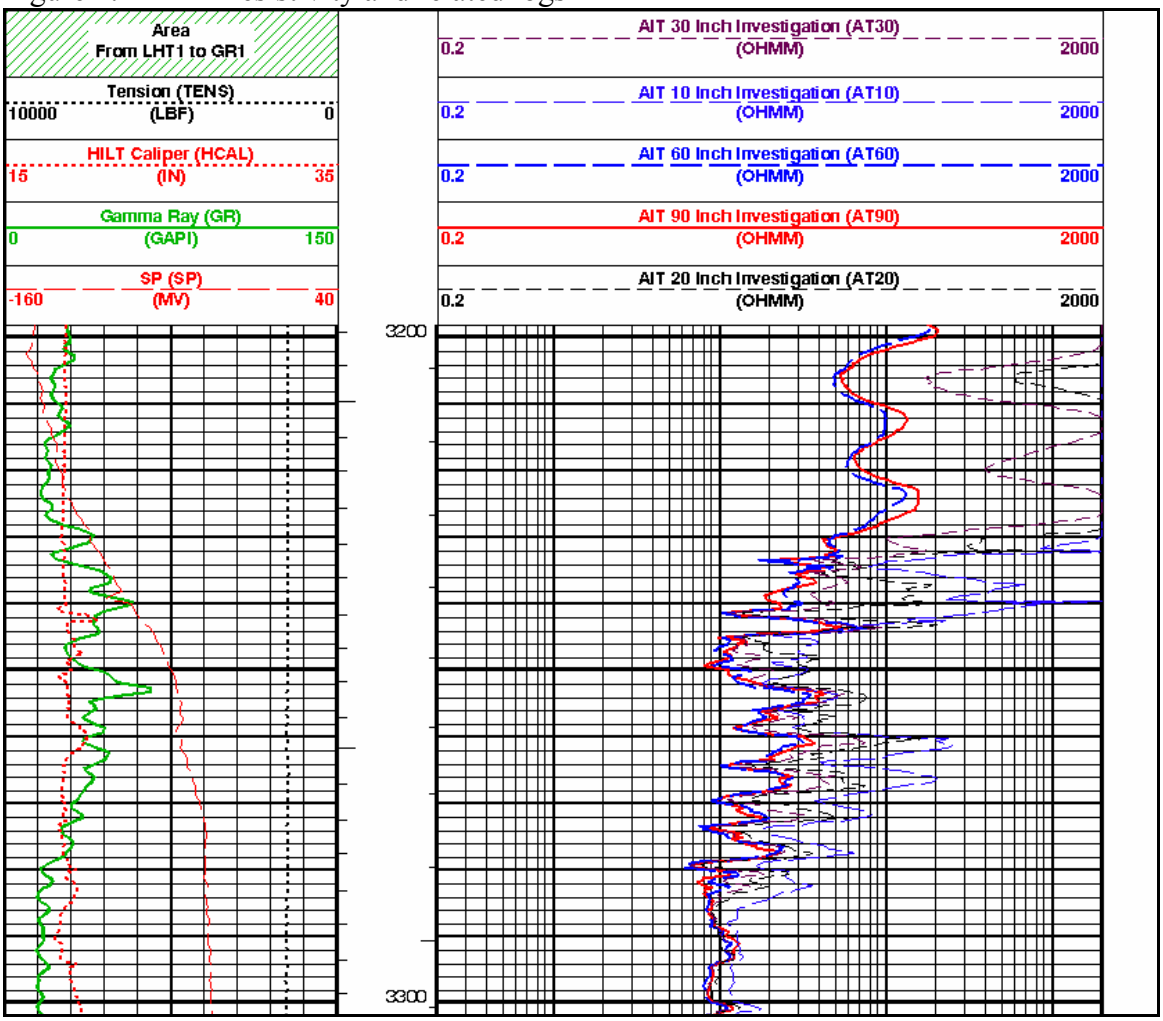
The Archie formula is the oldest and most widely used equation for solving log data for water saturation. The formula is:

$$Sw^n = (a * R_w) / (\Phi^m * R_t)$$

Where:
Sw = Water Saturation
n = Saturation Exponent (normally = 2.0)
a = empirically derived correction factor (normally = 1.0)
R_w = Resistivity of the water
Φ = Porosity
m = Cementation factor (normally = 2.0)
R_t = True Resistivity of the un-invaded formation

For this analysis rather than using the equation and measurements to solve for water saturation, the water saturation will be assumed to be 100%. The equation can then be used to solve for the resistivity of the water which is usually an input parameter. The parameters "a" and "n" can have some affect on the analysis but in many cases the amount of change is not significant, and these parameters are difficult to measure. The default values of 1 and 2 will be used respectively for these parameters. The value of "m" is easier to determine as this can be done by the use of the Pickett plot. The Pickett plot is a cross plot of porosity versus resistivity and can be used for determining the average value of R_w in a zone as well as "m". "m" is determined by the slope of the line that can be drawn through the highest frequency of data points in a water bearing formation. Figures 4 and 5 are Pickett plots of the St. Peter Sandstone with lines that represent different "m" values. Figure 4 has an "m" of 2.0 and Figure 5 has an "m" of 1.85. The value of m=1.85 was selected as the most appropriate value for this formation, but the results using a "m" value of 2.0 are also presented since this is the most commonly used value in sandstone. It can

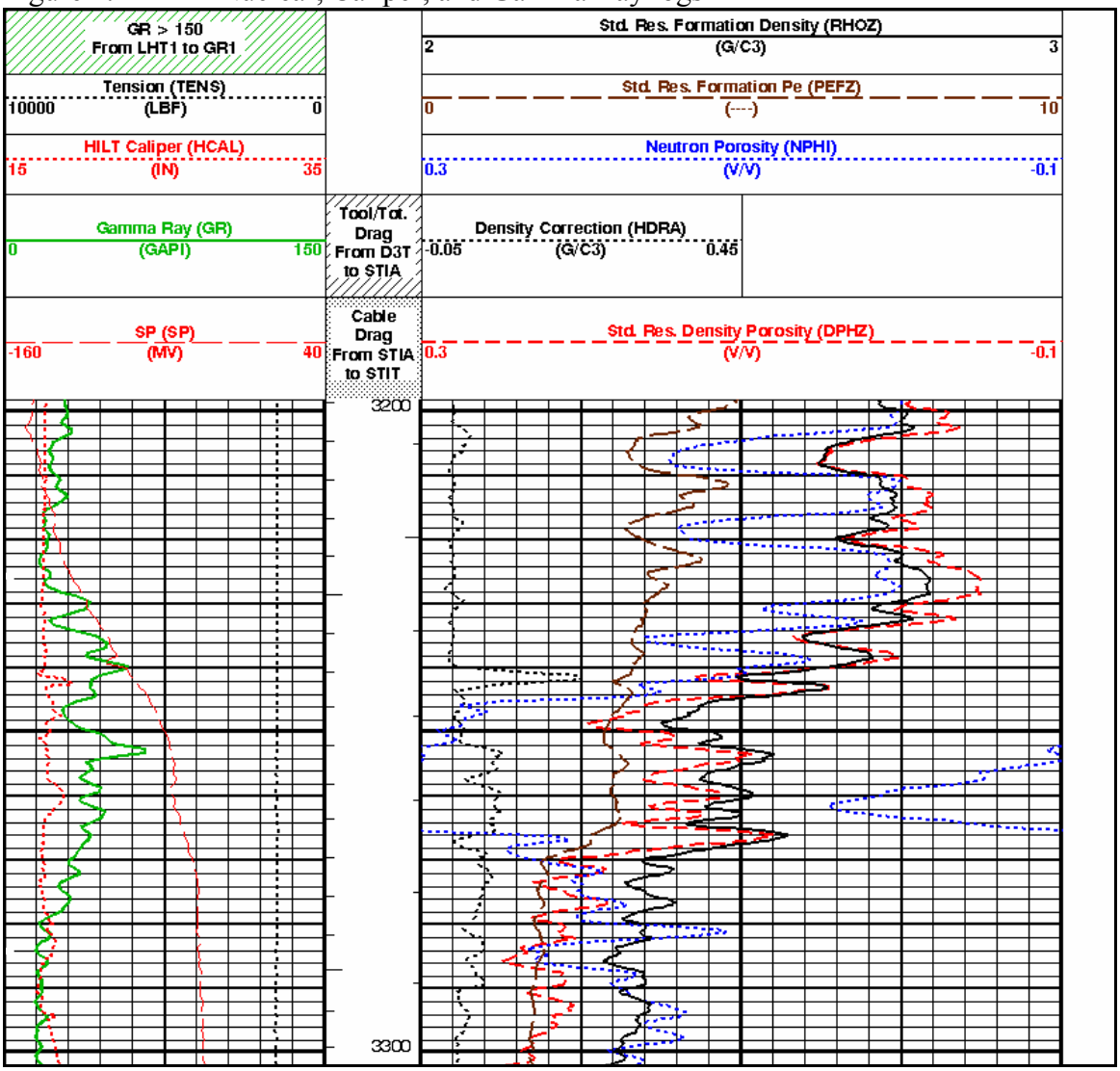
Figure 1. PEX – Resistivity and related logs



Track 1 (left side)
Tension – Tension on the cable while logging. This can indicate pick-up or pulls where tool stops.
SP (Spontaneous Potential) – Can be used as an indicator of sand/shale.
Caliper – A measurement of the borehole size on one axis.
Gamma Ray – Measurement of naturally occurring gamma rays. An indicator of sand/shale.

Tracks 2 & 3 (right side)
AIT Mud – Resistivity of the drilling mud.
AIT90 – Array Induction measurement with 90 inch radial depth of investigation.
AIT60 – Array Induction measurement with 60 inch radial depth of investigation.
AIT30 – Array Induction measurement with 30 inch radial depth of investigation.
AIT20 – Array Induction measurement with 20 inch radial depth of investigation.
AIT10 – Array Induction measurement with 10 inch radial depth of investigation.

Figure 2. PEX – Nuclear, Caliper, and Gamma Ray logs



Track 1 (left side)

Tension – Tension on the cable while logging. This can indicate pick-up or pulls where tool stops.

SP (Spontaneous Potential) – Can be used as an indicator of sand/shale.

Caliper – A measurement of the borehole size on one axis.

Gamma Ray – Measurement of naturally occurring gamma rays. An indicator of sand/shale.

Tracks 2 & 3 (right side)

PEFZ – Photoelectric Effect. This is used for lithology identification.

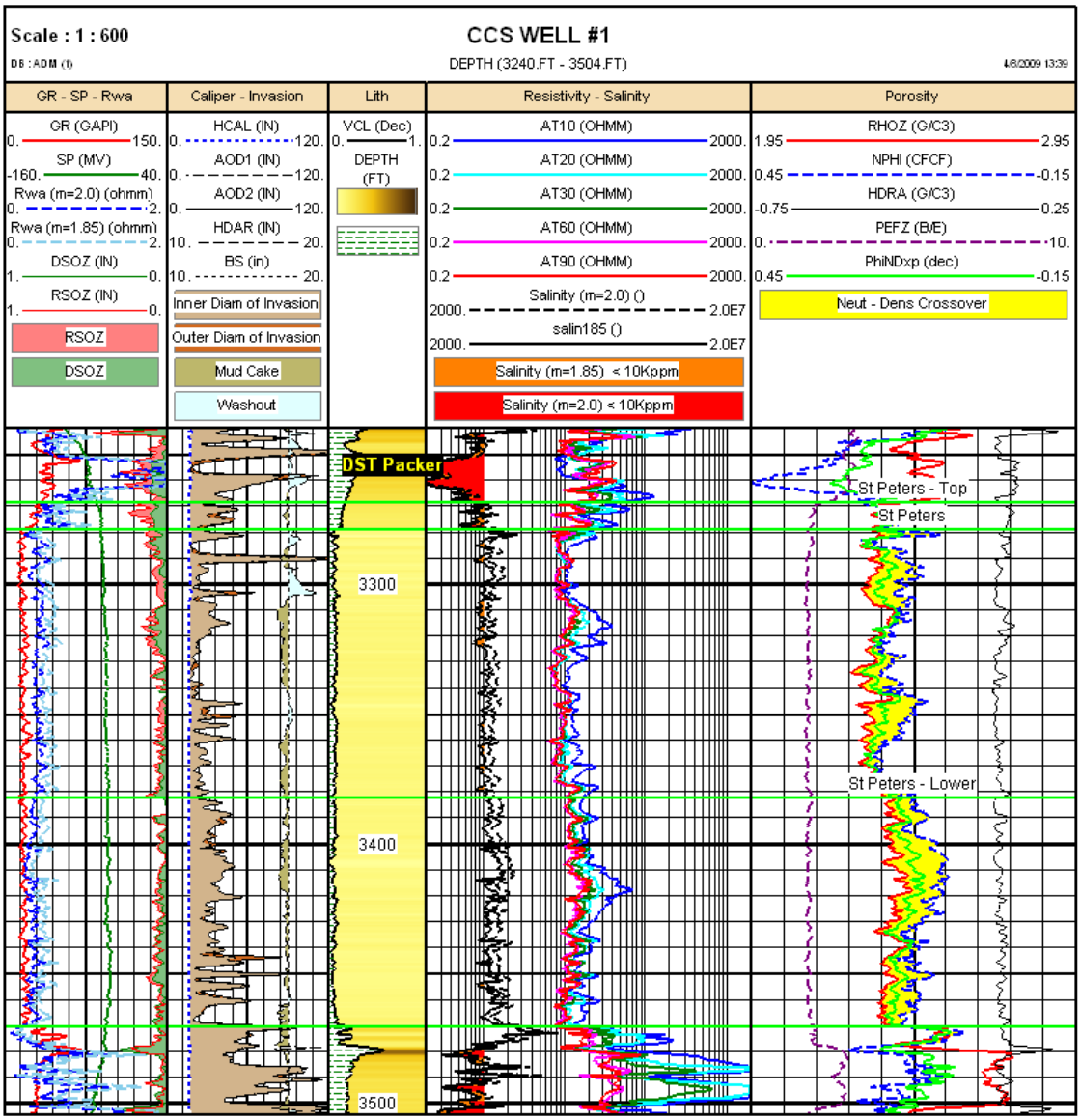
RHOZ – Measurement of the bulk density of the formation. This is used in combination with the neutron and sonic for lithology identification as well as identification of fluids in the porosity.

NPHI - Measurement of the neutron porosity of the formation. This is used in combination with the density and sonic for lithology identification as well as identification of fluids in the porosity.

HDRA – This is the correction that has been applied to the density measurement to account for things like mudcake. This is used as a quality control indicator for the density measurement.

DPHZ – This is the porosity calculated using the bulk density measurement assuming the porosity is water-filled.

Figure 3. Salinity Analysis of the St. Peter Sandstone



Track 1 – GR-SP-Rwa (left side)
Gamma Ray – Measurement of naturally occurring gamma rays. An indicator of sand/shale
SP (Spontaneous Potential) – Can be used as an indicator of sand/shale.
RSOZ – Resistivity Standoff, Quality control indicating enlarged borehole.
DSOZ – Density Standoff, Quality control indicating enlarged borehole.
Rwa (m=2.0) – Apparent water resistivity using an m value of 2.0 in the Archie equation.
Rwa (m=1.85) – Apparent water resistivity using an m value of 1.85 in the Archie equation.

Track 2 – Caliper-Invasion (left center)
HCAL – Caliper measurement, shows hole size
HDAR – Hole Diameter measurement, shows hole size
BS – Bit Size
AOD1 – Calculated Inner Diameter of Invasion
AOD2 - Calculated Inner Diameter of Invasion

Track 3 – Lithology (center)
VCL – Indicates total volume of clay and volume of sand (no porosity)

Depth – Measured Depth

Track 4 – Resistivity – Salinity (right center)
AIT10 – Array Induction measurement with 10 inch radial depth of investigation.
AIT20 – Array Induction measurement with 20 inch radial depth of investigation.
AIT30 – Array Induction measurement with 30 inch radial depth of investigation.
AIT60 – Array Induction measurement with 60 inch radial depth of investigation.
AIT90 – Array Induction measurement with 90 inch radial depth of investigation.
Salinity (m=2.0) – Salinity calculated from Rwa using m=2.0 in Archie equation.
Salinity185 – Salinity calculated from Rwa using m=1.85 in Archie equation.

Track 4 – Porosity (right)
PEFZ – Photoelectric Effect. This is used for lithology identification.
RHOZ – Measurement of the bulk density of the formation. This is used in combination with the neutron and sonic for lithology identification as well as identification of fluids in the porosity.
NPHI - Measurement of the neutron porosity of the formation. This is used in combination with the density and sonic for lithology identification as well as identification of fluids in the porosity.
HDRA – This is the correction that has been applied to the density measurement to account for things like mudcake. This is used as a quality control indicator for the density measurement.
PhiNDxp – Calculated "Cross plot" porosity using Density and Neutron measurements.

be noted that using the "m" value of 2.0 increases the salinity. The continuous outputs of salinity can be seen on the log and the average values over the selected intervals can be seen in Table 1. In Table 1, the Av Sal2 is the values with m= 2.0 and the Av Sal185 is the values with m= 1.85.

Figures 4 and 5 were made using data from the entire interval of the St. Peter and are presented as frequency plots. To understand the relationship between "m" and Rw in the three intervals that have been identified within the St. Peter, Pickett plots have been made for each of the intervals and are presented as Figures 6, 7, and 8. When comparing the Pickett plots of the three intervals within the St. Peter, the slope of the data remains constant yet the points within a section plot differently relative to the plotted line that was derived using all points. As the points move down and to the left, this would indicate that the salinity is increasing. As the points move up and to the right as in Figure 8, this would indicate that the salinity of the water is decreasing.

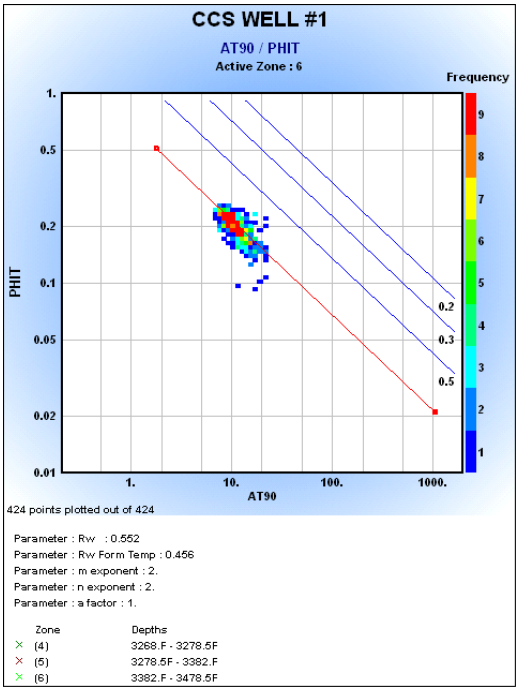


Figure 4. Pickett plot, m=2

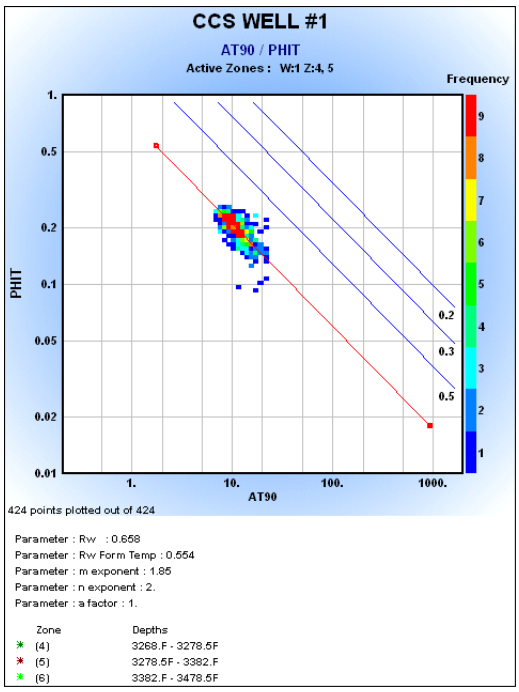


Figure 5. Pickett plot, m=1.85

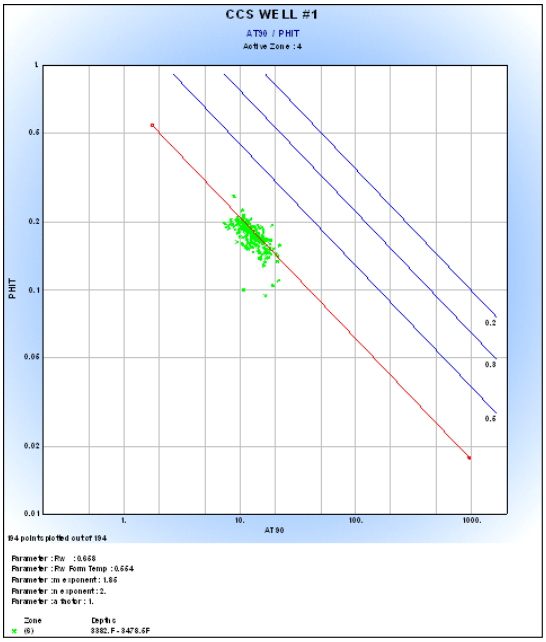


Figure 6. Pickett plot of St. Peter (bottom)

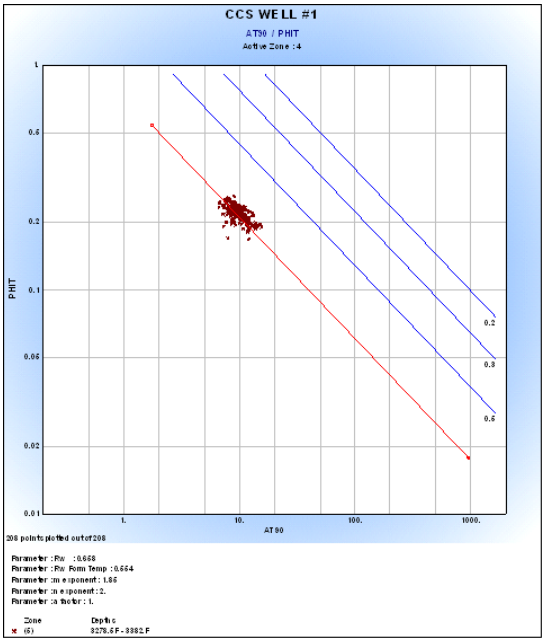


Figure 7. Pickett plot of St. Peter (middle)

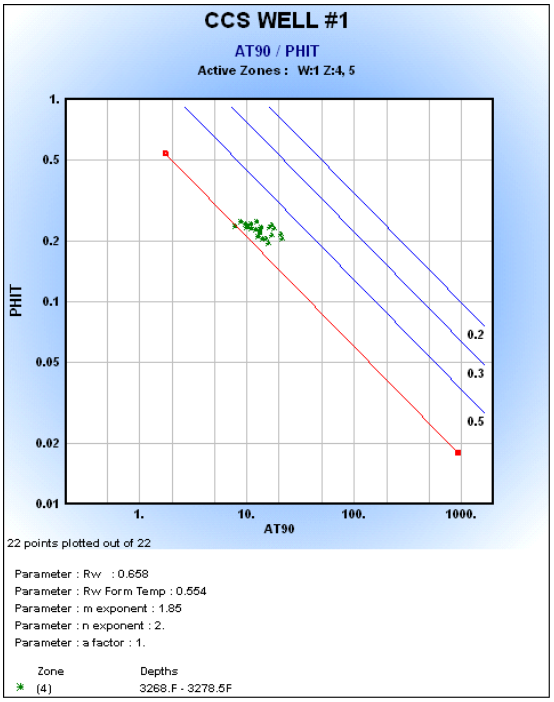


Figure 8. Pickett plot of St. Peter (top)

Testing of the Pennsylvanian Bedrock

E. Mehnert, S. Frailey, A. Iranmanesh, Ivan G. Krapac, T.C. Young, ISGS Draft: 6/23/09

Introduction

Per its Underground Injection Control Class I permit with Illinois Environmental Protection Agency, ADM is required to monitor the lowermost underground source of drinking water (USDW). A USDW is defined based on its hydraulic conductivity (K> $1x10^{-4}$ cm/sec) and its water quality (total dissolved solids <10,000 mg/L). At the time that the permit was issued, the available data indicated that the lowermost USDW would be found in the St. Peter Sandstone or at a depth greater than 200 feet and less than 800 feet beneath the ADM facility. The 200 foot depth was determined by water sampling in MMV-01, which is approximately 100 feet north of the injection well. The 800-foot depth was determined from analysis of resistivity logs by Illinois State Geological Survey (ISGS) scientists for wells approximately 5 miles west of the ADM facility. The bedrock beneath the ADM facility, at depths exceeding 800 feet, is Pennsylvanian-age bedrock.

To locate the lowermost USDW within the Pennsylvanian bedrock, the ISGS collected core of the Pennsylvanian bedrock and ran a number of tests. Packer testing was conducted to determine in situ hydraulic conductivity. Geophysical logs were run to determine the rock and pore fluid properties and included natural gamma, SP, single point resistivity (SPR), resistivity (8", 16", 32" & 64") and fluid temperature/resistivity. In addition, fluid samples were collected using a discrete interval sampler, which is a stainless steel tool that allows borehole fluid to flow into an air-filled chamber at the desired depth. The results for the coring, geophysical logging, and fluid sampling are summarized below.

Drilling and Coring Operations

The corehole was named MMV-04B (API= 121152339600) and is located in Macon Co., Sec 32 T17N R3E. This site is located approximately 200 feet SE of the intersection of Brush College Rd. and Rea's Bridge Rd. in Decatur and approximately 1,850 northwest of ADM CCS#1 (injection well). Ground surface elevation of the drilling site is approximately 681 ft above MSL.

Materials in this borehole were not sampled to a depth of 148 ft, but the bedrock surface was found at an approximate depth of 120 feet (±5 feet). Albrecht Well Drilling (Ohio, IL) was hired to drill through the Quaternary sediments and into the upper bedrock. The borehole was drilled using an Ingersoll-Rand TH-60 drill rig equipped with a 10-inch tri-cone roller bit. This mud rotary rig used a bentonite based mud for this portion of the project. Albrecht installed 6 inch, steel casing from the ground surface to 148 feet below ground surface. This casing was cemented with neat cement slurry using the Halliburton method. The cement was supplied by Grohne Concrete (Decatur, IL). All water used for drilling and coring was supplied by ADM. This portion of the project was conducted from February 16 through February 19, 2009.

Beginning at a depth of 148 ft, HQ-sized core (2.5 inch outside diameter) was collected by a CME-75 coring rig and a wireline coring system owned and operated by Raimonde Drilling Corporation (Addison, IL). The coring system used diamond bits and water as the drilling fluid. The core barrel was spun at a high rate, approximately 800 revolutions per minute. Wireline coring was used to collect core to a depth of 504 feet. Core recovery from this borehole was excellent, with RQD (Rock Quality Designation) generally greater than 95%. This portion of the project was conducted from February 23 through February 28, 2009. The bedrock materials recovered from this borehole are described in Table 1.

Table 1. Brief Geologic Log for MMV-04B (Macon Co., Sec 32 T17N R3E, API = 121152339600)

Depth (ft)	Description
0-148	Not sampled
148-165	Shale, gray with thin siltstone and sandstone (156.75-156.95 ft) layers
165-171	Limestone, gray, fossiliferous, with shale layer (169.7-170.1)
171-183	Shale, gray and black (171.8-174.0)
183-224	Siltstone with shale and sandstone (184.0-184.2, 214.0-214.2) interbedded
224-229	Shale, gray and brown
229-244	Limestone, greenish gray, some weathering?
244-250	Siltstone, shaley
250-257	Carbonate (LS or dolomite)
257-259	Shale, black, organic rich & oily (256.8-259.2)
259-263	Carbonate, gray, fossiliferous, fractured
263-266	Siltstone, laminated, softened by drilling
266-299	Sandstone, fine grained, slickensided face at 272, 275.4, 45 deg fracture at 296.2-296.6, laminated, horizontal and some deformed beds
299-303	Interbedded sandstone and siltstone, light to dark, greenish gray
303-304	Shale, black (0.9 ft) and coal (0.4 ft)
304-309	Shale, dark gray, laminated, heavy fossil concentration at 309.1-310
309-324	Limestone, dark greenish gray, slickensided fracs noted at 311.4, 312.0, 312.6, 315.0, core cut rough 314-317.5
324-330	Siltstone to shale (finer grained at bottom), reddish brown to greenish gray
330-359	Interbeds of gray shale and limestone
359-374	Limestone with shale (green to black) at 367.8-369.8 Carthage/Shoal Creek LS?
374-382	Interbedded shale, limestone & shale
382-383	Sandstone, very fine grained, beige to greenish gray Inglefield Sandstone?
383-390	Siltstone
390-405	Sandstone with siltstone interbeds, fine grained Trivoli Sandstone?
405-414	Siltstone with shale interbeds
414-424	Shale, gray
424-425	Coal
425-440	Shale with siltstone interbeds
440-459	Limestone with black shale at 449.8-450.1 West Franklin LS?
459-460	Shale, black & gray
460-504	Siltstone, greenish gray, vertical fractures at 488-489 & 493-494 (slickensided) Farmington Shale?

Upon completion of coring, the borehole was backfilled to a depth of 295 feet using gravel pack and bentonite pellets. This backfill was designed to hydraulically seal the monitored interval from groundwater in deeper sediments and to provide a stable base to build the well. For reasons to be explained below, a bentonite plug was set at a depth of 295 to 325 feet, while intervals of gravel pack and bentonite chips were used to backfill deeper portions of the borehole. After backfilling, the borehole was reamed by Albrecht using the mud and air rotary methods. A 6-inch diameter, tri-cone roller type TCI (tungsten carbide insert) bit was used, while water was utilized as the drilling fluid. Because borehole stability was an issue, the borehole was also

cleaned out using air rotary drilling with foam drilling fluid. After the borehole was completed, the monitoring well was constructed. See the **Monitoring Well Design** section for additional details. This portion of the project was conducted from March 5 through March 13, 2009.

The monitoring well was developed using a bailer from March 17 and 19 and May 12, 2009.

Geophysics/Borehole Logging

For borehole logging, the ISGS uses an MGXII data acquisition system manufactured by the Mount Sopris Instrument Company (MSI, Golden, CO). The wireline winch is a Mount Sopris, 4WNA-1000 model capable of holding 1,800 meters (or 5,900 feet) of 3/16" steel-armored, single- conductor coaxial cable. The entire system is mounted in a 2000 Ford Excursion. Probes used in the MMV-04B corehole included the: 1) 2PFA-1000 Fluid-Temperature & Resistivity probe, made by MSI, 2) 2PGA-1000 combination Natural Gamma, Self-Potential (SP), Single-Point Resistance (SpR), and 8", 16", 32", 64" Normal Resistivity probe, made by MSI, 3) ABI-40 Acoustic Televiewer Probe, made by Advanced Logic and Technology (Luxembourg), and 4) Model 006-4002-204 Fluid Sampler, made by Mineral Logging Systems (MLS, Houston, TX).

The fluid temperature & resistivity (FTR) probe was calibrated at between 1.75 to 94.3 ohm-m and the temperature between 5.5°C and 63.8°C. These calibration values were used to log MMV-04B. Fluid conductivity is the inverse of resistivity and is more commonly reported. The fluid resistivity values used for calibration convert to 0.106 (94.3 ohm-m) and 5.70 mS/cm (1.75 ohm-m). The fluid sampler is approximately 8 feet in length and less than 2 inch O.D. with a sample capacity of 2 quarts. The operation of the fluid sampler is relatively simple. The sampler is a stainless steel probe, designed with the sampling tube at the bottom, and a plunger or valve that is machined for 2 o-rings. The valve is actuated up and down by applying negative or positive voltages to a worm gear. A series of portholes are located above the seated valve at the closed position, preventing fluid from entering the tube while going downhole. When the sampler is positioned at the desired depth, a negative voltage is applied to the probe, which opens the valve upward and above the ports, allowing fluid to fill the tube. The expulsion of air and replacement of fluid can occur rapidly and will likely be detected by the weight indicator on the winch, or by a sudden jerking of the logging vehicle. New o-rings were also installed prior to logging to ensure a tight seal. A food grade silicone (Dow Corning 111 compound) valve lubricant was applied to the new o-rings, which is necessary to prevent the seals from being pulled out of their seats during operation, and to further help to ensure a tight seal.

The logging order for this borehole was chosen in part due to the drilling method and drilling fluid circulation used by the drilling contractor. The drilling method was wireline coring. The drilling contractor used fresh water and open-loop circulation. Thus, bentonite was not used in the borehole, nor were formation cuttings (muds) recirculated in the borehole. The geophysical logging sequence was planned to record data in the following order: 1) fluid temperature & resistivity, 2) gamma, SP, SpR, 8", 16", 32" & 64" normal resistivity, and 3) acoustic televiewer (ATV). Because the probes have little clearance in the corehole, they tend to mix the water in the borehole as the probes move in the borehole. Thus, the FTR was run to minimize the disturbance of the borehole fluids.

The first set of logs was recorded on February 24, 2009 (Tuesday evening). The depth of the hole was approximately 255 feet below ground surface (bgs). The logging followed packer testing which was conducted at 50 feet intervals. FTR, gamma, SP, SpR, 8, 16, 32 & 64 inch normal resistivity measurements were run in case the borehole collapsed. Borehole stability was a

concern because collapse and/or squeezing of shale and coal intervals is a relatively common occurrence in small-diameter boreholes in Pennsylvanian bedrock. Packer testing adds to the risk of borehole collapse.

The hole was logged a second time on February 27, after reaching a depth of 504 feet bgs. The HQ core rod was pulled completely out of the corehole to allow for openhole logging. The ATV probe uses 2 centralizers and cannot advance within the HQ casing due to its diameter and the weight of the probe. Logs were recorded in the sequence mentioned previously. However, during this stage of logging, the probes would not go beyond a depth of 314 feet. The hole was possibly bridged by a coal/underclay/shale interface that overlies a limestone. We speculate that the overlying materials may have been softened during the drilling of the harder limestone. An attempt was made to break through the bridged interval with each probe, but refusal occurred at approximately the same depth each time.

In the morning (Feb 28), the driller pushed through this zone using only the weight of the drilling rod. The drilling rod was set at a depth of 326 ft to allow logging from 330 ft to TD and later raised to 286 ft to allow logging from 330 to 310 ft (the missed interval). Logging was then conducted a third time, approximately 10.5 hours after the second round of logging. Instead of starting with the FTR probe on this attempt, logging began using the gamma, resistivity, SP, SpR probe because it weighs more than the FTR probe, allowing it to more easily breach any potential bridged or collapsed intervals. The ATV probe could not be used because the HQ rod was used to keep the hole open. Data from all three logging runs were merged and are presented as a single log (Figures 1-3).

The FTR log shows fluid temperature, fluid resistivity, and fluid conductivity (Figures 1 and 2). The fluid conductivity (left side in Figures 1 and 2) increases smoothly from the surface to approximately 290 ft bgs (1.2 mS/cm), then increases more sharply until the sudden shift at 317 ft bgs. Fluid conductivity jumps off-scale at a depth of 317 ft. The maximum conductivity value recorded on the log was 126 mS/cm. The conductivity/resistivity data went off-scale (reported as negative value) at 317.3 ft bgs. At 317.2 ft bgs, the resistivity was recorded at 0.06 ohm-m and conductivity at 155 mS/cm. At 317.1 feet, the conductivity was 3.2 mS/cm. This apparently reflects a very sharp & distinct boundary within the fluid column. After the drilling rod was raised to 286 ft, the sharp break in fluid conductivity also shifted upward, to a depth of 314.7 ft (Figure 2).

Using the original FTR log (lighter traces in Figure 1), fluid samples were collected using a discrete interval sampler at 380 ft and then at 300 ft. The 380 ft sample was collected first and was thought to represent water with higher TDS. The 300 ft sample was collected to represent the upper end of the "brine" water column. The water quality of these samples is discussed in the **Fluid Samples** section.

Estimation of Formation Water Quality

Other geophysical logs (ATV, natural gamma, SP, SPR, & resistivity) are shown from ground surface to TD in Figure 3. Resistivity logs can be used to estimate fluid resistivity. Several researchers have published methods to compute salinity or TDS based on resistivity specifically for wells completed in the Illinois Basin (Pryor, 1965; Poole et al., 1989; Jorgensen, 1995; and Schnobelen et al., 1989). Using the natural gamma, SP, SPR, temperature, and resistivity (16 and 64 inch normal) logs, intervals were selected to compute the formation water resistivity (Rw). Porous intervals were selected (Table 2). Fresh water was used as the drilling mud in MMV-04B,

and it had a wellhead temperature of 38.3°F. The conductivity of the "drilling mud" was measured at 0.21 mS/cm (Table 3); consequently the resistivity for mud fluid (Rmf) was calculated to be 47.62 ohm-m. Based on the temperature from the logs, Rmf at the formation temperature was calculated using a modified correction from Jorgensen (1995):

$$R2 = R1\ [(T1 + 6.77)/ (T2 + 6.77)]$$

where T1= temperature at the well head
T2= formation temperature
R1= resistivity of drilling mud (Rmf) at the ground surface
R2= resistivity of drilling mud (Rmf) in the formation

Rw is the resistivity of the formation fluid and is a function of the formation temperature, the concentration of ions, and the ion species. Assuming normal fluid invasion (Z= 0.075), Rw can be calculated:

$$Rw = RtRz/Ri \text{ and } 1/Rz = (Z/Rw) + (1 - Z/Rmf)$$

where Rt= resistivity of the formation in the uninvaded zone (matrix and fluid not affected by drilling fluid) measured by the 64" normal log
Rz= resistivity of fluid in transition zone (resistivity of formation fluid between flushed and uninvaded zones)
Ri= resistivity of formation matrix and fluid in the transition zone measured by the 16" normal log
Rmf = resistivity of mud filtrate or the fluid in the flushed zone corrected to formation temperature (R2 from the equation above)

TDS was estimated from Rw by use of two nomographs from Poole et al. (1989), which were used to compute salinity and then TDS. Salinity is reported as a sodium chloride equivalent.

Table 2. Water quality estimated from resistivity logs in MMV-04B

Depth interval (ft)	Lithology	Rw (ohm-m)	Estimated TDS (mg/L)	
			Salinity as NaCl equivalent (mg/L)	TDS (mg/L)
336-345	Limestone (?)	8.98	700	700
359-367	Limestone	0.68	>10,000	>10,000

Fluid Sampling

As discussed above, fluid samples were collected in the borehole using a using a discrete interval sampler. The sample collected at 380 feet, showed high TDS by hand-held meter (Orion 130) and lab testing (Table 3). The 300 foot sample showed low TDS by hand-held meter (Orion 130) and lab testing. In addition, grab samples of the water used during drilling were tested —clean drilling water which was obtained from an ADM hydrant and the drilling return fluid (water used to displace the cuttings back to the ground surface). Both of these fluids had low specific conductance (<1 mS/cm) throughout the four days of coring. Detailed chemical analysis for the 380 ft and 300 ft samples are listed in Table 4.

Table 3. Specific Conductance and TDS of various samples

Sample	Specific Conductance (mS/cm)	TDS* (mg/L)
300 ft sample	3.2	1,550
380 ft sample	40.9	25,300
Drilling return fluid (depths ranging from 150 to 500 ft)	0.24 – 0.69	
Drilling water (water from ADM)	0.21 – 0.23	

*: TDS analysis determined by Prairie Analytical Systems, Inc., Springfield, IL on March 10, 2009

Estimation of Hydraulic Conductivity

Packer testing is a technique that allows one to estimate hydraulic conductivity (K) without the installation of a monitoring well. Another technique to estimate K involves the use of a spinner flowmeter, but this method requires a stable borehole. The Pennsylvanian bedrock in central Illinois is widely known for poor borehole stability, which we experienced in this project. Seven packer tests were conducted using pressures of approximately 20 and 40 psi above hydrostatic pressure (Table 5). These tests show that the rock had very low hydraulic conductivity.

Each packer test was conducted in three 18-minute segments—low pressure, high pressure and low pressure. These tests were conducted using a double packer system owned and operated by Raimonde Drilling Corp. The packer assembly fits in the bottom of the core barrel. The upper packer seals the drilling rod, while the lower packer seals the rock. Water flows down the drilling rod, through the packers and into the test interval. The packer test data were analyzed using Moye (1967) and Hvorslev (1951). Both methods provided similar values, but the higher value is reported in the table. These packer test results show the low hydraulic conductivity (K) of the tested bedrock. Many tests resulted in zero flow at pressures of 20 and 40 psi above hydrostatic pressure. Of the ten estimates, K values ranged from 3.1×10^{-8} to 2.7×10^{-6} cm/sec. All tests had K $< 1 \times 10^{-4}$ cm/sec, which is part of the definition of an underground source of drinking water (USDW).

For the packer tests which had "zero take", the hydraulic conductivity can be estimated to be $< 10^{-8}$ cm/sec if you assume that a small, but unmeasureable volume of water actually flowed into the rock. For this estimate, this assumed volume was 0.05 gallons, which is one-half of the volume gage's smallest increment.

MMV-01B is located approximately 1800 ft southeast of MMV-04B and is completed at a depth of 126 to 200 ft below ground surface. Using a recovery test and analyzing the data with Hvorslev (1951), the hydraulic conductivity of bedrock was estimated to be 3.1×10^{-5} cm/sec. The K estimated from the recovery test is higher than the K that could be estimated by Test 1 ($< 10^{-8}$ cm/sec). This could indicate:

1) The bedrock is heterogeneous across the site.
2) The shallower bedrock in MMV-01B has higher K than the deeper bedrock tested in MMV-04B.
3) K determined after well development will exceed K determined by packer testing.

Table 4. Chemical composition of water samples collected from MMV-04B on March 2, 2009 to determine lowermost USDW at Archer Daniels Midland (Decatur IL) as part of the Illinois Basin- Decatur Project. MMV-04B1 was collected from 380 feet and MMV-04B2 was collected from 300 feet using a wireline discrete sampling tool.

Constituent	MMV-04B1 380 ft sample (mg/L)	MMV-04B2 300 ft sample (mg/L)	Drinking Water Standard (mg/L)
Al	0.070	0.224	NA
As	<0.108	<0.108	0.010
B	0.706	0.496	NA
Ba	1.66	0.0363	2
Be	<0.00055	<0.00055	0.004
Ca	586	6.26	NA
Cd	<0.012	<0.012	0.005
Co	<0.013	<0.013	NA
Cr	<0.0058	<0.0058	NA
Cu	<0.00079	<0.00079	1.3
Fe	0.0237	0.0271	0.3
K	47.0	4.67	NA
Li	0.353	<0.018	NA
Mg	275	3.19	NA
Mn	0.862	0.0076	0.05
Mo	<0.022	0.064	NA
Na	9250	661	NA
Ni	0.141	<0.014	NA
P	<0.063	<0.063	NA
Pb	<0.041	<0.041	0.015
S	13.6	14.9	NA
Sb	<0.059	<0.059	NA
Se	0.157	<0.131	NA
Si	2.02	1.42	NA
Sn	<0.086	<0.086	NA
Sr	30.2	0.139	NA
Ti	<0.0056	0.00101	NA
Tl	0.025	<0.017	0.002
V	<0.047	<0.047	NA
Zn	0.0308	<0.0073	5
F	0.21	1.22	2
Br	35.4	2.90	NA
Cl	16830	875	NA
SO_4	32.1	40.0	250
SO_4 by cal. of S	40.7	44.6	NA
pH	7.91	9.09	6.5-8.5
EC (Ms/cm)	39.9	3.14	NA
Alkalinity (mg/L as $CaCO_3$)	79.0	129	NA
TDS (measured)	27,243- ISGS 25,300 - PA	1,876-ISGS 1,550- PA	500/10,000
TDS (calculated)	26,317	1,716	NA
TDS difference	1.04 ISGS[a] 0.96 PA	1.09 ISGS[a] 0.90 PA	NA
Anion/Cation Balance (%)	-2.3[a]	+2.0[a]	NA

ND= not determined

NA= not applicable or no standard

[a] = Within acceptable criteria for correctness of analyses (APHA. 1992, p.1-12)

Table 5. Summary of packer test results

Test #	Interval tested (ft)	Materials in tested interval	Pressure (psi)	Inflow (gals)	Hydraulic Conductivity (cm/sec)
1	162-194	Limestone, sandstone & other *(MMV-01 is screened in this interval)*	19	0	--
			39	0	--
			18	0	--
2	202-254	Various	27	0	--
			40	0	--
			25	0	--
3	252-304	Various	20	0.26	5.2×10^{-8}
			38	2.29	4.1×10^{-7}
			20	0	--
4	302-354	Various *(Driller noted that coal at 304' took water)*	20	0	--
			37	0.97	1.6×10^{-7}
			20	0	--
5	359-374	Carthage or Shoal Creek Limestone	22	5.8	**2.7×10^{-6}**
			41	1.6	6.7×10^{-7}
			22	0.17	7.8×10^{-8}
6	383-404	Inglefield and Trivoli Sandstones	20	0.11	3.6×10^{-8}
			35	0.01	3.1×10^{-8}
			18	0	--
7	412-454	Coal & West Franklin Limestone (top 13.5 of 18.5 ft)	18	0	--
			41	1.05	1.6×10^{-7}
			21	0.2	3.4×10^{-8}

Monitoring Well Design

Per the UIC permit requirements, ADM is required to monitor the lowermost underground source of drinking water. Based on the data collected in MMV-04B (Tables 3 to 5), the pore water appears to consistently exceed 10,000 mg/L TDS at a depth of 317 feet below ground surface (Figures 1 and 2). Thus, groundwater shallower than 317 ft should meet the water quality requirement. None of the tested bedrock met the hydraulic conductivity definition of a USDW.

As shown in Table 1, a limestone (309-324 ft) is found at a depth of 317 ft. This limestone appears to be brine filled. This limestone is overlain by gray shale (304-309 ft), black shale and coal (303 to 304 ft), interbedded sandstone and siltstone (299-303 ft), and fine-grained sandstone (266-299 ft). This fine-grained sandstone may be suitable for providing small volumes of water needed for geochemical monitoring. Packer testing indicated that the interval from 252 to 304 ft took some water during the test, so this is encouraging. The hydraulic conductivity of the sandstone may increase if any well skin is removed during well development.

The monitoring well was constructed with stainless steel casing and screen (Figure 4). The well's depth places it at the limit of the collapse pressure of PVC, so PVC casing was not used. Using a tremie pipe, the borehole was backfilled to a depth of 295 feet to provide a stable base for well construction. Bentonite pellets and noncalcareous gravel pack were used below 325 ft. Bentonite pellets were placed from 295 to 325 ft, which should adequately seal the sandstone (266-299 ft) from the briney water below. Other well specifications include—

Screened interval: 275-295 ft
Sand pack (silica or gravel pack): 265-295 ft
Bentonite chips/pellets: 262-265 ft
High solids bentonite grout: 2-262 ft
Cement (to hold well protector): 0-2 ft

References

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Jorgensen, D.G., 1995. The Ratio Method of Estimating Water Resistivity and TDS from Resistivity Logs, **Ground Water 34**(3): 519-522.

Moye, D.G., 1967. Diam ond drilling for foundation exploration, **Civil Engineering Transactions 9**: 95-100.

Pryor, W.A., 1956. Quality of Groundwater Estimate d fro m Electric Resistivit y Logs, Il linois State Geological Survey Circular 215, 15 p.

Poole, V.L., K. Cartwright and D. Leap, 1 989. Use of Geoph ysical Logs t o Es timate Water- Qualit y of Basal Pennsylvanian Sandstones, Southwestern Illinois, **Ground Water 27**(5): 682-688.

Schnobelen, D.J., E.F. Bugliosi, and N. C. Krothe, 1995. Delineation of a Saline Groundwater Boundary from Borehole Geophysical Data, **Ground Water 33**(6):965-976.

Figure 1. Fluid temperature/resistivity log recorded in MMV-04B on February 27 & 28, 2009 by Tim Young, ISGS. Fluid conductivity (navy blue) is shown on the left side, while fluid temperature (red) and fluid resistivity (royal blue) are shown on the right side. Recorded interval is 0 to 484 feet below ground surface.

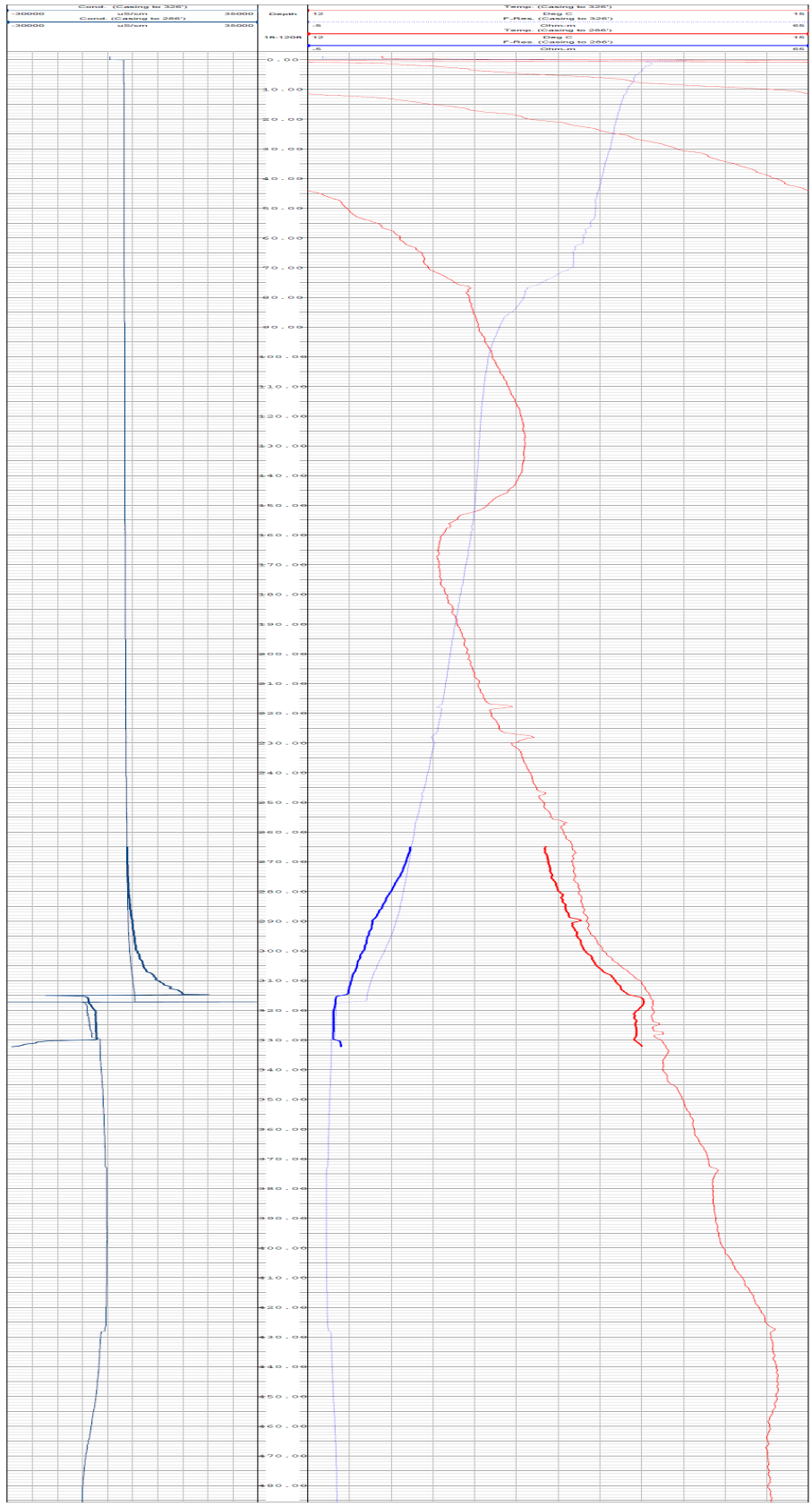


Figure 2. Fluid temperature/resistivity log recorded in MMV-04B on February 27 & 28, 2009 by Tim Young, ISGS. Fluid conductivity (navy blue) is shown on the left side, while fluid temperature (red) and fluid resistivity (royal blue) are shown on the right side. Recorded interval is 290 to 340 feet below ground surface.

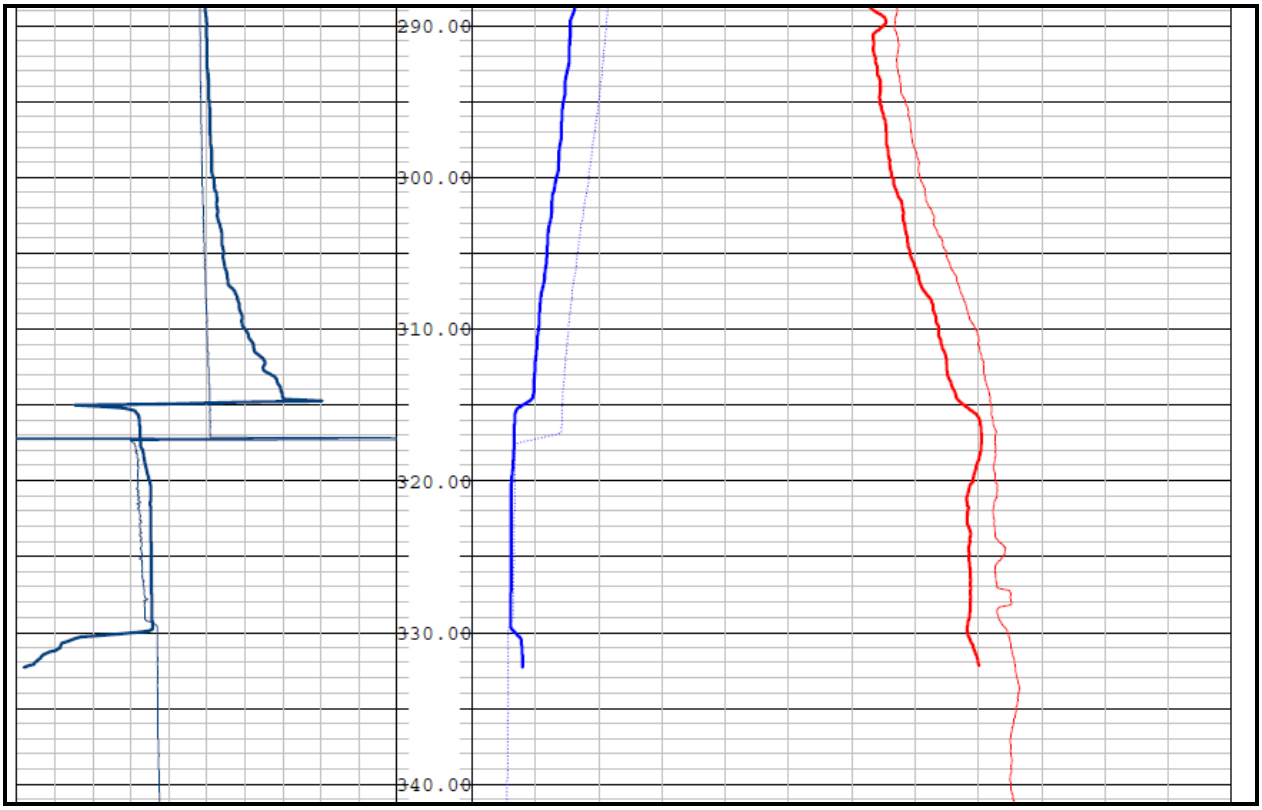


Figure 3. Polyprobe log recorded in MMV-04B on February 27 & 28, 2009 by Tim Young, ISGS. Acoustic televiewer, natural gamma, SP, SPR, and resis tivity (8”, 16” 32” & 64”) are shown. Recorded interval is 0 to 484 feet below ground surface.

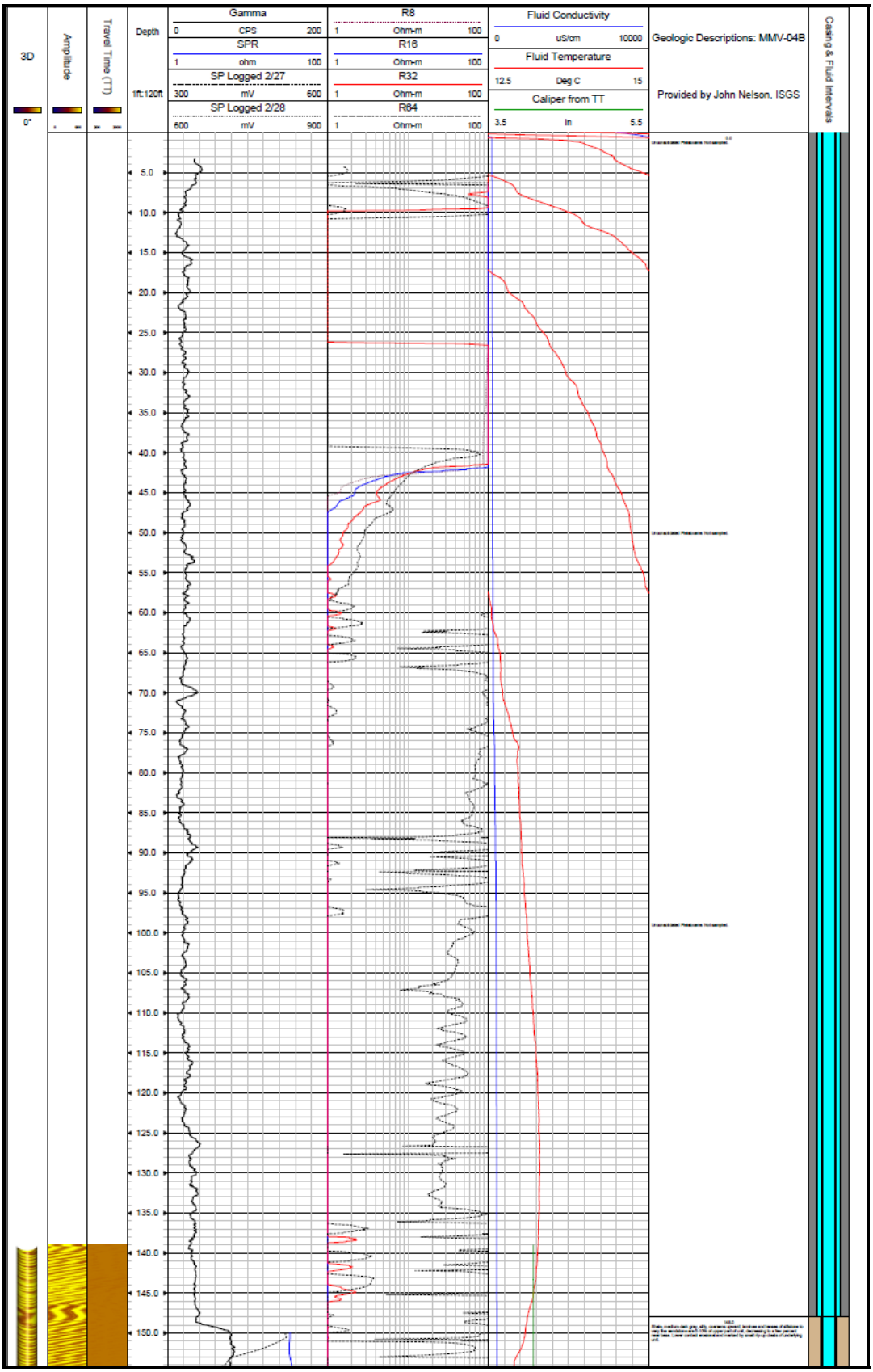


Figure 3. (continued)

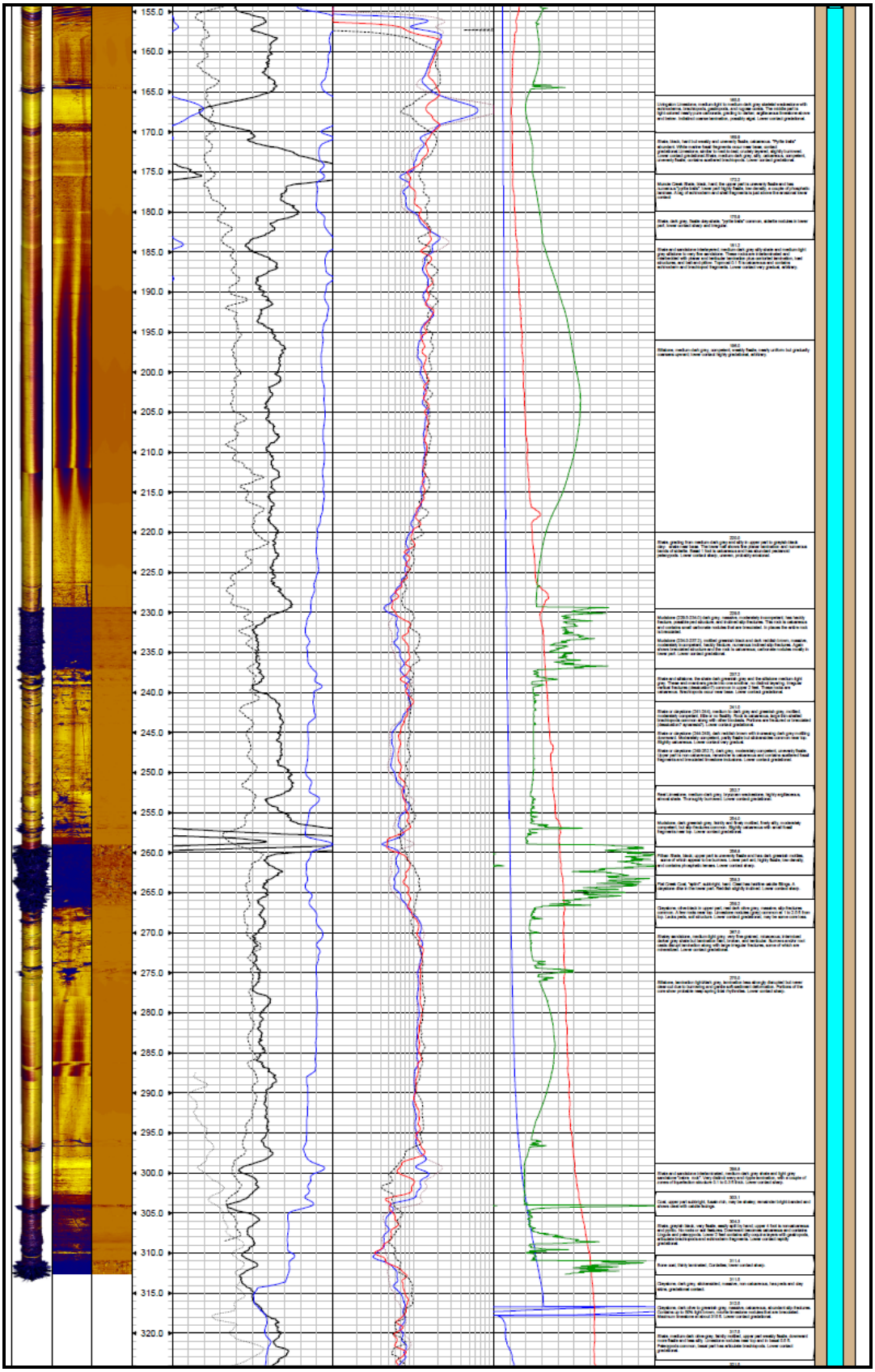


Figure 3. (continued)

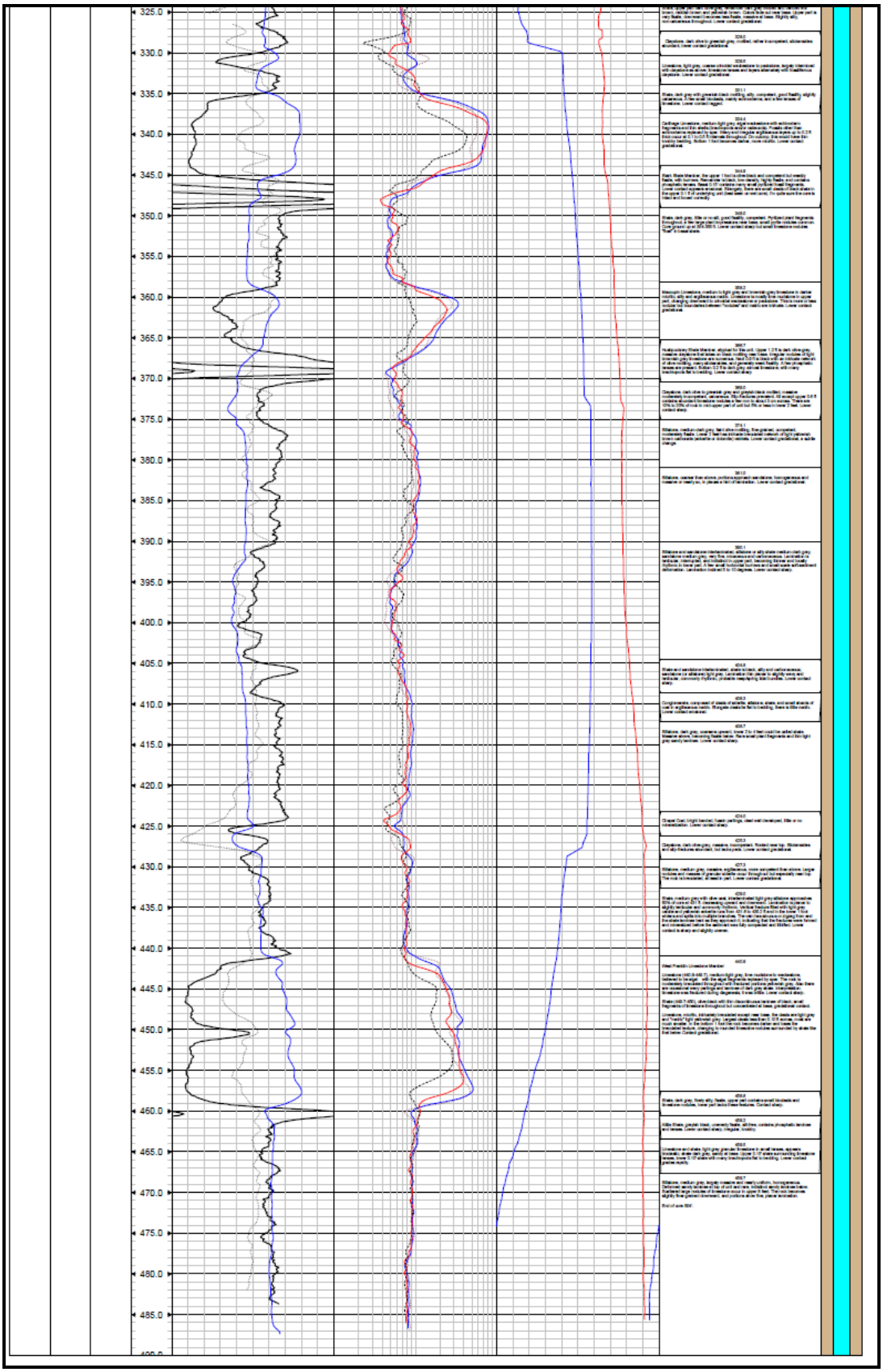


Figure 4. Construction details for MMV-04B

Illinois Environmental Protection Agency **Well Completion Report**

Site Number: 1150155136 County: Macon

Site Name: ADM Corn Sweeteners Plant 180 Well #: MMV-04B

State Plane Coordinate: X 826014.5 ft Y 1171093.3 ft (or) Latitude: ___ ___ ___ Longitude: ___ ___ ___ Borehole #: 121152339600

Surveyed by: Edward Mehnert IL Registration #: ___

Drilling Contractor: Albrecht Well Drilling (Ohio, IL) Driller: Pat Dye

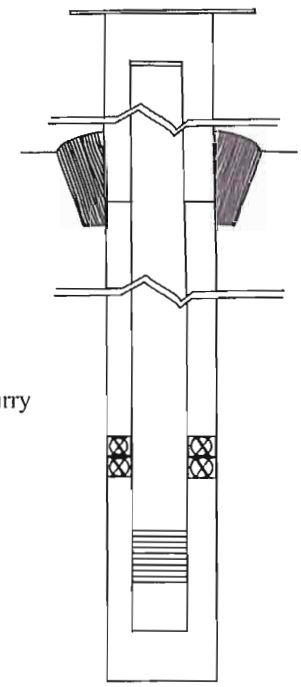
Consulting Firm: Illinois State Geological Survey Geologist: Edward Mehnert

Drilling Method: Mud rotary Drilling Fluid (Type): mud for glacial, water for rock

Logged By: Edward Mehnert Date Started: 2/16/09 Date Finished: 3/13/09

Report Form Completed By: Edward Mehnert Date: 3/26/09

ANNULAR SPACE DETAILS



Elevations (MSL)*	Depths (BGS)	(.01ft.)
684.67	3.00	Top of Protective Casing
684.62	2.83	Top of Riser Pipe
681.67	0	Ground Surface
679.67	2.0	Top of Annular Sealant
626.68	54.99	Static Water Level (After Completion)
419.67	262.0	Top of Seal
416.67	265.0	Top of Sand Pack
406.67	275.0	Top of Screen
386.67	295.0	Bottom of Screen
386.67	295.0	Bottom of Well
386.67	295.0	Bottom of Borehole

* Referenced to a National Geodetic Datum

Type of Surface Seal: concrete

Type of Annular Sealant: bentonite slurry

Installation Method: tremie pipe

Setting Time: 24 hours

Type of Bentonite Seal - - Granular, Pellet, Slurry (Choose One)

Installation Method: tremie pipe

Setting Time: 24 hours

Type of Sand Pack: silica sand

Grain Size: 0.055" (Sieve Size)

Installation Method: tremie pipe

Type of Backfill Material: bentonite & pea gravel (if applicable)

Installation Method: tremie pipe

WELL CONSTRUCTION MATERIAL

(Choose one type of material for each area)

Protective Casing	SS304, SS316, PTFE, PVC, or Other
Riser Pipe Above W.T.	SS304, SS316, PTFE, PVC, or Other
Riser Pipe Below W.T.	SS304, SS316, PTFE, PVC, or Other
Screen	SS304, SS316, PTFE, PVC, or Other

CASING MEASURMENTS

Diameter of Borehole (inches)	6.0
ID of Riser Pipe (inches)	2.0
Protective Casing Length (feet)	3.0
Riser Pipe Length (feet)	277.8
Bottom of Screen to End Cap (feet)	297.8
Screen Length (1st slot to last slot) (feet)	20.0
Total Length of Casing (feet)	277.8
Screen Slot Size **	10

**Hand-Slotted Well Screens are Unacceptable

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

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James R. Thompson Center, 100 West Randolph, Suite 11-300, Chicago, IL 60601 • (312) 814-6026

PAT QUINN, GOVERNOR DOUGLAS P. SCOTT, DIRECTOR

217/524-33300

December 2, 2009

Certified Mail
7004 2510 0001 8615 8534

Archer Daniels Midland Company
Attn: Mark Burau, Decatur Corn Plant Manager
4666 Faries Parkway
Decatur, Illinois 62526

Re: 1150155136 -- Macon County
ADM Company
ILD984791459
Permit No. UIC-012-ADM
Log No. PS09-206
Well No. CCS #1
UIC Administrative Record File
PS Corr

Dear Mr. Burau:

This is in response to a document submitted on behalf of ADM Company (ADM) by Dean Frommelt dated September 29, 2009 and received by the Illinois EPA on September 30, 2009. The subject document is a final report summarizing investigation results to determine the lowermost underground source of drinking water (USDW) in the vicinity of the ADM facility.

An Underground Injection Well (UIC) Permit effective January 27, 2009 was issued to ADM to construct an UIC well, known as Carbon Capture Sequestration Well No. 1 (CCS1). Pursuant to Section I of the UIC Permit ADM must install groundwater monitoring wells that will constitute the groundwater monitoring program associated with the injection well process for the UIC. These wells must be completed in the lowermost USDW.

The Illinois EPA has determined that it can approve the Pennsylvanian Bedrock as the lowermost USDW in the vicinity of the ADM facility. In addition, the Illinois EPA can approve the use of the verification well to collect groundwater data to serve as an early warning indicator of any $C0_2$ leaking from the Mt. Simon Sandstone as a result of the injection activities associated with ADM's UIC Permit. Therefore, the Illinois EPA can approve the subject submittal subject to the following conditions and modifications:

1. In accordance with Condition I.4.a of ADM's UIC Permit, within thirty (30) days of the installation and development of groundwater monitoring wells G101, G102, G103, and G104 ADM must submit additional information concerning the construction details to the

Illinois EPA. The additional information must be submitted as minor permit modification pursuant to 35 Ill. Adm. Code 704.264. These details include:

a. ADM Well Number;

b. Well Depth (Ft-bgs);

c. Well Depth Elevation (Ft-MSL); and

d. Well Screen Interval (Ft-MSL)

2. In accordance with Condition I.4.b of ADM's UIC Permit, construction of groundwater monitoring wells G101, G102, G103, and G104 must be in such a manner as to prevent the movement of fluids into or between underground sources of drinking water. The casing and cementing used in the construction of the wells must be designed for the life expectancy of the wells.

3. In accordance with Condition I.4.c of ADM's UIC Permit, construction G101, G102, G103, and G104 must be at a minimum in accordance with the diagram contained in Attachment F of the Permit, with the exception of the sandpack. The sandpack for groundwater monitoring wells G101, G102, G103 and G104 can be $\leq$ 5 feet.

4. Pursuant to Condition I.4.c of ADM's UIC Permit and due to the construction of groundwater monitoring well MMV-04B, the well cannot be used as a groundwater monitoring well for the lowermost USDW. In accordance with Condition I.4.h, all groundwater monitoring wells not utilized in the groundwater monitoring system, but retained by the facility, must be maintained in accordance with 35 Ill. Adm. Code 920 regulations.

5. All groundwater related activities must be conducted in accordance with Section I of the UIC Permit.

Work required by this letter, your submittal or the regulations may also be subject to other laws governing professional services, such a the Illinois Professional Land Surveyor Act of 1989, the Professional engineering Practice Act of 1989, the Professional Geologist Licensing Act, and the Structural Engineering Licensing Act of 1989. This approval letter does not relieve anyone from compliance with these laws and the regulations adopted pursuant to these laws. All work that falls within the scope and definitions of these laws must be performed in compliance with them. The Illinois EPA may refer any discovered violation of these laws to the appropriate regulating authority.

Should you have any questions regarding this submittal, please contact Terri Blake Myers, L.P.G. of my staff at 217/524-3284. If you any questions regarding other issues associated with the Permit, please contact Kevin Lesko at 217/524-3271.

Sincerely,

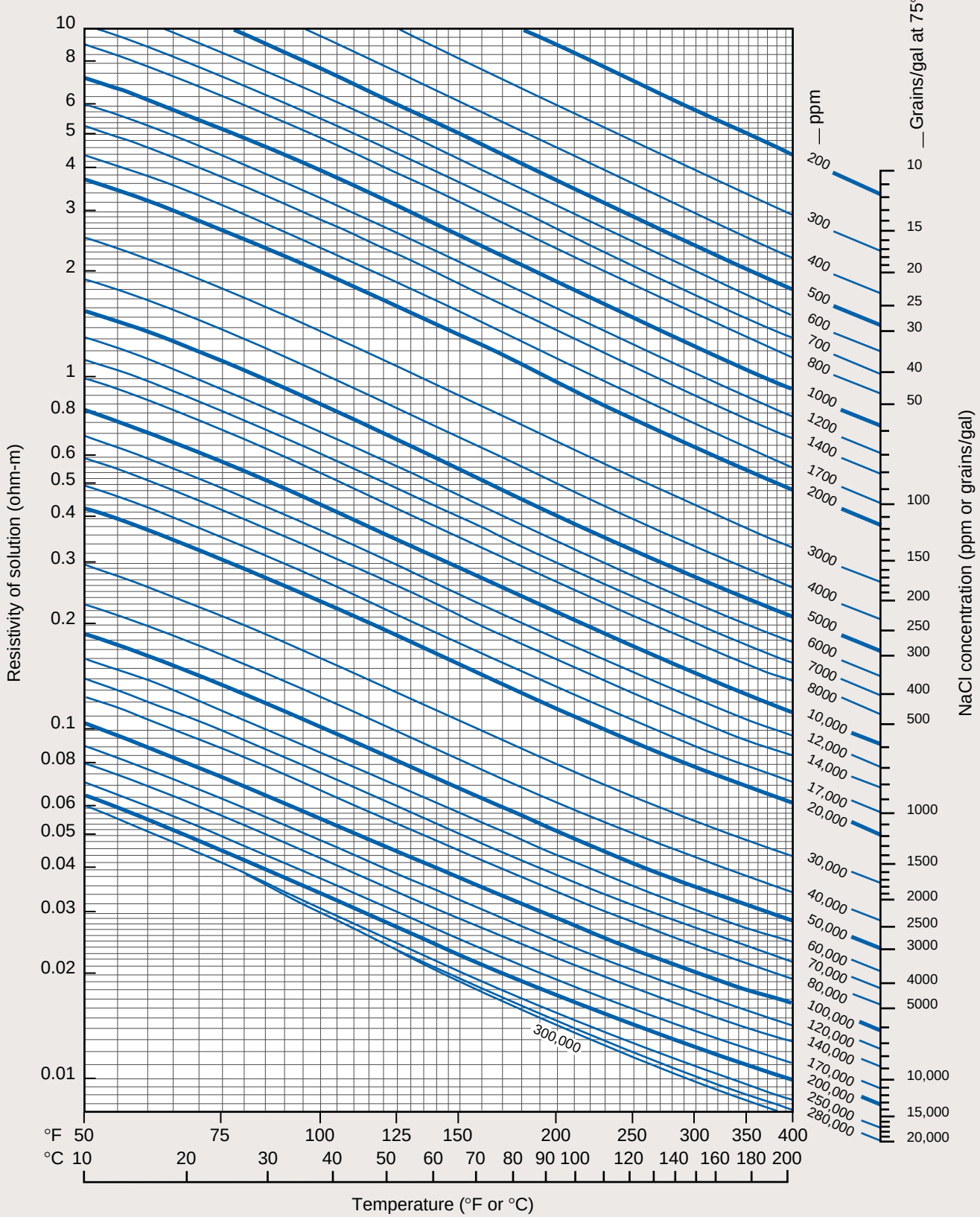
Stephen F. Nightingale, P.E.
Manager, Permit Section
Bureau of Land

SFN:TBM:mls/090383s.doc
cc: Dean Frommelt, Division Environmental Manager -- ADM
Sallie Greenburg – Illinois State Geological Survey

Appendix J - GEN 9 Salinity Chart

Resistivity of NaCl Solutions

Conversion **approximated** by $R_2 = R_1 [(T_1 + 6.77)/(T_2 + 6.77)]°F$ or $R_2 = R_1 [(T_1 + 21.5)/(T_2 + 21.5)]°C$



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Appendix K – ADM CCS#1 Descriptive Report Geophysical Logs

Appendix K

ADM CCS #1

Geophysical Log Descriptive Report

Bob Butsch – Schlumberger Carbon Services

The Logging Program

The table below identifies the logging runs made by date and depth, the tools included in each run, and the primary reason for running that logging tool.

Logging Tools by Run

Date / Depth	Logging Run	Logging tools	Data Used For:
March 9, 2009 352 - 3541 ft	**PEX-AIT (Platform Express)**	GR, Caliper, SP, Resistivity (Induction), Density, Neutron	Correlation, Porosity, Saturations, Hole Size
April 5, 2009 352 – 5317 ft	**PEX-AIT (Platform Express)**	GR, Caliper, SP, Resistivity (Induction), Density, Neutron	Correlation, Porosity, Saturations, Hole Size
	HRLA	Resistivity (Laterolog)	Resistivity - Saturation
	SonicScanner, FMI	Sonic compressional and shear, Formation Micro-Imager borehole images	Porosity, Mechanical Properties, Structure, Env. Deposition, Fractures
	CMR, ECS, HNGS	Magnetic Resonance, Elemental Capture Spectroscopy, Spectral GR	Lithology, Clay Minerals, Porosity, free and bound fluids, Permeability
	MSCT	Sidewall Coring Tool	Porosity, Permeability
April 26, 2009 5339 – 7221 ft	**PEX-HRLA (Platform Express)**	GR, Caliper, SP, Resistivity (Laterolog), Density, Neutron	Correlation, Porosity, Saturations, Hole Size
	Sonic Scanner, FMI	Sonic compressional and shear, Formation Micro-Imager borehole images	Porosity, Mechanical Properties, Structure, Env. Deposition, Fractures
	CMR, ECS, HNGS	Magnetic Resonance, Elemental Capture Spectroscopy, Spectral GR	Lithology, Clay Minerals, Porosity, free and bound fluids, Permeability
	MSCT	Sidewall Coring Tool	Porosity, Permeability
	MDT	Modular Dynamic Tester	Formation Pressure, Mobility
	VSIT	Versatile Seismic Imager	Tie logs to seismic

In summary the standard "Triple Combo" data of the Platform Express (PEX) run includes GR, Caliper, Resistivity, Density, and Neutron measurements and is run for basic petrophysical properties of volume of shale, basic lithology, porosity and saturations. The Gamma Ray and Resistivity are also the primary measurements used for correlation to other wells. Either an induction tool or laterolog tool are used to measure the formation resistivity depending on the conductivity of the mud system in the borehole and

the conductivity of the formation water. The Elemental Capture Spectroscopy (ECS) is used to identify lithology type by measuring elemental yields and to improve the clay volume calculation. The HNGS provides natural gamma ray spectroscopy to aid in the analysis of the different clay types and special minerals containing potassium. The Combinable Magnetic Resonance (CMR) manipulates the nuclei of hydrogen atoms buy applying a strong magnetic field and RF pulses. The tool then measures the response of the nuclei to the changing magnetic field, with the resulting measurement is the T2 distribution. From this measurement porosity is derived and this porosity can be subdivided based on the T2 measurement to provide information on the pore size distribution, and what portion of the fluid in the porosity is bound fluid and what is free fluid. This measurement is also used to calculate a continuous permeability based on porosity and the pore size distribution. The Sonic Scanner tool is an array sonic tool used to measure the compressional and shear sonic velocities in the formation. These measurements can then be used to calculate sonic porosity and Mechanical Rock Properties. The FMI is used to identify structure, depositional environment and fractures that may be present in the formations. The Mechanical Sidewall Coring Tool (MSCT) will take multiple rotary sidewall cores and return them to surface for analysis. The Modular formation Dynamics Tester (MDT) can take multiple pressures and fluid samples depending on its configuration. The Versatile Seismic Imager (VSIT) data aids in the tie between the seismic data and the log data.

General Interpretation of the data

The interpretation of the data is done using the ELAN-Plus computer program within GeoFrame. The Elemental Log ANalysis (ELAN) evaluation is done by optimizing simultaneous equations described by one or more interpretation models. The resulting analysis provides key petrophysical answers that describe the reservoir. Answers derived from this analysis include but are not limited to porosity, lithology, and permeability. Following is a brief description of the data provided on the ELAN analysis presentation.

Depth Track

GR – Gamma Ray

Caliper – Hole Size

RSOZ – Resistivity Standoff, Quality control indicating enlarged borehole.

DSOZ – Density Standoff, Quality control indicating enlarged borehole.

Bad Hole Flag - Quality control indicator, hole is too large or rugose for a measurement to be made.

Track 1

RLA5 to RLA2 – Array laterolog resistivity measurements with different depth of investigation. RLA5 is the deepest depth of investigation

RXO_HRLT – Laterolog resistivity measurement with shallow depth of investigation indicating the resistivity of the invaded zone.

Track 2

PEFZ – Photoelectric Effect. This is used for lithology identification.

RHOZ – Measurement of the bulk density of the formation. This is used in combination with the neutron and sonic for lithology identification as well as identification of fluids in the porosity.

Neutron - Measurement of the neutron porosity (lime) of the formation. This is used in combination with the density and sonic for lithology identification as well as identification of fluids in the porosity.

Density Correction – Correction applied to the density measurement for borehole affects such as mudcake.

DTCO – Delta T, sonic travel time of the compressional mode from the Sonic Scanner

Track 3

Kint ELAN – Permeability derived from the ELAN analysis. Core data presented if available.

Track 4

Porosity – Effective porosity as calculated by ELAN. This analysis also includes the vuggy porosity identified in the carbonates. Core data presented if available.

Track 5

Volumetric display of lithology and fluids solved for in ELAN. Core data presented if available.

Detailed Interpretation of the Injection Zone (Mount Simon)

The injection zone in the ADM CCS #1 well is the Mount Simon Formation which extends from the base of the Eau Claire Shale at 5544 ft to the top of the Granite Wash zone at 7049 ft. The petrophysical model used to evaluate the Mount Simon Formation included all minerals identified to be present in significant quantities in the cores that were analyzed for lithology. Though the Mount Simon is considered to be a clean sand, the major reservoir type rocks of limestone and dolomite were also included in the model. The clays used in the model were illite, chlorite, and kaolinite. Also included in the analysis is orthoclase due to the significant amount of potassium feldspar minerals found in the cores. Water was the only fluid included in the formation model, but the T2 pore size distribution measurement from the CMR tool was used to differentiate the free fluids from the bound fluids.

The results of the analysis indicate that the Mount Simon can be thought of as three separate units primarily based on the pore volume and pore size distribution. The bottom interval in the Mount Simon contains the highest average porosity and quite good permeability. This interval extends from the base up to 6420 ft. The section of the Mount Simon from 6420 ft to approximately 5950 ft is relatively low porosity with significantly reduced permeability. The third interval of the Mount Simon is from approximately 5950 ft to the top of the Mount Simon at 5544 ft. While the lithology does not vary significantly and is dominated by sand (quartz), there can be up to 15% clay and 25% orthoclase.

The bottom interval in the Mount Simon is the primary injection zone and has an average porosity of 16.8%, but there are intervals where the porosity approaches 30%. Average permeability in this interval is 33 md; however, permeability in the perforated interval ranges from 60 md to several hundred md.

There are a few thin shale intervals within the bottom section of the Mount Simon however, correlating this interval in the CCS #1 well with the Verification Well #1 it is thought that these shale intervals are more likely to act as baffles rather than barriers to the movement of injected CO_2 as they do not appear to be continuous.

The middle interval of the Mount Simon has an average porosity of 9% and an average permeability of only 2.5 md. Based on the CMR pore size distribution and measurement of bound fluids, most of the fluids in this interval appear to be bound fluids, hence the greatly reduced permeability. While this interval is not considered to be a seal to the movement of CO_2, it will significantly retard the upward movement of CO_2.

The top interval of the Mount Simon has an average porosity of 10.6% and an average permeability of 66 md. The permeability increase in this interval is due to the measurement of the pore size distribution indicating that in this interval, while having lower total pore volume than the bottom interval the pores are larger therefore permeability is greater.

Detailed Interpretation of the Primary Seal (Eau Claire Shale)

The Eau Claire Shale will act as the primary seal for injected CO_2 into the Mount Simon. The Eau Claire Shale is 317 feet thick and covers the interval from 5227 ft to 5544 ft. The clays identified from the analysis include primarily illite and chlorite, with just a small amount of kaolinite. Based on the analysis of the CMR data the pore sizes in the Eau Claire are quite small and the resulting permeability is therefore very low. There are only a few small intervals of less than a few feet that have any permeability greater than 0.1 mD and these do not appear to be continuous. The Eau Claire Shale should provide a good seal for CO_2 injected into the Mount Simon.

Robert J. Butsch

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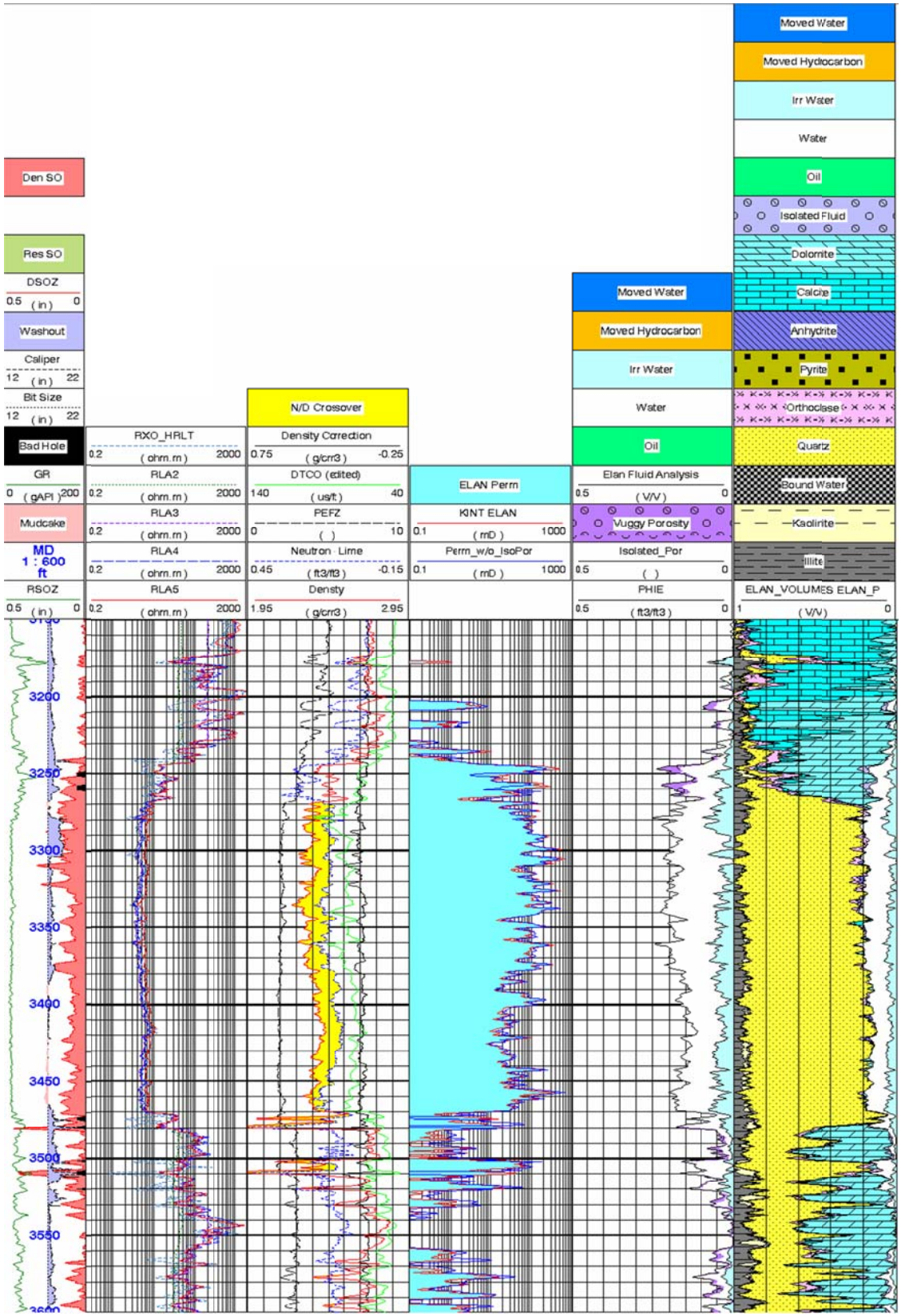
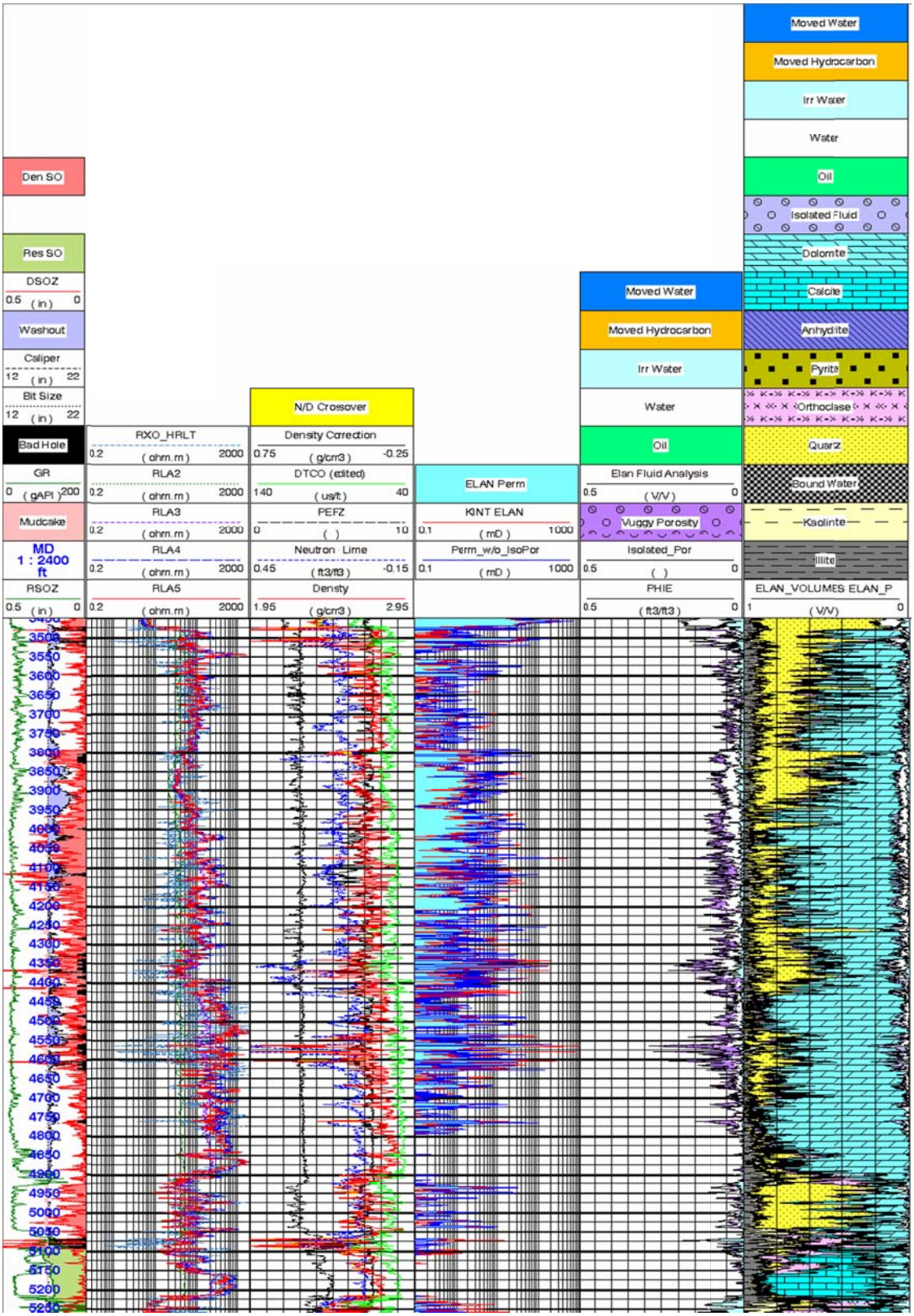
bbutsch@slb.com

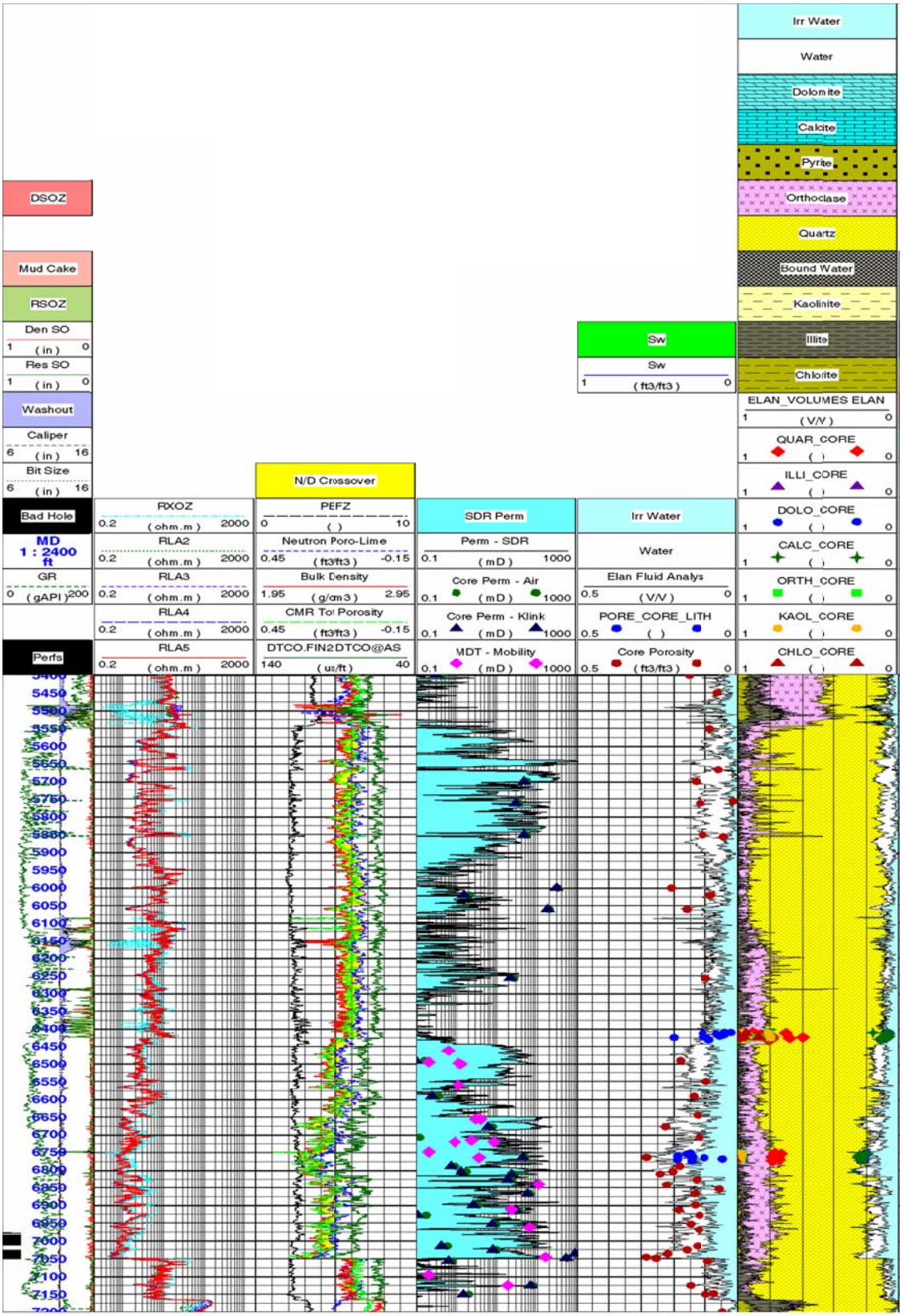
ELAN of St. Peter – CCS #1



ELAN of Knox – CCS #1



ELAN of Mt. Simon – CCS #1



Appendix L – CCS#1 Completion Report

CCS Well#1 Completion Report Certification

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who managed the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Mark Burau, Decatur Corn Plant Manager
Name & Official Title

217-424-5750
Phone Number

Signature

May 5, 2010
Date Signed

Archer Daniels Midland Company

UIC Permit No. UIC-012-ADM
Illinois Environmental Protection Agency
Bureau of Land
Class I – Non-Hazardous Permit

UIC Form 4h, CCS Well #1 Completion Report
Revised May 05, 2010

Geological Sequestration in the Illinois Basin

Location in Application

LOCATION IN APPLICATION **2**

LIST OF ABBREVIATIONS **3**

UIC FORM 4H, CCS WELL #1 COMPLETION REPORT **5**

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Appendices

Appendix VIII. Schematics of injection wellbore, wellhead, and bottom hole completion assembly

Appendix IX. Operational Drilling Log

Appendix X. Records of Tests and Logs During and After Drilling (see file boxes, not in 3-ring binder)

Appendix XI. Casing and Centralizer Tally Sheets

Appendix XIII.

A. Revised UIC Form 4a

B. Revised UIC Form 4d

C. Revised UIC Form 4g

D. Copy of D.N.R. Completion Report Form

NOTE: Appendices have been numbered to correspond to the specific section of the Completion Report Form 4h with which they are associated. Not all sections are accompanied by appendices.

List of Abbreviations

ADM, Archer Daniels Midland
Aka, also known as
Bbls, barrels
BHA, bottom hole assembly
BHCT, bottom hole circulating temperature
BHST, bottom hole static temperature
BOD, basis of design
BOP, blow out preventer
B-T gauge, Bourdon-tube gauge
BTU, British thermal unit
CCS, carbon capture and sequestration
Cf, cubic feet
Cf/sk, cubic feet per sack
CFR, Code of Federal Regulations
Cm, centimeter(s)
CO_2, carbon dioxide
Csg, casing
D&CWOP, Drill and complete well on paper
Eg, for example
EMR, electronic memory recorder
EOR, enhanced oil recovery
Etc, etcetera
F, farenheit
FEED, front end engineering design
FOT, fall-off test
Ft., foot or feet
Ft/h, feet per hour
Ft/min, feet per minute
Gal/sk, gallons per sack
GR, gamma ray
HP, high pressure
Hr, hour
ID, inside diameter
IEPA, Illinois Environmental Protection Agency
ISGS, Illinois State Geological Survey
KCl, potassium chloride
L (l), liter(s)
Lb (lbs), pound (pounds)
Lb/ft, pounds per foot
Lb/sk, pounds per sack
M (m), meter(s)
M/h, meters per hour
MASIP, maximum allowable surface injection pressure
MDT, Modular Dynamics Tester* (mark of Schlumberger)
MeV, milli electronvolts

Mg/L, milligrams per liter
MGSC, Midwest Geologic Sequestration Consortium
MI, move in
MO, move out
MVA, monitoring, verification, and accounting
NaCL, sodium chloride
N/A, not applicable
NPDES, National Pollution Discharge Elimination System
NRC, Nuclear Regulatory Commission
OD, outside diameter
P&A, plugging and abandonment
PBTD, Plug back total depth
POOH, pull out of hole
Ppg, pounds per gallon
Psi, pounds per square inch
Psi/ft, pounds per square inch per foot
PV, plastic viscosity
QA, quality assurance
QA Zone, quality assurance zone
QHSE, quality, health, safety, and environment
Qty, quantity
RD, rig down
RU, rig up
RST, Reservoir Saturation Tool* (mark of Schlumberger)
S, seconds
SACROC, Scurry Area Canyon Reef Operators Committee
Sk, sack
SIP, surface injection pressure
SP, spontaneous potential
SRPG, surface-readout pressure gauge
SRTs, step rate tests
Sxs, sacks
TBD, to be determined
Tbg, tubing
TD, total depth
TDS, total dissolved solids
TIH, trip in hole
TOH, trip out of hole
UIC, underground injection control
US DOE, United States Department of Energy
USEPA, United States Environmental Protection Agency
USDW, underground source of drinking water
WFL, water flow log
WOC, wait on cement

UIC Form 4h, CCS Well #1 Completion Report

DRAFT UIC PERMIT FORMS

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT APPLICATION

FORM 4h - WELL COMPLETION REPORT

USEPA ID NUMBER: ILD984791459
IEPA ID NUMBER: 1150155136
WELL NUMBER: CCS #1

I. Type of Permit

Individual: ____
Emergency ____
New ____
Renewal ____
Permit Number ____
Area: Completion Report
Number of well CCS #1
Name of Field ____
Emergency ____
New ____
Renewal ____
Permit Number UIC-012-ADM

Location in Application

II. Location, see instructions

A. Township-Range-Section:

CCS Well #1 is located 438 feet South and 1332 feet East in the Northwest quadrant of Section 5 of Township 16 North and Range 3 East.

B. Latitude/Longitude:

The latitude and longitude coordinates of the well in degrees-minutes-seconds are 39° 52' 36.9402" N and 88° 53' 35.721" W.

C. Closest Municipality

The closest municipality to the well is Decatur, Macon County, IL.

III. Surface Elevation

Surface elevation of the well is 674 feet (205.4 meters) above Mean Sea Level.

IV. Well Depth

The well was drilled to a total measured depth of 7236 feet (2205.5 meters).

V. Static Water Level

The static water level in the well is 430 feet (131 meters) above Mean Sea Level

VI. Demonstrated Fracturing Pressure

The fracture pressure was demonstrated to be 5024 psig at a measured depth of 7025 feet via a step-rate injection test.

VII. Injection Well Completion

The injection well is fully-cased and perforated in the intervals 6982' – 7012' and 7025' – 7050' (wireline reference measured depth in feet) with 6 shots per foot and a shot phasing of 60 degrees.

VIII. Well schematic or other appropriate drawing of surface and subsurface construction details

Please see the injection wellbore, wellhead, and bottom hole completion assembly schematics included in Appendix VIII with this report.

IX. Well Design and Construction

Please see Appendix IX for an operational drilling log based which summarizes the rig performance throughout the drilling of the well.

A. Well hole diameters and corresponding depth intervals

The well was drilled in three stages with the following depth intervals and wellbore diameters:

<u>Surface Hole:</u> 0 – 355 feet, 26-inch diameter

<u>Intermediate Hole:</u> 355 – 5339 feet, 17.5-inch diameter

<u>Final Hole:</u> 5339 – 7236 feet, 12.25-inch diameter

B. Annulus Protection System

For additional details on the Annulus Protection System, please see the Major Permit Modification first submitted on October 30, 2009.

1. *Annular space, ID and OD (inches)*

The annular spaces between the wellbore tubulars are detailed below and reflect the various casing/tubing sizes that were used in the wellbore design.

Surface-Intermediate (0 – 355 feet): 13.375 / 19.124

Intermediate-Final #1 (3630 – 5339 feet): 9.625 / 12.415

Intermediate-Final #2 (0 – 3630 feet): 9.625 / 12.515

Final-Tubing #1 (5285 – 6363 feet): 4.5 / 8.681

Final-Tubing #2 (0 – 5285 feet): 4.5 / 8.835

2. *Type of annular fluid(s)*

The fluids occupying the annular spaces between the wellbore tubulars are described below.

Surface-Intermediate: fully cemented (see cement details in section XI.C)

Intermediate-Final #1 & #2: fully cemented (see cement details in section XI.C)

Final-Tubing #1 & #2: 9.4 lb/gal sodium-chloride brine with corrosion inhibitor and oxygen scavenger additives

3. *Specific gravity of annular fluid*

The fluid occupying the annulus space between the final casing string and the injection tubing has a specific gravity of 1.127. Other annular spaces are filled with solid cement.

4. *Coefficient of annular fluid*

The fluid occupying the annulus space between the final casing string and the injection tubing has a hydrostatic coefficient of 0.488 psi/ft.

5. *Packer(s)*

a. *Setting depth*

The top of the packer is set at a wireline-referenced depth of 6363.7 feet (1939.6 meters) with the center of the sealing elements at 6365 feet (1940 meters).

b. *Type*

The packer used in the completion assembly is a seal bore, retrievable production packer.

c. *Name and model*

The packer is a Schlumberger brand Quantum Max Type III Service Tool, Q-Max 13 Chrome designed for 9.625-inch outer diameter casing with linear weights ranging from 47 – 53 lb/ft.

6. *Description of fluid spotting frequency, type and quantity*

Before installing the lower portion of the injection completion (the packer), the wellbore was filled with approximately 500 barrels of 9.4 lb/gal sodium-chloride brine with corrosion inhibitor and oxygen scavenger additives. This fluid remained in the well as the upper completion (tubing, seal-bore assembly, sensors, etc.) was deployed and latched into the polished bore receptacle of the packer body. This is also the fluid that currently resides in the well and tubing-casing annular space.

7. *Information on well driller used for construction of this well*

The well was drilled with a rotary-table drilling rig with a water-based circulating mud system. Contact information for the drilling company is listed below.

Les Wilson Inc.
215 Industrial Ave.
Carmi, IL 62821
(618) 382-4666
Contact Person: Bob Wilson

X. *Tests and Logs*

A variety of wireline logs and tests were conducted during each stage of drilling and completing the well; the types of logs and tests run are listed below with detailed information included in the file box.

A. *During Drilling*

Intermediate Hole:

- Wireline Logs: (Logs included in File Box)
  - Compensated Neutron Porosity

    - Photoelectric Factor & Bulk Density
    - Resistivity
    - Micro-Resistivity Imaging (“fracture finder”)
    - Sonic
    - Elemental Capture Spectroscopy
    - Natural Gamma Ray Spectroscopy
    - Magnetic Resonance
    - Rotary Sidewall Cores

- Drill Stem Test: (Results included in File Box)

Final Hole:

- Wireline Logs: (Logs included in File Box)
    - Compensated Neutron Porosity
    - Photoelectric Factor & Bulk Density
    - Resistivity
    - Micro-Resistivity Imaging (“fracture finder”)
    - Sonic
    - Elemental Capture Spectroscopy
    - Natural Gamma Ray Spectroscopy
    - Magnetic Resonance
    - Rotary Sidewall Cores (Description of test procedures included in File Box Appendix X.A)
    - Formation Pressure Measurements & Fluid Samples
    - ‘Mini’ Fracture Pressure Measurement
    - Zero-offset Vertical Seismic Profile

- Whole Cores: (Description of test procedures included in File Box)
    - Core #1: 5474’ – 5504’
    - Core #2: 6404’ – 6434’
    - Core #3: 6750’ – 6780’

B. During and after casing installation

Surface Hole: (Logs included in File Box)

- Wireline Logs:
    - Variable Density Cement Bond Log

Intermediate Hole: (Logs included in File Box)

- Wireline Logs:
    - Ultrasonic Cement Imaging

Final Hole:

- Wireline Logs: (Logs included in File Box)

- Ultrasonic Cement Imaging
- Variable Density Cement Bond Log
- Pressure/Temperature Log
- Thermal Neutron Decay (Formation Sigma) Log
- Multi-finger Casing Caliper Log
- Casing Collar and Perforating Record Logs
- Injection Full Bore Spinner Logs

- Injectivity Testing: (Results included in File Box)
  - Step-rate Test
  - Pressure Fall-off Tests

C. Demonstrate mechanical integrity prior to operation

A mechanical integrity test of the tubing-casing annular space was conducted and recorded on April 27, 2010. Results are included in the file box.

D. Copies of logs and tests listed above

Please see file boxes accompanying completion report for copies of logs and test results.

E. Description of well stimulation

The injection interval was subjected to a small-scale acid injection delivered in two distinct pumping stages following the addition of perforations. Each acid injection was designed with the primary intention of reducing near-wellbore drilling or 'skin' damage. The chronology of these injections is as follows:

25-Sep-2009: The interval perforated from 7025' to 7050' was acidized with 1,500 gallons of 15% HCl acid and displaced into the formation with 123 barrels of freshwater with a potassium chloride substitute additive.

30-Sep-2009: The intervals perforated from 6,982' to 7,012' and 7025' to 7050' were acidized with 3,000 gallons of 15% HCl acid. The acid was pumped in four 750-gallon stages with 500 gallon spacers of freshwater with a potassium chloride substitute additive between each acid stage. The acid was then displaced into the formation with 121.5 barrels of freshwater with a potassium chloride substitute additive.

XI. Well Design and Construction

The depth intervals, outer and inner diameters, linear weight, grade, coupling type and coupling outer diameters, and thermal conductivity of the various strings of casing and tubing installed in the well are summarized below with appropriate units indicated. Please see Appendix XI for casing tally sheets and locations of casing centralizers.

A. Casings, see instructions

1. Conductive casing

N/A

2. Surface casing

Top Depth (feet): 0
Bottom Depth (feet): 355
O.D. (inch): 20
I.D. (inch): 19.124
Weight (lbs/ft): 94.00
Grade: H-40
Coupling Type: 8-round, STC
Coupling O.D. (inch): 21.00
Thermal Conductivity (BTU/ft-hr-°F): 29.02

3. Intermediate casing(s)

Top Section:
Top Depth (feet): 0
Bottom Depth (feet): 3630
O.D. (inch): 13.375
I.D. (inch): 12.515
Weight (lbs/ft): 59.50
Grade: J-55
Coupling Type: Buttress
Coupling O.D. (inch): 14.375
Thermal Conductivity (BTU/ft-hr-°F): 29.02

Bottom Section:
Top Depth (feet): 3630
Bottom Depth (feet): 5339
O.D. (inch): 13.375
I.D. (inch): 12.415
Weight (lbs/ft): 66.17
Grade: J-55
Coupling Type: Buttress
Coupling O.D. (inch): 14.375
Thermal Conductivity (BTU/ft-hr-°F): 29.02

4. Long string casing

Top Section:
Top Depth (feet): 0
Bottom Depth (feet): 5272
O.D. (inch): 9.625

I.D. (inch): 8.835
Weight (lbs/ft): 38.97
Grade: N-80
Coupling Type: 8-round, LTC
Coupling O.D. (inch): 10.625
Thermal Conductivity (BTU/ft-hr-°F): 31

Bottom Section:
Top Depth (feet): 5272
Bottom Depth (feet): 7219
O.D. (inch): 9.625
I.D. (inch): 8.681
Weight (lbs/ft): 47.00
Grade: L-80, 13Cr80
Coupling Type: JFE BEAR
Coupling O.D. (inch): 10.485
Thermal Conductivity (BTU/ft-hr-°F): 13

5. Other casing

N/A

B. Injection Tubing, see instructions

Top Depth (feet): 0
Bottom Depth (feet): 6363
O.D. (inch): 4.5
I.D. (inch): 3.958
Weight (lbs/ft): 12.6
Grade: JFE 13Cr85
Coupling Type: JFE BEAR
Coupling O.D. (inch): 5.00
Thermal Conductivity (BTU/ft-hr-°F): 13

1. Maximum allowable suspended weight based on joint strength

The joint strength of the tubing and, hence, maximum allowable suspended weight is 306 Kip (1361 kN).

2. Weight of injection tubing string (axial load) in air

The injection tubing weighs (in air) 79539 lbs (36078 kgs).

C. Cement, see instructions

Details about the various cement blends used in each stage of the construction of CCS Well #1, including the depth interval, type and grade, additives, quantity, thermal conductivity, and whether or not the cement was circulated to surface, are summarized in the following sections with

the appropriate units indicated.

1. *Conductive casing*

N/A

2. *Surface casing(s)*

Depth Interval (feet): 0 – 355
Type/Grade (Lead): Class A
Additives (Lead): 0.2% D-46 Anti-foam, 0.25 lb/sk flake
Quantity (Lead) (cubic yards): 58

Type/Grade (Tail): Class A
Additives (Tail): 1% CaCl2, 0.2% D-46 Anti-foam, 0.25 lb/sk flake
Quantity (Tail) (cubic yards): 38.67
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.7

3. *Intermediate casing*

A comment on the intermediate casing cement design:
The lead cement system was changed from that proposed in the permit application due to lost circulation encountered while drilling the well. Lost circulation was encountered in the Knox at a depth of approximately 4562 feet and again in the Ironton-Galesville at 5017 feet. Both zones were sealed off with cement plugs, however, there was concern that during cementing operations the plugs might fail and lost circulation would be encountered while cementing. Therefore, the cement job was completed in two stages with a stage collar run at 3715 feet. The first stage cement was changed from a Class A system to Class H cement due to better performance characteristics of Class H cement – primarily lack of a gelation tendency present in Class A. The second stage lead system was changed from a 50/50 Class A- Pozzolan with 6% bentonite and 10% salt mixed at a density of 13.3 ppg to a 65/35 Class A-Pozzolan system with 4% bentonite and 10% salt with 5 lbs/sk Kolite mixed at a density of 12.7 ppg in order to lighten the slurry, thus enabling cement to be circulated to surface. The difference in 24 hour compressive strength was small: 575 psi in 24 hours for the 65/35 system compared to 655 psi in 24 hours for the original 50/50 system. The actual job went very well with cement circulated to surface and good bonding obtained from the base of the intermediate casing to surface.

Stage 1:

Depth Interval (feet): 3715 – 5339
Type/Grade (Lead): Class H

Additives (Lead):

Additives		
Code	**Concentration**	**Function**
D081	0.040 gal/sk blend	Retarder
D047	0.020 gal/sk blend	Antifoam

Quantity (Lead) (cubic yards): 54.7
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.71

Type/Grade (Slurry): Class H
Additives (Slurry):

Additives		
Code	**Concentration**	**Function**
D081	0.080 gal/sk blend	Retarder
D047	0.020 gal/sk blend	Antifoam

Quantity (Slurry) (cubic yards): 46.3
Circulated: No
Thermal Conductivity (BTU/ft-hr-°F): 0.75

Type/Grade (Tail): Class H
Additives (Tail):

Additives		
Code	**Concentration**	**Function**
D081	0.080 gal/sk blend	Retarder
D047	0.020 gal/sk blend	Antifoam

Quantity (Tail) (cubic yards): 45.8
Circulated: No
Thermal Conductivity (BTU/ft-hr-°F): 0.78

Stage 2:

Depth Interval (feet): 0 – 3715
Type/Grade (Lead): 35:65 (pozzolan:cement blend)
Additives (Lead):

Additives		
Code	**Concentration**	**Function**
D020	4.000 %BWOB	Extender
D044	10.000 %BWOW	Salt
D065	0.600 %BWOB	Dispersant
D167	0.200 %BWOB	Fluid loss
D046	0.200 %BWOB	Antifoam
D042	4.787 lb/sk blend	LCM/extender

Quantity (Lead) (cubic yards): 221.3
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.47

Type/Grade (Slurry): 35:65 (pozzolan:cement blend)
Additives (Slurry):

Additives		
Code	**Concentration**	**Function**
D020	4.000 %BWOB	Extender
D044	10.000 %BWOW	Salt
D065	0.600 %BWOB	Dispersant
D167	0.200 %BWOB	Fluid loss
D046	0.200 %BWOB	Antifoam
D042	4.787 lb/sk blend	LCM/extender

Quantity (Slurry) (cubic yards): 239.2
Circulated: No
Thermal Conductivity (BTU/ft-hr-°F): 0.5

Type/Grade (Tail): Class H
Additives (Tail):

Additives		
Code	**Concentration**	**Function**
D047	0.020 gal/sk blend	Antifoam
D081	0.020 gal/sk blend	Retarder

Quantity (Tail) (cubic yards): 38.67
Circulated: No
Thermal Conductivity (BTU/ft-hr-°F): 0.72

4. *Long string casing*

Depth Interval (feet): 0 – 4170
Type/Grade (Lead): 35:65 LP3:A (pozzolan:cement blend)
Additives (Lead):

Additives		
Code	**Concentration**	**Function**
D020	6.000 %BWOB	Extender
D046	0.200 %BWOB	Antifoam
D167	0.400 %BWOB	Fluid loss

Quantity (Lead) (cubic yards): 249.5
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.47

Depth Interval (feet): 4170 - 7219
Type/Grade (Tail): EverCRETE
Additives (Tail):

Additives		
Code	**Concentration**	**Function**
D081	0.035 gal/sk blend	Retarder
D168	0.170 gal/sk blend	Fluid loss
D206	0.030 gal/sk blend	Antifoam
D080	0.050 gal/sk blend	Dispersant

Quantity (Tail) (cubic yards): 112.1
Circulated: No
Thermal Conductivity (BTU/ft-hr-°F): 0.72

5. *Other casing*

N/A

XII. *Surface Facilities*

For additional details on the surface facilities, please see the Major Permit Modification first submitted on October 30, 2009.

A. *Filters(s)*

N/A

B. *Injection pump(s)*

The table below summarizes the specifications of the various injection pumps in the surface compression system. Please see annotations on the Process Control Strategy Diagram accompanying the Major Permit Modification first submitted on October 30, 2009 for the location of pumps with respect to the entire compression/dehydration facility.

TYPE	NAME	MODEL NUMBER	CAPACITY
Multistage Centrifugal Blower	BL-101	HSI 18604	21 MMSCFD
Reciprocating Compressor	VC-201 & VC-301	Ariel JGC6-4, 3250 HP	10.85 MMSCFD (each)
Multistage Centrifugal Pump	ESP PUMP	Wood Group SJ0270	21 MMSCFD (282.9 US GPM)

XIII. *Hydrogeologic Information*

A. *Revised UIC Form 4a*

Please see Revised UIC Form 4a included as Appendix XIII.A.

B. *Revised UIC Form 4d using actual data on injection formation*

Please see Revised UIC Form 4d included as Appendix XIII.B.

C. *Revised UIC Form 4g*

Please see Revised UIC Form 4g included as Appendix XIII.C.

D. *Copy of well completion report submitted to the Department of Natural Resources (Formerly Mines and Minerals)*

Please see attached copy of well completion report submitted to the DNR included as Appendix XIII.D.

E. *Copy of any plugging affidavits on injection well filed with Department of Natural Resources*

N/A

XIV. Injection Fluid Compatibility

The following information is presented as an update to that which was previously submitted with the original permit application in Chapter 9: UIC Form 4f, Section V. In the cases where no new information is presented, reference is made to the language in the original permit application.

A. *Compatibility with injection zones fluid*

No compatibility problems are anticipated in the injection zone. Geochemical modeling was used to predict the effects of injecting supercritical CO_2 into a model Mt. Simon sandstone (Berger et al., 2009). Based on chemical and mineralogical data from the Manlove Gas Storage Field in Illinois, the geochemical modeling software package, Geochemist's Workbench (Bethke, 2006), was used to simulate geochemical reactions. As expected, the injected CO_2 decreased the pH of the formation brine to about pH 4.5. As the reaction was allowed to progress, the pH of the formation brine increased to pH 5.4.

B. *Compatibility with minerals in the injection zone*

In the geochemical simulations mentioned in above, Berger et al. (2009), it was predicted that illite and glauconite dissolved initially. As the reaction was allowed to proceed, kaolinite and smectite were predicted to precipitate. It was predicted that the volume of pore space would not be significantly altered (Berger et al., 2009). Therefore, no compatibility problems, such as a major reduction in injection-formation permeability resulting from chemical precipitates, are expected.

C. *Compatibility with minerals in confining zone*

In the geochemical simulations mentioned above, Geochemist's Workbench predicted that as the CO_2 reacts with the Eau Claire formation, illite and smectite would initially dissolve, but that the dissolved CO_2 could be precipitated as carbonates (Berger et al., 2009). This dissolution and precipitation process is not expected to affect the caprock integrity.

D. Compatibility with injection well components

1. Injection tubing

As the CO_2 will be dehydrated to less than 30 lb/MMSCF or 630 ppmv, the expected reactivity with the tubing will be negligible. Nevertheless, the injection tubing is composed of chrome steel (13 Cr) and is specifically engineered to function in environments with high concentrations of CO_2. This reflects the design specifications approved under the UIC Permit No. UIC-012-ADM.

2. Long string casing

As per the design specifications approved under the UIC Permit No. UIC-012-ADM, the long string casing installed from total depth of the well past the base of the confining layer (to a depth of 5285') is composed of chrome steel (13 CR) and is specifically engineered to function in environments with high concentrations of CO_2. The long string casing in the remainder of the well (5285' to surface) is carbon steel. This section of casing, however, will remain isolated from the injected CO_2 due to the tubing-annulus protection system and the protective cement sheath in which it encased. Reactivity between the injected CO_2 and the long string casing is expected to be negligible.

3. Cement

As specified under UIC Permit No. UIC-012-ADM, the long string casing is encased from total depth to approximately 4170 feet (or approximately 1170 feet into the intermediate casing string) in Schlumberger's proprietary blend of CO_2-resistant cement, EverCRETE. Technical descriptions of the cement properties can be found in the original permit application (Chapter 9: UIC Form 4f, Section V, pages 135-139) and accompanying appendices. Reactivity between the injected CO_2 and the cement is expected to be negligible.

4. Annular fluid

The annular fluid between the injection tubing and the long string casing is a 9.4 lb/gal sodium chloride brine with corrosion inhibitor and oxygen scavenger additives that are compatible with the injected CO2 and will minimize corrosion to the tubing and casing. Reactivity between the injected CO_2 and the annular fluid is expected to be negligible.

5. Packer(s)

The injection packer installed is a Schlumberger Quantum Max Type III Seal-bore Assembly packer composed of chrome steel (13 Cr). The sealing elements of the packer and seal-bore assembly are comprised of Nitrile rubber which is designed to be durable in environments with high CO_2 concentration. As a result, reactivity between the injected CO_2 and the injection packer is expected to be negligible.

6. Well head equipment

Components of the wellhead equipment expected to be in contact with the injected CO_2 are constructed from schedule 310 and 410 stainless steel; therefore, no adverse reactions are expected between the injected CO_2 and any the wellhead components.

7. Holding tank(s) and flow lines

There will be no holding tanks for the injection fluid. Consequently, there are no CO_2 holding tank compatibility concerns.

The CO_2 is transferred from the surface compression facilities via approximately 6400 feet of 6-inch Schedule 40 carbon steel pipeline to the wellhead. The design basis for the surface facility gas dehydration unit is to reduce the water content of the CO_2 to a range of 7 to 30 lb of H_2O/MMSCF (150 to 630 ppmv H_2O). This water content range is consistent with typical U.S. CO_2 transmission pipeline water content specifications for carbon steel pipe, therefore, no corrosive reactions are anticipated.

E. Full description of compatibility of injection fluid with items A-D

In summary, there are no compatibility concerns with the injection zone, minerals in the injection zone, and minerals in the confining zone. The CO_2 is expected to have negligible to no reaction with the minerals and formation water. Any reactions that may occur are not expected to affect the containment of the CO_2 below the primary seal.

Components to the injection wellhead and wellbore have been selected to minimize and negate any reaction with the CO_2. Additional details on the corrosion monitoring plan are included the Major Permit Modification first submitted on October 30, 2009.

Sources:

Bethke, C.M.. 2006. The Geochemist's Workbench (Release 6.0) Reference Manual. RockWare, Inc., Golden CO, 240 p.

Berger, P.M., Mehnert, E., and Roy, W.R. (2009) Geochemical Modeling of Carbon Sequestration in the Mt. Simon Sandstone. Geological Society of America *Abstracts with Programs*, vol. 41, no. 4, p. 4.

XV. Monitoring Program

Details of the various process monitoring sensors and gauges are summarized below and include the location of the device, the brand and model number, the device type (electrical or mechanical), and whether or not the device is continuously recording.

A. Injection pressure gauge(s)

Surface Injection Pressure Gauge: PIT-009 (Please see Process Control Strategy Diagram in Appendix XII)
Location: Installed directly into the wellhead tree cap port.
Make / Model: ABB / 264HSVKTA1L1N2
Type: Electrical; Continuous Recording
Operating Range (psig): 0 – 4000; this exceeds maximum operating range of system by more than 20%

Downhole Injection Pressure Gauge: (Please see injection wellbore schematic in Appendix VIII)
Location: Mounted within the downhole solid gauge mandrel at a measured depth of 6325 feet as part of the tubing completion.
Make / Model: Schlumberger / NDPG-CA (P/N 500897)
Type: Electrical; Continuous Recording
Operating Range (psig): 0 – 10000; this exceeds maximum operating range of system by more than 20%

B. Casing-tubing annular pressure gauge(s)

For additional details on the Annulus Protection System, refer to the description included as Appendix IX.A.

Location: Mounted on the wellhead port open to the casing-tubing annulus.
Make / Model: Unknown at this time; compliant with ASME B 40.1 specifications
Type: Electrical (4-20 mA); Continuous Recording
Operating Range (psig): 0 – 600; this exceeds maximum operating range of system by more than 20%

C. Flow meter(s)

Location: Installed downstream of the multistage centrifugal pump (FIT006 – Please see Process Control Strategy Diagram in Appendix XII)
Make / Model: SCADASense / 4203
Type: Electrical; Continuous Recording

Operating Range (tonnes/day): 250 – 1100; this meets the maximum operating range of the system but does not exceed it by more than 20%

D. pH recording device(s)

N/A

E. Temperature

Surface Temperature Gauge: TIT-009 (Please see Process Control Strategy Diagram in Appendix XII)
Location: Installed downstream of the multistage centrifugal pump along the section of pipeline immediately upstream of the wellhead wing valve inlet and check valve.
Make / Model: INOR / Meso-HX 70MEHX1001
Type: Electrical; Continuous Recording
Operating Range (degF): -40 – 185; this exceeds maximum operating range of system by more than 20%

Downhole Temperature Gauge: (Please see injection wellbore schematic in Appendix VIII)
Location: Mounted within the downhole solid gauge mandrel at a measured depth of 6325 feet as part of the tubing completion.
Make / Model: Schlumberger / NDPG-CA (P/N 500897)
Type: Electrical; Continuous Recording
Operating Range (degF): 0 – 212; this exceeds maximum operating range of system by more than 20%

Appendix VIII – CCS Well #1 Wellbore & Wellhead Schematics

Schlumberger

Illinois Basin - Decatur Project

Prepared for :	Date :	Casing :	Completion Type :	Pressure/Temp.
Paul Huges	Nov-24-2009	9 5/8" 40&47# N-80& CR13	Upper Compleation	
Field Name :	**Well Name :**	**Casing Drift**	**Rig:**	
Illinois Basin	ADM CCS #1	ID 8.681/Drift 8.525	Wilson 28	
Prepared by :	**District/Phone # :**			3245psi BHP
Roberto Schuldes	Houma, LA / (985) 851-1074			135 Degree F
Production Tubing :				
4 1/2" 12.6# CR13 JFE Bear				

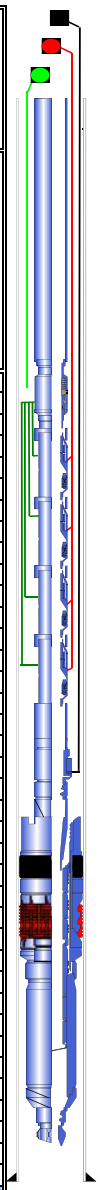
String Weight Include Block -		Rig: Ideco H-35/Pioner Rig 15	
Block Weight -		Item's Actual Pipe Measured Length -	6335.32
Weight On Locator -		Packer Fluid Type and Weight -	9.4 ppg NaCl
Original RKB -		Completion Fluid Type and Weight -	9.4 ppg NaCl

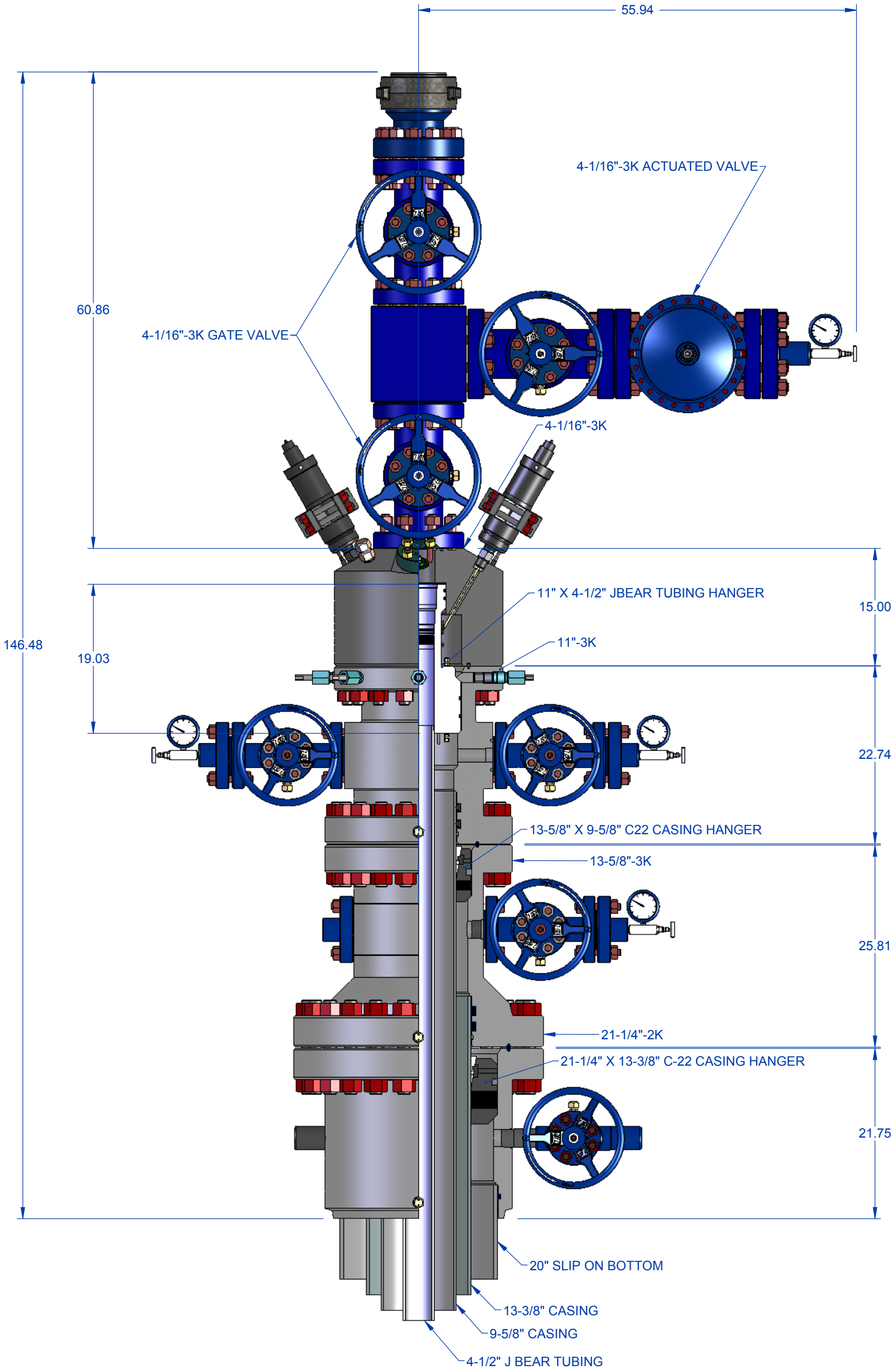
All Depths Are Wireline Depths

Production String Assembly

0.00	0.55	11.000	3.958	**Hanger PN: HTG6561, Top Thread: 4-1/2 EUE 8rd**
0.55	30.75	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joints (5.52+10.34+8.34+6.55)
31.30	4883.83	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing (Adjusted by 49.07)
4915.13	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
4925.47	9.97	8.350	3.958	**Geophone #3**
4935.44	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
4945.78	786.51	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing
5732.29	10.36	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
5742.65	9.97	8.350	3.958	**Geophone #2**
5752.62	10.38	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
5763.00	236.64	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing
5999.64	8.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6007.98	118.40	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing
6126.38	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6136.72	9.97	8.350	3.958	**Geophone #1**
6146.69	10.34	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6157.03	157.96	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear tubing
6314.99	10.36	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6325.35	6.01	5.712	3.879	**4 1/2, 12.60, SGM-FS, NDPG/NLOG, SINGLE, TUBING**
6331.36	10.33	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6341.69	10.33	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6352.02	1.36	4.500	3.813	**4 1/2" x 3.813 X-nipple JFE Bear**
6353.38	10.33	4.500	3.958	4 1/2 12.6# 13Cr JFE Bear pup joint
6363.71	2.08	7.000	3.500	**4.75" Snap latch 13Cr (4 1/2 12.6# JFE Bear)**
6365.79	9.00	4.690	3.500	4.75" Seal Unit 4.124" 13Cr SLHT pin x box ID:127088 PN:4
6374.79	0.81	4.690	3.500	X-O, 4.063-8 SA Pin x 4.124" 13Cr SLHT Box PN: 100714412
6375.60	2.51	4.724	3.750	SAGS w/ inner sleeve 13chr 4.063 8SA Box ID: 164949-01, PN:100602582/AA
6378.11				End of Assembly

Depth	Length	ID	OD	Quantum Max Packer Assembly
6363.71	6.47	4.750	8.341	9 5/8" x 4.75" (47-53.5#) Q-Max 13Cr w/HNBR ID# 250148-03
6370.18	0.83	5.443	7.013	X-O, 6.375" 6-SA Box x 6.25" 8-SA Box HOS-252940
6371.01	19.06	4.750	6.974	9 5/8" x 4.75" x 20' PBR PO# 101046
6390.07	1.14	3.431	6.950	X-O, 4" 11.6# NU 8rd Pin x 6.375" 6-SA Box HOS-252941
6391.21	10.33	3.442	4.752	4" NU 8rd 11.6# 13Cr85 Pup Joint w/ Collar
6401.54	1.54	3.313	4.744	4" x 3.313" X-Nipple C-36025-01
6403.08	10.31	3.442	4.745	4" NU 8rd 11.6# 13Cr85 Pup Joint w/ Collar
6413.39	0.71	3.672	4.780	4" NU 8rd 11.6# 13Cr85 Wireline Re-Entry Guide w/ mule shoe SO# 729775
6414.10				EOA





DRW BY: NJB	DATE:	TITLE	SCHLUMBERGER DECATUR, IL
APVD BY:	DATE:		
This drawing contains confidential and proprietary information of T3 Energy Services. Neither this document nor any information disclosed herein shall be reproduced in any form, used, or disclosed to others for any purpose, including manufacturing without the express written permission of:	T3 Energy Services www.t3energy.com	EST. WEIGHT (LBS)	DRAWING NUMBER SL-288

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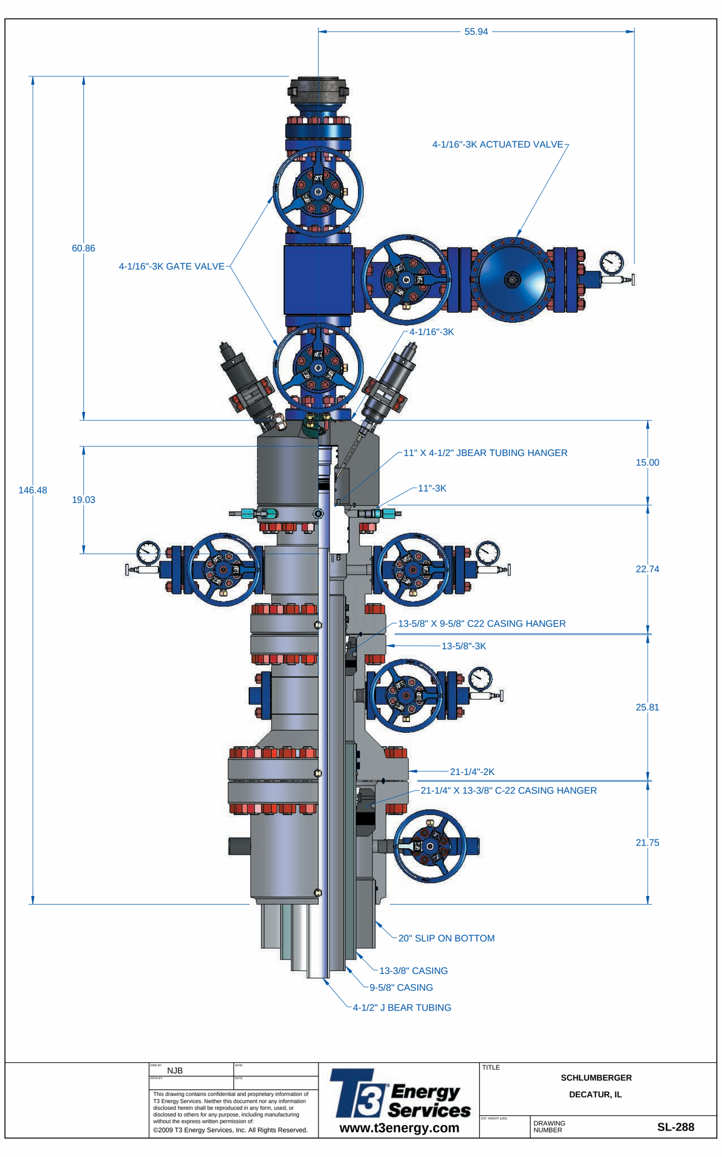
Appendix VIII - CCS# 1 Injection Wellbore Schematic



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Appendix IX – CCS Well #1 Operational Drilling Log

NOTE: the following operational drilling log is a continuous record of key drilling rig performance metrics which can be used to make qualitative inferences about the various geologic properties and drilling conditions encountered in the well. The log, which includes the entirety of the drilling operation of CCS Well #1, includes such information as the weight on the drilling bit, the weight on the rig's travelling block ('Hook Load'), rate of rotation, rotational torque, mud pump output, rate of penetration, along with the driller's comments during various operational milestones or decision points and the chronology of these events.

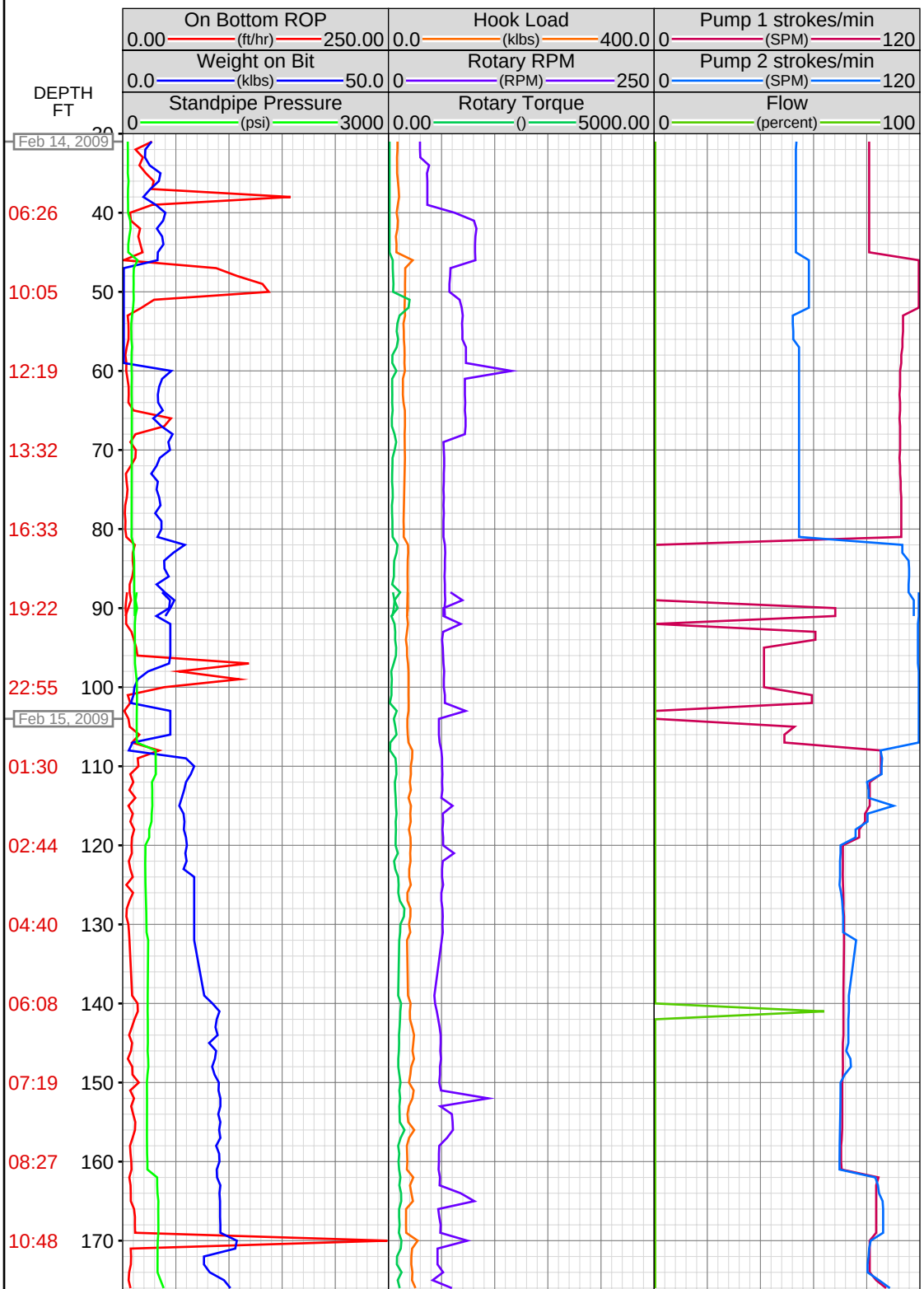
NOTE: the following operational drilling log is a continuous record of key drilling rig performance metrics which can be used to make qualitative inferences about the various geologic properties and drilling conditions encountered in the well. The log, which includes the entirety of the drilling operation of CCS Well #1, includes such information as the weight on the drilling bit, the weight on the rig's travelling block ('Hook Load'), rate of rotation, rotational torque, mud pump output, rate of penetration, along with the driller's comments during various operational milestones or decision points and the chronology of these events.

DataHub EDR Log

Tue Mar 16, 2010 08:33:19
Well Dossier 1607061
Ethan Chabora

OPERATOR: ADM (Archer Daniel Midland)
WELL: ADM COMPANY CCS WELL NO 1
FIELD:
LOCATION:
COUNTRY: USA
RIG: Les-Wilson 25

CONTRACTOR: Les Wilson Drilling
UNIQUE WELL ID:
SPUD DATE: Feb 14, 2009 05:00
RELEASE DATE: May 05, 2009 10:08



MEMOS

45.00ft: TORQUE LOW READING RECALIBRATED
45.00ft: TORQUE HIGH READING RECALIBRATED
45.00ft: SYSTEM-WIDE UNIT CHANGE FOR TORQUE TO FT-LBS
45.00ft: SYSTEM-WIDE UNIT CHANGE FOR TORQUE TO kFT-LBS
50.00ft: HOLE DEPTH CHANGED TO 30.0 FEET
50.00ft: SYSTEM-WIDE UNIT CHANGE FOR TORQUE TO PSI
52.00ft: HOOK LOAD THRESHOLD RECALIBRATED TO 11
52.00ft: STANDPIPE PRESSURE SENSOR CHANGED
52.82ft: STANDPIPE PRESSURE SENSOR CHANGED
56.00ft: TORQUE HIGH READING RECALIBRATED
56.14ft: TORQUE LOW READING RECALIBRATED
59.54ft: ZWOB from DHC

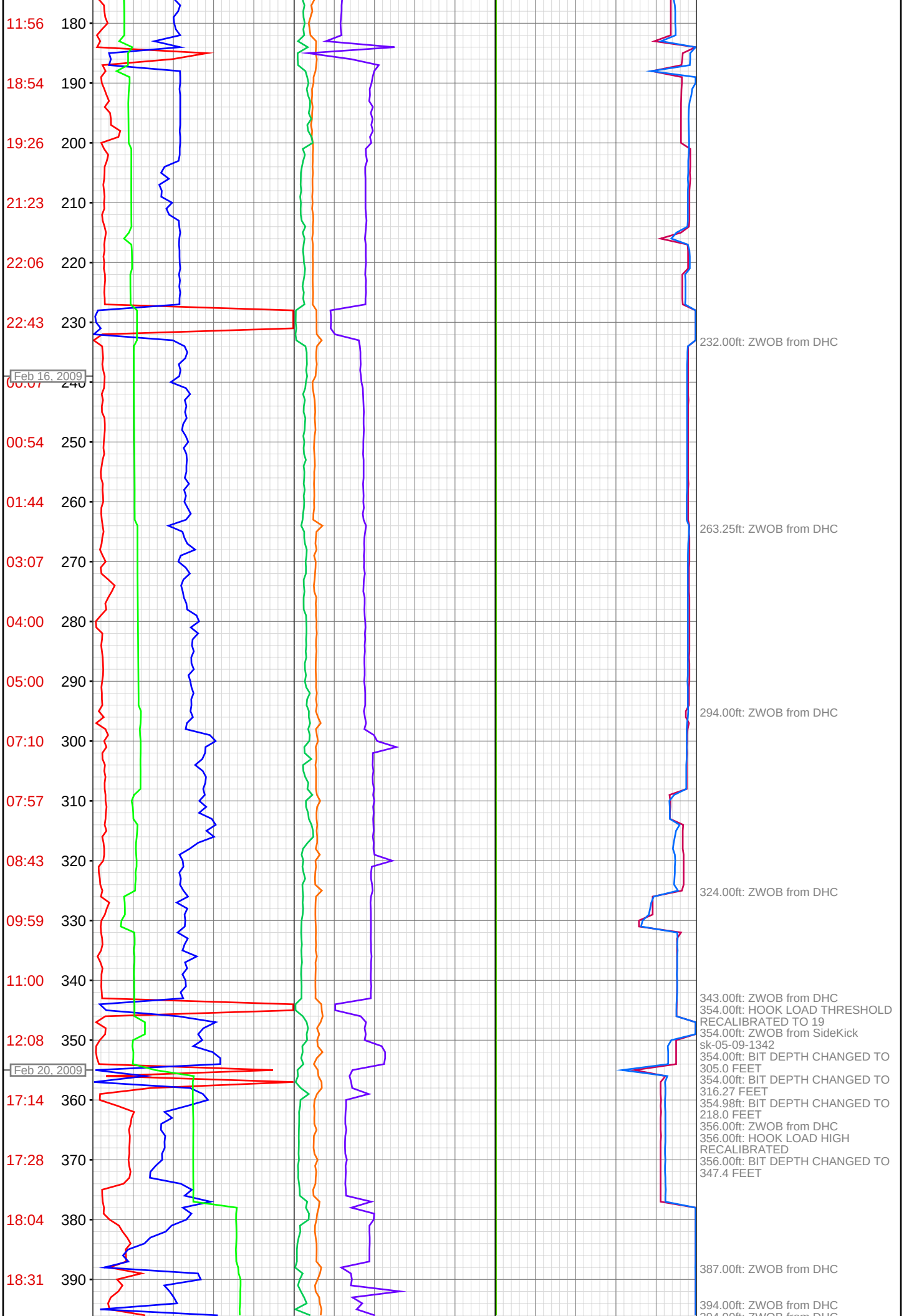
81.00ft: BIT DEPTH CHANGED TO 81.5 FEET

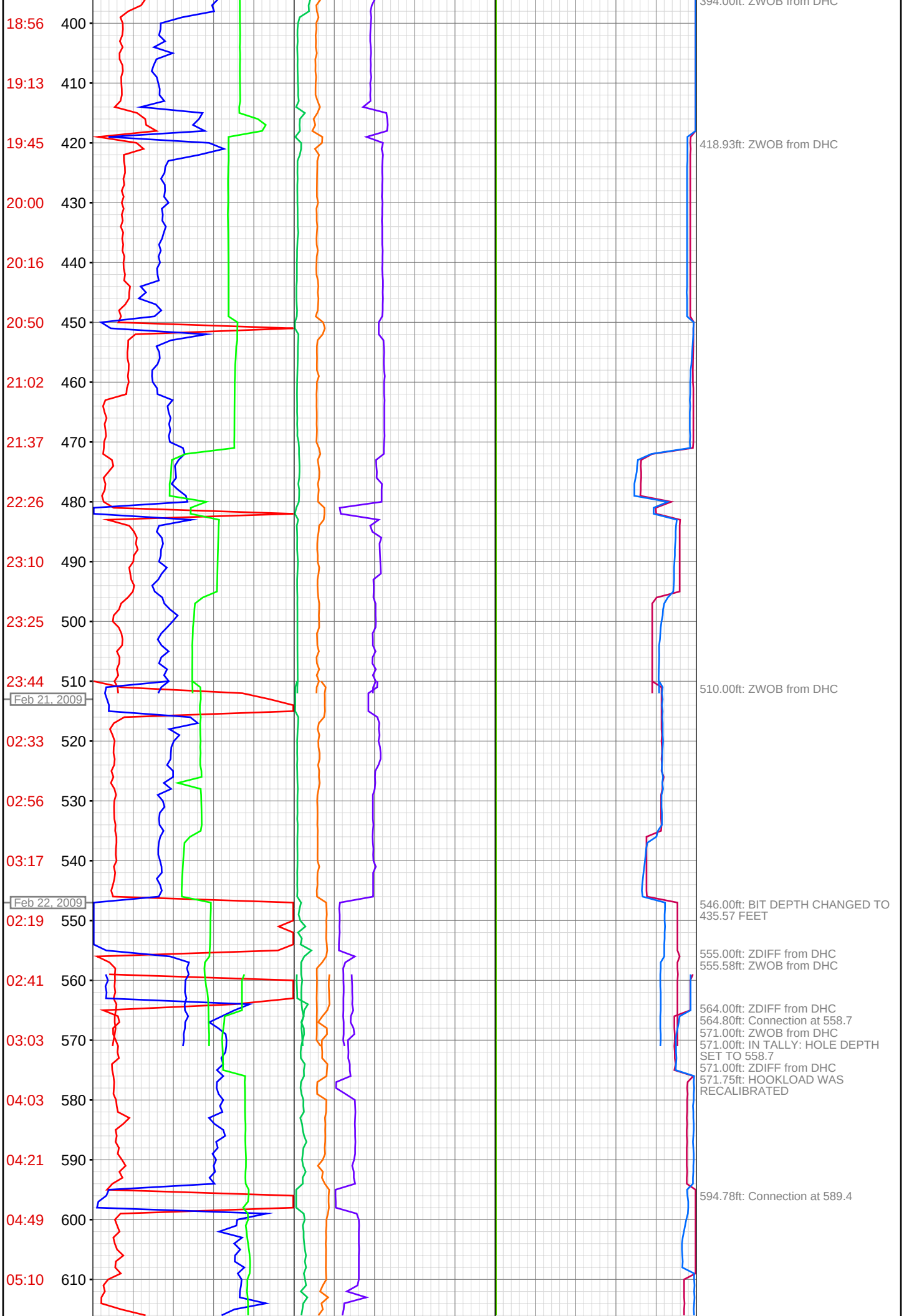
89.01ft: SURVEY
91.00ft: HOOK LOAD THRESHOLD RECALIBRATED TO 21
91.63ft: HOOKLOAD WAS RECALIBRATED

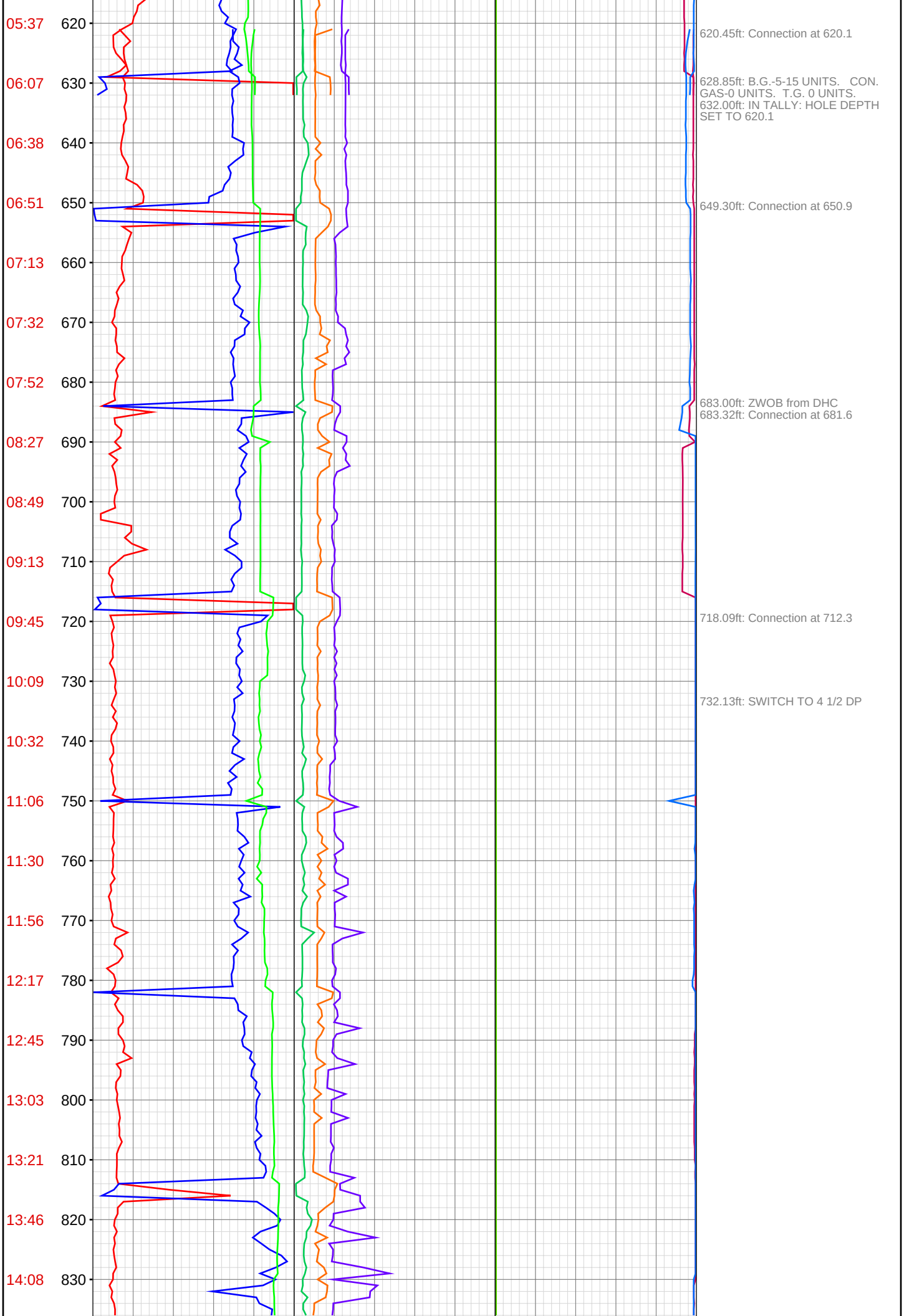
107.00ft: ZWOB from DHC
107.87ft: REMOTE: What's up?? - SM

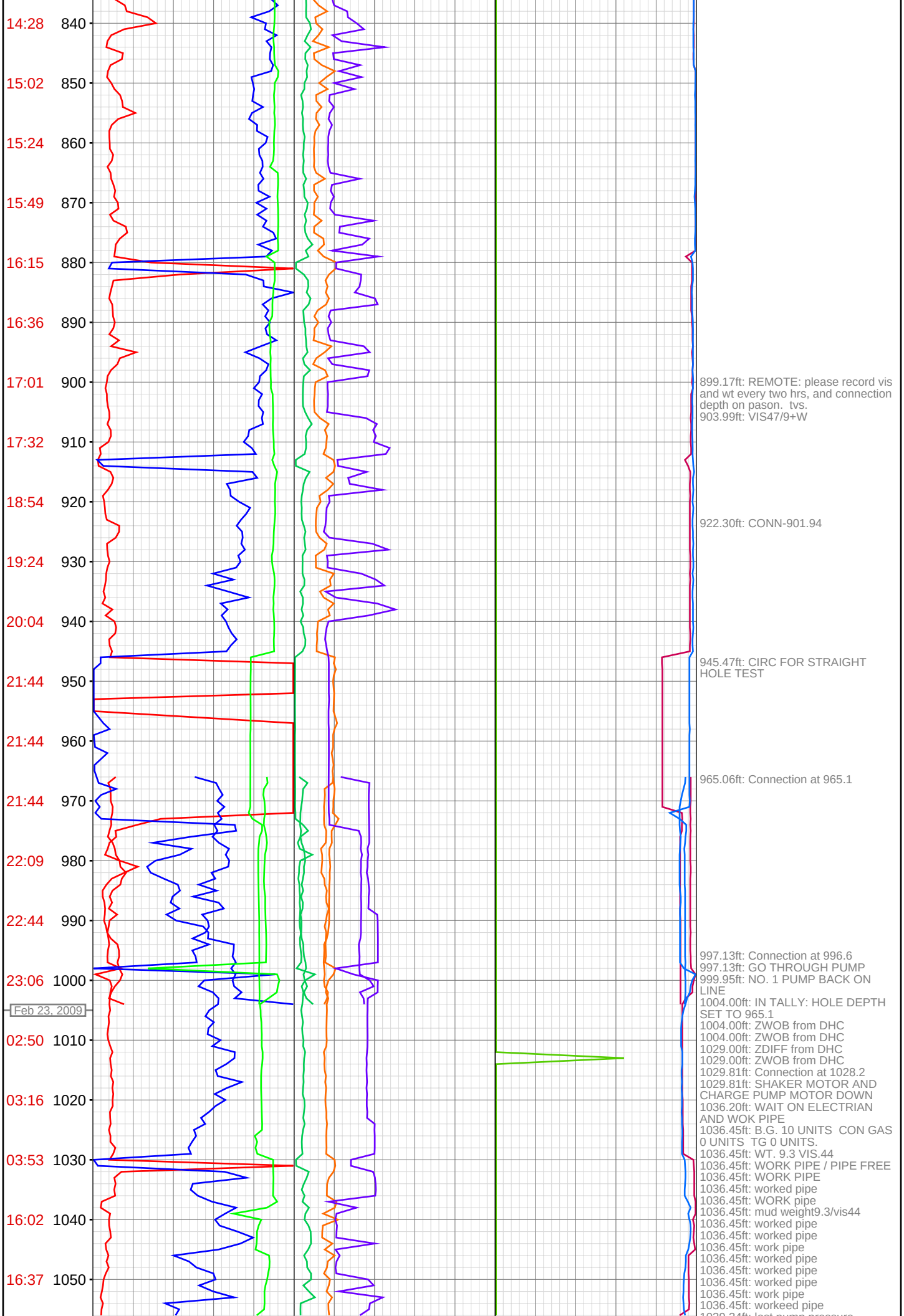
132.00ft: ZWOB from DHC

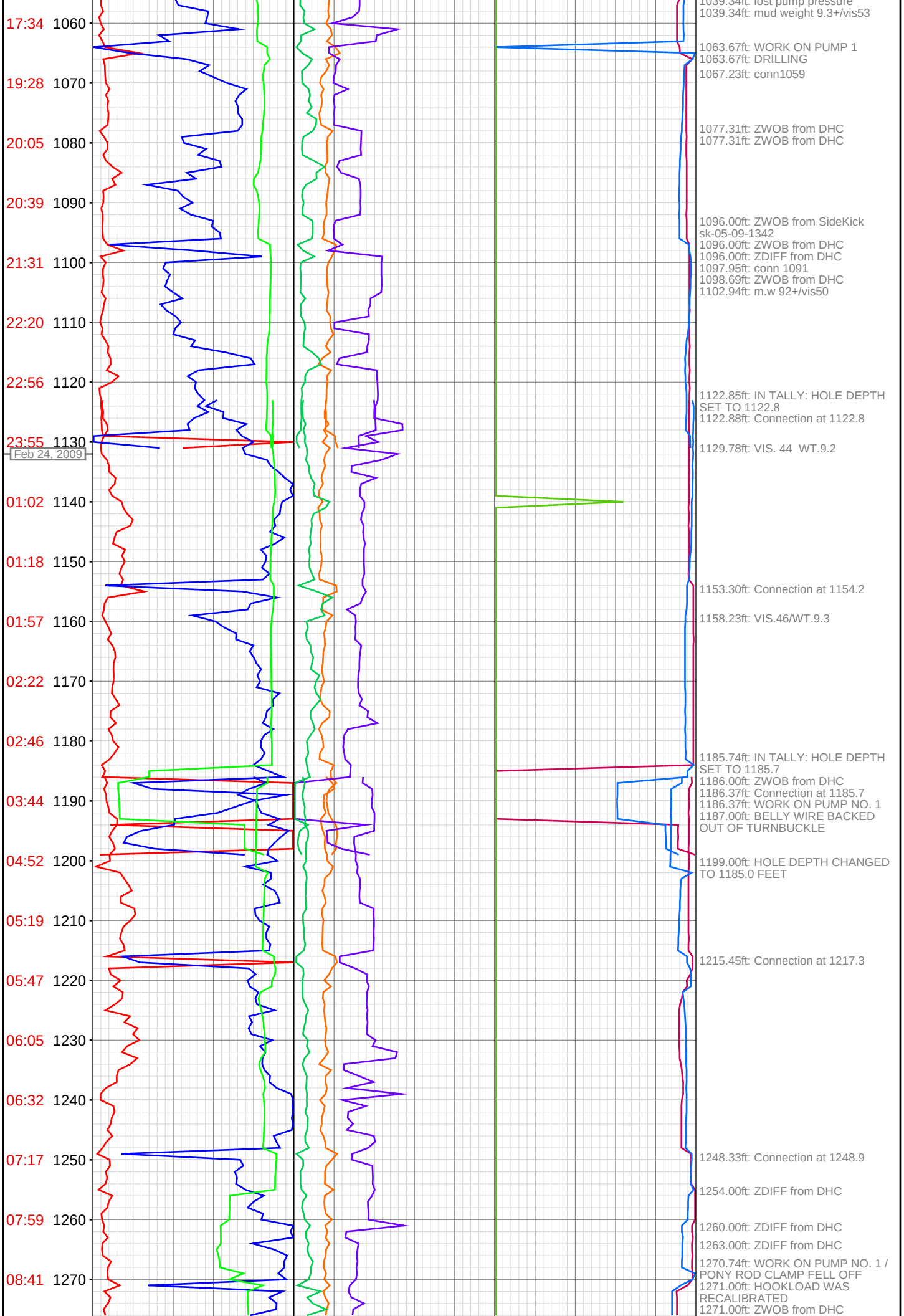
169.00ft: ZWOB from SideKick sk-05-09-1342
169.00ft: ZWOB from DHC

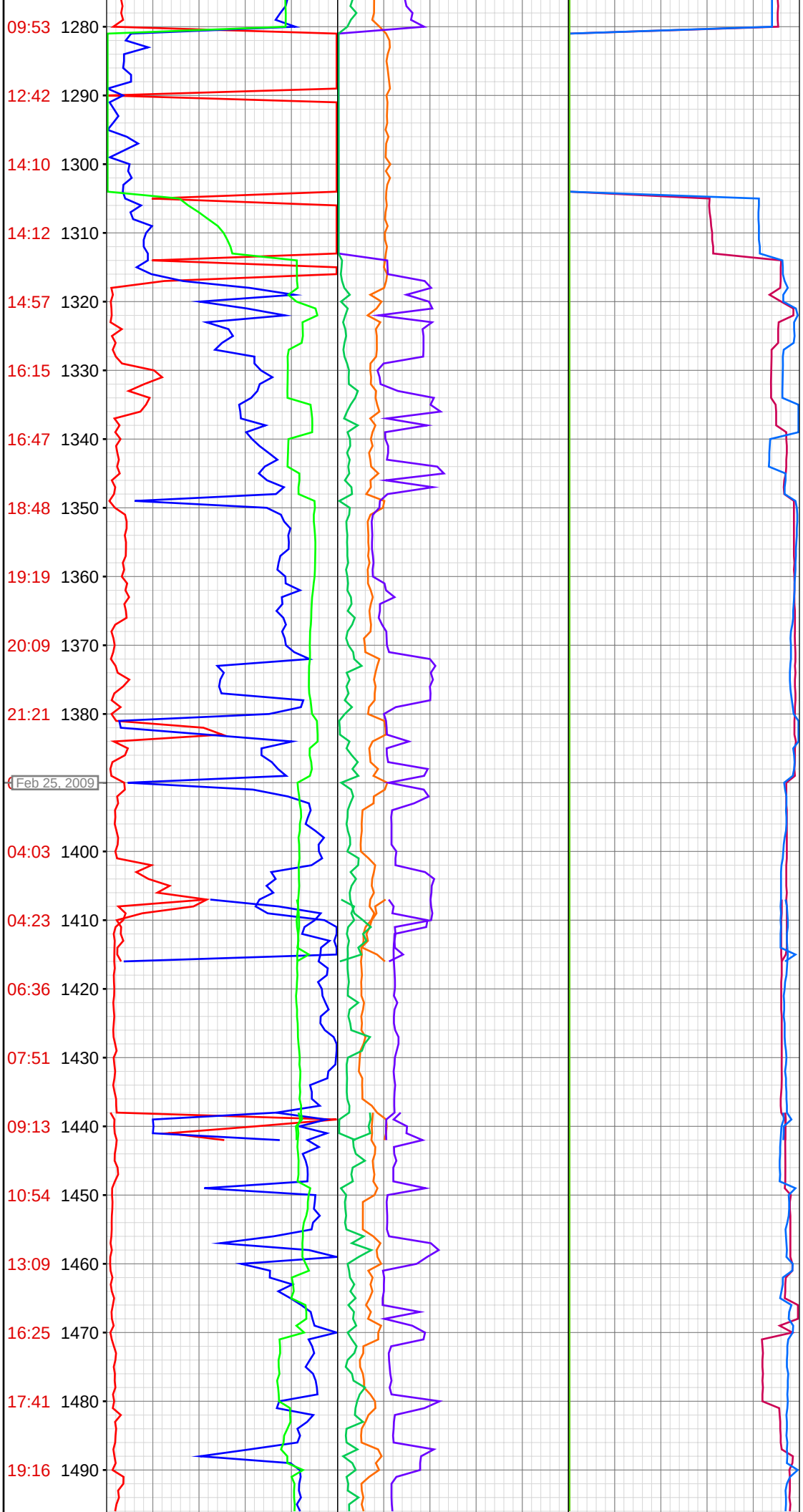

11:56 180
18:54 190
19:26 200
21:23 210
22:06 220
22:43 230
Feb 16, 2009
00:07 240
00:54 250
01:44 260
03:07 270
04:00 280
05:00 290
07:10 300
07:57 310
08:43 320
09:59 330
11:00 340
12:08 350
Feb 20, 2009
17:14 360
17:28 370
18:04 380
18:31 390
232.00ft: ZWOB from DHC
263.25ft: ZWOB from DHC
294.00ft: ZWOB from DHC
324.00ft: ZWOB from DHC
343.00ft: ZWOB from DHC
354.00ft: HOOK LOAD THRESHOLD RECALIBRATED TO 19
354.00ft: ZWOB from SideKick sk-05-09-1342
354.00ft: BIT DEPTH CHANGED TO 305.0 FEET
354.00ft: BIT DEPTH CHANGED TO 316.27 FEET
354.98ft: BIT DEPTH CHANGED TO 218.0 FEET
356.00ft: ZWOB from DHC
356.00ft: HOOK LOAD HIGH RECALIBRATED
356.00ft: BIT DEPTH CHANGED TO 347.4 FEET
387.00ft: ZWOB from DHC
394.00ft: ZWOB from DHC

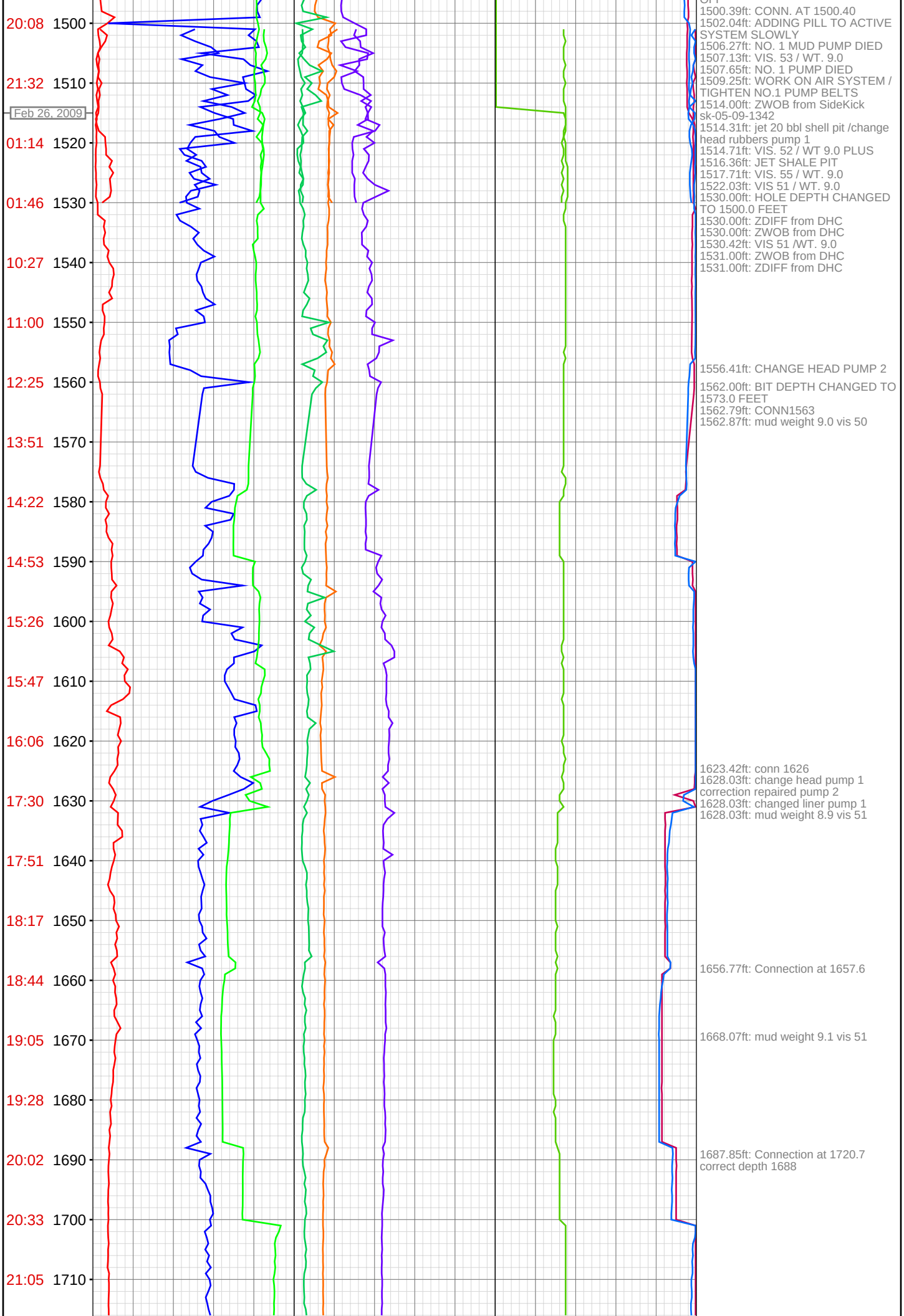

394.00ft: ZWOB from DHC
418.93ft: ZWOB from DHC
510.00ft: ZWOB from DHC
546.00ft: BIT DEPTH CHANGED TO 435.57 FEET
555.00ft: ZDIFF from DHC
555.58ft: ZWOB from DHC
564.00ft: ZDIFF from DHC
564.80ft: Connection at 558.7
571.00ft: ZWOB from DHC
571.00ft: IN TALLY: HOLE DEPTH SET TO 558.7
571.00ft: ZDIFF from DHC
571.75ft: HOOKLOAD WAS RECALIBRATED
594.78ft: Connection at 589.4
18:56 400
19:13 410
19:45 420
20:00 430
20:16 440
20:50 450
21:02 460
21:37 470
22:26 480
23:10 490
23:25 500
23:44 510
Feb 21, 2009
02:33 520
02:56 530
03:17 540
Feb 22, 2009
02:19 550
02:41 560
03:03 570
04:03 580
04:21 590
04:49 600
05:10 610

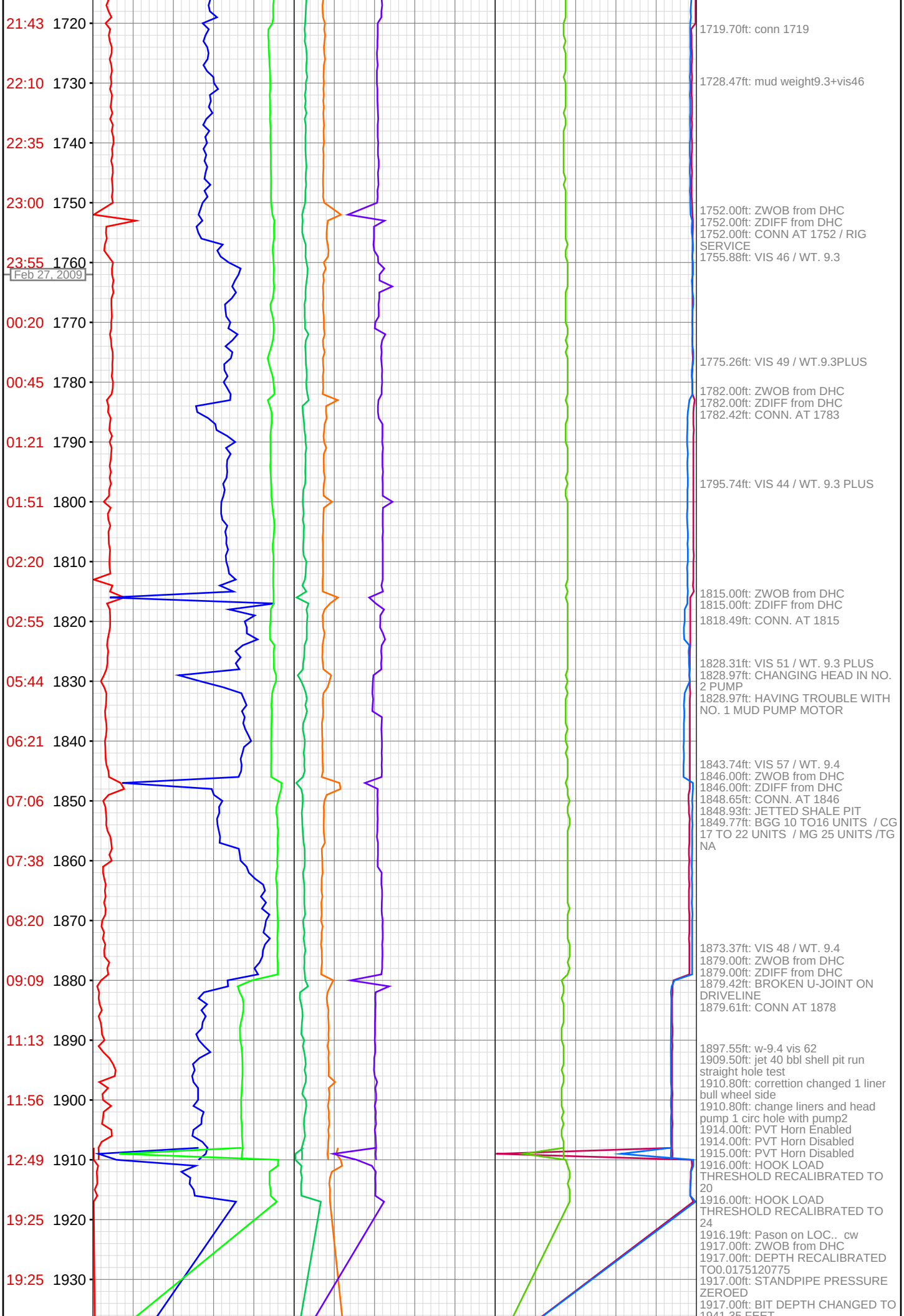

05:37 620
06:07 630
06:38 640
06:51 650
07:13 660
07:32 670
07:52 680
08:27 690
08:49 700
09:13 710
09:45 720
10:09 730
10:32 740
11:06 750
11:30 760
11:56 770
12:17 780
12:45 790
13:03 800
13:21 810
13:46 820
14:08 830
620.45ft: Connection at 620.1
628.85ft: B.G.-5-15 UNITS. CON. GAS-0 UNITS. T.G. 0 UNITS.
632.00ft: IN TALLY: HOLE DEPTH SET TO 620.1
649.30ft: Connection at 650.9
683.00ft: ZWOB from DHC
683.32ft: Connection at 681.6
718.09ft: Connection at 712.3
732.13ft: SWITCH TO 4 1/2 DP

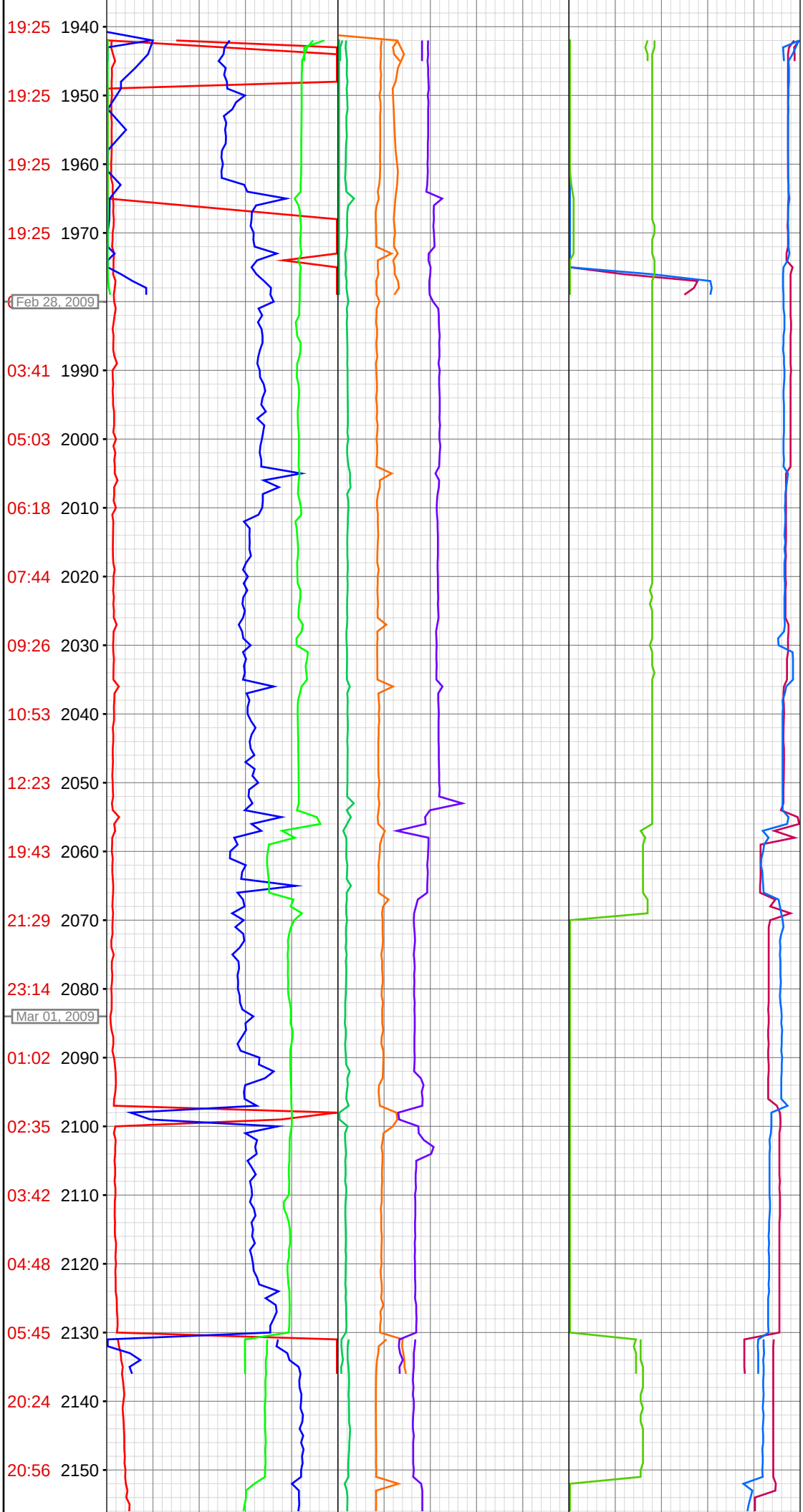

14:28 840
15:02 850
15:24 860
15:49 870
16:15 880
16:36 890
17:01 900
17:32 910
18:54 920
19:24 930
20:04 940
21:44 950
21:44 960
21:44 970
22:09 980
22:44 990
23:06 1000
Feb 23, 2009
02:50 1010
03:16 1020
03:53 1030
16:02 1040
16:37 1050
899.17ft: REMOTE: please record vis and wt every two hrs, and connection depth on pason. tvs.
903.99ft: VIS47/9+W
922.30ft: CONN-901.94
945.47ft: CIRC FOR STRAIGHT HOLE TEST
965.06ft: Connection at 965.1
997.13ft: Connection at 996.6
997.13ft: GO THROUGH PUMP
999.95ft: NO. 1 PUMP BACK ON LINE
1004.00ft: IN TALLY: HOLE DEPTH SET TO 965.1
1004.00ft: ZWOB from DHC
1004.00ft: ZWOB from DHC
1029.00ft: ZDIFF from DHC
1029.00ft: ZWOB from DHC
1029.81ft: Connection at 1028.2
1029.81ft: SHAKER MOTOR AND CHARGE PUMP MOTOR DOWN
1036.20ft: WAIT ON ELECTRIAN AND WOK PIPE
1036.45ft: B.G. 10 UNITS CON GAS 0 UNITS TG 0 UNITS.
1036.45ft: WT. 9.3 VIS.44
1036.45ft: WORK PIPE / PIPE FREE
1036.45ft: WORK PIPE
1036.45ft: worked pipe
1036.45ft: WORK pipe
1036.45ft: mud weight9.3/vis44
1036.45ft: worked pipe
1036.45ft: worked pipe
1036.45ft: work pipe
1036.45ft: worked pipe
1036.45ft: worked pipe
1036.45ft: worked pipe
1036.45ft: work pipe
1036.45ft: workeed pipe


17:34 1060
19:28 1070
20:05 1080
20:39 1090
21:31 1100
22:20 1110
22:56 1120
23:55 1130
Feb 24, 2009
01:02 1140
01:18 1150
01:57 1160
02:22 1170
02:46 1180
03:44 1190
04:52 1200
05:19 1210
05:47 1220
06:05 1230
06:32 1240
07:17 1250
07:59 1260
08:41 1270
1039.34ft: lost pump pressure
1039.34ft: mud weight 9.3+/vis53
1063.67ft: WORK ON PUMP 1
1063.67ft: DRILLING
1067.23ft: conn1059
1077.31ft: ZWOB from DHC
1077.31ft: ZWOB from DHC
1096.00ft: ZWOB from SideKick
sk-05-09-1342
1096.00ft: ZWOB from DHC
1096.00ft: ZDIFF from DHC
1097.95ft: conn 1091
1098.69ft: ZWOB from DHC
1102.94ft: m.w 92+/vis50
1122.85ft: IN TALLY: HOLE DEPTH
SET TO 1122.8
1122.88ft: Connection at 1122.8
1129.78ft: VIS. 44 WT.9.2
1153.30ft: Connection at 1154.2
1158.23ft: VIS.46/WT.9.3
1185.74ft: IN TALLY: HOLE DEPTH
SET TO 1185.7
1186.00ft: ZWOB from DHC
1186.37ft: Connection at 1185.7
1186.37ft: WORK ON PUMP NO. 1
1187.00ft: BELLY WIRE BACKED
OUT OF TURNBUCKLE
1199.00ft: HOLE DEPTH CHANGED
TO 1185.0 FEET
1215.45ft: Connection at 1217.3
1248.33ft: Connection at 1248.9
1254.00ft: ZDIFF from DHC
1260.00ft: ZDIFF from DHC
1263.00ft: ZDIFF from DHC
1270.74ft: WORK ON PUMP NO. 1 /
PONY ROD CLAMP FELL OFF
1271.00ft: HOOKLOAD WAS
RECALIBRATED
1271.00ft: ZWOB from DHC


09:53 1280
12:42 1290
14:10 1300
14:12 1310
14:57 1320
16:15 1330
16:47 1340
18:48 1350
19:19 1360
20:09 1370
21:21 1380
Feb 25, 2009
04:03 1400
04:23 1410
06:36 1420
07:51 1430
09:13 1440
10:54 1450
13:09 1460
16:25 1470
17:41 1480
19:16 1490
1271.00ft: ZDIFF from DHC
1280.84ft: ran straight hole test
1289.07ft: worked pipe
1294.86ft: worked pipe
1294.86ft: worked pipe
1317.00ft: ZWOB from SideKick sk-05-09-1342
1322.00ft: ZWOB from DHC
1335.97ft: w.9.3 vis43
1348.00ft: ZWOB from SideKick sk-05-09-1342
1348.99ft: conn1280
1380.00ft: ZWOB from SideKick sk-05-09-1342
1380.47ft: conn 1380 pull tight
1386.80ft: mud w9.2 vis41
1389.00ft: PUMP 2 DISPLACEMENT RECALIBRATED
1389.00ft: PUMP 1 EFFICIENCY RECALIBRATED
1389.00ft: PUMP 2 EFFICIENCY RECALIBRATED
1389.00ft: ZDIFF from DHC
1389.00ft: ZWOB from DHC
1389.05ft: CIRCULATE REPAIR PUMPS 1 AND 2
1389.05ft: PUMP 1 DISPLACEMENT RECALIBRATED
1389.05ft: WORK PIPE/PIPE FREE
1389.05ft: NO DRAG
1389.05ft: WORK PIPE /PIPE FREE
1389.05ft: WORK PIPE /PIPE FREE
1389.05ft: WORK PIPE/PIPE FREE
1389.05ft: AIR NO. 2 PUMP OFF
1394.39ft: VIS.40/WT.9.2
1413.97ft: COOLING BOX LINE BROKE
1414.26ft: VIS.49/WT.9.2
1416.00ft: IN TALLY: HOLE DEPTH SET TO 1406.2
1416.20ft: Connection at 1406.2
1424.79ft: VIS.55/WT.9.2 PLUS
1435.27ft: TRACE OF ANHIDRITE
1438.00ft: IN TALLY: HOLE DEPTH SET TO 1437.7
1438.18ft: JET SAND TRAP
1438.41ft: Connection at 1437.7
1442.00ft: IN TALLY: HOLE DEPTH SET TO 1437.7
1459.00ft: ZWOB from SideKick sk-05-09-1342
1459.51ft: picked up off bottom to jet shell pit 50 bbl
1461.28ft: picked up off bottom to jet pit 40bbl
1465.00ft: ZWOB from SideKick sk-05-09-1342
1465.60ft: picked up off bottom to jet 40 bbl
1465.60ft: change head rubber pump 1/ middle head
1467.81ft: worked on pump 1 /clogged screen
1468.00ft: ZWOB from SideKick sk-05-09-1342
1468.39ft: weight9.1 vis69
1470.00ft: ZWOB from DHC
1488.82ft: weight 9.0+ vis50
1489.50ft: change head rubber pump 2
1489.50ft: TRACKING OFF ON PASON
1500.00ft: PASON TRACKING WAS OFF


20:08 1500
21:32 1510
Feb 26, 2009
01:14 1520
01:46 1530
10:27 1540
11:00 1550
12:25 1560
13:51 1570
14:22 1580
14:53 1590
15:26 1600
15:47 1610
16:06 1620
17:30 1630
17:51 1640
18:17 1650
18:44 1660
19:05 1670
19:28 1680
20:02 1690
20:33 1700
21:05 1710
1500.39ft: CONN. AT 1500.40
1502.04ft: ADDING PILL TO ACTIVE SYSTEM SLOWLY
1506.27ft: NO. 1 MUD PUMP DIED
1507.13ft: VIS. 53 / WT. 9.0
1507.65ft: NO. 1 PUMP DIED
1509.25ft: WORK ON AIR SYSTEM / TIGHTEN NO.1 PUMP BELTS
1514.00ft: ZWOB from SideKick sk-05-09-1342
1514.31ft: jet 20 bbl shell pit /change head rubbers pump 1
1514.71ft: VIS. 52 / WT 9.0 PLUS
1516.36ft: JET SHALE PIT
1517.71ft: VIS. 55 / WT. 9.0
1522.03ft: VIS 51 / WT. 9.0
1530.00ft: HOLE DEPTH CHANGED TO 1500.0 FEET
1530.00ft: ZDIFF from DHC
1530.00ft: ZWOB from DHC
1530.42ft: VIS 51 /WT. 9.0
1531.00ft: ZWOB from DHC
1531.00ft: ZDIFF from DHC
1556.41ft: CHANGE HEAD PUMP 2
1562.00ft: BIT DEPTH CHANGED TO 1573.0 FEET
1562.79ft: CONN1563
1562.87ft: mud weight 9.0 vis 50
1623.42ft: conn 1626
1628.03ft: change head pump 1 correction repaired pump 2
1628.03ft: changed liner pump 1
1628.03ft: mud weight 8.9 vis 51
1656.77ft: Connection at 1657.6
1668.07ft: mud weight 9.1 vis 51
1687.85ft: Connection at 1720.7 correct depth 1688


21:43 1720
22:10 1730
22:35 1740
23:00 1750
23:55 1760
Feb 27, 2009
00:20 1770
00:45 1780
01:21 1790
01:51 1800
02:20 1810
02:55 1820
05:44 1830
06:21 1840
07:06 1850
07:38 1860
08:20 1870
09:09 1880
11:13 1890
11:56 1900
12:49 1910
19:25 1920
19:25 1930
1719.70ft: conn 1719
1728.47ft: mud weight9.3+vis46
1752.00ft: ZWOB from DHC
1752.00ft: ZDIFF from DHC
1752.00ft: CONN AT 1752 / RIG SERVICE
1755.88ft: VIS 46 / WT. 9.3
1775.26ft: VIS 49 / WT.9.3PLUS
1782.00ft: ZWOB from DHC
1782.00ft: ZDIFF from DHC
1782.42ft: CONN. AT 1783
1795.74ft: VIS 44 / WT. 9.3 PLUS
1815.00ft: ZWOB from DHC
1815.00ft: ZDIFF from DHC
1818.49ft: CONN. AT 1815
1828.31ft: VIS 51 / WT. 9.3 PLUS
1828.97ft: CHANGING HEAD IN NO. 2 PUMP
1828.97ft: HAVING TROUBLE WITH NO. 1 MUD PUMP MOTOR
1843.74ft: VIS 57 / WT. 9.4
1846.00ft: ZWOB from DHC
1846.00ft: ZDIFF from DHC
1848.65ft: CONN. AT 1846
1848.93ft: JETTED SHALE PIT
1849.77ft: BGG 10 TO16 UNITS / CG 17 TO 22 UNITS / MG 25 UNITS /TG NA
1873.37ft: VIS 48 / WT. 9.4
1879.00ft: ZWOB from DHC
1879.00ft: ZDIFF from DHC
1879.42ft: BROKEN U-JOINT ON DRIVELINE
1879.61ft: CONN AT 1878
1897.55ft: w-9.4 vis 62
1909.50ft: jet 40 bbl shell pit run straight hole test
1910.80ft: correttion changed 1 liner bull wheel side
1910.80ft: change liners and head pump 1 circ hole with pump2
1914.00ft: PVT Horn Enabled
1914.00ft: PVT Horn Disabled
1915.00ft: PVT Horn Disabled
1916.00ft: HOOK LOAD THRESHOLD RECALIBRATED TO 20
1916.00ft: HOOK LOAD THRESHOLD RECALIBRATED TO 24
1916.19ft: Pason on LOC.. cw
1917.00ft: ZWOB from DHC
1917.00ft: DEPTH RECALIBRATED TO0.0175120775
1917.00ft: STANDPIPE PRESSURE ZEROED
1917.00ft: BIT DEPTH CHANGED TO



1941.35 FEET
1917.00ft: HOOKLOAD WAS RECALIBRATED
1917.00ft: HOOK LOAD THRESHOLD RECALIBRATED TO 26
1917.21ft: ran sraight hole test
1941.54ft: conn 1941
1942.33ft: w-9.2 vis45

1967.48ft: VIS 42 / WT. 9.2 PLUS
1972.00ft: ZWOB from DHC
1972.00ft: ZDIFF from DHC
1972.47ft: CONN. AT 1972 RIG SERVICE
1972.47ft: JET SHALE PIT
1979.00ft: HOLE DEPTH CHANGED TO 1941.35 FEET

2000.09ft: VIS 45 / WT.9.2PLUS
2004.00ft: ZDIFF from DHC
2004.00ft: ZWOB from DHC
2004.12ft: CONN AT 2004

2010.92ft: VIS 45 / WT. 9.2PLUS

2022.49ft: VIS 46 / WT. 9.2
2025.03ft: REMOTE: please log bit hrs. on pason , thanks tvs
2025.26ft: BIT HRS. / 110.7
2026.35ft: REPAIR ROD OILER LINE ON PUMP NO. 2
2035.00ft: ZWOB from DHC
2035.26ft: ZDIFF from DHC
2036.06ft: CONN. AT 2035 JETTED SHALE PIT
2036.92ft: JETTED SHALE PIT
2037.04ft: VIS 52 / WT. 9.2PLUS

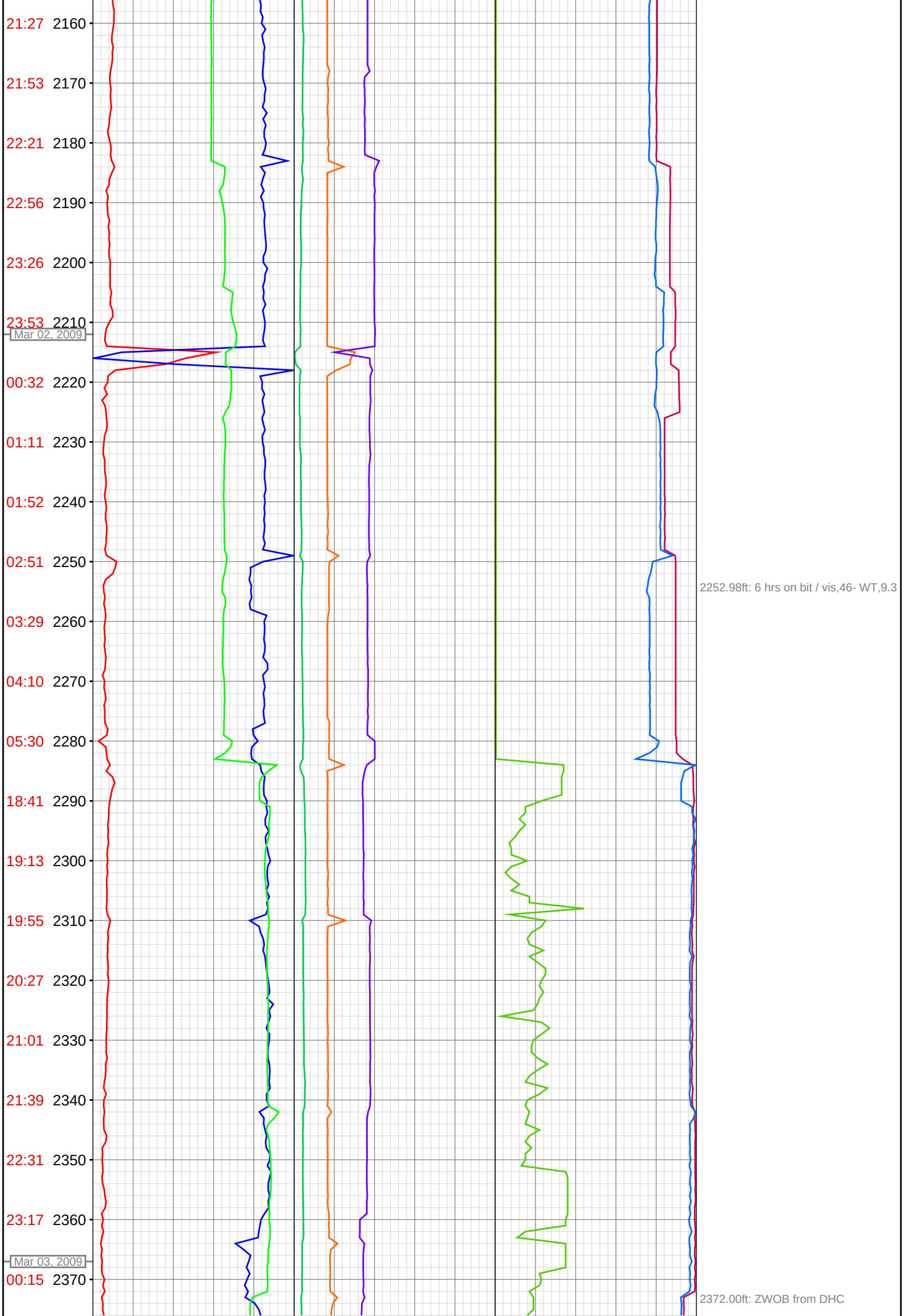
2054.00ft: ZWOB from DHC
2054.87ft: shut down repair pump 2/cheange oil-filters
2054.87ft: slow pump rate -pump 1 /50 strokes at 600 rpm
2054.87ft: change fan belt pump 2
2054.87ft: w-9.3+ vis51
2061.75ft: w-9.2+ vis44
2066.08ft: 116.5 hours on bit
2066.67ft: conn 2065
2066.81ft: jet 40 bbls shell pit\

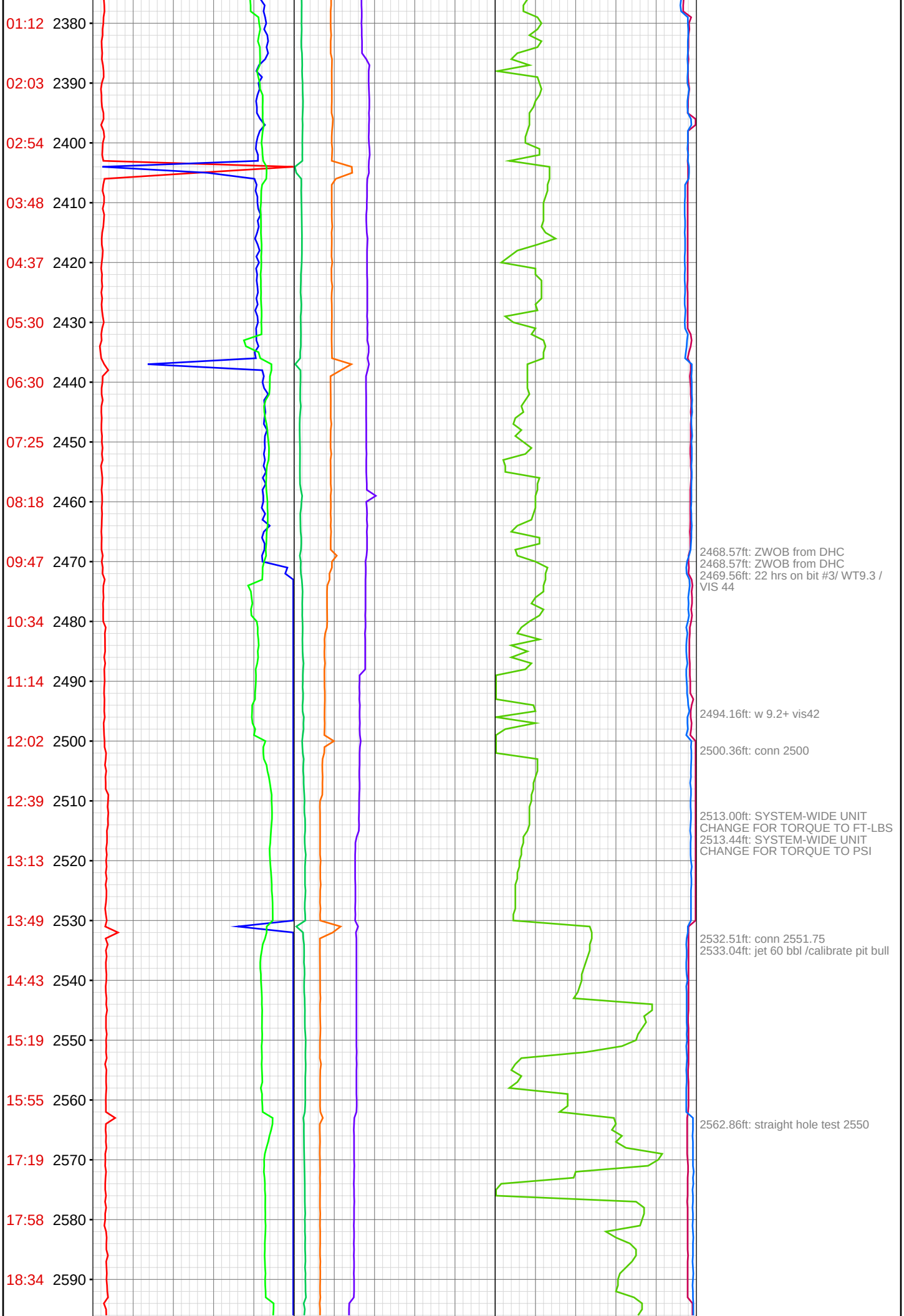
2085.94ft: 120 hrs / 9.2 WT - 42 vis

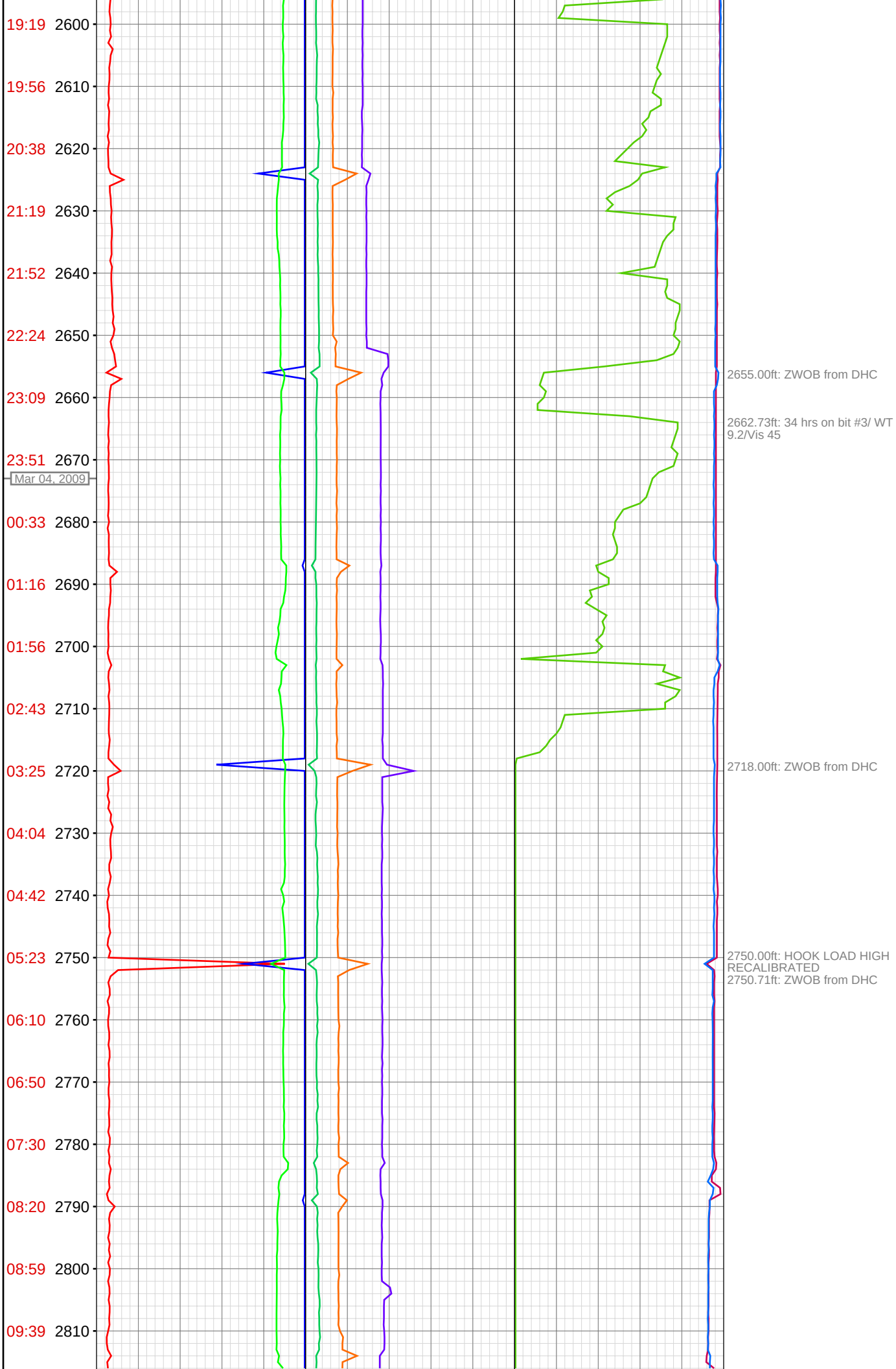
2094.31ft: jet shale and suction pits 80 barrels
2097.00ft: HOOK LOAD HIGH RECALIBRATED
2097.00ft: ZWOB from DHC

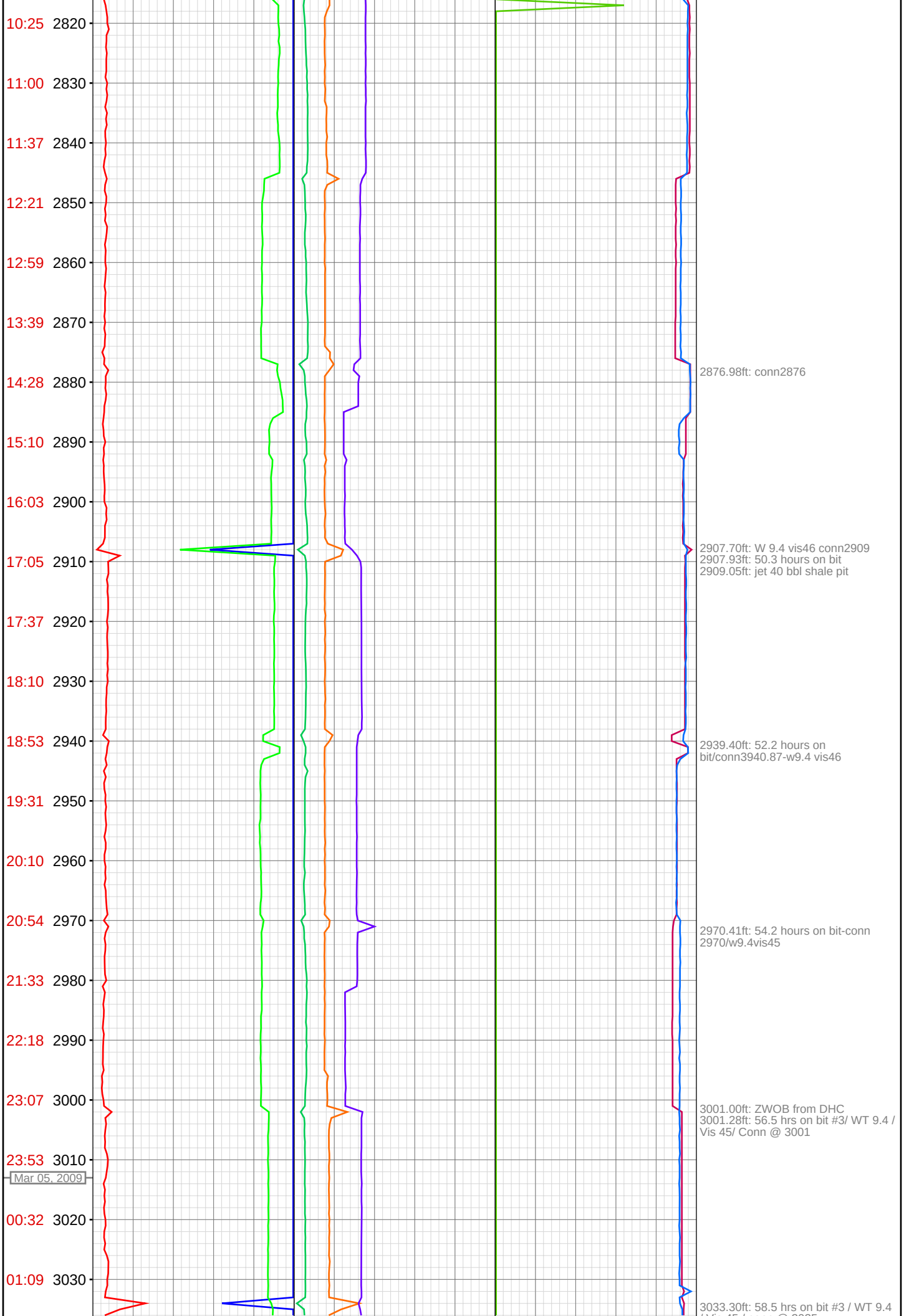
2104.93ft: 122.5 hrs on bit / 9.2WT - 40 vis

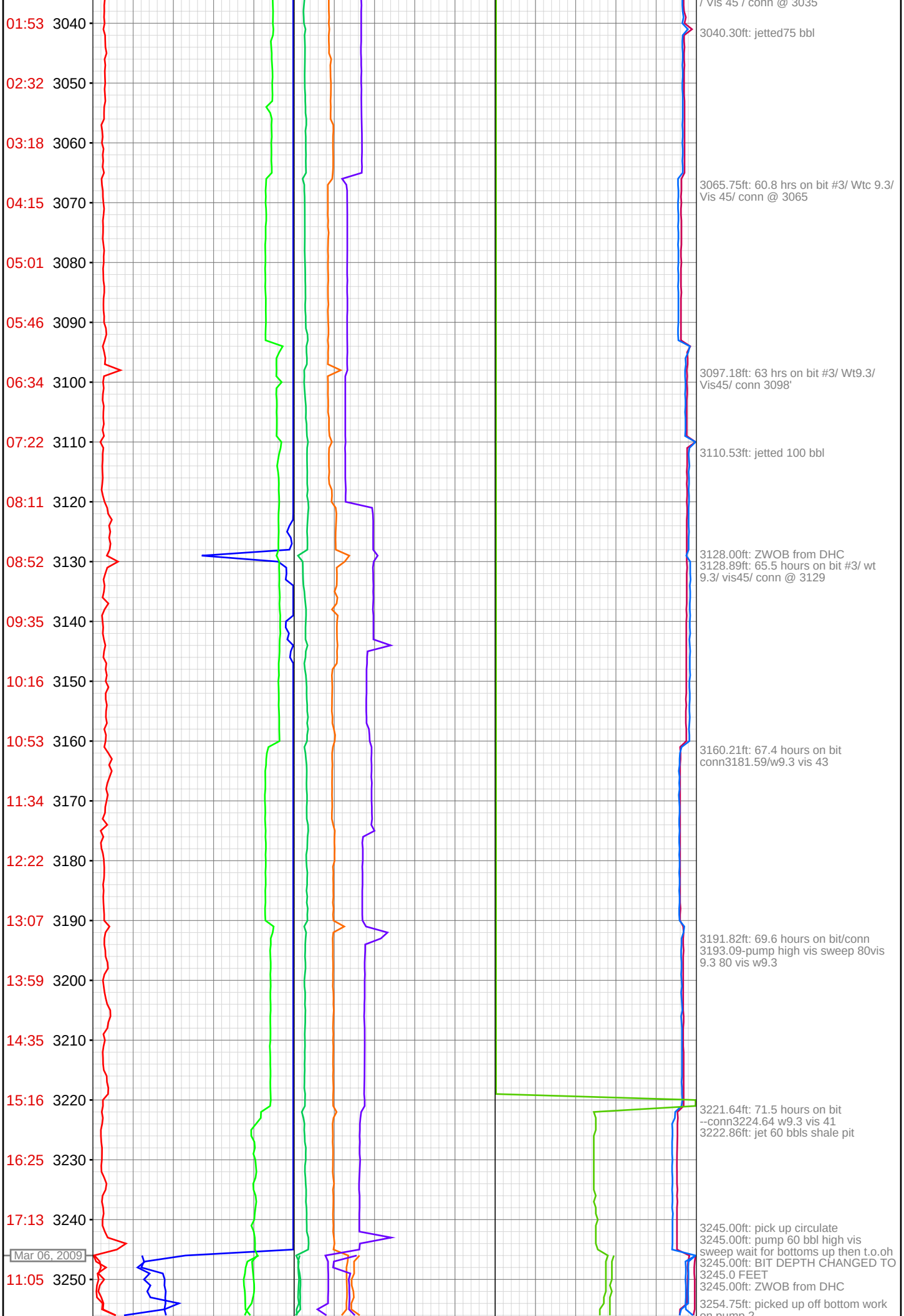
2130.46ft: circulate bottoms up / pumped high vis sweep
2130.46ft: 125.3 hrs on bit/ T.I.H @ 2130'
2130.46ft: LAY DOWN STABLIZERS
2130.46ft: PICKING UP 8INCH DCS

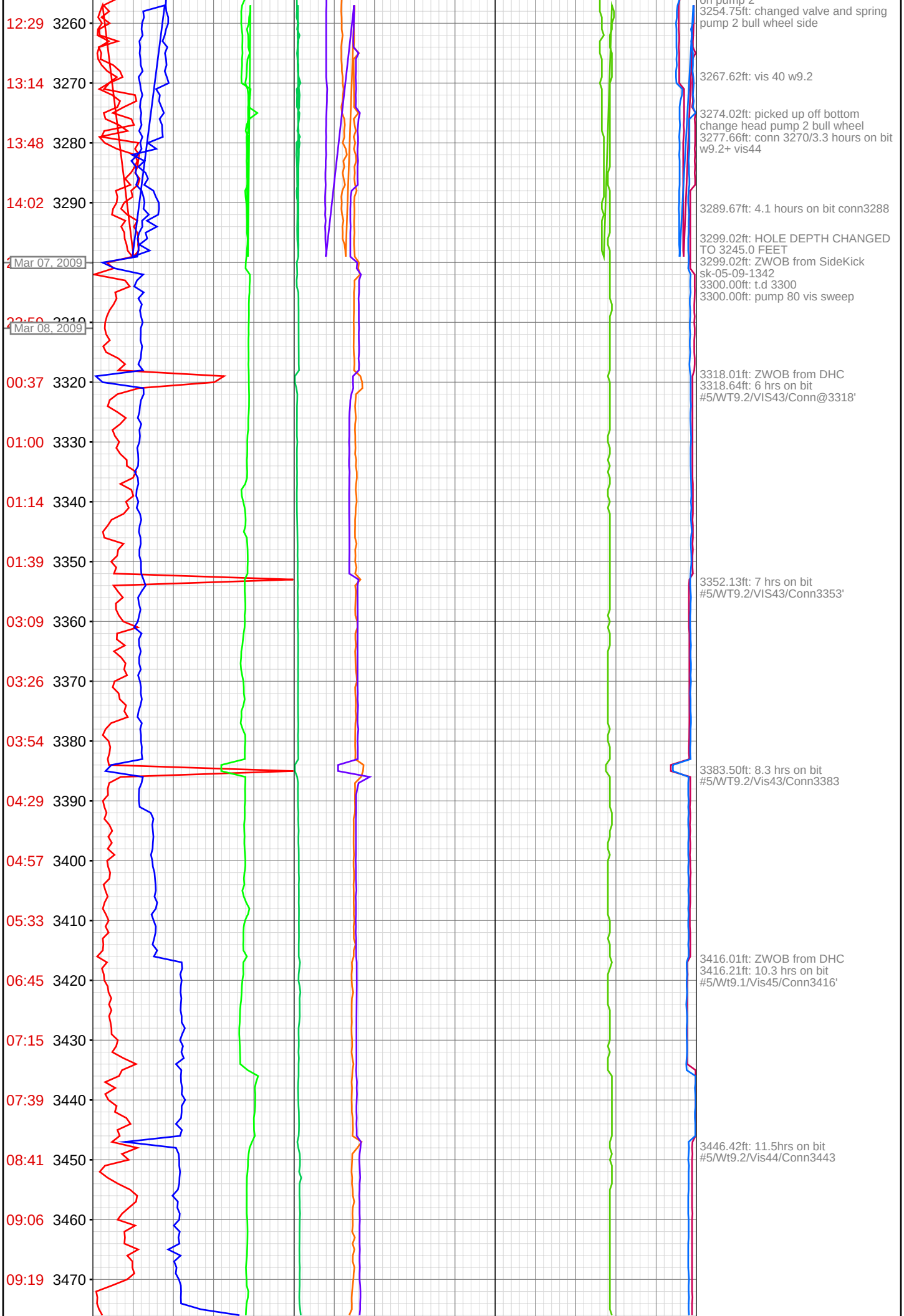

21:27 2160
21:53 2170
22:21 2180
22:56 2190
23:26 2200
23:53 2210
Mar 02, 2009
00:32 2220
01:11 2230
01:52 2240
02:51 2250
2252.98ft: 6 hrs on bit / vis,46- WT,9.3
03:29 2260
04:10 2270
05:30 2280
18:41 2290
19:13 2300
19:55 2310
20:27 2320
21:01 2330
21:39 2340
22:31 2350
23:17 2360
Mar 03, 2009
00:15 2370
2372.00ft: ZWOB from DHC

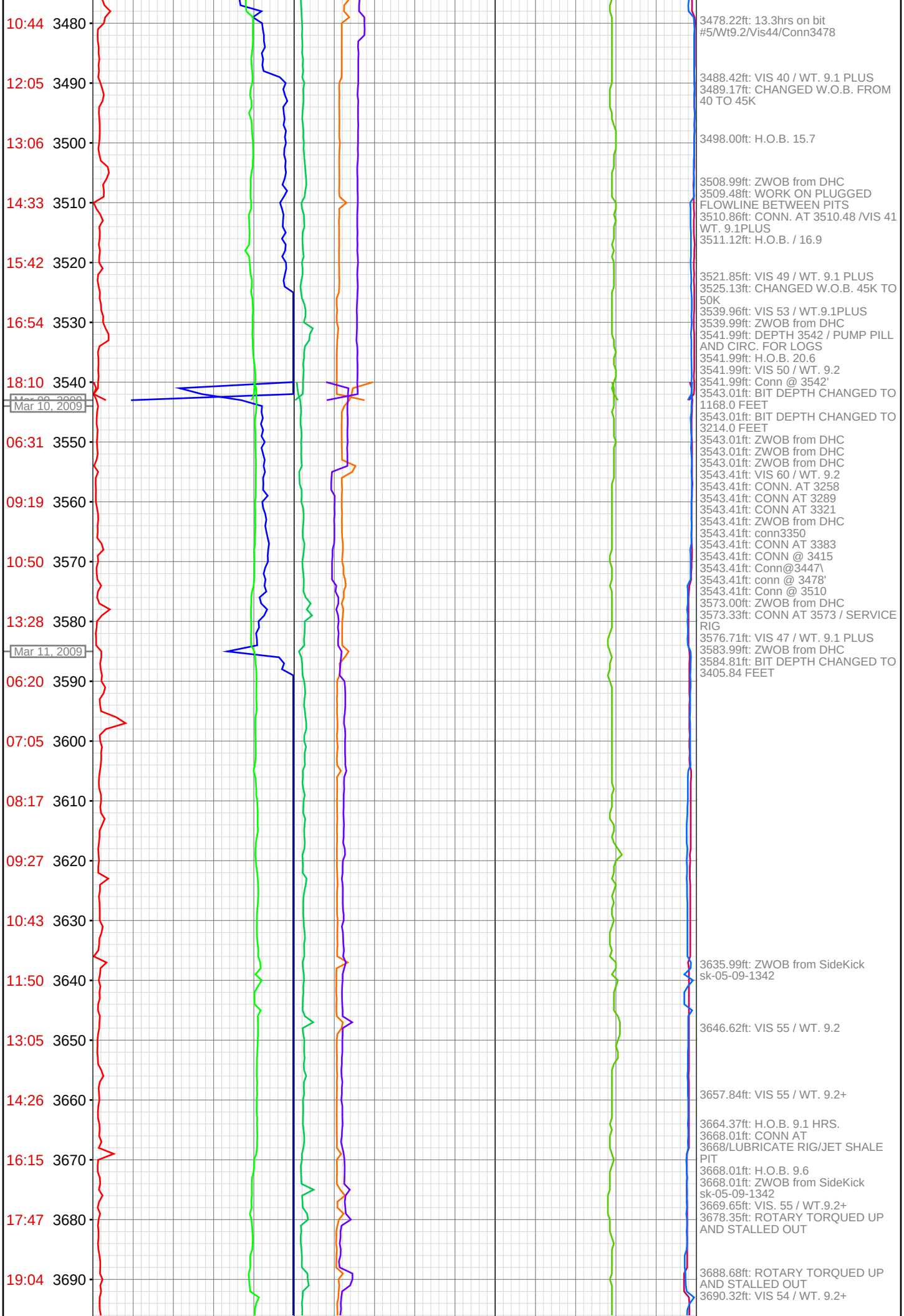

01:12 2380
02:03 2390
02:54 2400
03:48 2410
04:37 2420
05:30 2430
06:30 2440
07:25 2450
08:18 2460
09:47 2470
10:34 2480
11:14 2490
12:02 2500
12:39 2510
13:13 2520
13:49 2530
14:43 2540
15:19 2550
15:55 2560
17:19 2570
17:58 2580
18:34 2590
2468.57ft: ZWOB from DHC
2468.57ft: ZWOB from DHC
2469.56ft: 22 hrs on bit #3/ WT9.3 / VIS 44
2494.16ft: w 9.2+ vis42
2500.36ft: conn 2500
2513.00ft: SYSTEM-WIDE UNIT CHANGE FOR TORQUE TO FT-LBS
2513.44ft: SYSTEM-WIDE UNIT CHANGE FOR TORQUE TO PSI
2532.51ft: conn 2551.75
2533.04ft: jet 60 bbl /calibrate pit bull
2562.86ft: straight hole test 2550

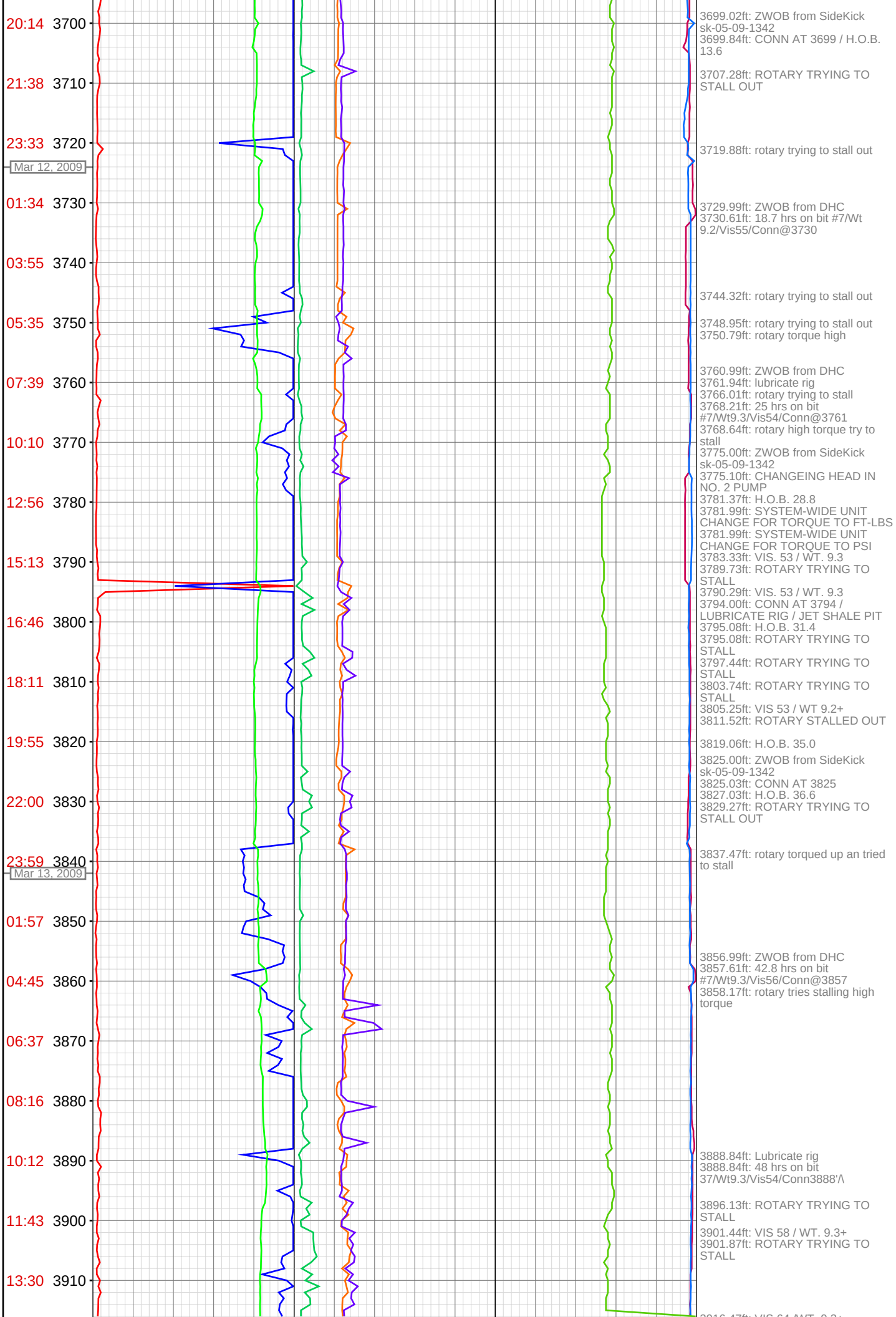

19:19 2600
19:56 2610
20:38 2620
21:19 2630
21:52 2640
22:24 2650
23:09 2660
23:51 2670
Mar 04, 2009
00:33 2680
01:16 2690
01:56 2700
02:43 2710
03:25 2720
04:04 2730
04:42 2740
05:23 2750
06:10 2760
06:50 2770
07:30 2780
08:20 2790
08:59 2800
09:39 2810
2655.00ft: ZWOB from DHC
2662.73ft: 34 hrs on bit #3/ WT 9.2/Vis 45
2718.00ft: ZWOB from DHC
2750.00ft: HOOK LOAD HIGH RECALIBRATED
2750.71ft: ZWOB from DHC


10:25 2820
11:00 2830
11:37 2840
12:21 2850
12:59 2860
13:39 2870
14:28 2880
15:10 2890
16:03 2900
17:05 2910
17:37 2920
18:10 2930
18:53 2940
19:31 2950
20:10 2960
20:54 2970
21:33 2980
22:18 2990
23:07 3000
23:53 3010
Mar 05, 2009
00:32 3020
01:09 3030
2876.98ft: conn2876
2907.70ft: W 9.4 vis46 conn2909
2907.93ft: 50.3 hours on bit
2909.05ft: jet 40 bbl shale pit
2939.40ft: 52.2 hours on bit/conn3940.87-w9.4 vis46
2970.41ft: 54.2 hours on bit-conn 2970/w9.4vis45
3001.00ft: ZWOB from DHC
3001.28ft: 56.5 hrs on bit #3/ WT 9.4 / Vis 45/ Conn @ 3001
3033.30ft: 58.5 hrs on bit #3 / WT 9.4


/ Vis 45 / conn @ 3035
01:53 3040
3040.30ft: jetted75 bbl
02:32 3050
03:18 3060
3065.75ft: 60.8 hrs on bit #3/ Wtc 9.3/ Vis 45/ conn @ 3065
04:15 3070
05:01 3080
05:46 3090
06:34 3100
3097.18ft: 63 hrs on bit #3/ Wt9.3/ Vis45/ conn 3098'
07:22 3110
3110.53ft: jetted 100 bbl
08:11 3120
08:52 3130
3128.00ft: ZWOB from DHC
3128.89ft: 65.5 hours on bit #3/ wt 9.3/ vis45/ conn @ 3129
09:35 3140
10:16 3150
10:53 3160
3160.21ft: 67.4 hours on bit conn3181.59/w9.3 vis 43
11:34 3170
12:22 3180
13:07 3190
3191.82ft: 69.6 hours on bit/conn
3193.09-pump high vis sweep 80vis 9.3 80 vis w9.3
13:59 3200
14:35 3210
15:16 3220
3221.64ft: 71.5 hours on bit --conn3224.64 w9.3 vis 41
3222.86ft: jet 60 bbls shale pit
16:25 3230
17:13 3240
3245.00ft: pick up circulate
3245.00ft: pump 60 bbl high vis sweep wait for bottoms up then t.o.oh
Mar 06, 2009
3245.00ft: BIT DEPTH CHANGED TO 3245.0 FEET
11:05 3250
3245.00ft: ZWOB from DHC
3254.75ft: picked up off bottom work on pump 2


on pump 2
3254.75ft: changed valve and spring pump 2 bull wheel side
3267.62ft: vis 40 w9.2
3274.02ft: picked up off bottom change head pump 2 bull wheel
3277.66ft: conn 3270/3.3 hours on bit w9.2+ vis44
3289.67ft: 4.1 hours on bit conn3288
3299.02ft: HOLE DEPTH CHANGED TO 3245.0 FEET
3299.02ft: ZWOB from SideKick sk-05-09-1342
3300.00ft: t.d 3300
3300.00ft: pump 80 vis sweep
3318.01ft: ZWOB from DHC
3318.64ft: 6 hrs on bit #5/WT9.2/VIS43/Conn@3318'
3352.13ft: 7 hrs on bit #5/WT9.2/VIS43/Conn3353'
3383.50ft: 8.3 hrs on bit #5/WT9.2/Vis43/Conn3383
3416.01ft: ZWOB from DHC
3416.21ft: 10.3 hrs on bit #5/Wt9.1/Vis45/Conn3416'
3446.42ft: 11.5hrs on bit #5/Wt9.2/Vis44/Conn3443
12:29 3260
13:14 3270
13:48 3280
14:02 3290
Mar 07, 2009
Mar 08, 2009
00:37 3320
01:00 3330
01:14 3340
01:39 3350
03:09 3360
03:26 3370
03:54 3380
04:29 3390
04:57 3400
05:33 3410
06:45 3420
07:15 3430
07:39 3440
08:41 3450
09:06 3460
09:19 3470


10:44 3480
12:05 3490
13:06 3500
14:33 3510
15:42 3520
16:54 3530
18:10 3540
Mar 10, 2009
06:31 3550
09:19 3560
10:50 3570
13:28 3580
Mar 11, 2009
06:20 3590
07:05 3600
08:17 3610
09:27 3620
10:43 3630
11:50 3640
13:05 3650
14:26 3660
16:15 3670
17:47 3680
19:04 3690
3478.22ft: 13.3hrs on bit #5/Wt9.2/Vis44/Conn3478
3488.42ft: VIS 40 / WT. 9.1 PLUS
3489.17ft: CHANGED W.O.B. FROM 40 TO 45K
3498.00ft: H.O.B. 15.7
3508.99ft: ZWOB from DHC
3509.48ft: WORK ON PLUGGED FLOWLINE BETWEEN PITS
3510.86ft: CONN. AT 3510.48 /VIS 41 WT. 9.1PLUS
3511.12ft: H.O.B. / 16.9
3521.85ft: VIS 49 / WT. 9.1 PLUS
3525.13ft: CHANGED W.O.B. 45K TO 50K
3539.96ft: VIS 53 / WT.9.1PLUS
3539.99ft: ZWOB from DHC
3541.99ft: DEPTH 3542 / PUMP PILL AND CIRC. FOR LOGS
3541.99ft: H.O.B. 20.6
3541.99ft: VIS 50 / WT. 9.2
3541.99ft: Conn @ 3542'
3543.01ft: BIT DEPTH CHANGED TO 1168.0 FEET
3543.01ft: BIT DEPTH CHANGED TO 3214.0 FEET
3543.01ft: ZWOB from DHC
3543.01ft: ZWOB from DHC
3543.01ft: ZWOB from DHC
3543.41ft: VIS 60 / WT. 9.2
3543.41ft: CONN. AT 3258
3543.41ft: CONN AT 3289
3543.41ft: CONN AT 3321
3543.41ft: ZWOB from DHC
3543.41ft: conn3350
3543.41ft: CONN AT 3383
3543.41ft: CONN @ 3415
3543.41ft: Conn@3447\
3543.41ft: conn @ 3478'
3543.41ft: Conn @ 3510
3573.00ft: ZWOB from DHC
3573.33ft: CONN AT 3573 / SERVICE RIG
3576.71ft: VIS 47 / WT. 9.1 PLUS
3583.99ft: ZWOB from DHC
3584.81ft: BIT DEPTH CHANGED TO 3405.84 FEET
3635.99ft: ZWOB from SideKick sk-05-09-1342
3646.62ft: VIS 55 / WT. 9.2
3657.84ft: VIS 55 / WT. 9.2+
3664.37ft: H.O.B. 9.1 HRS.
3668.01ft: CONN AT 3668/LUBRICATE RIG/JET SHALE PIT
3668.01ft: H.O.B. 9.6
3668.01ft: ZWOB from SideKick sk-05-09-1342
3669.65ft: VIS. 55 / WT.9.2+
3678.35ft: ROTARY TORQUED UP AND STALLED OUT
3688.68ft: ROTARY TORQUED UP AND STALLED OUT
3690.32ft: VIS 54 / WT. 9.2+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23:33 3720
Mar 12, 2009
01:34 3730
03:55 3740
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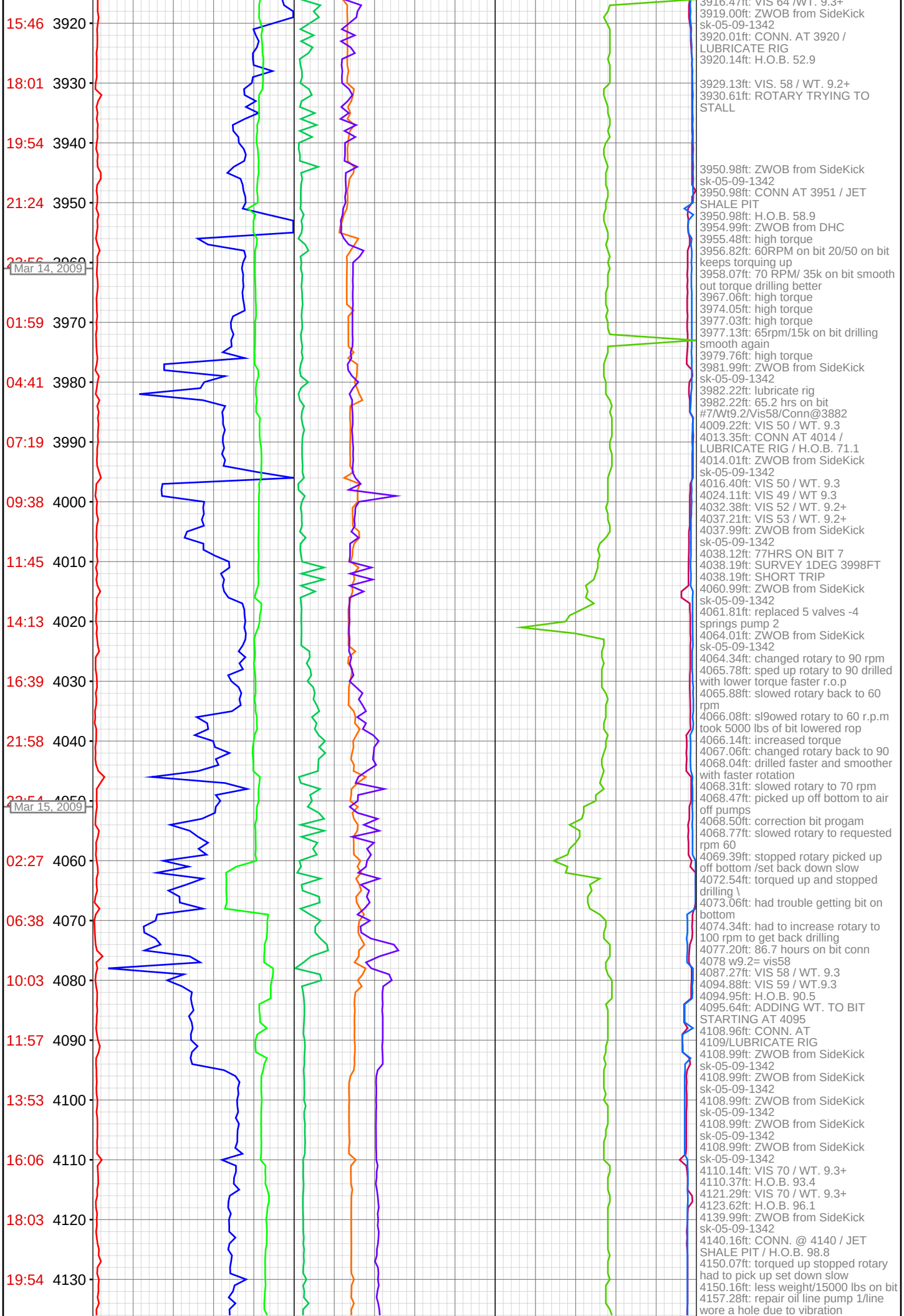
07:39 3760
10:10 3770
12:56 3780
15:13 3790
16:46 3800
18:11 3810
19:55 3820
22:00 3830
23:59 3840
Mar 13, 2009
01:57 3850
04:45 3860
06:37 3870
08:16 3880
10:12 3890
11:43 3900
13:30 3910
3699.02ft: ZWOB from SideKick sk-05-09-1342
3699.84ft: CONN AT 3699 / H.O.B. 13.6
3707.28ft: ROTARY TRYING TO STALL OUT
3719.88ft: rotary trying to stall out
3729.99ft: ZWOB from DHC
3730.61ft: 18.7 hrs on bit #7/Wt 9.2/Vis55/Conn@3730
3744.32ft: rotary trying to stall out
3748.95ft: rotary trying to stall out
3750.79ft: rotary torque high
3760.99ft: ZWOB from DHC
3761.94ft: lubricate rig
3766.01ft: rotary trying to stall
3768.21ft: 25 hrs on bit #7/Wt9.3/Vis54/Conn@3761
3768.64ft: rotary high torque try to stall
3775.00ft: ZWOB from SideKick sk-05-09-1342
3775.10ft: CHANGEING HEAD IN NO. 2 PUMP
3781.37ft: H.O.B. 28.8
3781.99ft: SYSTEM-WIDE UNIT CHANGE FOR TORQUE TO FT-LBS
3781.99ft: SYSTEM-WIDE UNIT CHANGE FOR TORQUE TO PSI
3783.33ft: VIS. 53 / WT. 9.3
3789.73ft: ROTARY TRYING TO STALL
3790.29ft: VIS. 53 / WT. 9.3
3794.00ft: CONN AT 3794 / LUBRICATE RIG / JET SHALE PIT
3795.08ft: H.O.B. 31.4
3795.08ft: ROTARY TRYING TO STALL
3797.44ft: ROTARY TRYING TO STALL
3803.74ft: ROTARY TRYING TO STALL
3805.25ft: VIS 53 / WT 9.2+
3811.52ft: ROTARY STALLED OUT
3819.06ft: H.O.B. 35.0
3825.00ft: ZWOB from SideKick sk-05-09-1342
3825.03ft: CONN AT 3825
3827.03ft: H.O.B. 36.6
3829.27ft: ROTARY TRYING TO STALL OUT
3837.47ft: rotary torqued up an tried to stall
3856.99ft: ZWOB from DHC
3857.61ft: 42.8 hrs on bit #7/Wt9.3/Vis56/Conn@3857
3858.17ft: rotary tries stalling high torque
3888.84ft: Lubricate rig
3888.84ft: 48 hrs on bit 37/Wt9.3/Vis54/Conn3888'/\
3896.13ft: ROTARY TRYING TO STALL
3901.44ft: VIS 58 / WT. 9.3+
3901.87ft: ROTARY TRYING TO STALL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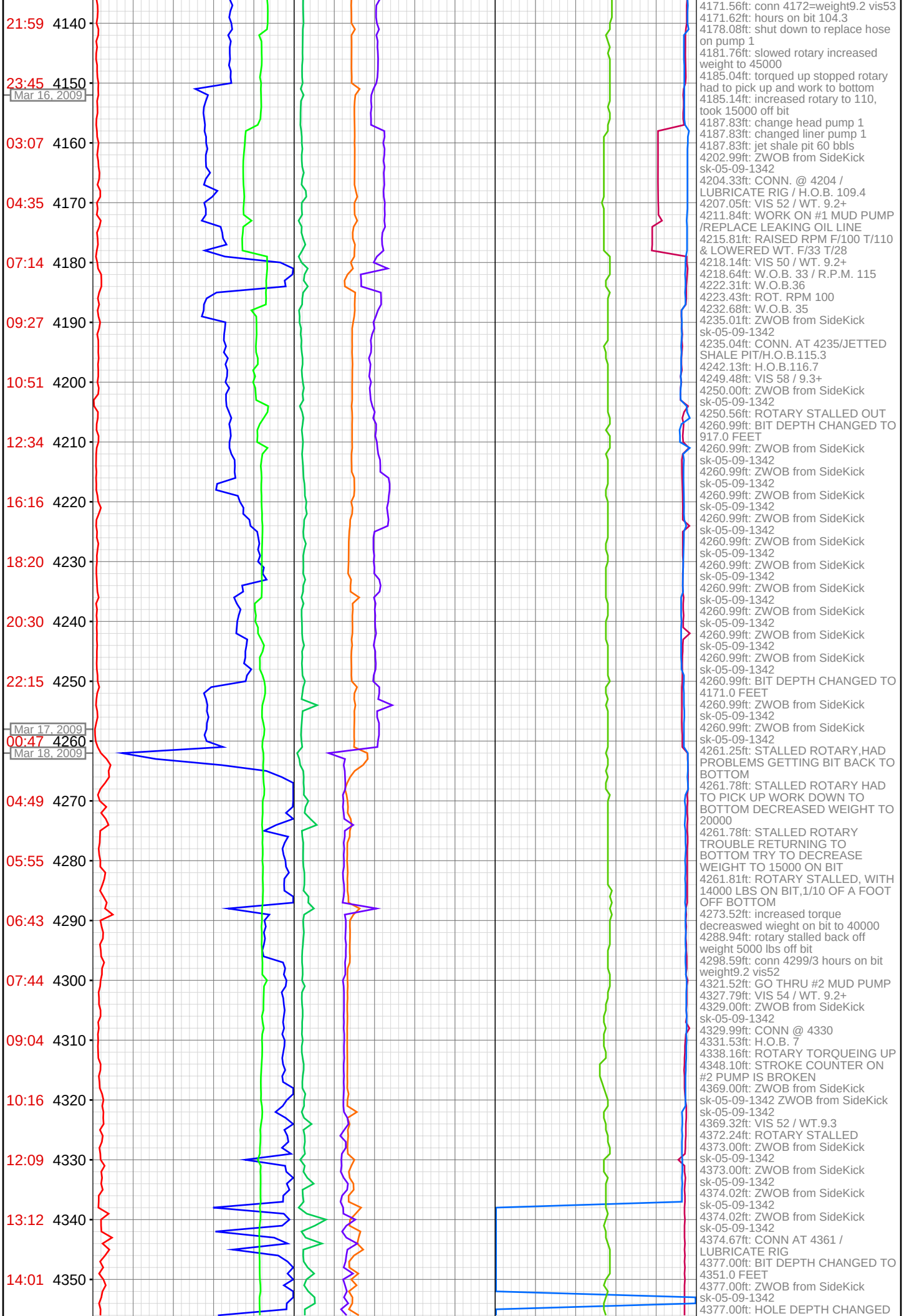
18:01 3930
19:54 3940
21:24 3950
Mar 14, 2009
01:59 3970
04:41 3980
07:19 3990
09:38 4000
11:45 4010
14:13 4020
16:39 4030
21:58 4040
Mar 15, 2009
02:27 4060
06:38 4070
10:03 4080
11:57 4090
13:53 4100
16:06 4110
18:03 4120
19:54 4130
3916.47ft: VIS 64 /WT. 9.3+
3919.00ft: ZWOB from SideKick sk-05-09-1342
3920.01ft: CONN. AT 3920 / LUBRICATE RIG
3920.14ft: H.O.B. 52.9
3929.13ft: VIS. 58 / WT. 9.2+
3930.61ft: ROTARY TRYING TO STALL
3950.98ft: ZWOB from SideKick sk-05-09-1342
3950.98ft: CONN AT 3951 / JET SHALE PIT
3950.98ft: H.O.B. 58.9
3954.99ft: ZWOB from DHC
3955.48ft: high torque
3956.82ft: 60RPM on bit 20/50 on bit keeps torquing up
3958.07ft: 70 RPM/ 35k on bit smooth out torque drilling better
3967.06ft: high torque
3974.05ft: high torque
3977.03ft: high torque
3977.13ft: 65rpm/15k on bit drilling smooth again
3979.76ft: high torque
3981.99ft: ZWOB from SideKick sk-05-09-1342
3982.22ft: lubricate rig
3982.22ft: 65.2 hrs on bit #7/Wt9.2/Vis58/Conn@3882
4009.22ft: VIS 50 / WT. 9.3
4013.35ft: CONN AT 4014 / LUBRICATE RIG / H.O.B. 71.1
4014.01ft: ZWOB from SideKick sk-05-09-1342
4016.40ft: VIS 50 / WT. 9.3
4024.11ft: VIS 49 / WT 9.3
4032.38ft: VIS 52 / WT. 9.2+
4037.21ft: VIS 53 / WT. 9.2+
4037.99ft: ZWOB from SideKick sk-05-09-1342
4038.12ft: 77HRS ON BIT 7
4038.19ft: SURVEY 1DEG 3998FT
4038.19ft: SHORT TRIP
4060.99ft: ZWOB from SideKick sk-05-09-1342
4061.81ft: replaced 5 valves -4 springs pump 2
4064.01ft: ZWOB from SideKick sk-05-09-1342
4064.34ft: changed rotary to 90 rpm
4065.78ft: sped up rotary to 90 drilled with lower torque faster r.o.p
4065.88ft: slowed rotary back to 60 rpm
4066.08ft: sl9owed rotary to 60 r.p.m took 5000 lbs of bit lowered rop
4066.14ft: increased torque
4067.06ft: changed rotary back to 90
4068.04ft: drilled faster and smoother with faster rotation
4068.31ft: slowed rotary to 70 rpm
4068.47ft: picked up off bottom to air off pumps
4068.50ft: correction bit progam
4068.77ft: slowed rotary to requested rpm 60
4069.39ft: stopped rotary picked up off bottom /set back down slow
4072.54ft: torqued up and stopped drilling \
4073.06ft: had trouble getting bit on bottom
4074.34ft: had to increase rotary to 100 rpm to get back drilling
4077.20ft: 86.7 hours on bit conn 4078 w9.2= vis58
4087.27ft: VIS 58 / WT. 9.3
4094.88ft: VIS 59 / WT.9.3
4094.95ft: H.O.B. 90.5
4095.64ft: ADDING WT. TO BIT STARTING AT 4095
4108.96ft: CONN. AT 4109/LUBRICATE RIG
4108.99ft: ZWOB from SideKick sk-05-09-1342
4108.99ft: ZWOB from SideKick sk-05-09-1342
4108.99ft: ZWOB from SideKick sk-05-09-1342
4108.99ft: ZWOB from SideKick sk-05-09-1342
4108.99ft: ZWOB from SideKick sk-05-09-1342
4110.14ft: VIS 70 / WT. 9.3+
4110.37ft: H.O.B. 93.4
4121.29ft: VIS 70 / WT. 9.3+
4123.62ft: H.O.B. 96.1
4139.99ft: ZWOB from SideKick sk-05-09-1342
4140.16ft: CONN. @ 4140 / JET SHALE PIT / H.O.B. 98.8
4150.07ft: torqued up stopped rotary had to pick up set down slow
4150.16ft: less weight/15000 lbs on bit
4157.28ft: repair oil line pump 1/line wore a hole due to vibration


21:59 4140
23:45 4150
Mar 16, 2009
03:07 4160
04:35 4170
07:14 4180
09:27 4190
10:51 4200
12:34 4210
16:16 4220
18:20 4230
20:30 4240
22:15 4250
Mar 17, 2009
00:47 4260
Mar 18, 2009
04:49 4270
05:55 4280
06:43 4290
07:44 4300
09:04 4310
10:16 4320
12:09 4330
13:12 4340
14:01 4350
4171.56ft: conn 4172=weight9.2 vis53
4171.62ft: hours on bit 104.3
4178.08ft: shut down to replace hose on pump 1
4181.76ft: slowed rotary increased weight to 45000
4185.04ft: torqued up stopped rotary had to pick up and work to bottom
4185.14ft: increased rotary to 110, took 15000 off bit
4187.83ft: change head pump 1
4187.83ft: changed liner pump 1
4187.83ft: jet shale pit 60 bbls
4202.99ft: ZWOB from SideKick sk-05-09-1342
4204.33ft: CONN. @ 4204 / LUBRICATE RIG / H.O.B. 109.4
4207.05ft: VIS 52 / WT. 9.2+
4211.84ft: WORK ON #1 MUD PUMP /REPLACE LEAKING OIL LINE
4215.81ft: RAISED RPM F/100 T/110 & LOWERED WT. F/33 T/28
4218.14ft: VIS 50 / WT. 9.2+
4218.64ft: W.O.B. 33 / R.P.M. 115
4222.31ft: W.O.B.36
4223.43ft: ROT. RPM 100
4232.68ft: W.O.B. 35
4235.01ft: ZWOB from SideKick sk-05-09-1342
4235.04ft: CONN. AT 4235/JETTED SHALE PIT/H.O.B.115.3
4242.13ft: H.O.B.116.7
4249.48ft: VIS 58 / 9.3+
4250.00ft: ZWOB from SideKick sk-05-09-1342
4250.56ft: ROTARY STALLED OUT
4260.99ft: BIT DEPTH CHANGED TO 917.0 FEET
4260.99ft: ZWOB from SideKick sk-05-09-1342
4260.99ft: ZWOB from SideKick sk-05-09-1342
4260.99ft: ZWOB from SideKick sk-05-09-1342
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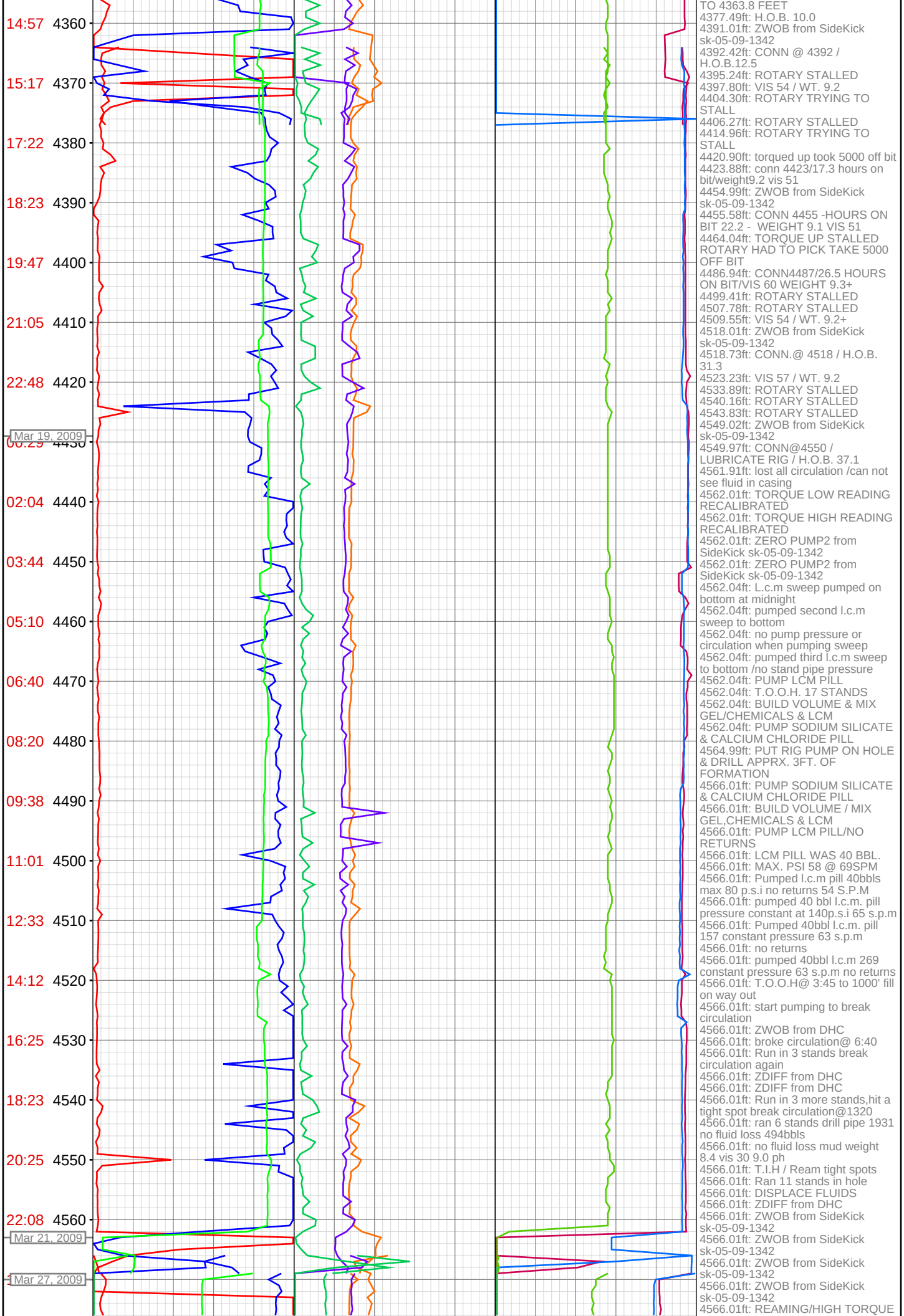
4260.99ft: ZWOB from SideKick sk-05-09-1342
4260.99ft: ZWOB from SideKick sk-05-09-1342
4260.99ft: ZWOB from SideKick sk-05-09-1342
4260.99ft: BIT DEPTH CHANGED TO 4171.0 FEET
4260.99ft: ZWOB from SideKick sk-05-09-1342
4260.99ft: ZWOB from SideKick sk-05-09-1342
4261.25ft: STALLED ROTARY,HAD PROBLEMS GETTING BIT BACK TO BOTTOM
4261.78ft: STALLED ROTARY HAD TO PICK UP WORK DOWN TO BOTTOM DECREASED WEIGHT TO 20000
4261.78ft: STALLED ROTARY TROUBLE RETURNING TO BOTTOM TRY TO DECREASE WEIGHT TO 15000 ON BIT
4261.81ft: ROTARY STALLED, WITH 14000 LBS ON BIT,1/10 OF A FOOT OFF BOTTOM
4273.52ft: increased torque decreaswed wieght on bit to 40000
4288.94ft: rotary stalled back off weight 5000 lbs off bit
4298.59ft: conn 4299/3 hours on bit weight9.2 vis52
4321.52ft: GO THRU #2 MUD PUMP
4327.79ft: VIS 54 / WT. 9.2+
4329.00ft: ZWOB from SideKick sk-05-09-1342
4329.99ft: CONN @ 4330
4331.53ft: H.O.B. 7
4338.16ft: ROTARY TORQUEING UP
4348.10ft: STROKE COUNTER ON #2 PUMP IS BROKEN
4369.00ft: ZWOB from SideKick sk-05-09-1342 ZWOB from SideKick sk-05-09-1342
4369.32ft: VIS 52 / WT.9.3
4372.24ft: ROTARY STALLED
4373.00ft: ZWOB from SideKick sk-05-09-1342
4373.00ft: ZWOB from SideKick sk-05-09-1342
4374.02ft: ZWOB from SideKick sk-05-09-1342
4374.02ft: ZWOB from SideKick sk-05-09-1342
4374.67ft: CONN AT 4361 / LUBRICATE RIG
4377.00ft: BIT DEPTH CHANGED TO 4351.0 FEET
4377.00ft: ZWOB from SideKick sk-05-09-1342
4377.00ft: HOLE DEPTH CHANGED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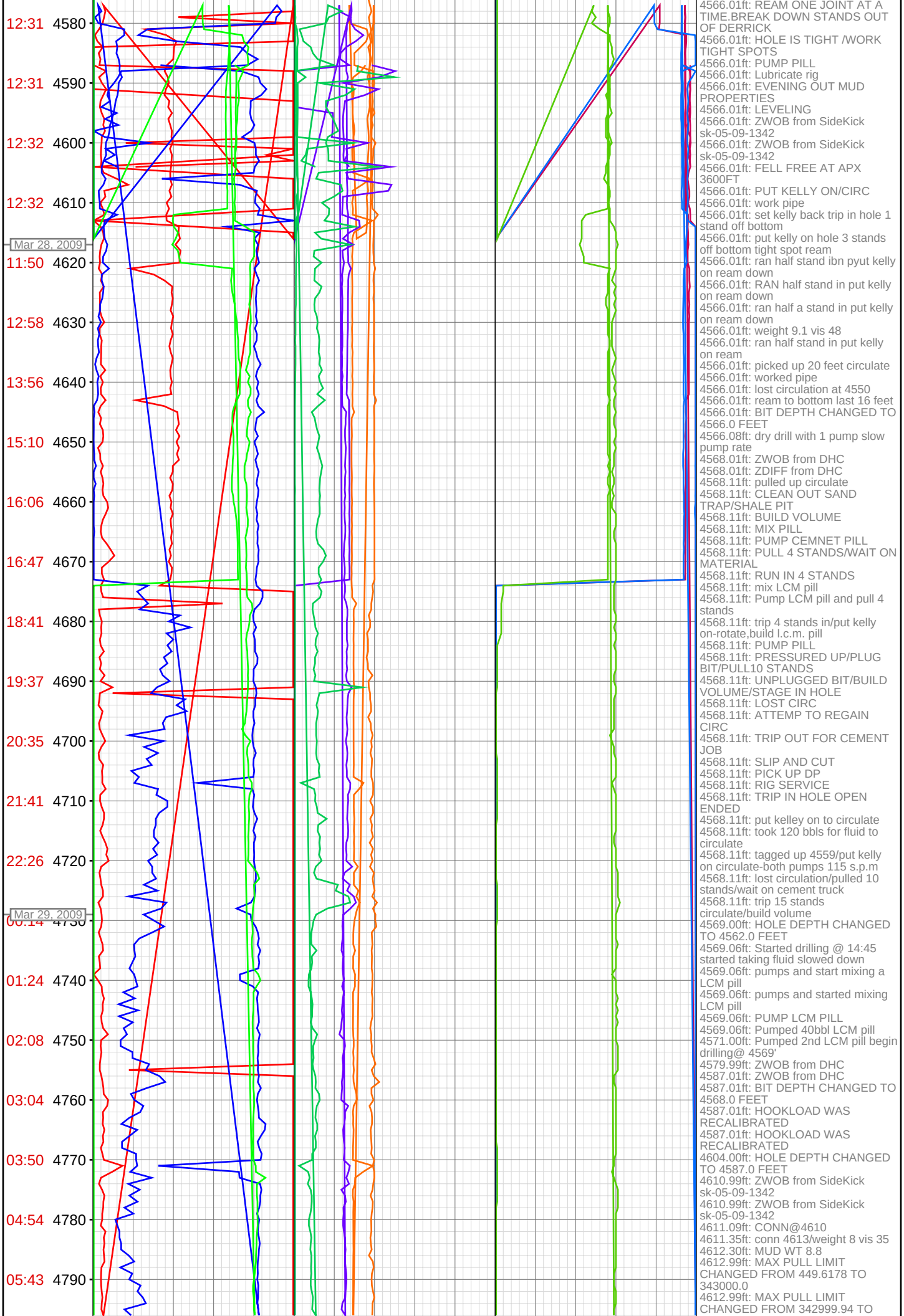
21:05 4410
22:48 4420
Mar 19, 2009
00:29 4430
02:04 4440
03:44 4450
05:10 4460
06:40 4470
08:20 4480
09:38 4490
11:01 4500
12:33 4510
14:12 4520
16:25 4530
18:23 4540
20:25 4550
22:08 4560
Mar 21, 2009
Mar 27, 2009
TO 4363.8 FEET
4377.49ft: H.O.B. 10.0
4391.01ft: ZWOB from SideKick sk-05-09-1342
4392.42ft: CONN @ 4392 / H.O.B.12.5
4395.24ft: ROTARY STALLED
4397.80ft: VIS 54 / WT. 9.2
4404.30ft: ROTARY TRYING TO STALL
4406.27ft: ROTARY STALLED
4414.96ft: ROTARY TRYING TO STALL
4420.90ft: torqued up took 5000 off bit
4423.88ft: conn 4423/17.3 hours on bit/weight9.2 vis 51
4454.99ft: ZWOB from SideKick sk-05-09-1342
4455.58ft: CONN 4455 -HOURS ON BIT 22.2 - WEIGHT 9.1 VIS 51
4464.04ft: TORQUE UP STALLED ROTARY HAD TO PICK TAKE 5000 OFF BIT
4486.94ft: CONN4487/26.5 HOURS ON BIT/VIS 60 WEIGHT 9.3+
4499.41ft: ROTARY STALLED
4507.78ft: ROTARY STALLED
4509.55ft: VIS 54 / WT. 9.2+
4518.01ft: ZWOB from SideKick sk-05-09-1342
4518.73ft: CONN.@ 4518 / H.O.B. 31.3
4523.23ft: VIS 57 / WT. 9.2
4533.89ft: ROTARY STALLED
4540.16ft: ROTARY STALLED
4543.83ft: ROTARY STALLED
4549.02ft: ZWOB from SideKick sk-05-09-1342
4549.97ft: CONN@4550 / LUBRICATE RIG / H.O.B. 37.1
4561.91ft: lost all circulation /can not see fluid in casing
4562.01ft: TORQUE LOW READING RECALIBRATED
4562.01ft: TORQUE HIGH READING RECALIBRATED
4562.01ft: ZERO PUMP2 from SideKick sk-05-09-1342
4562.01ft: ZERO PUMP2 from SideKick sk-05-09-1342
4562.04ft: L.c.m sweep pumped on bottom at midnight
4562.04ft: pumped second l.c.m sweep to bottom
4562.04ft: no pump pressure or circulation when pumping sweep
4562.04ft: pumped third l.c.m sweep to bottom /no stand pipe pressure
4562.04ft: PUMP LCM PILL
4562.04ft: T.O.O.H. 17 STANDS
4562.04ft: BUILD VOLUME & MIX GEL/CHEMICALS & LCM
4562.04ft: PUMP SODIUM SILICATE & CALCIUM CHLORIDE PILL
4564.99ft: PUT RIG PUMP ON HOLE & DRILL APPRX. 3FT. OF FORMATION
4566.01ft: PUMP SODIUM SILICATE & CALCIUM CHLORIDE PILL
4566.01ft: BUILD VOLUME / MIX GEL,CHEMICALS & LCM
4566.01ft: PUMP LCM PILL/NO RETURNS
4566.01ft: LCM PILL WAS 40 BBL.
4566.01ft: MAX. PSI 58 @ 69SPM
4566.01ft: Pumped l.c.m pill 40bbls max 80 p.s.i no returns 54 S.P.M
4566.01ft: pumped 40 bbl l.c.m. pill pressure constant at 140p.s.i 65 s.p.m
4566.01ft: Pumped 40bbl l.c.m. pill 157 constant pressure 63 s.p.m
4566.01ft: no returns
4566.01ft: pumped 40bbl l.c.m 269 constant pressure 63 s.p.m no returns
4566.01ft: T.O.O.H@ 3:45 to 1000' fill on way out
4566.01ft: start pumping to break circulation
4566.01ft: ZWOB from DHC
4566.01ft: broke circulation@ 6:40
4566.01ft: Run in 3 stands break circulation again
4566.01ft: ZDIFF from DHC
4566.01ft: ZDIFF from DHC
4566.01ft: Run in 3 more stands,hit a tight spot break circulation@1320
4566.01ft: ran 6 stands drill pipe 1931 no fluid loss 494bbls
4566.01ft: no fluid loss mud weight 8.4 vis 30 9.0 ph
4566.01ft: T.I.H / Ream tight spots
4566.01ft: Ran 11 stands in hole
4566.01ft: DISPLACE FLUIDS
4566.01ft: ZDIFF from DHC
4566.01ft: ZWOB from SideKick sk-05-09-1342
4566.01ft: ZWOB from SideKick sk-05-09-1342
4566.01ft: ZWOB from SideKick sk-05-09-1342
4566.01ft: ZWOB from SideKick sk-05-09-1342
4566.01ft: REAMING/HIGH TORQUE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Mar 28, 2009
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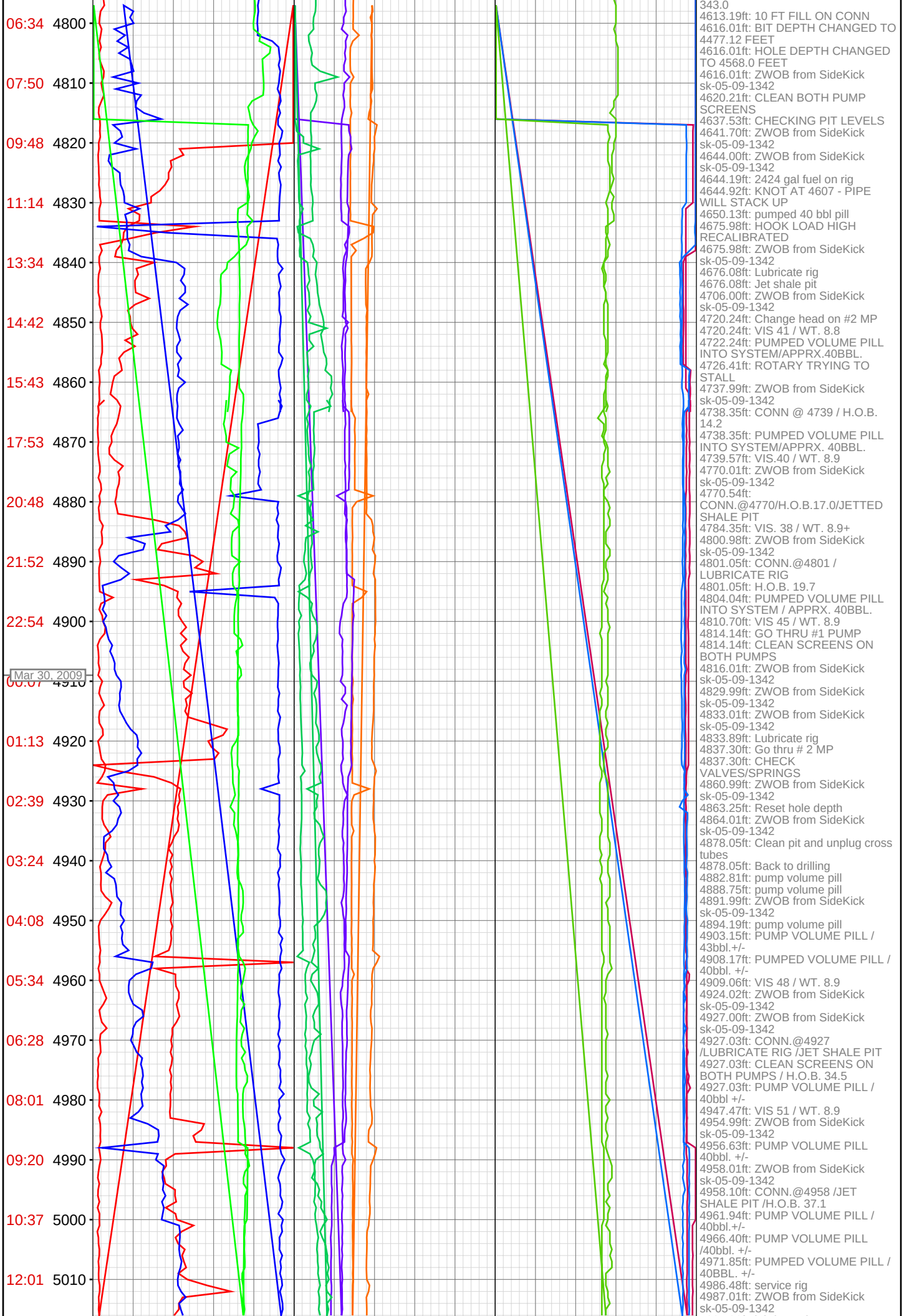
19:37 4690
20:35 4700
21:41 4710
22:26 4720
Mar 29, 2009
00:14 4730
01:24 4740
02:08 4750
03:04 4760
03:50 4770
04:54 4780
05:43 4790
4566.01ft: REAM ONE JOINT AT A TIME.BREAK DOWN STANDS OUT OF DERRICK
4566.01ft: HOLE IS TIGHT /WORK TIGHT SPOTS
4566.01ft: PUMP PILL
4566.01ft: Lubricate rig
4566.01ft: EVENING OUT MUD PROPERTIES
4566.01ft: LEVELING
4566.01ft: ZWOB from SideKick sk-05-09-1342
4566.01ft: ZWOB from SideKick sk-05-09-1342
4566.01ft: FELL FREE AT APX 3600FT
4566.01ft: PUT KELLY ON/CIRC
4566.01ft: work pipe
4566.01ft: set kelly back trip in hole 1 stand off bottom
4566.01ft: put kelly on hole 3 stands off bottom tight spot ream
4566.01ft: ran half stand ibn pyut kelly on ream down
4566.01ft: RAN half stand in put kelly on ream down
4566.01ft: ran half a stand in put kelly on ream down
4566.01ft: weight 9.1 vis 48
4566.01ft: ran half stand in put kelly on ream
4566.01ft: picked up 20 feet circulate
4566.01ft: worked pipe
4566.01ft: lost circulation at 4550
4566.01ft: ream to bottom last 16 feet
4566.01ft: BIT DEPTH CHANGED TO 4566.0 FEET
4566.08ft: dry drill with 1 pump slow pump rate
4568.01ft: ZWOB from DHC
4568.01ft: ZDIFF from DHC
4568.11ft: pulled up circulate
4568.11ft: CLEAN OUT SAND TRAP/SHALE PIT
4568.11ft: BUILD VOLUME
4568.11ft: MIX PILL
4568.11ft: PUMP CEMNET PILL
4568.11ft: PULL 4 STANDS/WAIT ON MATERIAL
4568.11ft: RUN IN 4 STANDS
4568.11ft: mix LCM pill
4568.11ft: Pump LCM pill and pull 4 stands
4568.11ft: trip 4 stands in/put kelly on-rotate,build l.c.m. pill
4568.11ft: PUMP PILL
4568.11ft: PRESSURED UP/PLUG BIT/PULL10 STANDS
4568.11ft: UNPLUGGED BIT/BUILD VOLUME/STAGE IN HOLE
4568.11ft: LOST CIRC
4568.11ft: ATTEMP TO REGAIN CIRC
4568.11ft: TRIP OUT FOR CEMENT JOB
4568.11ft: SLIP AND CUT
4568.11ft: PICK UP DP
4568.11ft: RIG SERVICE
4568.11ft: TRIP IN HOLE OPEN ENDED
4568.11ft: put kelley on to circulate
4568.11ft: took 120 bbls for fluid to circulate
4568.11ft: tagged up 4559/put kelly on circulate-both pumps 115 s.p.m
4568.11ft: lost circulation/pulled 10 stands/wait on cement truck
4568.11ft: trip 15 stands circulate/build volume
4569.00ft: HOLE DEPTH CHANGED TO 4562.0 FEET
4569.06ft: Started drilling @ 14:45 started taking fluid slowed down
4569.06ft: pumps and start mixing a LCM pill
4569.06ft: pumps and started mixing LCM pill
4569.06ft: PUMP LCM PILL
4569.06ft: Pumped 40bbl LCM pill
4571.00ft: Pumped 2nd LCM pill begin drilling@ 4569'
4579.99ft: ZWOB from DHC
4587.01ft: ZWOB from DHC
4587.01ft: BIT DEPTH CHANGED TO 4568.0 FEET
4587.01ft: HOOKLOAD WAS RECALIBRATED
4587.01ft: HOOKLOAD WAS RECALIBRATED
4604.00ft: HOLE DEPTH CHANGED TO 4587.0 FEET
4610.99ft: ZWOB from SideKick sk-05-09-1342
4610.99ft: ZWOB from SideKick sk-05-09-1342
4611.09ft: CONN@4610
4611.35ft: conn 4613/weight 8 vis 35
4612.30ft: MUD WT 8.8
4612.99ft: MAX PULL LIMIT CHANGED FROM 449.6178 TO 343000.0
4612.99ft: MAX PULL LIMIT CHANGED FROM 342999.94 TO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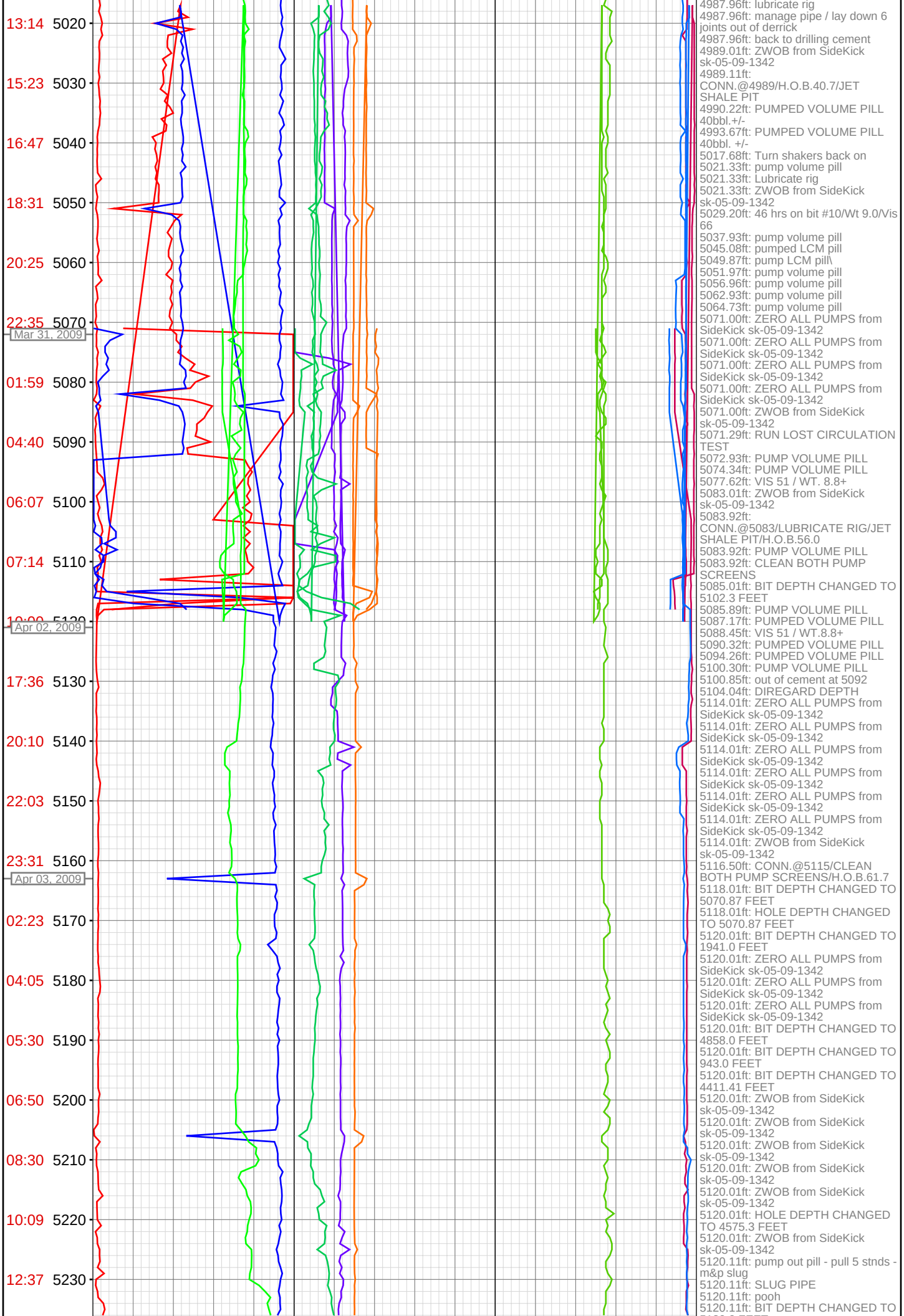
21:52 4890
22:54 4900
Mar 30, 2009
00:07 4910
01:13 4920
02:39 4930
03:24 4940
04:08 4950
05:34 4960
06:28 4970
08:01 4980
09:20 4990
10:37 5000
12:01 5010
343.0
4613.19ft: 10 FT FILL ON CONN
4616.01ft: BIT DEPTH CHANGED TO 4477.12 FEET
4616.01ft: HOLE DEPTH CHANGED TO 4568.0 FEET
4616.01ft: ZWOB from SideKick sk-05-09-1342
4620.21ft: CLEAN BOTH PUMP SCREENS
4637.53ft: CHECKING PIT LEVELS
4641.70ft: ZWOB from SideKick sk-05-09-1342
4644.00ft: ZWOB from SideKick sk-05-09-1342
4644.19ft: 2424 gal fuel on rig
4644.92ft: KNOT AT 4607 - PIPE WILL STACK UP
4650.13ft: pumped 40 bbl pill
4675.98ft: HOOK LOAD HIGH RECALIBRATED
4675.98ft: ZWOB from SideKick sk-05-09-1342
4676.08ft: Lubricate rig
4676.08ft: Jet shale pit
4706.00ft: ZWOB from SideKick sk-05-09-1342
4720.24ft: Change head on #2 MP
4720.24ft: VIS 41 / WT. 8.8
4722.24ft: PUMPED VOLUME PILL INTO SYSTEM/APPRX.40BBL.
4726.41ft: ROTARY TRYING TO STALL
4737.99ft: ZWOB from SideKick sk-05-09-1342
4738.35ft: CONN @ 4739 / H.O.B. 14.2
4738.35ft: PUMPED VOLUME PILL INTO SYSTEM/APPRX. 40BBL.
4739.57ft: VIS.40 / WT. 8.9
4770.01ft: ZWOB from SideKick sk-05-09-1342
4770.54ft: CONN.@4770/H.O.B.17.0/JETTED SHALE PIT
4784.35ft: VIS. 38 / WT. 8.9+
4800.98ft: ZWOB from SideKick sk-05-09-1342
4801.05ft: CONN.@4801 / LUBRICATE RIG
4801.05ft: H.O.B. 19.7
4804.04ft: PUMPED VOLUME PILL INTO SYSTEM / APPRX. 40BBL.
4810.70ft: VIS 45 / WT. 8.9
4814.14ft: GO THRU #1 PUMP
4814.14ft: CLEAN SCREENS ON BOTH PUMPS
4816.01ft: ZWOB from SideKick sk-05-09-1342
4829.99ft: ZWOB from SideKick sk-05-09-1342
4833.01ft: ZWOB from SideKick sk-05-09-1342
4833.89ft: Lubricate rig
4837.30ft: Go thru # 2 MP
4837.30ft: CHECK VALVES/SPRINGS
4860.99ft: ZWOB from SideKick sk-05-09-1342
4863.25ft: Reset hole depth
4864.01ft: ZWOB from SideKick sk-05-09-1342
4878.05ft: Clean pit and unplug cross tubes
4878.05ft: Back to drilling
4882.81ft: pump volume pill
4888.75ft: pump volume pill
4891.99ft: ZWOB from SideKick sk-05-09-1342
4894.19ft: pump volume pill
4903.15ft: PUMP VOLUME PILL / 43bbl.+/-
4908.17ft: PUMPED VOLUME PILL / 40bbl. +/-
4909.06ft: VIS 48 / WT. 8.9
4924.02ft: ZWOB from SideKick sk-05-09-1342
4927.00ft: ZWOB from SideKick sk-05-09-1342
4927.03ft: CONN.@4927 /LUBRICATE RIG /JET SHALE PIT
4927.03ft: CLEAN SCREENS ON BOTH PUMPS / H.O.B. 34.5
4927.03ft: PUMP VOLUME PILL / 40bbl +/-
4947.47ft: VIS 51 / WT. 8.9
4954.99ft: ZWOB from SideKick sk-05-09-1342
4956.63ft: PUMP VOLUME PILL 40bbl. +/-
4958.01ft: ZWOB from SideKick sk-05-09-1342
4958.10ft: CONN.@4958 /JET SHALE PIT /H.O.B. 37.1
4961.94ft: PUMP VOLUME PILL / 40bbl.+/-
4966.40ft: PUMP VOLUME PILL /40bbl. +/-
4971.85ft: PUMPED VOLUME PILL / 40BBL. +/-
4986.48ft: service rig
4987.01ft: ZWOB from SideKick sk-05-09-1342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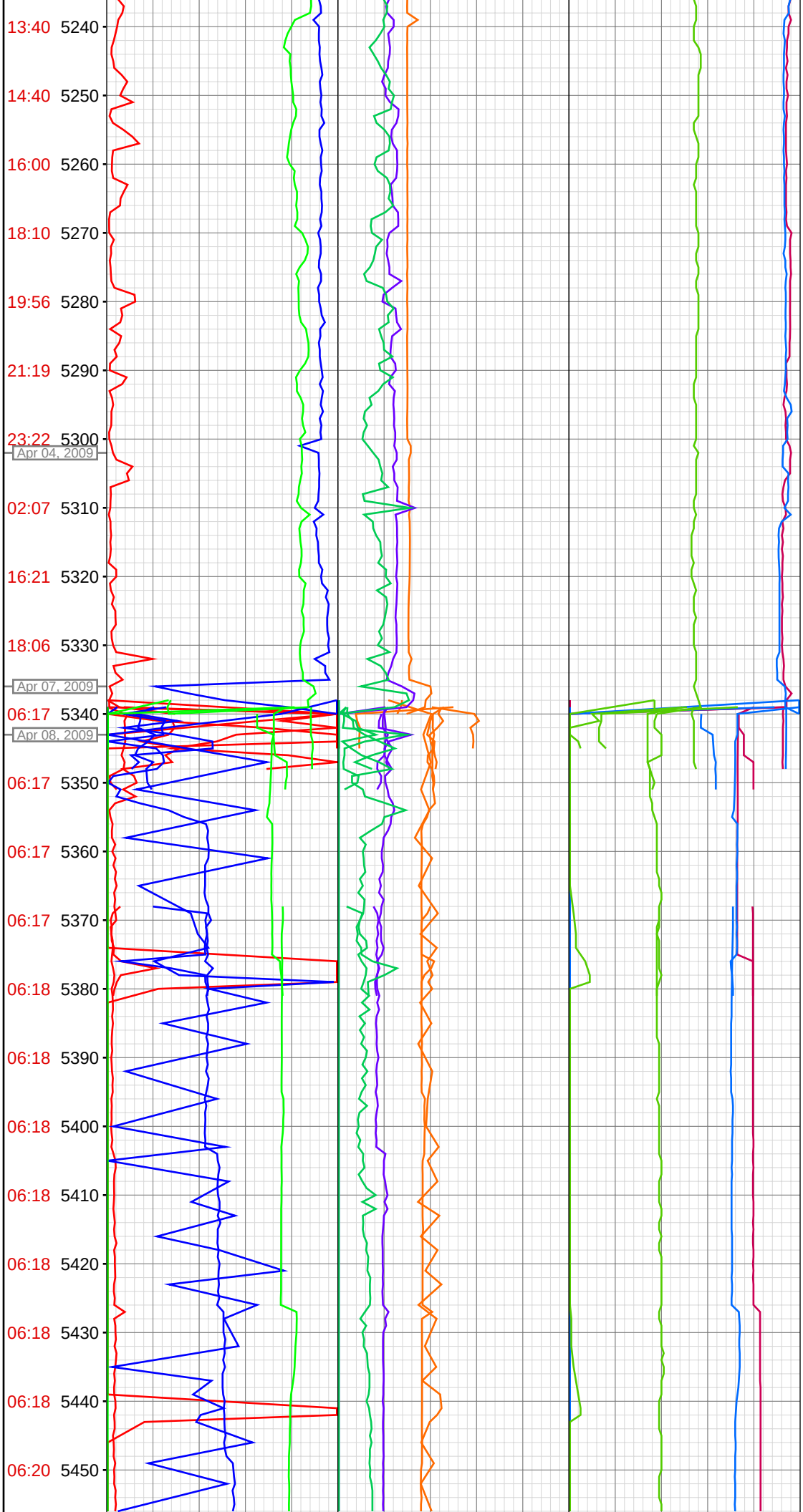
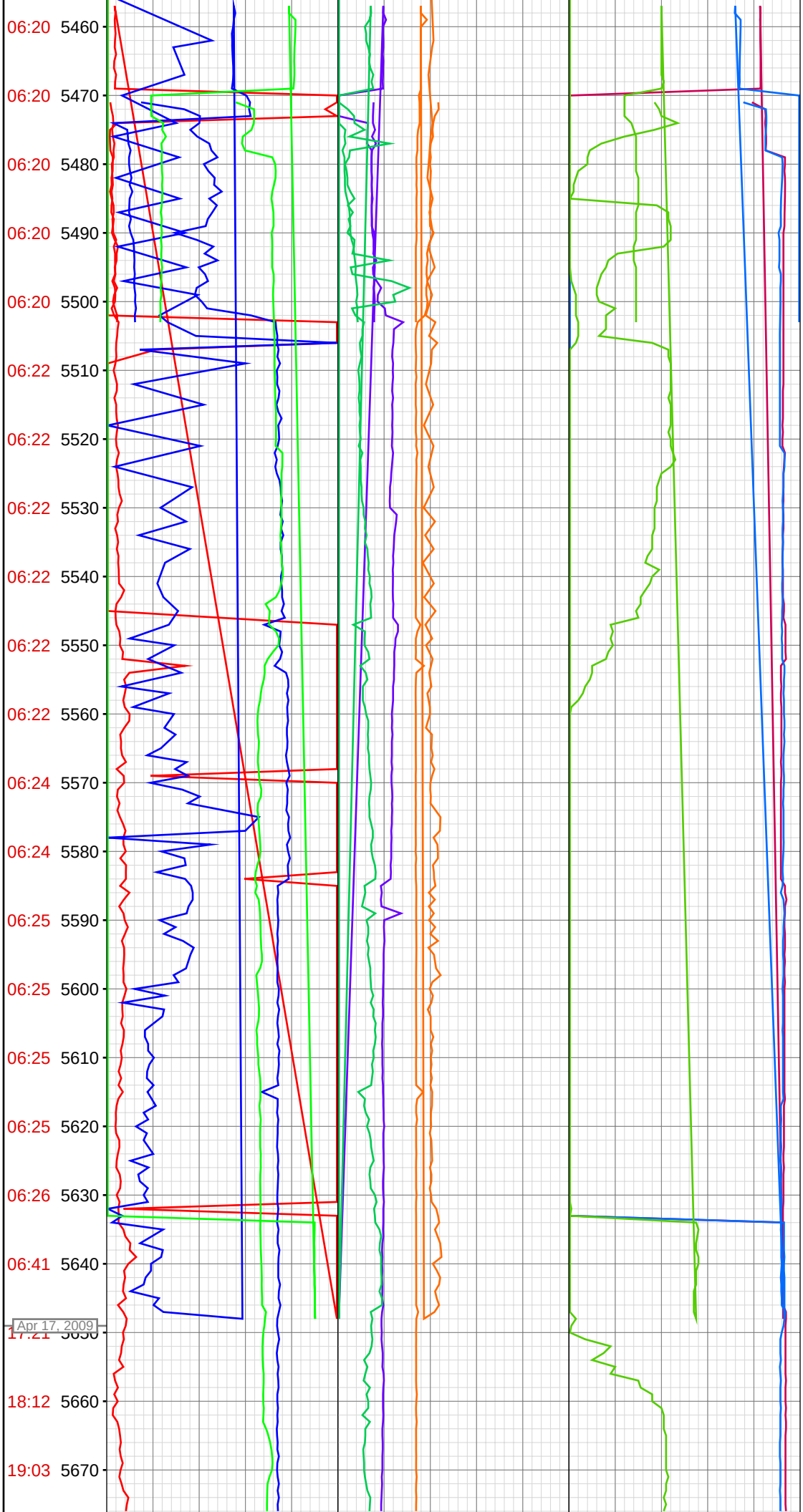
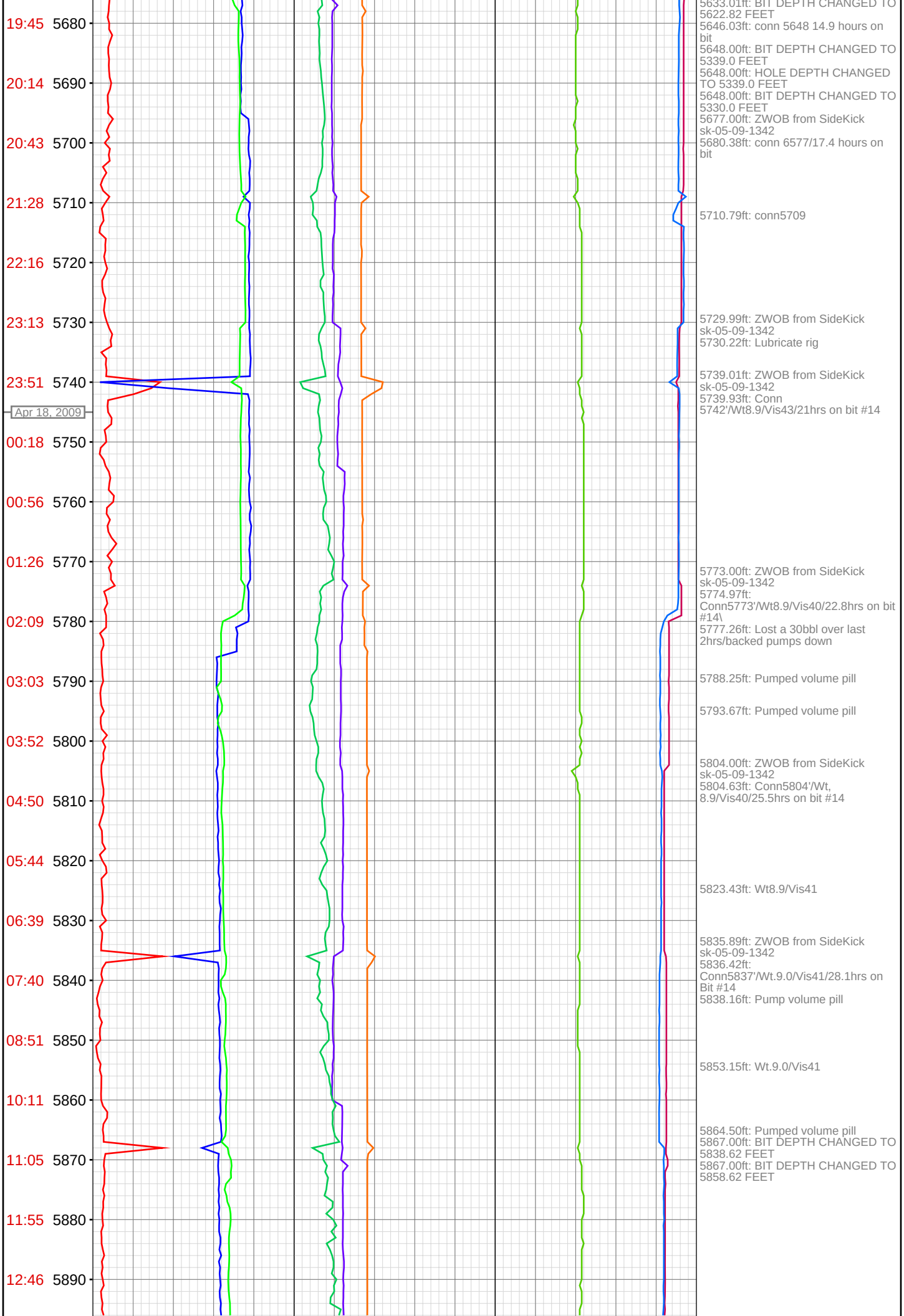
Mar 31, 2009
01:59 5080
04:40 5090
06:07 5100
07:14 5110
10:00 5120
Apr 02, 2009
17:36 5130
20:10 5140
22:03 5150
23:31 5160
Apr 03, 2009
02:23 5170
04:05 5180
05:30 5190
06:50 5200
08:30 5210
10:09 5220
12:37 5230
4987.96ft: lubricate rig
4987.96ft: manage pipe / lay down 6 joints out of derrick
4987.96ft: back to drilling cement
4989.01ft: ZWOB from SideKick sk-05-09-1342
4989.11ft: CONN.@4989/H.O.B.40.7/JET SHALE PIT
4990.22ft: PUMPED VOLUME PILL 40bbl.+/-
4993.67ft: PUMPED VOLUME PILL 40bbl. +/-
5017.68ft: Turn shakers back on
5021.33ft: pump volume pill
5021.33ft: Lubricate rig
5021.33ft: ZWOB from SideKick sk-05-09-1342
5029.20ft: 46 hrs on bit #10/Wt 9.0/Vis 66
5037.93ft: pump volume pill
5045.08ft: pumped LCM pill
5049.87ft: pump LCM pill\
5051.97ft: pump volume pill
5056.96ft: pump volume pill
5062.93ft: pump volume pill
5064.73ft: pump volume pill
5071.00ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5071.00ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5071.00ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5071.00ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5071.00ft: ZWOB from SideKick sk-05-09-1342
5071.29ft: RUN LOST CIRCULATION TEST
5072.93ft: PUMP VOLUME PILL
5074.34ft: PUMP VOLUME PILL
5077.62ft: VIS 51 / WT. 8.8+
5083.01ft: ZWOB from SideKick sk-05-09-1342
5083.92ft: CONN.@5083/LUBRICATE RIG/JET SHALE PIT/H.O.B.56.0
5083.92ft: PUMP VOLUME PILL
5083.92ft: CLEAN BOTH PUMP SCREENS
5085.01ft: BIT DEPTH CHANGED TO 5102.3 FEET
5085.89ft: PUMP VOLUME PILL
5087.17ft: PUMPED VOLUME PILL
5088.45ft: VIS 51 / WT.8.8+
5090.32ft: PUMPED VOLUME PILL
5094.26ft: PUMPED VOLUME PILL
5100.30ft: PUMP VOLUME PILL
5100.85ft: out of cement at 5092
5104.04ft: DIREGARD DEPTH
5114.01ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5114.01ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5114.01ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5114.01ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5114.01ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5114.01ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5114.01ft: ZWOB from SideKick sk-05-09-1342
5116.50ft: CONN.@5115/CLEAN BOTH PUMP SCREENS/H.O.B.61.7
5118.01ft: BIT DEPTH CHANGED TO 5070.87 FEET
5118.01ft: HOLE DEPTH CHANGED TO 5070.87 FEET
5120.01ft: BIT DEPTH CHANGED TO 1941.0 FEET
5120.01ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5120.01ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5120.01ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5120.01ft: BIT DEPTH CHANGED TO 4858.0 FEET
5120.01ft: BIT DEPTH CHANGED TO 943.0 FEET
5120.01ft: BIT DEPTH CHANGED TO 4411.41 FEET
5120.01ft: ZWOB from SideKick sk-05-09-1342
5120.01ft: ZWOB from SideKick sk-05-09-1342
5120.01ft: ZWOB from SideKick sk-05-09-1342
5120.01ft: ZWOB from SideKick sk-05-09-1342
5120.01ft: ZWOB from SideKick sk-05-09-1342
5120.01ft: HOLE DEPTH CHANGED TO 4575.3 FEET
5120.01ft: ZWOB from SideKick sk-05-09-1342
5120.11ft: pump out pill - pull 5 stnds - m&p slug
5120.11ft: SLUG PIPE
5120.11ft: pooh
5120.11ft: BIT DEPTH CHANGED TO



5120.0 FEET
5120.11ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5120.11ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
5120.11ft: PUMP VOLUME PILL
5120.11ft: fluid level static in annulus
5120.11ft: r/u and run survey
5120.11ft: Survey at 4800 - 1/4 degree
5120.11ft: working on pason
5120.11ft: CONN.@4515
5120.11ft: CONN@4547
5120.11ft: CONN@4578
5125.98ft: ZWOB from SideKick sk-05-09-1342
5126.08ft: stop drilling to change flag
5130.45ft: stop drilling for new flag
5140.16ft: fix rod oiler line
5162.01ft: ZWOB from SideKick sk-05-09-1342
5162.96ft: GO THRU #2 PUMP
5168.73ft: VIS. 51 / WT. 8.8
5173.95ft: ZWOB from SideKick sk-05-09-1342
5174.05ft: CONN@5175 / H.O.B.15.0
5186.78ft: VIS48 / WT.8.8
5204.99ft: ZWOB from SideKick sk-05-09-1342
5206.00ft: CONN@5206 / H.O.B.19.3
5224.38ft: Lubricate rig
5300.30ft: CONN@5301/LUBRICATE RIG/H.O.B.34.3
5300.30ft: GO THRU #2 PUMP & CLEAN BOTH PUMP SCREENS
5300.30ft: ZWOB from SideKick sk-05-09-1342
5309.97ft: REPLACE VALVES & SEATS OBS #2 PUMP
5310.99ft: ZWOB from SideKick sk-05-09-1342
5311.12ft: ZEROD GAIN/LOSS @ 0236am
5311.32ft: WORK ON #2 PUMP CLUTCH
5311.61ft: 8HRS. ESTIMATED DOWNTIME /PUMP REPAIRS
5314.99ft: Pump 40 bbl sweep
5317.06ft: Pump 40 bbl sweep
5331.00ft: ZWOB from SideKick sk-05-09-1342
5335.01ft: BIT DEPTH CHANGED TO 0.0 FEET
5335.01ft: ZWOB from SideKick sk-05-09-1342
5335.01ft: BIT DEPTH CHANGED TO 5320.0 FEET
5335.01ft: ZWOB from SideKick sk-05-09-1342
5335.01ft: ZWOB from SideKick sk-05-09-1342
5335.96ft: TD @ 5336 Casing point
5335.96ft: Pulled 50 bbl of mud from live to make pill
5335.96ft: Pump high vis sweep
5335.96ft: Pump high vis sweep
5335.96ft: DROP TOTCO / T.O.O.H. FOR LOGS
5335.96ft: SAFETY MTG. W/LOGGERS
5335.96ft: RIG UP LOGGERS
5335.96ft: PICK UP BIT/ T.I.H
5335.96ft: ZWOB from SideKick sk-05-09-1342
5337.73ft: VIS 55 / WT.9.1
5339.01ft: BIT DEPTH CHANGED TO 5332.0 FEET
5339.01ft: PUMPED SWEEP
5339.01ft: BIT DEPTH CHANGED TO 40.0 FEET
5339.01ft: ZWOB from DHC
5339.01ft: BIT DEPTH CHANGED TO 1680.0 FEET
5339.01ft: circulation at 12:15
5339.01ft: hook cement trucks on hole
5339.01ft: CEMENTING 1ST STAGE
5339.01ft: dropped bomb at 6:15
5339.01ft: cement noticed coming up hole @7:15
5339.01ft: cement still flowing out of hole
5339.01ft: start second stage of cement
5339.01ft: pick up pipe trip in hole
5339.01ft: BIT DEPTH CHANGED TO 2500.25 FEET
5339.01ft: lubricate rig
5339.01ft: build volume circulate hole
5339.01ft: TEST HYDRILL /550 PSI ON RIG GAUGE
5339.01ft: TEST PIPE RAMS / 1075 PSI RIG GAUGE
5339.01ft: test under DV tool @1100 psi on rig gauge
5339.01ft: test choke manifold @1100 psi
5339.01ft: test casing to 900psi
5339.01ft: Run a F.I.T. @ 875psi for 10min
5339.01ft: Lubricate rig
5339.01ft: BIT DEPTH CHANGED TO 5339.5 FEET
5339.07ft: PUMPED SWEEP



5339.07ft: ZEROD GAIN/LOSS
5339.07ft: FILLING PILL PIT
5339.17ft: 1 foot of fill
5342.36ft: circulate bottoms up
5345.01ft: HOLE DEPTH CHANGED TO 5339.0 FEET
5345.01ft: BIT DEPTH CHANGED TO 48.6 FEET
5345.01ft: BIT DEPTH CHANGED TO 2472.0 FEET
5345.01ft: BIT DEPTH CHANGED TO 3084.84 FEET
5345.01ft: ZWOB from SideKick sk-05-09-1342
5345.01ft: BIT DEPTH CHANGED TO 3670.49 FEET
5345.01ft: ZWOB from SideKick sk-05-09-1342
5345.01ft: HOOK LOAD HIGH RECALIBRATED
5345.01ft: BIT DEPTH CHANGED TO 5270.34 FEET
5345.01ft: ZWOB from SideKick sk-05-09-1342
5345.01ft: BIT DEPTH CHANGED TO 5301.76 FEET
5345.47ft: saftey meetting/nipple up b.o.p
5345.47ft: 2472gal on rig/238 gal used
5345.47ft: pressure test blind rams
5346.00ft: BIT DEPTH CHANGED TO 5317.0 FEET
5346.00ft: ZWOB from SideKick sk-05-09-1342
5348.00ft: HOLE DEPTH CHANGED TO 5339.0 FEET
5350.98ft: BIT DEPTH CHANGED TO 5291.64 FEET
5350.98ft: HOLE DEPTH CHANGED TO 5339.0 FEET
5350.98ft: STANDPIPE PRESSURE ZEROED
5350.98ft: ZWOB from DHC
5351.35ft: weight8.9 vis43
5353.54ft: conn5342
5375.49ft: conn 5375
5381.00ft: HOLE DEPTH CHANGED TO 5367.8 FEET
5381.50ft: BIT DEPTH CHANGED TO 5354.69 FEET
5395.01ft: ZWOB from SideKick sk-05-09-1342
5395.28ft: Conn @ 5396 / 11.3hrs on bit #12
5426.21ft: Lubricate rig
5426.21ft: Conn @ 5427' / 15.6 hrs on bit #12
5426.21ft: ZWOB from SideKick sk-05-09-1342
5457.22ft: conn 5459 19.2 hours on bit
5469.00ft: BIT DEPTH CHANGED TO 5162.2 FEET
5469.98ft: circulate clean hole for core
5473.00ft: ZWOB from SideKick sk-05-09-1342
5473.00ft: ZWOB from SideKick sk-05-09-1342
5473.39ft: Begin coring @ 5474'
5477.33ft: Wt8.9 / Vis40
5480.58ft: Wt.8.9/Vis 40
5484.74ft: REMOTE: please record vis and wt. every 2 hrs. on pason-----tvs
5488.81ft: Wt8.9 / Vis40
5489.01ft: HOOK LOAD HIGH RECALIBRATED
5489.01ft: ZWOB from SideKick sk-05-09-1342
5492.09ft: Conn @ 5490/Wt.8.9/Vis40/3.1hrs on bit # 14\
5502.99ft: BIT DEPTH CHANGED TO 0.0 FEET
5502.99ft: BIT DEPTH CHANGED TO 366.5 FEET
5502.99ft: BIT DEPTH CHANGED TO 5456.08 FEET
5502.99ft: BIT DEPTH CHANGED TO 5449.1 FEET
5503.90ft: T.O.O.H Core #1
5503.90ft: kelly on fill pipe
5503.90ft: run straight hole test 5456
5503.90ft: ZWOB from SideKick sk-05-09-1342
5503.90ft: HOLE DEPTH CHANGED TO 5470.4 FEET
5509.78ft: Wt.8.9/Vis40/5.4 hrs on bit #14
5521.29ft: Lubricate rig
5521.33ft: Conn @ 5542'/Wt.8.9/Vis40
5521.33ft: ZWOB from SideKick sk-05-09-1342
5539.01ft: pump volume pill
5552.00ft: ZWOB from SideKick sk-05-09-1342
5583.99ft: ZWOB from SideKick sk-05-09-1342
5584.25ft: conn 5585/10.9 hours on bit-weight 8.9vis40 lubricate rig
5615.58ft: conn 5615 hour on bit 12.7/weight vis 43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23:51 5740
Apr 18, 2009
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02:09 5780
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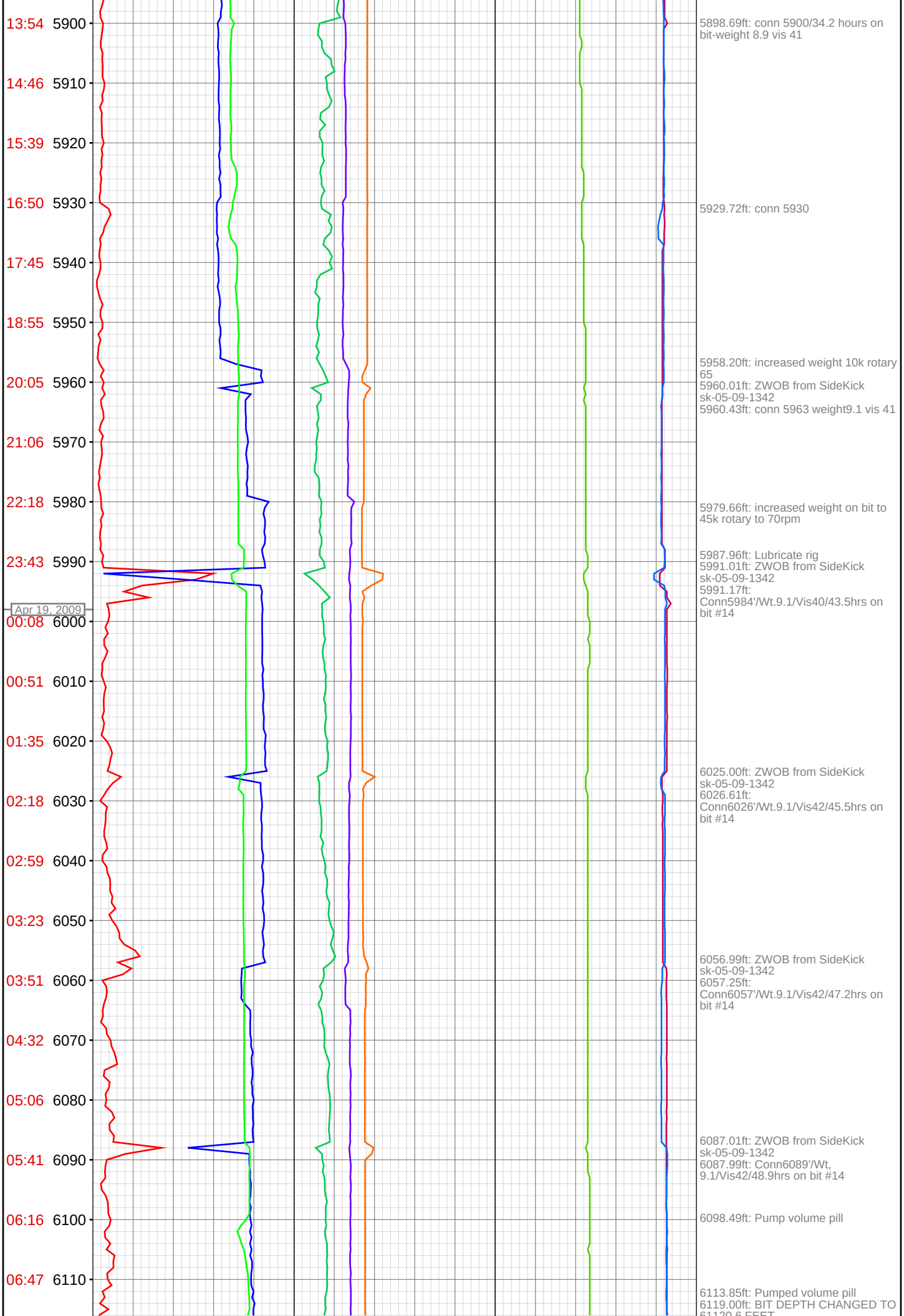
04:50 5810
05:44 5820
06:39 5830
07:40 5840
08:51 5850
10:11 5860
11:05 5870
11:55 5880
12:46 5890
5633.01ft: BIT DEPTH CHANGED TO 5622.82 FEET
5646.03ft: conn 5648 14.9 hours on bit
5648.00ft: BIT DEPTH CHANGED TO 5339.0 FEET
5648.00ft: HOLE DEPTH CHANGED TO 5339.0 FEET
5648.00ft: BIT DEPTH CHANGED TO 5330.0 FEET
5677.00ft: ZWOB from SideKick sk-05-09-1342
5680.38ft: conn 6577/17.4 hours on bit
5710.79ft: conn5709
5729.99ft: ZWOB from SideKick sk-05-09-1342
5730.22ft: Lubricate rig
5739.01ft: ZWOB from SideKick sk-05-09-1342
5739.93ft: Conn 5742'/Wt8.9/Vis43/21hrs on bit #14
5773.00ft: ZWOB from SideKick sk-05-09-1342
5774.97ft: Conn5773'/Wt8.9/Vis40/22.8hrs on bit #14\
5777.26ft: Lost a 30bbl over last 2hrs/backed pumps down
5788.25ft: Pumped volume pill
5793.67ft: Pumped volume pill
5804.00ft: ZWOB from SideKick sk-05-09-1342
5804.63ft: Conn5804'/Wt, 8.9/Vis40/25.5hrs on bit #14
5823.43ft: Wt8.9/Vis41
5835.89ft: ZWOB from SideKick sk-05-09-1342
5836.42ft: Conn5837'/Wt.9.0/Vis41/28.1hrs on Bit #14
5838.16ft: Pump volume pill
5853.15ft: Wt.9.0/Vis41
5864.50ft: Pumped volume pill
5867.00ft: BIT DEPTH CHANGED TO 5838.62 FEET
5867.00ft: BIT DEPTH CHANGED TO 5858.62 FEET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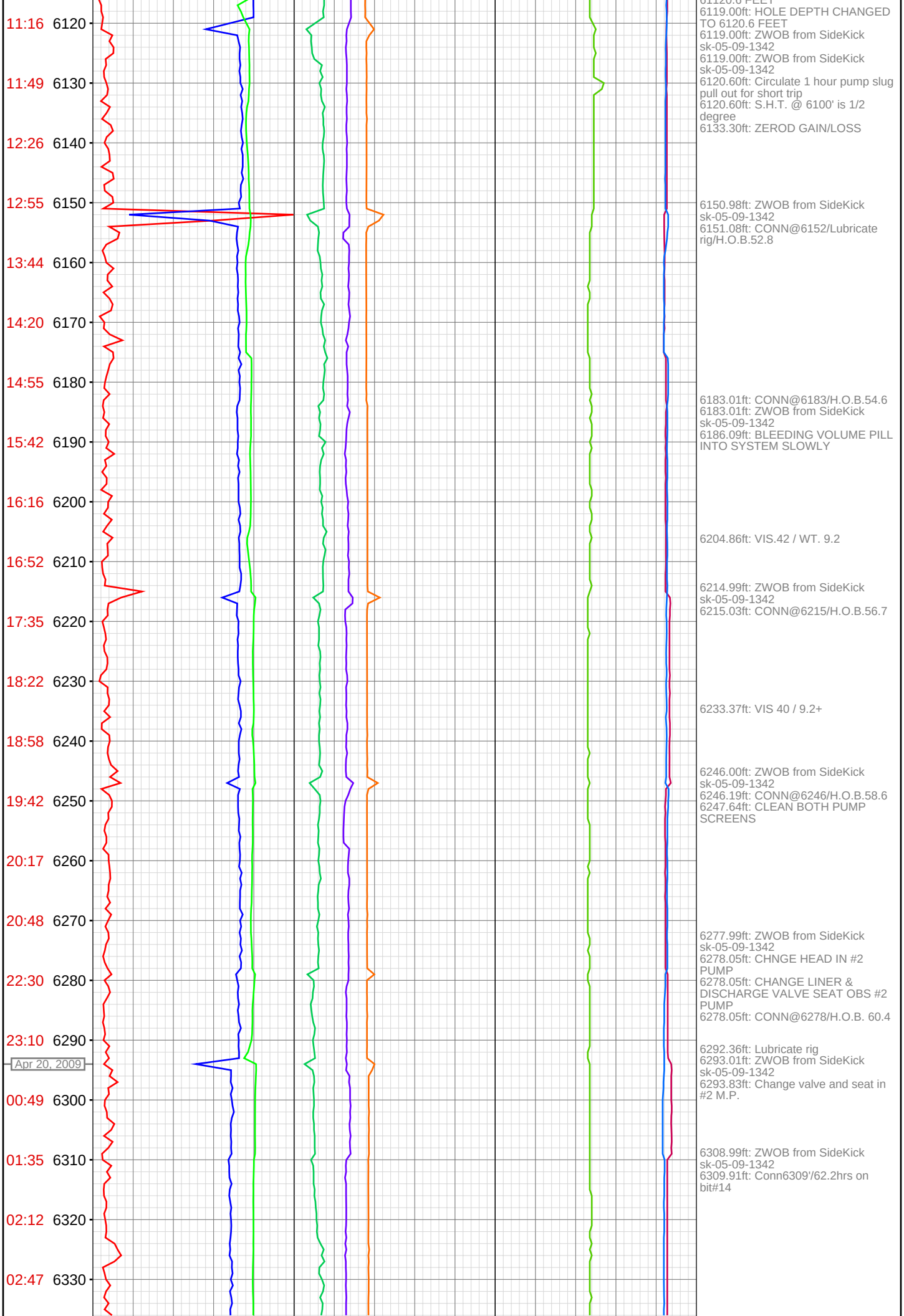
23:43 5990
Apr 19, 2009
00:08 6000
00:51 6010
01:35 6020
02:18 6030
02:59 6040
03:23 6050
03:51 6060
04:32 6070
05:06 6080
05:41 6090
06:16 6100
06:47 6110
5898.69ft: conn 5900/34.2 hours on bit-weight 8.9 vis 41
5929.72ft: conn 5930
5958.20ft: increased weight 10k rotary 65
5960.01ft: ZWOB from SideKick sk-05-09-1342
5960.43ft: conn 5963 weight9.1 vis 41
5979.66ft: increased weight on bit to 45k rotary to 70rpm
5987.96ft: Lubricate rig
5991.01ft: ZWOB from SideKick sk-05-09-1342
5991.17ft: Conn5984'/Wt.9.1/Vis40/43.5hrs on bit #14
6025.00ft: ZWOB from SideKick sk-05-09-1342
6026.61ft: Conn6026'/Wt.9.1/Vis42/45.5hrs on bit #14
6056.99ft: ZWOB from SideKick sk-05-09-1342
6057.25ft: Conn6057'/Wt.9.1/Vis42/47.2hrs on bit #14
6087.01ft: ZWOB from SideKick sk-05-09-1342
6087.99ft: Conn6089'/Wt, 9.1/Vis42/48.9hrs on bit #14
6098.49ft: Pump volume pill
6113.85ft: Pumped volume pill
6119.00ft: BIT DEPTH CHANGED TO 61120.6 FEET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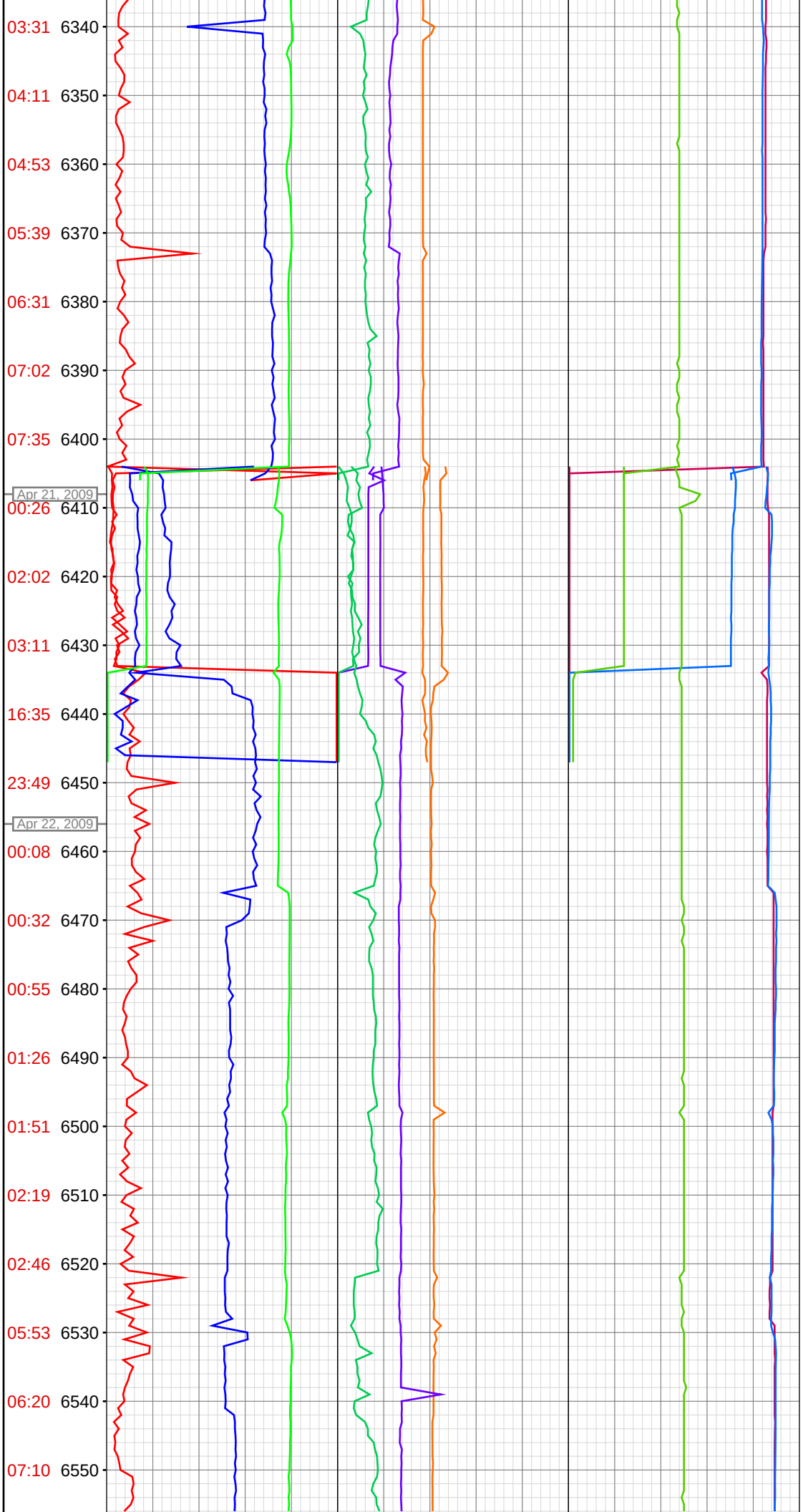
20:17 6260
20:48 6270
22:30 6280
23:10 6290
Apr 20, 2009
00:49 6300
01:35 6310
02:12 6320
02:47 6330
6119.00ft: HOLE DEPTH CHANGED TO 6120.6 FEET
6119.00ft: ZWOB from SideKick sk-05-09-1342
6119.00ft: ZWOB from SideKick sk-05-09-1342
6120.60ft: Circulate 1 hour pump slug pull out for short trip
6120.60ft: S.H.T. @ 6100' is 1/2 degree
6133.30ft: ZEROD GAIN/LOSS
6150.98ft: ZWOB from SideKick sk-05-09-1342
6151.08ft: CONN@6152/Lubricate rig/H.O.B.52.8
6183.01ft: CONN@6183/H.O.B.54.6
6183.01ft: ZWOB from SideKick sk-05-09-1342
6186.09ft: BLEEDING VOLUME PILL INTO SYSTEM SLOWLY
6204.86ft: VIS.42 / WT. 9.2
6214.99ft: ZWOB from SideKick sk-05-09-1342
6215.03ft: CONN@6215/H.O.B.56.7
6233.37ft: VIS 40 / 9.2+
6246.00ft: ZWOB from SideKick sk-05-09-1342
6246.19ft: CONN@6246/H.O.B.58.6
6247.64ft: CLEAN BOTH PUMP SCREENS
6277.99ft: ZWOB from SideKick sk-05-09-1342
6278.05ft: CHNGE HEAD IN #2 PUMP
6278.05ft: CHANGE LINER & DISCHARGE VALVE SEAT OBS #2 PUMP
6278.05ft: CONN@6278/H.O.B. 60.4
6292.36ft: Lubricate rig
6293.01ft: ZWOB from SideKick sk-05-09-1342
6293.83ft: Change valve and seat in #2 M.P.
6308.99ft: ZWOB from SideKick sk-05-09-1342
6309.91ft: Conn6309'/62.2hrs on bit#14



6339.90ft: Conn6340'/64 hrs on bit #14
6341.63ft: Pumped volume pill

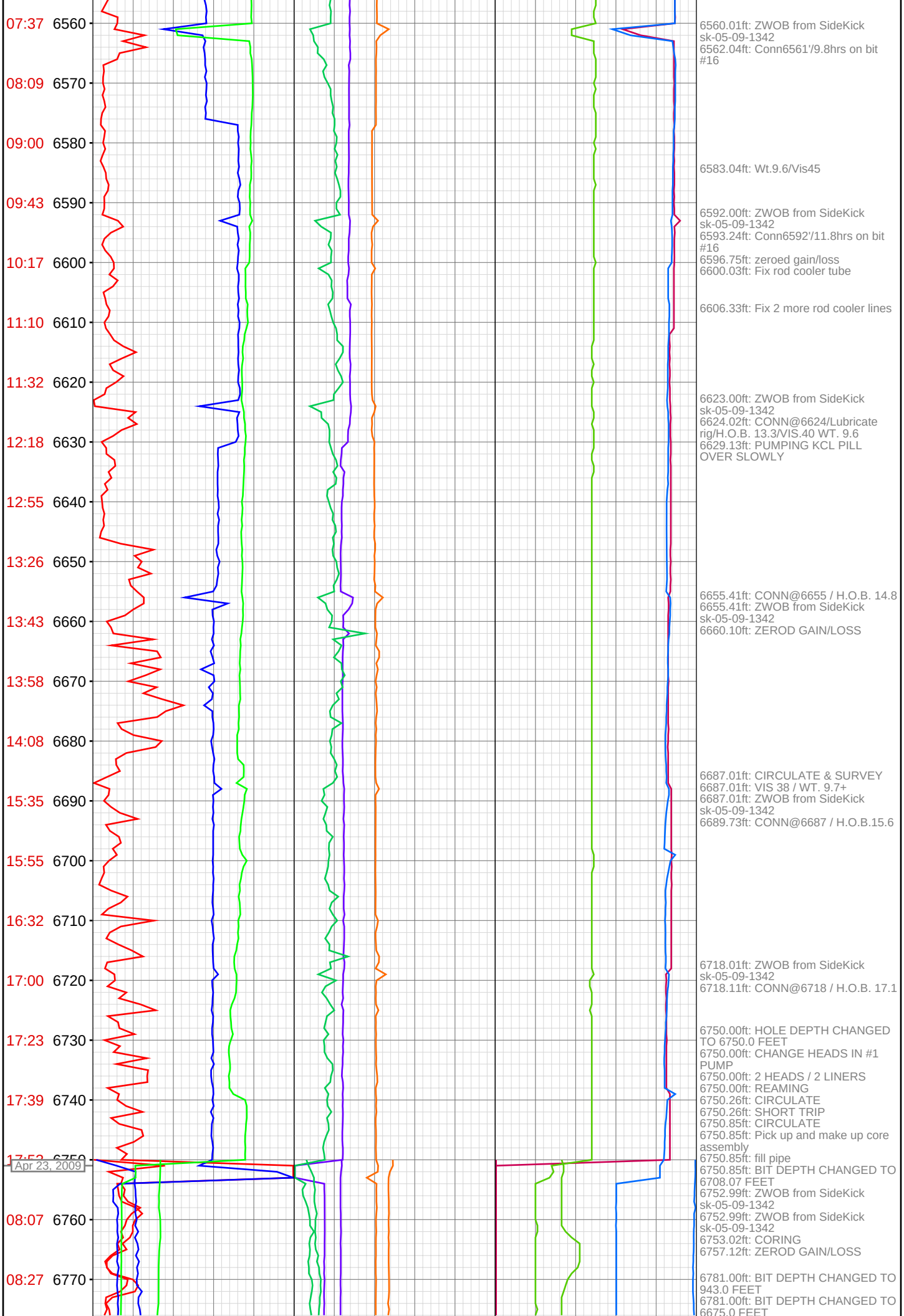
6372.01ft: ZWOB from SideKick sk-05-09-1342
6372.08ft: Conn6372'/66.3 hrs on bit #14
6404.00ft: Run S.H.T. @ 6350'
6404.00ft: TRIP OUT FOR CORE 2
6404.00ft: RIG SERVICE
6404.00ft: MAKE UP CORE BARREL
6404.00ft: START IN HOLE
6404.00ft: BIT DEPTH CHANGED TO 6400.11 FEET
6404.00ft: ZWOB from SideKick sk-05-09-1342
6404.00ft: SURVEY
6404.04ft: ZWOB from SideKick sk-05-09-1342
6404.66ft: Begin core #2
6406.43ft: REAMING
6410.01ft: ZWOB from SideKick sk-05-09-1342
6410.76ft: CHANGE HEAD & LINER OBS #1 PUMP
6410.76ft: BACK TO REAMING
6414.17ft: ZEROD GAIN/LOSS
6417.22ft: VIS 46 / WT. 9.5
6433.56ft: Lubricate rig
6433.56ft: ZWOB from SideKick sk-05-09-1342
6433.83ft: CIRC
6433.83ft: TRIP OUT CORE
6433.83ft: BRAKE DOWN CORE ASSEM
6433.83ft: SLIP AND CUT
6433.83ft: CHANGE OIL IN BOTH PUMPS
6433.83ft: RIG SERVICE
6433.83ft: M. U. BIT /START IN HOLE
6433.83ft: LOAD BHA W/FLUID
6436.52ft: Wt.9.5/Vis44
6444.82ft: Conn6435'/4.1hrs on bit #16
6447.01ft: BIT DEPTH CHANGED TO 6359.89 FEET
6447.01ft: HOLE DEPTH CHANGED TO 6404.0 FEET
6447.01ft: ZWOB from SideKick sk-05-09-1342
6447.01ft: ZWOB from SideKick sk-05-09-1342
6465.91ft: Conn6466'/5.1hrs on bit #16

6482.94ft: Zeroed gain/loss

6497.90ft: Conn6498'/6.5hrs on bit #16/Wt.9.5/Vis.45

6521.03ft: REPLACE WASH PIPE/PACKING
6521.03ft: Back to drilling

6528.54ft: Conn6529'/Wt.9.5/Vis47/8hrs on bit #16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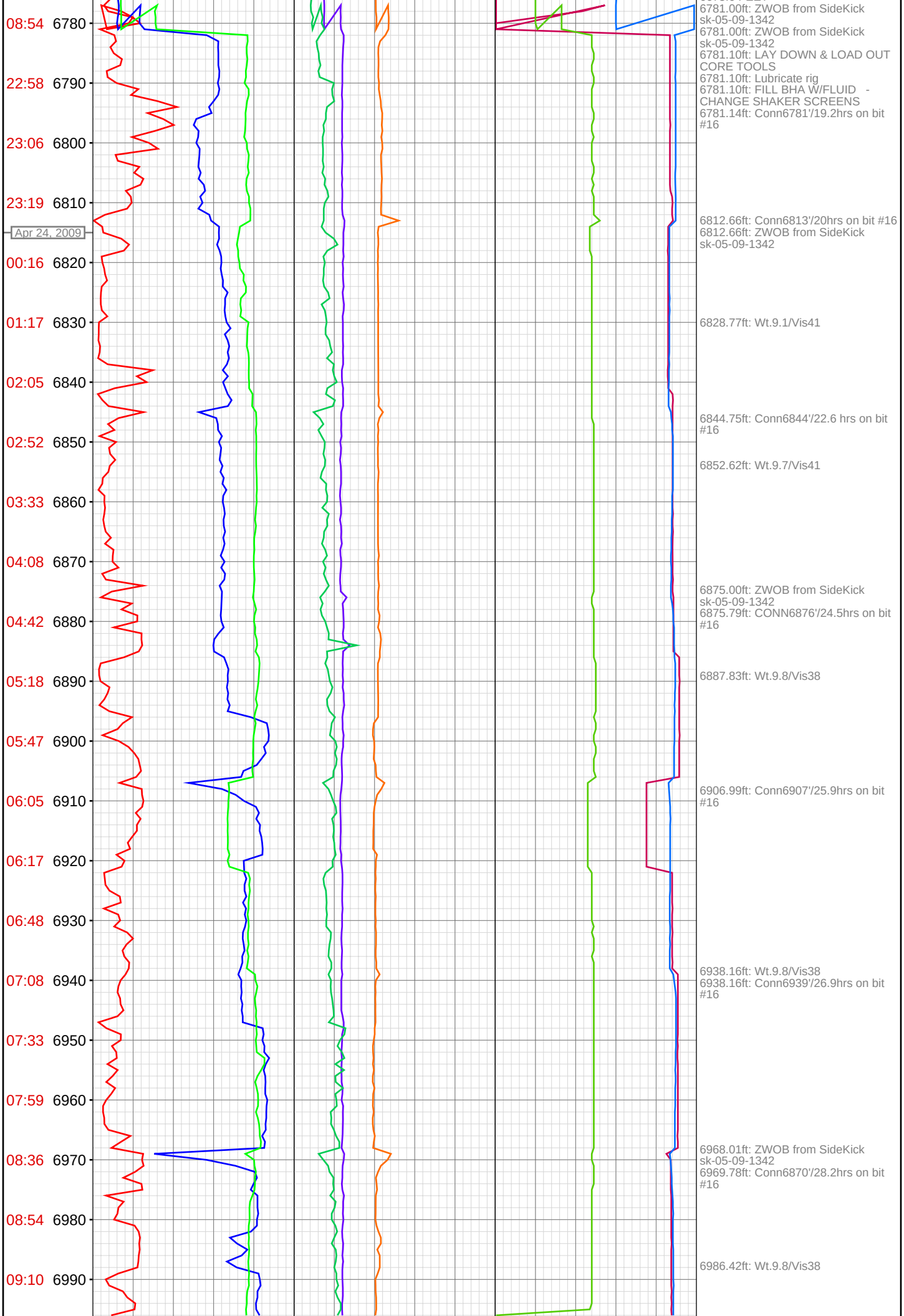
13:58 6670
14:08 6680
15:35 6690
15:55 6700
16:32 6710
17:00 6720
17:23 6730
17:39 6740
Apr 23, 2009
08:07 6760
08:27 6770
6560.01ft: ZWOB from SideKick sk-05-09-1342
6562.04ft: Conn6561'/9.8hrs on bit #16
6583.04ft: Wt.9.6/Vis45
6592.00ft: ZWOB from SideKick sk-05-09-1342
6593.24ft: Conn6592'/11.8hrs on bit #16
6596.75ft: zeroed gain/loss
6600.03ft: Fix rod cooler tube
6606.33ft: Fix 2 more rod cooler lines
6623.00ft: ZWOB from SideKick sk-05-09-1342
6624.02ft: CONN@6624/Lubricate rig/H.O.B. 13.3/VIS.40 WT. 9.6
6629.13ft: PUMPING KCL PILL OVER SLOWLY
6655.41ft: CONN@6655 / H.O.B. 14.8
6655.41ft: ZWOB from SideKick sk-05-09-1342
6660.10ft: ZEROD GAIN/LOSS
6687.01ft: CIRCULATE & SURVEY
6687.01ft: VIS 38 / WT. 9.7+
6687.01ft: ZWOB from SideKick sk-05-09-1342
6689.73ft: CONN@6687 / H.O.B.15.6
6718.01ft: ZWOB from SideKick sk-05-09-1342
6718.11ft: CONN@6718 / H.O.B. 17.1
6750.00ft: HOLE DEPTH CHANGED TO 6750.0 FEET
6750.00ft: CHANGE HEADS IN #1 PUMP
6750.00ft: 2 HEADS / 2 LINERS
6750.00ft: REAMING
6750.26ft: CIRCULATE
6750.26ft: SHORT TRIP
6750.85ft: CIRCULATE
6750.85ft: Pick up and make up core assembly
6750.85ft: fill pipe
6750.85ft: BIT DEPTH CHANGED TO 6708.07 FEET
6752.99ft: ZWOB from SideKick sk-05-09-1342
6752.99ft: ZWOB from SideKick sk-05-09-1342
6753.02ft: CORING
6757.12ft: ZEROD GAIN/LOSS
6781.00ft: BIT DEPTH CHANGED TO 943.0 FEET
6781.00ft: BIT DEPTH CHANGED TO 6675.0 FEET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Apr 24, 2009
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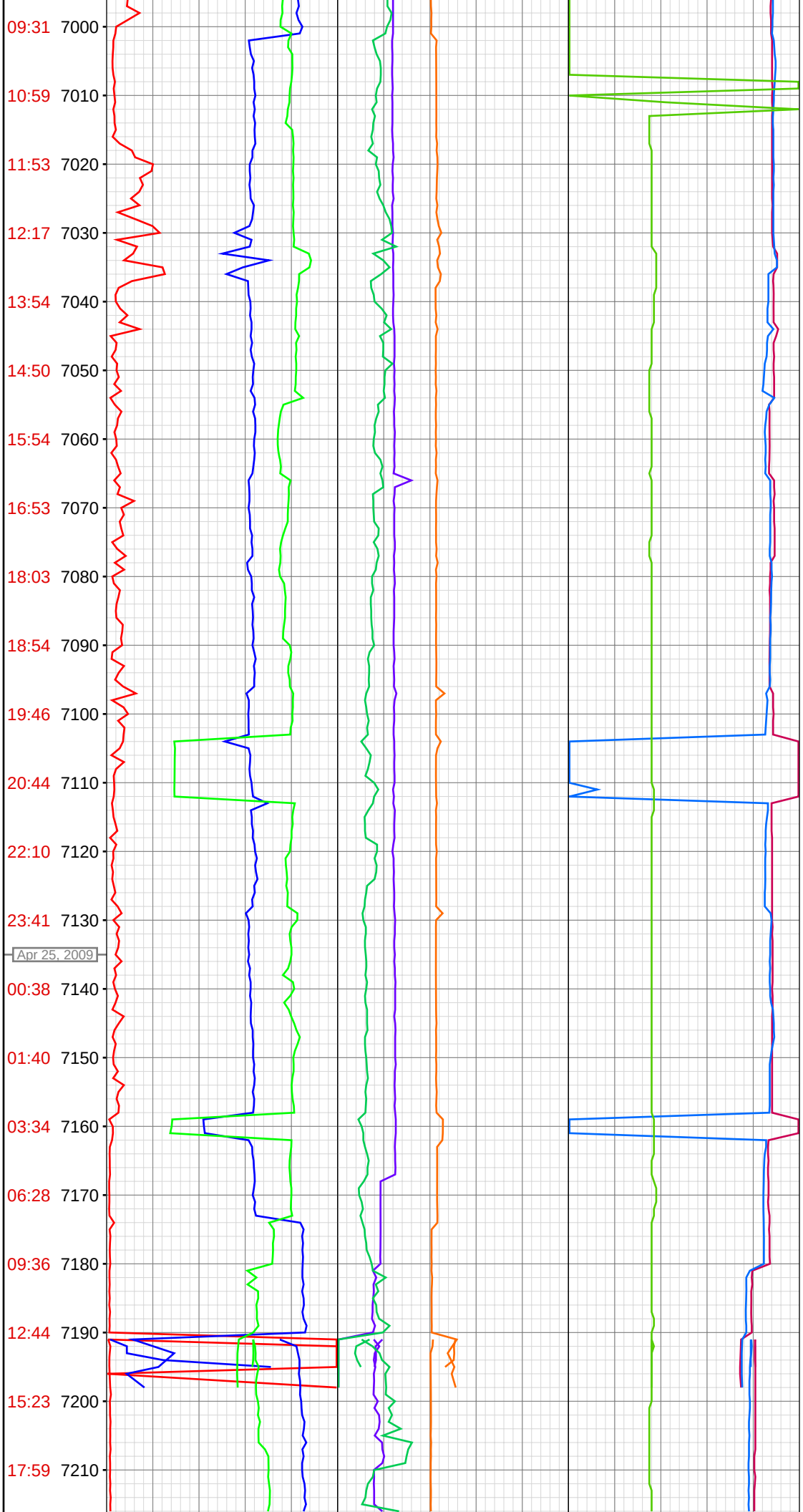
06:05 6910
06:17 6920
06:48 6930
07:08 6940
07:33 6950
07:59 6960
08:36 6970
08:54 6980
09:10 6990
6781.00ft: ZWOB from SideKick sk-05-09-1342
6781.00ft: ZWOB from SideKick sk-05-09-1342
6781.10ft: LAY DOWN & LOAD OUT CORE TOOLS
6781.10ft: Lubricate rig
6781.10ft: FILL BHA W/FLUID - CHANGE SHAKER SCREENS
6781.14ft: Conn6781'/19.2hrs on bit #16
6812.66ft: Conn6813'/20hrs on bit #16
6812.66ft: ZWOB from SideKick sk-05-09-1342
6828.77ft: Wt.9.1/Vis41
6844.75ft: Conn6844'/22.6 hrs on bit #16
6852.62ft: Wt.9.7/Vis41
6875.00ft: ZWOB from SideKick sk-05-09-1342
6875.79ft: CONN6876'/24.5hrs on bit #16
6887.83ft: Wt.9.8/Vis38
6906.99ft: Conn6907'/25.9hrs on bit #16
6938.16ft: Wt.9.8/Vis38
6938.16ft: Conn6939'/26.9hrs on bit #16
6968.01ft: ZWOB from SideKick sk-05-09-1342
6969.78ft: Conn6870'/28.2hrs on bit #16
6986.42ft: Wt.9.8/Vis38



7000.75ft: zeroed gain/loss
7000.98ft: ZWOB from SideKick sk-05-09-1342
7001.31ft: Conn7002'/29.4hrs on bit #16

7031.99ft: ZWOB from SideKick sk-05-09-1342
7032.97ft: SURVEY / LUBRICATE RIG
7033.76ft: CONN @ 7033 / H.O.B. 31.9
7039.21ft: VIS 37 / WT. 9.9

7062.57ft: VIS 39 / WT. 9.8+
7064.99ft: ZWOB from SideKick sk-05-09-1342
7065.06ft: CONN@7065 / H.O.B. 34.9
7077.69ft: ROD OILER PROBLEM #2 PUMP
7080.74ft: ZEROD GAIN/LOSS
7090.03ft: VIS 40 / WT. 9.9
7096.00ft: ZWOB from SideKick sk-05-09-1342
7096.06ft: CONN@7096 / H.O.B. 34.9
7125.82ft: Wt.9.8/Vis35
7128.90ft: Conn7128'/41.4hrs on bit #16
7136.35ft: Pumped volume pill
7136.81ft: zeroed gain/loss
7140.12ft: Pumped volume pill
7140.91ft: zeroed gain/loss
7144.62ft: Wt.9.9/Vis36
7158.60ft: Change two heads and liner in #2 M.P.
7158.60ft: ZWOB from SideKick sk-05-09-1342
7158.60ft: Drillin 1 pump @ 120stokes 20k on bit
7158.60ft: CONN7159'/Wt.9.8/Vis36/45hrs on bit #16
7161.35ft: Both pumps on hole 30k on bit
7163.91ft: Wt.9.8/Vis36
7164.27ft: Bleed over KCL volume pill
7167.49ft: zeroed gain/loss
7170.08ft: Wt.9.8/Vis36
7173.33ft: Wt on bit 40k
7177.17ft: Wt.9.8/Vis36\
7179.07ft: 50.2hrs on bit #16
7184.19ft: Wt.9.8/Vis36
7191.31ft: CONN@7191/H.O.B.53.8/VIS.40/WT .9.9/LUBRICATE RIG
7198.00ft: ZWOB from SideKick sk-05-09-1342
7198.00ft: HOLE DEPTH CHANGED TO 7191.0 FEET
7199.84ft: VIS 40 / WT.9.9
7212.53ft: VIS. 46 / WT. 10.0
7213.42ft: ZEROD GAIN/LOSS
7221.00ft: ZWOB from SideKick sk-05-09-1342
7221.98ft: CONN@7222/H.O.B.62.3
7223.66ft: VIS 51 / WT. 10.0
7229.00ft: BIT DEPTH CHANGED TO 0.0 FEET
7229.00ft: TOP-OFF HOLE W/FLUID
7229.00ft: BIT DEPTH CHANGED TO 7177.0 FEET
7229.00ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
7229.00ft: ZWOB from SideKick sk-05-09-1342
7229.95ft: short trip 9 stands
7229.95ft: circulate
7229.95ft: TRIP OUT OR LOGS
7229.95ft: LAY DOWN SUBS / BIT
7229.95ft: GOING IN HOLE W/1ST LOG
7229.95ft: filled hole 12 bbls
7229.95ft: TOPPED OFF HOLE W/FLUID
7229.95ft: filled hole 9 bbls
7229.95ft: TOPPED HOLE W/FLUID-2.5bbl.
7229.95ft: TOPPED-OFF HOLE W/FLUID-7.07bbl.
7229.95ft: filled hole 8 bbls
7229.95ft: GO IN HOLE
7229.95ft: LOAD BHA W/FLUID
7231.00ft: BIT DEPTH CHANGED TO 0.0 FEET
7231.00ft: ZERO ALL PUMPS from SideKick sk-05-09-1342
7231.00ft: BIT DEPTH CHANGED TO 0.0 FEET
7231.00ft: ZWOB from DHC
7235.01ft: finished laying down drill

20:40
7220
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7240
7235.01ft: finished laying down drill pipe
7235.01ft: RIGING UP TO RUN CSG.
7235.01ft: FILLED HOLE WITH 2 BBL.
7235.01ft: STARTED RUNING CSG.
7235.01ft: RUN CSG.
7235.01ft: FILLED CSG.
7235.01ft: FILLNG CSG.
7235.01ft: FILLING CSG.
7235.01ft: fill casing with fluid
7235.01ft: circulate
7235.01ft: RIG DOWN CSG. CREWS EQU.
7235.01ft: CIRC. 95/8 CSG.
7235.01ft: Pick up stack and set well head slips

Appendix XI – Tallies of Installed Casing Strings

ADM CCS WELL #1: Surface Casing Tally

Total Depth Tagged (ft): **355.00**

Joint #	Joint Length (ft)	Top Depth (ft)	Bottom Depth (ft)	Grade	Weight (lbs/ft)	Thread
1	44.88	310.12	355.00	H-40	94	8-round, STC
2	40.25	269.87	310.12	H-40	94	8-round, STC
3	41.67	228.20	269.87	H-40	94	8-round, STC
4	41.80	186.40	228.20	H-40	94	8-round, STC
5	41.56	144.84	186.40	H-40	94	8-round, STC
6	42.26	102.58	144.84	H-40	94	8-round, STC
7	42.97	59.61	102.58	H-40	94	8-round, STC
8	39.95	19.66	59.61	H-40	94	8-round, STC
9	40.74	-21.08	19.66	H-40	94	8-round, STC

ADM CCS WELL #1: Intermediate Casing Tally

Prepared by: PTH Jr/TG

Total Depth Tagged (ft): **5330** EST TD

Jt #	**Length**	Total	Top	Bottom	Grade	Wt	Thread	Cent.
Shoe	1.92	1.92	5328.08	5330.00				
1	**38.46**	40.38	5289.62	5328.08	J55	66.17	Butt	X
FC	**1.33**	41.71	5288.29	5289.62				
2	**47.82**	89.53	5240.47	5288.29	J55	66.17	Butt	X
3	**46.85**	136.38	5193.62	5240.47	J55	66.17	Butt	X
4	**46.82**	183.20	5146.80	5193.62	J55	66.17	Butt	X
5	**46.93**	230.13	5099.87	5146.80	J55	66.17	Butt	
6	**46.30**	276.43	5053.57	5099.87	J55	66.17	Butt	
7	**42.18**	318.61	5011.39	5053.57	J55	66.17	Butt	
8	**46.71**	365.32	4964.68	5011.39	J55	66.17	Butt	
9	**43.10**	408.42	4921.58	4964.68	J55	66.17	Butt	
10	**42.05**	450.47	4879.53	4921.58	J55	66.17	Butt	
11	**46.69**	497.16	4832.84	4879.53	J55	66.17	Butt	
12	**42.00**	539.16	4790.84	4832.84	J55	66.17	Butt	
13	**41.41**	580.57	4749.43	4790.84	J55	66.17	Butt	
14	**44.83**	625.40	4704.60	4749.43	J55	66.17	Butt	
15	**46.52**	671.92	4658.08	4704.60	J55	66.17	Butt	
16	**41.48**	713.40	4616.60	4658.08	J55	66.17	Butt	
17	**37.61**	751.01	4578.99	4616.60	J55	66.17	Butt	
18	**40.33**	791.34	4538.66	4578.99	J55	66.17	Butt	
19	**46.03**	837.37	4492.63	4538.66	J55	66.17	Butt	
20	**44.45**	881.82	4448.18	4492.63	J55	66.17	Butt	
21	**46.98**	928.80	4401.20	4448.18	J55	66.17	Butt	
22	**46.73**	975.53	4354.47	4401.20	J55	66.17	Butt	
23	**42.68**	1018.21	4311.79	4354.47	J55	66.17	Butt	
24	**45.63**	1063.84	4266.16	4311.79	J55	66.17	Butt	
25	**46.83**	1110.67	4219.33	4266.16	J55	66.17	Butt	
26	**43.18**	1153.85	4176.15	4219.33	J55	66.17	Butt	
27	**46.61**	1200.46	4129.54	4176.15	J55	66.17	Butt	
28	**46.96**	1247.42	4082.58	4129.54	J55	66.17	Butt	
29	**47.18**	1294.60	4035.40	4082.58	J55	66.17	Butt	
30	**46.09**	1340.69	3989.31	4035.40	J55	66.17	Butt	

ADM CCS WELL #1: Intermediate Casing Tally

** Stage tool 2.29' bottom of jt 37

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
31	**46.78**	1387.47	3942.53	3989.31	J55	66.17	Butt	
32	**45.32**	1432.79	3897.21	3942.53	J55	66.17	Butt	X
33	**44.79**	1477.58	3852.42	3897.21	J55	66.17	Butt	
34	**46.63**	1524.21	3805.79	3852.42	J55	66.17	Butt	X
35	**46.77**	1570.98	3759.02	3805.79	J55	66.17	Butt	
36	**41.18**	1612.16	3717.84	3759.02	J55	66.17	Butt	X
37	**44.63**	1656.79	3673.21	3717.84	J55	66.17	Butt	**
38	**42.58**	1699.37	3630.63	3673.21	J55	66.17	Butt	
39	**44.78**	1744.15	3585.85	3630.63	J55	59.50	Butt	
40	**41.82**	1785.97	3544.03	3585.85	J55	59.50	Butt	Bskt
41	**44.75**	1830.72	3499.28	3544.03	J55	59.50	Butt	
42	**43.78**	1874.50	3455.50	3499.28	J55	59.50	Butt	
43	**43.00**	1917.50	3412.50	3455.50	J55	59.50	Butt	
44	**43.95**	1961.45	3368.55	3412.50	J55	59.50	Butt	
45	**40.14**	2001.59	3328.41	3368.55	J55	59.50	Butt	
46	**44.19**	2045.78	3284.22	3328.41	J55	59.50	Butt	
47	**41.00**	2086.78	3243.22	3284.22	J55	59.50	Butt	
48	**44.68**	2131.46	3198.54	3243.22	J55	59.50	Butt	
49	**44.78**	2176.24	3153.76	3198.54	J55	59.50	Butt	
50	**41.50**	2217.74	3112.26	3153.76	J55	59.50	Butt	
51	**41.56**	2259.30	3070.70	3112.26	J55	59.50	Butt	
52	**44.23**	2303.53	3026.47	3070.70	J55	59.50	Butt	
53	**41.01**	2344.54	2985.46	3026.47	J55	59.50	Butt	
54	**44.73**	2389.27	2940.73	2985.46	J55	59.50	Butt	
55	**40.95**	2430.22	2899.78	2940.73	J55	59.50	Butt	
56	**40.60**	2470.82	2859.18	2899.78	J55	59.50	Butt	
57	**40.22**	2511.04	2818.96	2859.18	J55	59.50	Butt	
58	**41.40**	2552.44	2777.56	2818.96	J55	59.50	Butt	
59	**44.72**	2597.16	2732.84	2777.56	J55	59.50	Butt	
60	**41.48**	2638.64	2691.36	2732.84	J55	59.50	Butt	

ADM CCS WELL #1: Intermediate Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
61	**43.10**	2681.74	2648.26	2691.36	J55	59.50	Butt	
62	**40.94**	2722.68	2607.32	2648.26	J55	59.50	Butt	X
63	**41.03**	2763.71	2566.29	2607.32	J55	59.50	Butt	
64	**44.90**	2808.61	2521.39	2566.29	J55	59.50	Butt	
65	**44.16**	2852.77	2477.23	2521.39	J55	59.50	Butt	X
66	**40.68**	2893.45	2436.55	2477.23	J55	59.50	Butt	
67	**40.94**	2934.39	2395.61	2436.55	J55	59.50	Butt	
68	**40.63**	2975.02	2354.98	2395.61	J55	59.50	Butt	X
69	**44.66**	3019.68	2310.32	2354.98	J55	59.50	Butt	
70	**43.22**	3062.90	2267.10	2310.32	J55	59.50	Butt	
71	**40.80**	3103.70	2226.30	2267.10	J55	59.50	Butt	
72	**43.96**	3147.66	2182.34	2226.30	J55	59.50	Butt	
73	**41.68**	3189.34	2140.66	2182.34	J55	59.50	Butt	
74	**41.14**	3230.48	2099.52	2140.66	J55	59.50	Butt	
75	**44.21**	3274.69	2055.31	2099.52	J55	59.50	Butt	
76	**41.31**	3316.00	2014.00	2055.31	J55	59.50	Butt	
77	**44.34**	3360.34	1969.66	2014.00	J55	59.50	Butt	
78	**44.10**	3404.44	1925.56	1969.66	J55	59.50	Butt	
79	**44.27**	3448.71	1881.29	1925.56	J55	59.50	Butt	
80	**43.80**	3492.51	1837.49	1881.29	J55	59.50	Butt	
81	**44.32**	3536.83	1793.17	1837.49	J55	59.50	Butt	
82	**44.28**	3581.11	1748.89	1793.17	J55	59.50	Butt	
83	**42.91**	3624.02	1705.98	1748.89	J55	59.50	Butt	
84	**40.30**	3664.32	1665.68	1705.98	J55	59.50	Butt	
85	**41.08**	3705.40	1624.60	1665.68	J55	59.50	Butt	
86	**42.08**	3747.48	1582.52	1624.60	J55	59.50	Butt	
87	**41.20**	3788.68	1541.32	1582.52	J55	59.50	Butt	
88	**43.36**	3832.04	1497.96	1541.32	J55	59.50	Butt	
89	**44.78**	3876.82	1453.18	1497.96	J55	59.50	Butt	
90	**44.72**	3921.54	1408.46	1453.18	J55	59.50	Butt	

ADM CCS WELL #1: Intermediate Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
91	**44.00**	3965.54	1364.46	1408.46	J55	59.50	Butt	
92	**41.13**	4006.67	1323.33	1364.46	J55	59.50	Butt	
93	**39.95**	4046.62	1283.38	1323.33	J55	59.50	Butt	
94	**41.20**	4087.82	1242.18	1283.38	J55	59.50	Butt	
95	**41.58**	4129.40	1200.60	1242.18	J55	59.50	Butt	
96	**43.56**	4172.96	1157.04	1200.60	J55	59.50	Butt	
97	**44.68**	4217.64	1112.36	1157.04	J55	59.50	Butt	
98	**44.68**	4262.32	1067.68	1112.36	J55	59.50	Butt	
99	**41.26**	4303.58	1026.42	1067.68	J55	59.50	Butt	
100	**41.27**	4344.85	985.15	1026.42	J55	59.50	Butt	
101	**44.68**	4389.53	940.47	985.15	J55	59.50	Butt	
102	**44.68**	4434.21	895.79	940.47	J55	59.50	Butt	
103	**43.91**	4478.12	851.88	895.79	J55	59.50	Butt	
104	**42.90**	4521.02	808.98	851.88	J55	59.50	Butt	
105	**41.54**	4562.56	767.44	808.98	J55	59.50	Butt	
106	**44.60**	4607.16	722.84	767.44	J55	59.50	Butt	
107	**44.43**	4651.59	678.41	722.84	J55	59.50	Butt	
108	**38.85**	4690.44	639.56	678.41	J55	59.50	Butt	
109	**44.45**	4734.89	595.11	639.56	J55	59.50	Butt	
110	**40.30**	4775.19	554.81	595.11	J55	59.50	Butt	
111	**44.70**	4819.89	510.11	554.81	J55	59.50	Butt	
112	**44.80**	4864.69	465.31	510.11	J55	59.50	Butt	
113	**42.86**	4907.55	422.45	465.31	J55	59.50	Butt	
114	**41.27**	4948.82	381.18	422.45	J55	59.50	Butt	
115	**43.48**	4992.30	337.70	381.18	J55	59.50	Butt	
116	**41.25**	5033.55	296.45	337.70	J55	59.50	Butt	
117	**41.26**	5074.81	255.19	296.45	J55	59.50	Butt	
118	**44.70**	5119.51	210.49	255.19	J55	59.50	Butt	
119	**44.67**	5164.18	165.82	210.49	J55	59.50	Butt	
120	**41.08**	5205.26	124.74	165.82	J55	59.50	Butt	

ADM CCS WELL #1: Intermediate Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
121	**44.16**	5249.42	80.58	124.74	J55	59.50	Butt	
122	**43.99**	5293.41	36.59	80.58	J56	59.50	Butt	
123	**41.63**	5335.04	-5.04	36.59	J57	59.50	Butt	X
124	**41.25**	5376.29	-46.29	-5.04	J58	59.50	Butt	
125	**43.98**	5420.27	-90.27	-46.29	J59	59.50	Butt	X
126	**41.61**	5461.88	-131.88	-90.27	J60	59.50	Butt	
127	**43.34**	5505.22	-175.22	-131.88	J61	59.50	Butt	
128								
129								
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ADM CCS WELL #1: Final Casing Tally

Prepared by: PTH Jr/TG/BH III

Total Depth Tagged (ft.): **7219.47** EST TD

ChromeCasing

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
1	41.74	41.74	7177.73	7219.47	13 Cr 80	47.00	BEAR	
2	19.58	61.32	7158.15	7177.73	13 Cr 80	47.00	BEAR	X
FC	2.50	63.82	7155.65	7158.15	L80	47.00	BEAR	
3	40.09	103.91	7115.56	7155.65	13 Cr 80	47.00	BEAR	X
4	40.13	144.04	7075.43	7115.56	13 Cr 80	47.00	BEAR	X
5	40.05	184.09	7035.38	7075.43	13 Cr 80	47.00	BEAR	X
6	40.15	224.24	6995.23	7035.38	13 Cr 80	47.00	BEAR	X
7	40.16	264.40	6955.07	6995.23	13 Cr 80	47.00	BEAR	X
8	39.55	303.95	6915.52	6955.07	13 Cr 80	47.00	BEAR	X
9	39.77	343.72	6875.75	6915.52	13 Cr 80	47.00	BEAR	X
10	19.09	362.81	6856.66	6875.75	13 Cr 80	47.00	BEAR	X
11	40.18	402.99	6816.48	6856.66	13 Cr 80	47.00	BEAR	X
12	39.49	442.48	6776.99	6816.48	13 Cr 80	47.00	BEAR	X
13	40.04	482.52	6736.95	6776.99	13 Cr 80	47.00	BEAR	X
14	38.91	521.43	6698.04	6736.95	13 Cr 80	47.00	BEAR	X
15	39.36	560.79	6658.68	6698.04	13 Cr 80	47.00	BEAR	X
16	38.87	599.66	6619.81	6658.68	13 Cr 80	47.00	BEAR	X
17	38.52	638.18	6581.29	6619.81	13 Cr 80	47.00	BEAR	X
18	39.60	677.78	6541.69	6581.29	13 Cr 80	47.00	BEAR	
19	39.66	717.44	6502.03	6541.69	13 Cr 80	47.00	BEAR	X
20	40.12	757.56	6461.91	6502.03	13 Cr 80	47.00	BEAR	
21	40.05	797.61	6421.86	6461.91	13 Cr 80	47.00	BEAR	X
22	39.94	837.55	6381.92	6421.86	13 Cr 80	47.00	BEAR	
23	40.03	877.58	6341.89	6381.92	13 Cr 80	47.00	BEAR	X
24	39.85	917.43	6302.04	6341.89	13 Cr 80	47.00	BEAR	
25	40.12	957.55	6261.92	6302.04	13 Cr 80	47.00	BEAR	X
26	38.76	996.31	6223.16	6261.92	13 Cr 80	47.00	BEAR	
27	39.86	1036.17	6183.30	6223.16	13 Cr 80	47.00	BEAR	X
28	40.04	1076.21	6143.26	6183.30	13 Cr 80	47.00	BEAR	
29	40.14	1116.35	6103.12	6143.26	13 Cr 80	47.00	BEAR	X
30	40.02	1156.37	6063.10	6103.12	13 Cr 80	47.00	BEAR	
31	39.63	1196.00	6023.47	6063.10	13 Cr 80	47.00	BEAR	X

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
32	40.09	1235.63	5983.84	6023.47	13 Cr 80	47.00	BEAR	
33	39.90	1275.53	5943.94	5983.84	13 Cr 80	47.00	BEAR	X
34	39.79	1315.32	5904.15	5943.94	13 Cr 80	47.00	BEAR	
35	36.80	1352.12	5867.35	5904.15	13 Cr 80	47.00	BEAR	X
36	38.86	1390.98	5828.49	5867.35	13 Cr 80	47.00	BEAR	
37	40.07	1431.05	5788.42	5828.49	13 Cr 80	47.00	BEAR	X
38	34.92	1465.97	5753.50	5788.42	13 Cr 80	47.00	BEAR	
39	39.95	1505.92	5713.55	5753.50	13 Cr 80	47.00	BEAR	X
40	40.04	1545.96	5673.51	5713.55	13 Cr 80	47.00	BEAR	
41	40.15	1586.11	5633.36	5673.51	13 Cr 80	47.00	BEAR	X
42	39.62	1625.73	5593.74	5633.36	13 Cr 80	47.00	BEAR	
43	39.93	1665.66	5553.81	5593.74	13 Cr 80	47.00	BEAR	X
44	40.08	1705.74	5513.73	5553.81	13 Cr 80	47.00	BEAR	
45	38.45	1744.19	5475.28	5513.73	13 Cr 80	47.00	BEAR	X
46	39.88	1784.07	5435.40	5475.28	13 Cr 80	47.00	BEAR	X
47	39.86	1823.93	5395.54	5435.40	13 Cr 80	47.00	BEAR	X
48	40.05	1863.98	5355.49	5395.54	13 Cr 80	47.00	BEAR	X
49	40.14	1904.12	5315.35	5355.49	13 Cr 80	47.00	BEAR	X
50	40.00	1944.12	5275.35	5315.35	13 Cr 80	47.00	BEAR	
XO	1.50	1945.62	5273.85	5275.35	N80	40.00	LTC	X
51	44.26	1989.88	5229.59	5273.85	N80	40.00	LTC	
52	47.35	2037.23	5182.24	5229.59	N80	40.00	LTC	X
53	46.90	2084.13	5135.34	5182.24	N80	40.00	LTC	
54	46.95	2131.08	5088.39	5135.34	N80	40.00	LTC	X
55	47.55	2178.63	5040.84	5088.39	N80	40.00	LTC	
56	46.82	2225.45	4994.02	5040.84	N80	40.00	LTC	X
57	45.12	2270.57	4948.90	4994.02	N80	40.00	LTC	
58	43.47	2314.04	4905.43	4948.90	N80	40.00	LTC	
59	45.94	2359.98	4859.49	4905.43	N80	40.00	LTC	X
60	46.56	2406.54	4812.93	4859.49	N80	40.00	LTC	

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
61	**47.56**	2454.10	4765.37	4812.93	N80	40.00	LTC	
62	**46.29**	2500.39	4719.08	4765.37	N80	40.00	LTC	**X**
63	**46.22**	2546.61	4672.86	4719.08	N80	40.00	LTC	
64	**45.52**	2592.13	4627.34	4672.86	N80	40.00	LTC	
65	**46.50**	2638.63	4580.84	4627.34	N80	40.00	LTC	**X**
66	**47.55**	2686.18	4533.29	4580.84	N80	40.00	LTC	
67	**45.12**	2731.30	4488.17	4533.29	N80	40.00	LTC	
68	**46.01**	2777.31	4442.16	4488.17	N80	40.00	LTC	**X**
69	**46.06**	2823.37	4396.10	4442.16	N80	40.00	LTC	
70	**47.35**	2870.72	4348.75	4396.10	N80	40.00	LTC	
71	**47.36**	2918.08	4301.39	4348.75	N80	40.00	LTC	
72	**46.30**	2964.38	4255.09	4301.39	N80	40.00	LTC	
73	**47.06**	3011.44	4208.03	4255.09	N80	40.00	LTC	
74	**47.10**	3058.54	4160.93	4208.03	N80	40.00	LTC	
75	**46.50**	3105.04	4114.43	4160.93	N80	40.00	LTC	
76	**46.43**	3151.47	4068.00	4114.43	N80	40.00	LTC	**X**
77	**45.77**	3197.24	4022.23	4068.00	N80	40.00	LTC	
78	**47.55**	3244.79	3974.68	4022.23	N80	40.00	LTC	
79	**46.05**	3290.84	3928.63	3974.68	N80	40.00	LTC	
80	**43.08**	3333.92	3885.55	3928.63	N80	40.00	LTC	
81	**46.90**	3380.82	3838.65	3885.55	N80	40.00	LTC	
82	**47.24**	3428.06	3791.41	3838.65	N80	40.00	LTC	
83	**45.10**	3473.16	3746.31	3791.41	N80	40.00	LTC	
84	**47.54**	3520.70	3698.77	3746.31	N80	40.00	LTC	
85	**47.05**	3567.75	3651.72	3698.77	N80	40.00	LTC	
86	**46.93**	3614.68	3604.79	3651.72	N80	40.00	LTC	
87	**47.55**	3662.23	3557.24	3604.79	N80	40.00	LTC	**X**
88	**46.65**	3708.88	3510.59	3557.24	N80	40.00	LTC	
89	**47.34**	3756.22	3463.25	3510.59	N80	40.00	LTC	
90	**47.43**	3803.65	3415.82	3463.25	N80	40.00	LTC	

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
91	**47.46**	3851.11	3368.36	3415.82	N80	40.00	LTC	
92	**46.55**	3897.66	3321.81	3368.36	N80	40.00	LTC	
93	**47.26**	3944.92	3274.55	3321.81	N80	40.00	LTC	
94	**47.45**	3992.37	3227.10	3274.55	N80	40.00	LTC	
95	**47.24**	4039.61	3179.86	3227.10	N80	40.00	LTC	
96	**46.35**	4085.96	3133.51	3179.86	N80	40.00	LTC	
97	**47.55**	4133.51	3085.96	3133.51	N80	40.00	LTC	**X**
98	**47.33**	4180.84	3038.63	3085.96	N80	40.00	LTC	
99	**47.36**	4228.20	2991.27	3038.63	N80	40.00	LTC	
100	**46.29**	4274.49	2944.98	2991.27	N80	40.00	LTC	
101	**47.24**	4321.73	2897.74	2944.98	N80	40.00	LTC	
102	**47.38**	4369.11	2850.36	2897.74	N80	40.00	LTC	
103	**45.35**	4414.46	2805.01	2850.36	N80	40.00	LTC	
104	**47.35**	4461.81	2757.66	2805.01	N80	40.00	LTC	
105	**46.63**	4508.44	2711.03	2757.66	N80	40.00	LTC	
106	**47.53**	4555.97	2663.50	2711.03	N80	40.00	LTC	
107	**46.70**	4602.67	2616.80	2663.50	N80	40.00	LTC	
108	**47.25**	4649.92	2569.55	2616.80	N80	40.00	LTC	**X**
109	**47.53**	4697.45	2522.02	2569.55	N80	40.00	LTC	
110	**47.25**	4744.70	2474.77	2522.02	N80	40.00	LTC	
111	**46.13**	4790.83	2428.64	2474.77	N80	40.00	LTC	
112	**45.49**	4836.32	2383.15	2428.64	N80	40.00	LTC	
113	**47.26**	4883.58	2335.89	2383.15	N80	40.00	LTC	
114	**46.63**	4930.21	2289.26	2335.89	N80	40.00	LTC	
115	**45.76**	4975.97	2243.50	2289.26	N80	40.00	LTC	
116	**47.54**	5023.51	2195.96	2243.50	N80	40.00	LTC	
117	**47.32**	5070.83	2148.64	2195.96	N80	40.00	LTC	
118	**45.78**	5116.61	2102.86	2148.64	N80	40.00	LTC	
119	**47.34**	5163.95	2055.52	2102.86	N80	40.00	LTC	**X**
120	**45.89**	5209.84	2009.63	2055.52	N80	40.00	LTC	

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
121	**45.72**	5255.56	1963.91	2009.63	N80	40.00	LTC	
122	**46.23**	5301.79	1917.68	1963.91	N80	40.00	LTC	
123	**46.55**	5348.34	1871.13	1917.68	N80	40.00	LTC	
124	**47.04**	5395.38	1824.09	1871.13	N80	40.00	LTC	
125	**46.95**	5442.33	1777.14	1824.09	N80	40.00	LTC	
126	**46.22**	5488.55	1730.92	1777.14	N80	40.00	LTC	
127	**45.86**	5534.41	1685.06	1730.92	N80	40.00	LTC	
128	**46.96**	5581.37	1638.10	1685.06	N80	40.00	LTC	
129	**46.58**	5627.95	1591.52	1638.10	N80	40.00	LTC	**X**
130	**47.54**	5675.49	1543.98	1591.52	N80	40.00	LTC	
131	**47.34**	5722.83	1496.64	1543.98	N80	40.00	LTC	
132	**46.12**	5768.95	1450.52	1496.64	N80	40.00	LTC	
133	**47.35**	5816.30	1403.17	1450.52	N80	40.00	LTC	
134	**46.37**	5862.67	1356.80	1403.17	N80	40.00	LTC	
135	**45.06**	5907.73	1311.74	1356.80	N80	40.00	LTC	
136	**47.26**	5954.99	1264.48	1311.74	N80	40.00	LTC	
137	**47.28**	6002.27	1217.20	1264.48	N80	40.00	LTC	
138	**47.55**	6049.82	1169.65	1217.20	N80	40.00	LTC	
139	**46.65**	6096.47	1123.00	1169.65	N80	40.00	LTC	
140	**45.34**	6141.81	1077.66	1123.00	N80	40.00	LTC	
141	**47.34**	6189.15	1030.32	1077.66	N80	40.00	LTC	**X**
142	**45.84**	6234.99	984.48	1030.32	N80	40.00	LTC	
143	**47.54**	6282.53	936.94	984.48	N80	40.00	LTC	
144	**46.86**	6329.39	890.08	936.94	N80	40.00	LTC	
145	**46.50**	6375.89	843.58	890.08	N80	40.00	LTC	
146	**44.99**	6420.88	798.59	843.58	N80	40.00	LTC	
147	**45.95**	6466.83	752.64	798.59	N80	40.00	LTC	
148	**47.55**	6514.38	705.09	752.64	N80	40.00	LTC	
149	**47.47**	6561.85	657.62	705.09	N80	40.00	LTC	
150	**47.03**	6608.88	610.59	657.62	N80	40.00	LTC	

ADM CCS WELL #1: Final Casing Tally

X = BOW SPRING CENTRALIZER @ CASING COUPLINGS

Jt #	Length	Total	Top	Bottom	Grade	Wt	Thread	Cent.
151	**47.25**	6656.13	563.34	610.59	N80	40.00	LTC	**X**
152	**47.37**	6703.50	515.97	563.34	N80	40.00	LTC	
153	**46.62**	6750.12	469.35	515.97	N80	40.00	LTC	
154	**47.54**	6797.66	421.81	469.35	N80	40.00	LTC	
155	**47.32**	6844.98	374.49	421.81	N80	40.00	LTC	
156	**47.33**	6892.31	327.16	374.49	N80	40.00	LTC	
157	**46.53**	6938.84	280.63	327.16	N80	40.00	LTC	
158	**43.42**	6982.26	237.21	280.63	N80	40.00	LTC	**X**
159	**47.54**	7029.80	189.67	237.21	N80	40.00	LTC	
160	**47.54**	7077.34	142.13	189.67	N80	40.00	LTC	
161	**47.53**	7124.87	94.60	142.13	N80	40.00	LTC	
162	**47.35**	7172.22	47.25	94.60	N80	40.00	LTC	
163	**47.25**	7219.47	0.00	47.25	N80	40.00	LTC	
~~164~~	~~47.12~~	~~7266.59~~	~~-47.12~~	~~0.00~~	~~N80~~	~~40.00~~	~~LTC~~	
~~165~~	~~47.55~~	~~7314.14~~	~~-94.67~~	~~-47.12~~	~~N80~~	~~40.00~~	~~LTC~~	
~~166~~	~~46.33~~	~~7360.47~~	~~-141.00~~	~~-94.67~~	~~N80~~	~~40.00~~	~~LTC~~	
~~167~~	~~45.47~~	~~7405.94~~	~~-186.47~~	~~-141.00~~	~~N80~~	~~40.00~~	~~LTC~~	
~~168~~	~~46.93~~	~~7452.87~~	~~-233.40~~	~~-186.47~~	~~N80~~	~~40.00~~	~~LTC~~	
~~169~~	~~47.38~~	~~7500.25~~	~~-280.78~~	~~-233.40~~	~~N80~~	~~40.00~~	~~LTC~~	
~~170~~	~~47.53~~	~~7547.78~~	~~-328.31~~	~~-280.78~~	~~N80~~	~~40.00~~	~~LTC~~	
~~171~~	~~47.34~~	~~7595.12~~	~~-375.65~~	~~-328.31~~	~~N80~~	~~40.00~~	~~LTC~~	
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Appendix XIII.A – Revised Form 4a

4 UIC Form 4a, Hydrogeologic Information

Last revised: 4/29/2010 (note: EM added page numbers to this section).

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT APPLICATION

FORM 4a - HYDROGEOLOGIC INFORMATION

USEPA I.D. NUMBER ILD984791459
IEPA I.D. NUMBER 1150155136
UIC Well Number CCS #1

I Elevation of Land Surface at Well Location

The surface elevation at the CCS#1 well is 674.22 feet above mean seal level (MSL). During well drilling, the reference elevation was the rig's kelly bushing, which had an elevation of 689.85 feet above MSL.

II Faults, known or suspected within the area of review

No regional faults that are known to cross the area of review. Analysis of the current seismic reflection data showed no observable faults. The CCS#1 did not penetrate any known faults. As discussed in the Feasibility Report, the original 2D seismic reflection data acquired before the well was drilled suggested that possible fractured intervals may be found in the Mt. Simon. A review of the original seismic reflection data suggests that these fractured zones may be artifacts of poor quality data. Noise from the nearby ADM industrial plant and the Caterpillar plant on the west side of the study area reduces the quality of the seismic data and limits our ability to draw firm conclusions from the seismic data

III Maps and cross sections as required by Section 730.114(a) or 730.134(a)

Maps and cross-sections perpendicular to each other at the ADM injection site were shown in Figures 20-22 of the Feasibility Report. The cross-sections included available log control, geologic units, and lithology from the surface to the lower confining bed below the injection zone. The closest Mt. Simon well to the Decatur area (17 miles southeast of CCS#1) is the Sanders #7. The Sanders #7 only drilled the uppermost 200 feet of the Mt. Simon and did not penetrate the deeper reservoir zone. Unfortunately, there were no deep wells that penetrated the Knox, Ironton-Galesville, Eau Clare (the primary seal), or Mt. Simon Sandstone within a 17 mile radius of the proposed injection site. All of the deeper horizons are projected from regional mapping.

The closest wells that penetrate the injection horizon are 51 miles (Weaber-Horn #1) and 37 miles (Hinton#7) from the CCS#1 well. The Weaber-Horn #1 well had an average Mt. Simon reservoir porosity of about 12 percent, as calculated from wireline logs. The Weaber-Horn #1 well porosity data are similar to those found in the Hinton #7 at the Manlove Gas Storage Field in Champaign County. The Manlove Field is the deepest Mt. Simon gas storage field in the Illinois Basin and provides one of the best sets of reservoir data for characterization of the deep Mt. Simon. As expected the porosity values at the CCS#1 well are similar to those found at the Weaber-Horn #1 well and the Manlove Gas Storage Field. A north-south trending cross section (see A-A' in Figure CCS1_hinton_xsd_Mehnert.pdf, Figure 4a1) across the Hinton #7, CCS#1, Harrison #1, and Weaber-Horn #1 wells shows that the Mt. Simon at the CCS#1 well has the same lower porous and permeable interval.

IV Injection Zone

Regional

The thickest and most widespread saline water bearing reservoir (saline reservoir) in the Illinois Basin is the Cambrian-age Mt. Simon Sandstone (Figure 4a2). CO_2 injected through CCS#1 will be contained in the injection zone. The initial injection interval is a portion of the Mt. Simon where the injection well is perforated, between depths of 6,982 to 7,050 feet.

It is overlain by the Cambrian Eau Claire Formation, a regionally extensive very low-permeability shale, and underlain by the Precambrian granitic basement.

The regional properties and thickness of the Mt. Simon were discussed in the Feasibility Report.

A. Geologic name(s) of injection zone.

The injection zone is the Cambrian-age Mt. Simon Sandstone (Figure 4a2). CO_2 injected through CCS#1 will be contained in the injection zone and will flow into the Mt. Simon at the injection interval. The injection interval is a portion of the Mt. Simon where the injection well is perforated.

B. Depth interval of injection zone beneath land surface

At the ADM site, the Mt. Simon was found at a depth of 5,545 feet to 7,051 feet based on borehole logging data. An interval of high porosity and permeability was identified at the base of the Mt. Simon. This interval was selected as the initial injection interval and was perforated from 6,982 to 7,050 ft.

C. Characteristics of injection zone.

The injection zone is a porous and permeable sandstone that, in some intervals, is an arkose. Grain size varies from very-fine grained to coarse grained. The sandstones are primarily composed of quartz, but some sandstone intervals can contain more than 15 percent feldspar. Diagenetic clay minerals are not common.

2. Injection zone thickness available to accept waste.

While CO_2 may be stored in the entire thickness of the Mt. Simon, CO_2 will be initially injected at the perforated or injection interval at the base of the Mt. Simon. CCS#1 is perforated at a depth of 6,982 to 7,050 feet.

3. Fracture pressure at top of injection interval

A step-rate test was conducted on September 26, 2009 into the initial 25 foot perforated interval from 7,025 to 7,050 feet at the base of the Mt. Simon (Earlougher, 1977). The primary purpose of the test was to estimate the fracture pressure of the injection interval. A bottom-hole pressure gauge with surface readout was used. The pressure gauge was located at 6,891 feet inside the tubing, 134 feet above the upper-most perforation.

Water with clay stabilizing potassium chloride was injected in 2.0 barrel per minute (bpm) increments starting at 2.0 bpm (84 gallons per min, gpm) to 8.0 bpm (336 gpm). Each rate was

maintained for approximately 45 minutes. The pressure near the end of each injection period was plotted against the injection rate in Figure 4a3 to determine the fracture pressure.

The first line with the greater slope at lower rates and pressure is the perforated interval's response to water injection prior to fracturing. The second line with the lower slope at higher rates and pressures is after the fracture developed. The intersection of the two straight lines is 4,966 psig. To find the fracture pressure at the top of the perforations, the hydrostatic pressure of the water in the wellbore between 6,891 (location of pressure gauge) and 7,025 feet was added to the 4,966 psig. The fracture pressure at 7,025 feet is 5,024 psig.

Source:
Earlougher, Jr., R.C., 1977. *Advances in Well Test Analysis*, Monograph Series, Society of Petroleum Engineers of AIME, Dallas, **5**.

4. Effective porosity, include source

The compensated neutron and litho-density open-hole, porosity logs run were run in CCS#1. The neutron and density logs provide total porosity data. Effective porosity was determined by lab testing using the helium porosimeter method on a limited number of core plug samples. See Section X for additional discussion about the helium porosimeter method.

A comparison was made between the neutron-density crossplot porosity (average neutron and density porosity) and core porosity (Figure 4a4). These porosity sources compared well. Consequently, the neutron-density crossplot porosity was used to estimate effective porosity.

Based on porosity trends, there are 7 major sub-intervals present in the Mt. Simon. Table 4a1 lists the intervals identified and the average effective porosity of each. Based on the neutron-density crossplot porosity, the 68-foot, injection interval (6,982-7,050 feet) has an average effective porosity of 21.0%.

Table 4a1: Average effective porosity based on the neutron-density crossplot porosity. The seven sub-intervals were selected based on major changes in the trend of porosity from the neutron-density logs.

Sub-Interval (feet)	Effective Porosity (%)
5,545-5,900	10.8
5,900-6,150	8.72
6,150-6,430	10.1
6,430-6,650	15.2
6,650-6,820	21.8
6,820-7,050	18.7
7,050-7,165	9.84

5. Intrinsic permeability, include source

Intrinsic permeability was directly available from core analyses and well testing. However, to estimate permeability over a larger interval where core is not available, a relationship between core permeability and log porosity is required.

Core Analysis

A core porosity-permeability transform was developed (Figure 4a5) based on grain size. A neutron-density crossplot porosity was used with this transform to estimate permeability with depth. Average permeability for sub-intervals of the Mt. Simon for CCS#1 is in Table 4a2. Based on the neutron-density crossplot porosity and the core porosity-permeability transform, the 68-foot, injection (perforated) interval (6,982-7,050 feet) has an average intrinsic permeability of 194 md.

Well Testing

Three pressure falloff (PFO) tests of varying duration were conducted in September and October 2009 as part of the initial completion of CCS#1. A pressure falloff test involves two segments. During the first test segment, the reservoir is stressed by injecting fluid, which changes the reservoir pressure. During the second test segment, the reservoir pressure is monitored as it returns to its pre-test pressure. An analogous test in the groundwater industry is a recovery test where water is pumped instead of injected during the first test segment.

The initial perforations in the injection interval were 7,025 to 7,050 feet. Water treated with a clay-stabilizing potassium chloride substitute was injected at 1.5 to 2.0 barrels per minute (bpm) (63 to 84 gallons per minute) for nearly two hours. A 19.5 hour PFO followed this injection period.

After this test, these perforations were acidized and a step-rate test was conducted. For the second step-rate test, treated water was injected at 3.1 bpm (130 gpm) for five hours, while pressure was monitored for approximately 45 hours.

The third PFO test was conducted after the well was perforated and stimulated. An additional 30 feet of perforations were added at 6,982 to 7,012 feet. The perforated zone received a second acid treatment. Additional information regarding perforations and acid treatment are described in Completion Report Form 4h, Section X.E. For the third PFO test, the treated water was injected at an increasing rate of 3.1 to 4.2 bpm (130 to 176 gpm) over 6.5 hours and then at 4.2 bpm (176 gpm) for an additional 6.5 hours. During this third PFO test, pressure was monitored for 105 hours.

Pressure Transient Analyses

PIE pressure transient software (Well-Test Solutions, Ltd., http://welltestsolutions.com/index.html) was used to analyze the pressure data for reservoir flow properties. Conventional semilog, log-log and nonlinear regression analyses were used to analyze the data.

During the first PFO, because only 25 feet of perforations were open in a very large vertical formation (gross thickness 1,506 feet), a partial penetration or partial completion effect was expected. The derivative (log-log plot) of the falloff test is used to qualitatively identify reservoir features including the partial penetration effect (Figure 4a6) and to determine permeability. Two radial, 2-dimensional responses (horizontal derivative) were measured during this test between 0.1 and 1 hrs (PPNSTB) and 20 to 100 hrs (STABIL). The first period corresponds to radial flow across the 25 ft perforated interval; the second period corresponds to the pressure response across a

larger thickness that would be between two much lower permeability sub-units. The transition between the two radial responses (SPHERE) is a spherical flow (3-dimensional flow) period that is influenced by vertical permeability (or kv/kh, the ratio of vertical to horizontal permeability).

To observe the effect of the acid treatment and the second set of perforations to the overall injection interval, the derivatives of the three pressure falloff tests were overlain (Figure 4a7). The data between 0.1 and 1.0 hrs match relatively well and the data between 1.0 and 100 hrs match very well. Similar trends of the first radial period, transition and final radial period indicates that the second set of perforations did not change the permeability estimated from the pressure transient tests or contribute to the perforated interval. As such the subsequent pressure transient analyses used a single layer, partial penetration model with 25 ft of perforations open at the base of the layer.

Simulation of the pressure transient data using analytical solutions (Figure 4a8), gave a permeability of 185 md over 75 ft of vertical thickness. The transition period gave a vertical permeability over the 75 ft as 2.45 md (kv/kh = 0.01326).

The Mt. Simon initial pressure at CCS#1 at 7,025 ft is about 3,200 psig.

The average Mt. Simon permeability for all of the cored Mt. Simon Sandstone was 29.7 md for the Manlove Field. These permeability values includes both reservoir and non-reservoir facies. The average permeability of the porous and permeable intervals of the Manlove Field is expected to be several hundred millidarcy. The permeability in the lower interval (injection interval of interest) had a sidewall core plug in the Hinton #7 well with permeability in excess of 1,000 md. Thus, the estimated mean permeability for CCS #1 is similar to other estimates of Mt. Simon in the Illinois Basin.

For the injection interval, the permeability estimates from three methods are very close. Based on the neutron-density crossplot porosity and the core porosity-permeability transform, the 68-foot, injection (perforated) interval (6,982 to 7,050 feet) has an average intrinsic permeability of 194 md Using the PIE pressure transient software for the third PFO, permeability was estimated to be 185 md over 75 ft of vertical thickness. Permeability for this same 75 feet of rock was calculated using core and well log analyses. The permeability from this analysis was estimated to be 182 md.

Table 4a2: Average intrinsic permeability based on a transform of core permeability and core porosity related to the neutron-density crossplot porosity for the sub-intervals shown. The seven sub-intervals were selected based on major changes in the trend of porosity from the neutron-density logs.

Sub-Interval (feet)	Intrinsic Permeability (md)
5,545-5,900	19.4
5,900-6,150	10.2
6,150-6,430	8.44
6,430-6,650	8.21
6,650-6,820	8.64
6,820-7,050	107
7,050-7,165	4.37

6. Hydraulic conductivity or permeability, include source

Intrinsic permeability (k) and hydraulic conductivity (K) are related according to the following equation (Freeze and Cherry, 1979):

$$K = k \rho g / \mu$$

where ρ= fluid density

g= gravitational acceleration

μ= dynamic viscosity

Intrinsic permeability (k) is a property of the rock, while hydraulic conductivity (K) includes properties of the rock and fluid. Intrinsic permeability is also known as permeability and is discussed in Section IV.C.5. Formation water density and dynamic viscosity are discussed in Sections IV.D.3 and IV.D.4, respectively. For the range of viscosity and density discussed, the hydraulic conductivity will vary.

The injection interval (6,982 to 7,050 feet) had an average intrinsic permeability of 194 md, this converts to a hydraulic conductivity of 3.9×10^{-6} m/sec, using the fluid properties at this depth.

Source:

Freeze, R. A. and J. A. Cherry, 1979. *Groundwater*. Englewood Cliffs, N.J., Prentice-Hall, Inc.

7. Storage coefficient, include source

The storage coefficient or storativity, S, ranges from 5×10^{-5} to 5×10^{-3} for confined aquifers (Freeze and Cherry, 1979). S is commonly determined by well testing; however, S is a function of fluid compressibility (c_f) and rock compressibility (c_r) and can be estimated from the following equation:

$$S = \rho g h (c_r + \phi c_f)$$

where ϕ= porosity

h= formation thickness

ρ= fluid density

g= gravitational acceleration

Rock compressibility can be expressed as the inverse of the bulk modulus (K_b) and in terms of the Young's modulus (E) and Poisson's ratio (ν) (Huang and Rudnicki, 2006):

$$c_r = 1/K_b = 3(1 - 2\nu)/E$$

Fluid density is discussed in Section IV.D.3. Gravitational acceleration equals 9.81 m/sec^2. For this calculation, the Mt. Simon is assumed to be 1,506 feet thick and have 10% porosity (Φ). Young's modulus (E) and Poisson's ratio (ν) were determined by Weatherford Laboratory (see Section X for more

details) for Mt. Simon samples collected at depths of 6,761 and 6,770 feet. These values were used to compute c_r using the equation shown above. These compressibility values are consistent with bulk compressibility values for sandstone reservoirs, which ranged from $6.5x10^{-5}$ to $2.7x10^{-4}$ MPa^{-1} at 7,000 psi (48.3 MPa) confining pressure (Zimmerman, 1991). Fluid compressibility (c_f) are known to vary with pressure and temperature changes (Huang and Rudnicki, 2006). Using two samples collected from CCS#1 (MDT-1 & MDT-4), fluid compressibility and storativity values were estimated (Table 4a4).

Based on the range of values described here, storativity was estimated to range from $8.1x10^{-5}$ to $9.3x10^{-4}$ (Table 4a3). These values area consistent with values published by Freeze and Cherry (1979).

Table 4a3. Estimates of rock (c_r) and fluid (c_f) compressibility and storativity (S)

depth (ft)	pressure (psi)	pressure (MPa)	T (°C)	ρ (g/L)	c_r (1/Mpa)	c_f (1/Mpa)	Φ (-)	h (m)	S (-)
5772	2582.9	1.78E+01	48.8	1089.7	2.02E-04	2.04E-04	0.10	459.0	8.91E-04
7045	3206.1	2.21E+01	52.1	1123.5	2.02E-04	1.83E-04	0.10	459.0	9.29E-04
5772	2582.9	1.78E+01	48.8	1089.7	3.68E-05	2.04E-04	0.10	459.0	8.07E-05
7045	3206.1	2.21E+01	52.1	1123.5	3.68E-05	1.83E-04	0.10	459.0	9.35E-05

Source:

Huang, T. and J.W. Rudnicki, 2006. A mathematical model for seepage of deeply buried groundwater under higher pressure and temperature. *Journal of Hydrology* 327(1-2): 42-54.

Freeze, R.A. and J.A. Cherry, 1979. *Groundwater*. Englewood Cliffs, N.J., Prentice-Hall, Inc.

Zimmerman, R.W., 1991. Compressibility of Sandstones. Amsterdam, Elsevier.

8. Seepage velocity (ft/yr) and flow direction of formation water, include source.

Groundwater flow in the deeper part of the Illinois Basin was discussed in the Feasibility Report and included model projections of groundwater flow in the Mt. Simon by Gupta and Bair (1997). The location of the CCS#1 was plotted on the potentiometric surface map developed by Gupta and Bair (1997). The potentiometric surface was estimated to be 76 m (250 ft) in Section IV.D.6, which is slightly higher than the projected estimate of 25 to 50 m from Figure 4a9 (gupta&bair_1997_revisedkorose.jpg).

References

Gupta, N., and E.S. Bair, 1997. Variable-density flow in the midcontinent basins and arches region of the United States. Water Resources Research, 33(8): 1785-1802.

D. Characteristics of injection zone formation water

Fluid samples were collected from the CCS#1 open borehole, after drilling and wireline geophysical testing were completed. Schlumberger's Modular Formation Dynamics Tester (MDT) and

Quiksilver wireline equipment were run on April 28 and 29, 2009. The tool was used to collect formation pressure, formation temperature, and high-quality reservoir fluid samples at five depths (Table 4a4). Prior to collecting a reservoir sample, the MDT measures the fluid resistivity to help discriminate between formation fluids and drilling mud filtrate. Fluid sample volume varied from 450 mL to 900 mL. These samples were analyzed by the Illinois State Water Survey.

Table 4a4. Data for fluid samples collected from the Mt. Simon sandstone using the MDT sampler in April 2009

Sample ID	Sample Depth (feet)	Formation Pressure (psi)	Formation Temperature (°F)	TDS (mg/L)	Density (g/L)
MDT-4	5,772	2,582.9	119.8	164,500	1,089.7
MDT-3	6,764	3,077.5	125.1	185,600	1,120.7
MDT-14	6,764	3,077.5	125.1	179,800	NA
MDT-5	6,840	3,105.9	125.0	182,300	1,124.1
MDT-2	6,912	3,141.8	125.8	211,700	1,136.5
MDT-9	6,840	3,105.9	125.0	219,800	NA
MDT-1	7,045	3,206.1	125.7	228,100	1,123.5
MDT-8	7,045	3,206.1	125.7	201,500	NA

NA= not analyzed

1. Temperature, include source

Based on the MDT sampler (Table 4a4), formation temperatures ranged from 119.8°F (48.8 °C) at a depth of 5,772 feet to 125.8°F (52.1°C) at depth of 6,912 feet.

2. Pressure, include source

Assuming a pressure gradient of 0.433 psi/feet, the pressure at the top of the Mt. Simon was estimated to be between 2,165 to 2,598 psi for estimated depths of 5,000 to 6,000 feet. The formation pressure measured with the MDT tool also varied with depth and had a minimum pressure of 2,583 psi recorded at 5,772 feet and a maximum pressure of 3,206 psi recorded at 7,045 feet.

3. Density, include source

Based on five samples collected with the MDT sampler, the fluid density ranged from 1,090 to 1,137 g/L, with an average of 1,119 g/L.

4. Viscosity, include source

Dynamic viscosity is a function of brine temperature, salinity, and formation pressure. Viscosity increases with higher salinity and with lower temperatures. Viscosity slightly increases with higher formation pressure (Kestin et al., 1981). Kestin et al. (1981) studied the viscosity of NaCl brines. Because the Mt. Simon brine is predominantly an NaCl brine, using the method of Kestin et al. (1981) is appropriate.

Using the data in Table 4a4, the brine viscosity for the Mt. Simon brine is estimated to range from 5.4×10^{-4} to 5.7×10^{-4} Pa sec with an average of 5.5×10^{-4} Pa sec.

Source:

> Kestin, J., E. Khalifa and R.J. Correia, 1981. Tables of dynamic and kinematic viscosity of aqueous NaCl solutions in the temperature range 20-150°C and the pressure range 0.1-35MPa., *Journal of Physical and Chemical Reference Data,* 10(1): 71-87.

5. Total Dissolved Solids, include source

Salinity, expressed as TDS, also affects the injection capacity because it reduces the CO_2 solubility in water. Figure 17 in the Feasibility report showed the broad distribution of TDS in the Mt. Simon which should exceed 60,000 mg/L over much of the Illinois Basin and 180,000 mg/L in the deeper portions of the basin (Leetaru et al., 2005).

At the ADM site, the Mt. Simon brine was expected to be 100,000 to 140,000 mg/L TDS. Samples collected from the injection well varied with depth (Table 4a4), with TDS of 164,500 mg/L TDS at 5,772 feet and 228,100 mg/L TDS at 7,045 feet. The average TDS for the eight samples is 196,700 mg/L.

Source:

Leetaru, H., E. Mehnert, S. Rittenhouse, J. Drahovzal, S. Fisher, and J. McBride, 2005. Saline reservoirs as a sequestration target, in An Assessment of Geological Carbon Sequestration Options in the Illinois Basin, Final Report for U.S. DOE Contract: DE-FC26-03NT41994, Principal Investigator: Robert Finley, p 253-324.

6. Potentiometric surface, include source

Little information is available about the potentiometric surface in the Mt. Simon sandstone in Macon County because very few wells penetrate the Mt. Simon in central Illinois. The best available information regarding the potentiometric surface is discussed in Section IV.C.8 of this form.

Using the formation pressure (p) and fluid density (ϱ) data in Table 4a4, the potentiometric head (h) was calculated using the relationship—$p= \varrho gh$, where g is the gravitational constant. The mean potentiometric head in the Mt. Simon has an elevation 249.5 feet above mean sea level. If the well were filled with freshwater (ϱ= 1,000 g/L), the potentiometric head would have an elevation of 996.1 feet.

E. Additional or alternative zones considered for injection

No other geologic zones are being considered for injection at the ADM site.

V. Upper Confining Zone

A. Geologic name(s) of confining zone

The primary confining zone (seal) is the Cambrian-age Eau Claire Formation (Figure 4a2). An isopach map based on regional well control suggests that the Eau Claire should be 300 to 500 feet thick at the

ADM site. Based on the data from CCS#1, the Eau Claire has a total thickness of 497.5 feet. The shale section of the Eau Claire has a thickness of 198.1 feet and is the lowermost section within the Eau Claire.

B. Depth interval of upper confining zone beneath land surface.

The Eau Claire Formation occurs at a depth of 5,047 feet to 5,545 feet below ground surface. The shale section of the Eau Claire occurs at a depth of 5,347 to 5,545 feet.

C. Characteristics of confining zone

1. Lithologic description

In the central part of the Illinois Basin, the Cambrian age Eau Claire Formation is a mixture of carbonates and fine-grained siliciclastics. At CCS#1, the upper section of the Eau Claire (5,047 to 5,347 feet) was dense limestone with thin stringers of siltstone. The lower section of the Eau Claire (5,347 to 5,545 feet) was a shale. As discussed in the Feasibility Report, the Eau Claire shale interval above the Mt. Simon is persistent in the Illinois Basin and is expected to provide a good seal for the injection zone.

From limited x-ray diffraction data, the mineraology of the shale is 60 percent clay minerals and 37 percent quartz and potassium feldspar. The shale is thinly laminated and dark gray to black in color.

2. Fracture pressure at depth, include source

A mini-frac test using Schlumberger's Modular Dynamics Testing tool was conducted across a 2.8-foot interval centered at a depth of 5,435 feet. Thus, this mini-frac test was conducted on the shale section of the Eau Claire formation. The test was designed for four, short-term injection/falloff test periods (15 to 60 minutes in duration). The fracture pressure from these four tests ranged from 5,078 to 5,324 psig, corresponding to a fracture gradient ranging from 0.93 to 0.98 psi/ft in the Eau Claire Shale.

3. Intrinsic permeability, include source

None of the sidewall rotary core plugs are described as shale. From the whole core, taken within the Eau Claire, no part of the shale was large enough for drilling a core plug and subsequent analyses. The sidewall rotary core plugs are taken horizontally, so permeability from these plugs is horizontal (not vertical) permeability which is less relevant for a confining layer.

The plugs are described as very fine grained sandstones, microcrystalline limestone and siltstone. Within the upper confining interval of 5,047 to 5,545 feet, 12 plugs were available for porosity and permeability testing. Because vertical flow is of most interest for the upper confining layer, the average vertical permeability over the confining layer was estimated. The average vertical permeability using the horizontal permeability from the 12 sidewall rotary core plugs is 0.000344 md.

The average vertical permeability over the upper confining layer is expected to be much lower than 0.000344 md because this average is based on horizontal permeability values and no shale permeability was included. Vertical permeability on plugs is generally lower than horizontal permeability and shale permeability is generally much lower than sandstone, limestone, and siltstone.

4. Hydraulic conductivity, include source

Intrinsic permeability (k) and hydraulic conductivity (K) are related according to the following equation (Freeze and Cherry, 1979):

$$K = k \rho g / \mu$$

where ρ = fluid density

g = gravitational acceleration

μ = dynamic viscosity

Intrinsic permeability (k) is a property of the rock, while hydraulic conductivity (K) includes properties of the rock and fluid. Intrinsic permeability is also known as permeability and is discussed in Section IV.C.5. Fluid density is discussed in Section IV.D.3, while dynamic viscosity is discussed in Section IV.D.4. No fluid samples were collected from the Eau Claire. For these calculations, the fluid properties of sample MDT-4 (Table 4a4) were used. This Mt. Simon brine sample was collected closest to the Eau Claire. Its measured properties include temperature of 119.8°F and density of 1,089.7 g/L. Its dynamic viscosity was estimated to be 758.0 microPa sec. For an intrinsic permeability values of 0.000344 md, the hydraulic conductivity equals 4.8×10^{-12} m/sec.

Sources:

Freeze, R. A. and J. A. Cherry, 1979. *Groundwater*. Englewood Cliffs, N.J., Prentice-Hall, Inc.

5. Alternative confining zones proposed, include explanation and depth interval(s)

Secondary seals provide additional backup containment of the CO_2 should an unlikely failure of the primary seal occur. Secondary seals listed here are units with low permeability that are regionally present and serve as cap rocks for oil, gas and gas storage fields throughout Illinois where they are present.

Two secondary seals were found at the ADM site. The Ordovician-age Maquoketa Shale (Figure 4a2) is laterally continuous across the ADM site and is 206 feet thick at the ADM site at a depth of 2,611 feet below ground. This shale is a regional seal for production from the Ordovician Galena (Trenton) Limestone. The Devonian-Mississippian-age New Albany Shale at a depth of 2,088 feet is about 126 feet thick at the ADM study area. Extensive well control from oil fields shows that this shale is a good seal for hydrocarbons; hence, it should also be a good secondary seal against the vertical migration of CO_2.

VI. Lower Confining Zone

Because the lower confining zone is the basement granite and no other sedimentary rocks are below the granite, no data were collected on the granite. The fracture pressure, porosity and permeability of the granite will not impact injection or fluid migration as the CO_2 injection interval will be above this confining zone and the CO_2 is expected to move upward away from the granite.

A. Geologic name(s) of confining zone

The lower confining zone is the Precambrian granite basement.

B. Depth interval of lower confining zone beneath land surface

The top of the Precambrian basement rock was found at a depth of 7,165 feet below ground surface.

C. Characteristics of confining zone

1. Lithologic description

The Precambrian-age rock in the Illinois Basin is composed of a medium- to coarse-grained granite or rhyolite and is between 1.1 to 1.4 billion years old (Bickford et al., 1986). At the CCS#1 well, we encountered the Precambrian granite/rhyolite at a measured depth of 7,165 feet.

Source:

Bickford, M.E., W.R. Van Schmus, and I. Zietz, 1986. Proterozoic history of the midcontinent region of North America: Geology, (14) 6, 492–496.

2. Fracture pressure at depth, include source

The Illinois State Geological Survey could not find any data on fracture pressure of granites in Illinois nor did we conduct any tests to determine the fracture pressure of the lower confining zone. The fracture pressure of the granite is not anticipated to have any effect on the injection or storage of CO_2 in the Mt. Simon.

3. Intrinsic permeability, include source

The top of the granite occurs at depth of 7,165 feet. A total of 65 feet of granite was drilled. At 7,200 feet, one core plug was collected; the permeability was 0.0091 mD.

4. Hydraulic conductivity, include source

Using the pressure and fluid properties obtained for MDT-1 (Table 4a4), hydraulic conductivity for the granite is estimated to be 1.8×10^{-10} m/sec.

5. Alternative confining zones proposed, include explanation and depth interval(s)

There are no alternative lower confining zones since no wells in Illinois have found anything else but the Precambrian granite basement below the Mt. Simon Sandstone.

VII. Overlying Sources of Groundwater at the Site

Overlying sources of groundwater which meet the definition of underground sources of drinking water (USDW) include three units from shallowest to deepest—Quaternary sand and gravel, Pennsylvanian

bedrock, and the St. Peter Sandstone. Field investigations to determine the lowermost USDW at this site were discussed in a letter from Dean Frommelt of ADM to Illinois EPA, dated September 29, 2009.

Summarizing the information in this letter, water sampling showed that the water in the St. Peter Sandstone had a total dissolved solids (TDS) concentration of 4,540 mg/L, which is below the USDW limit of 10,000 mg/L TDS. In addition, the water quality in the Pennsylvanian bedrock transitions from fresh water (TDS < 10,000 mg/L) to brine (TDS > 10,000 mg/L) with depth. Currently, groundwater in the Pennsylvanian bedrock below 275 feet is considered brine. Additional monitoring wells will be installed in 2010 to help establish the boundary between the fresh water and brine in the Pennsylvanian bedrock.

Source:

> Frommelt, D. 2009. Letter to Illinois Environmental Protection Agency, Subject: Lowermost underground source of drinking water (USDW), Archer Daniels Midland Compnay—UIC Permit UIC-012-ADM, dated September 29, 2009.

A. Characteristics of the aquifer immediately overlying the confining zone

1. Elevation at top of aquifer, include source

The first aquifer which contains salt water at the proposed location overlying the Eau Claire Formation (the primary seal for the Mt. Simon Sandstone) is the Ironton-Galesville Formation (Figure 4a2). Based on the geophysical logging in CCS#1, the Ironton-Galesville was found at depths of 4,928 to 5,047 feet (119 feet thick).

2. Potentiometric surface, include source

No potentiometric data were collected during drilling of CCS#1 for the Ironton-Galesville. Thus, this section can not be updated from the Feasibility Report.

3. Total Dissolved Solids, include source

No water quality data were collected during drilling of CCS#1 for the Ironton-Galesville. Thus, this section can not be updated from the Feasibility Report.

4. Lithology, include source

No lithologic data were collected during drilling of CCS#1 for the Ironton-Galesville. Thus, this section can not be updated from the Feasibility Report.

5. Aquifer thickness

Based on the geophysical logging in CCS#1, the Ironton-Galesville was found to be 119 feet thick.

6. Specific gravity, include source

No water quality data were collected during drilling of CCS#1 for the Ironton-Galesville. Thus, this section can not be updated from the Feasibility Report.

B. Underground Sources of Drinking Water (USDW)

1. Maps and cross sections required by 730.114(a)(4) or 730.134(a)(4)

See the Feasibility Report for current maps and cross-sections of USDW. However, significant new data regarding the lowermost USDW was presented in a letter from Dean Frommelt of ADM to Illinois EPA, dated September 29, 2009.

2. Lowest depth of USDW

Overlying sources of groundwater which meet the definition of underground sources of drinking water (USDW) include three units from shallowest to deepest—Quaternary sand and gravel, Pennsylvanian bedrock, and the St. Peter Sandstone. Field investigations to determine the lowermost USDW at this site were discussed in a letter from Dean Frommelt of ADM to Illinois EPA, dated September 29, 2009.

Summarizing the information in this letter, water sampling showed that the water in the St. Peter Sandstone had a total dissolved solids (TDS) concentration of 4,540 mg/L, which is below the USDW limit of 10,000 mg/L TDS. In addition, the water quality in the Pennsylvanian bedrock transitions from fresh water (TDS < 10,000 mg/L) to brine (TDS > 10,000 mg/L) with depth. Currently, groundwater in the Pennsylvanian bedrock below 275 feet is considered to be a brine. Additional monitoring wells will be installed in 2010 to help refine the boundary between the fresh water and brine in the Pennsylvanian bedrock.

3. Elevation of potentiometric surface of lowest USDW referenced to mean sea level

See the Feasibility Report for a discussion regarding the potentiometric surface of the lowermost USDW.

4. Distance to nearest water supply well

See the Feasibility Report for a discussion regarding data on the nearest water supply well.

5. Distance to nearest downgradient water supply well

See the Feasibility Report for a discussion regarding data on the nearest water supply well.

VIII. Minerals and Hydrocarbons

See the Feasibility Report for a description of Mineral and Hydrocarbon resources in the area.

Figure 4a1: A north-south trending cross section across the Hinton #7, CCS#1, Harrison #1, and Weaber-Horn #1 (see A-A' in Figure CCS1_hinton_xsd_Mehnert.pdf)

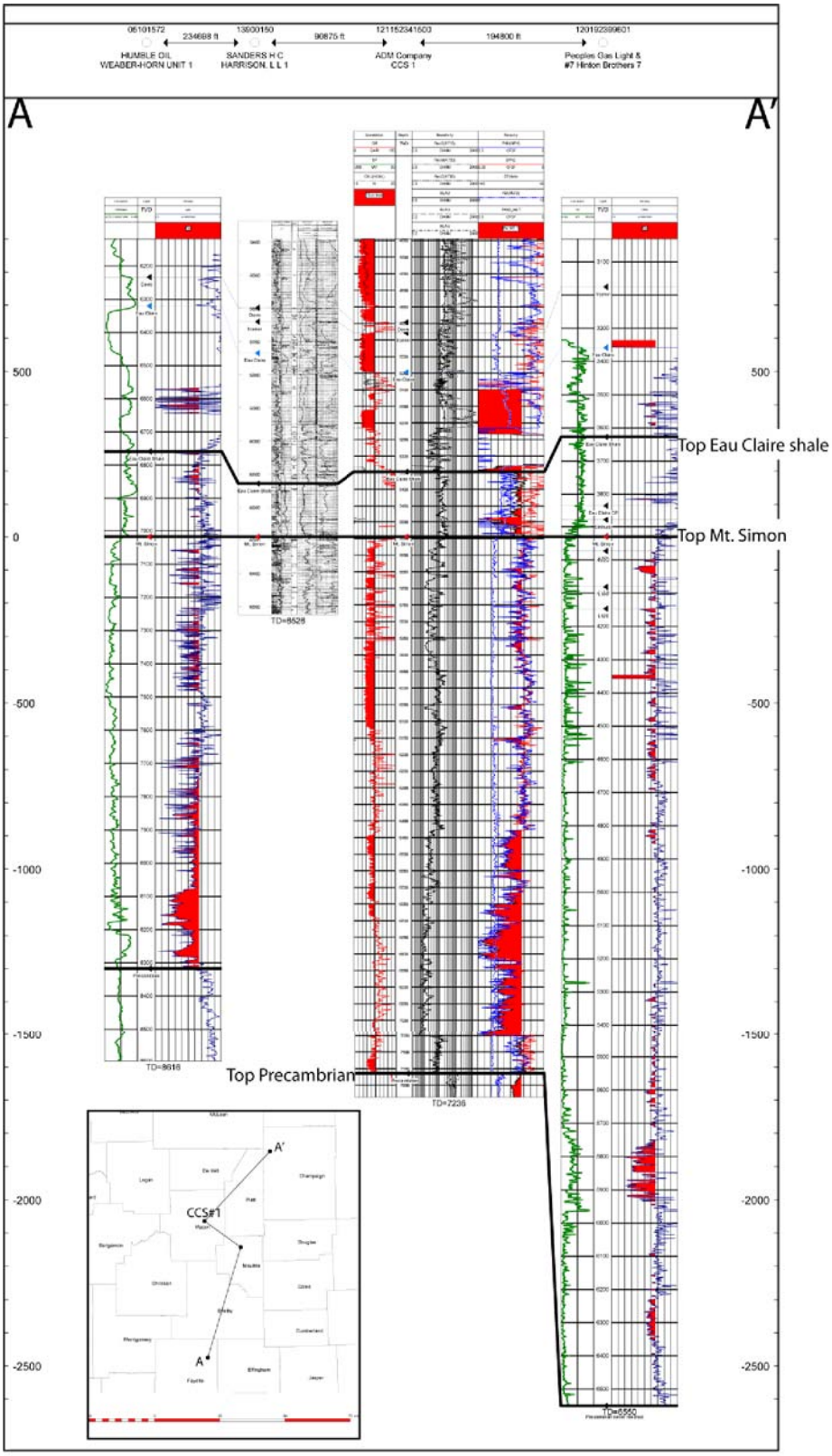


Figure 4a2 [use Figure 6 from Feas. Report]: Stratigraphic column of Ordovician through Precambrian rocks in northern Illinois (Kolata, 2005). Arrows point to the formations discussed in this UIC permit application. Dr., Darriwillian; Dol, dolomite; Fm, formation; Ls, limestone; MAYS., Maysvillian; Mbr, Member; Sh, shale; WH., Whiterockian; Mya, million years ago; Ss, sandstone; Silts, siltstone.

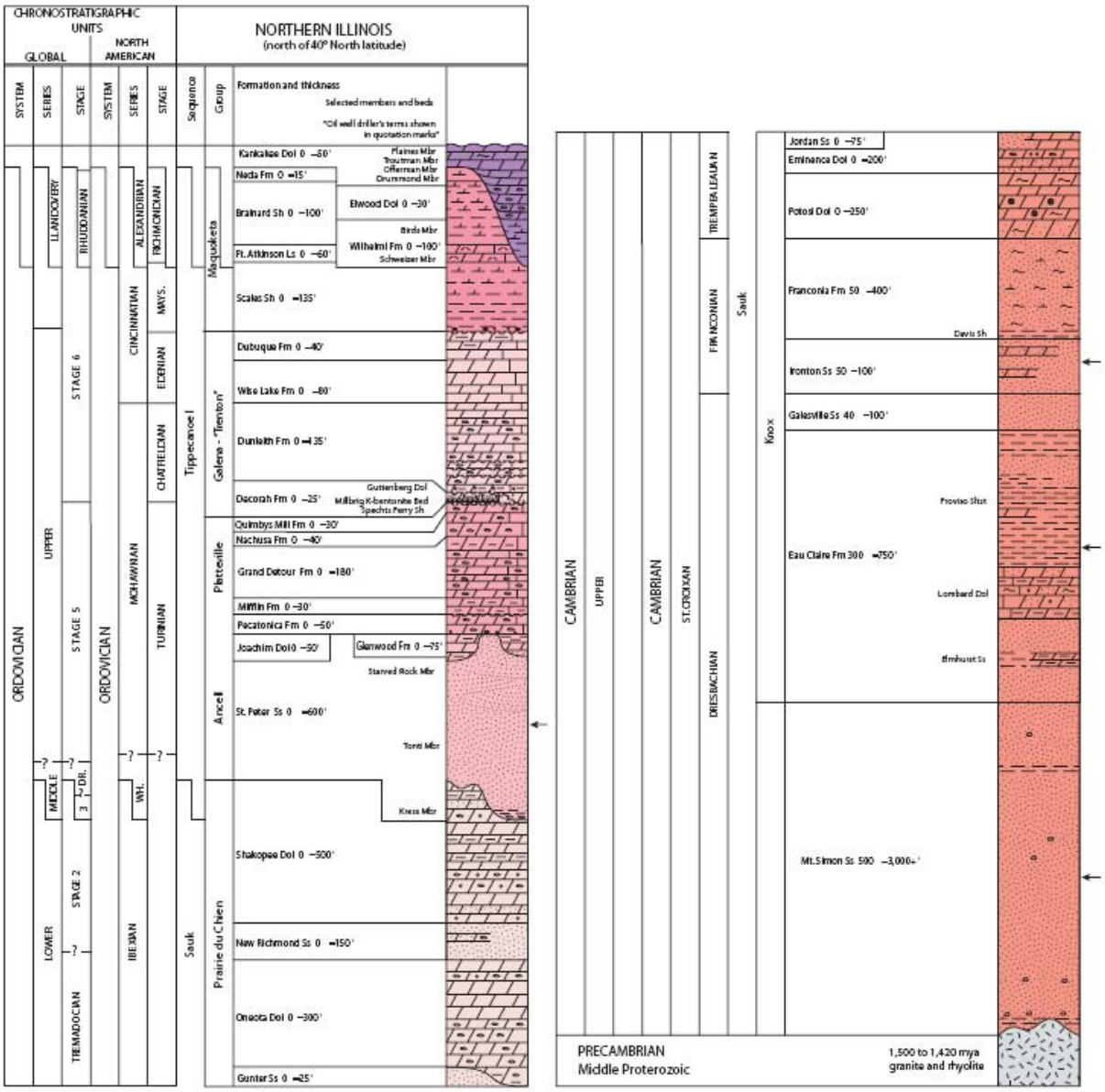


Figure 4a3: ADM CCS#1 step-rate test with fracture propagation pressure of 4966 psig estimated from the intersection of the two lines. The first line (2-6 bpm) represents radial flow of the Mt. Simon; the second line 7-8 bpm represents flow into the Mt. Simon after a fracture has propagated. The perforated interval was 7,025 to 7,050 feet during this step-rate test. (see Frailey_completionreport_0310.xls for original plot)

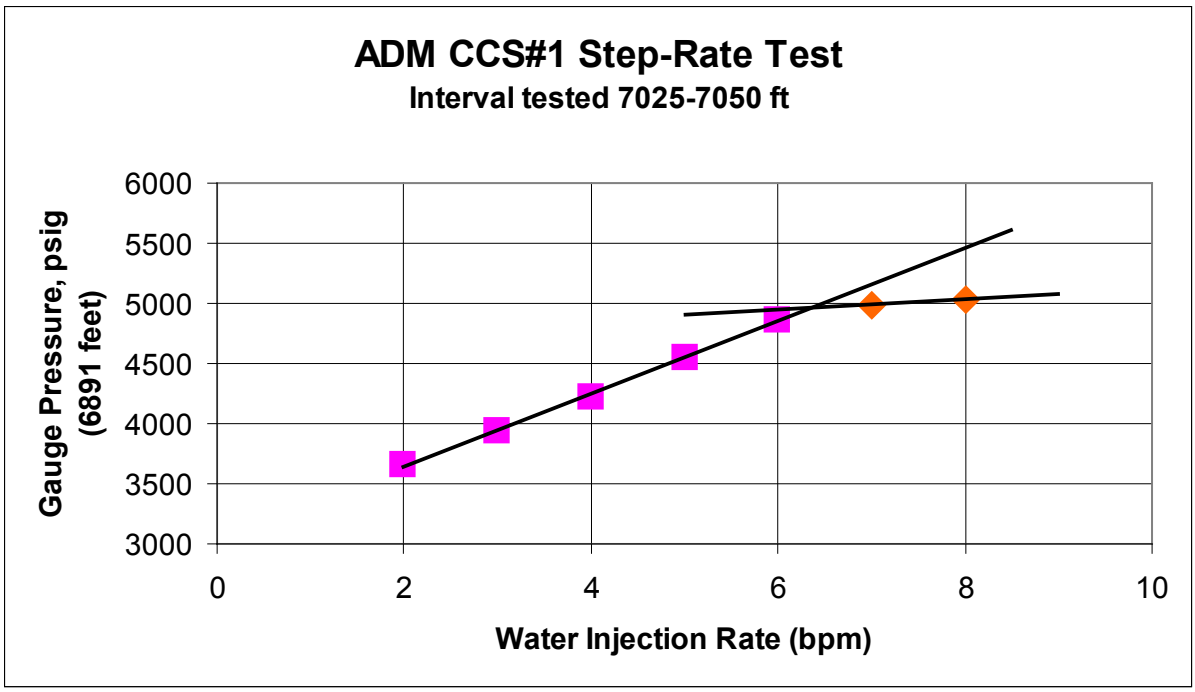


Figure 4a4: The bold line through the data is the unit slope, showing very good correlation between the two types of porosity data. For the porosity data from the rotary sidewall core plugs and the neutron-density crossplot porosity at the interval of the core plug, the porosity compares relatively well such that total and effective porosity are very similar. (see Frailey_completionreport_0310.xls for original plot)

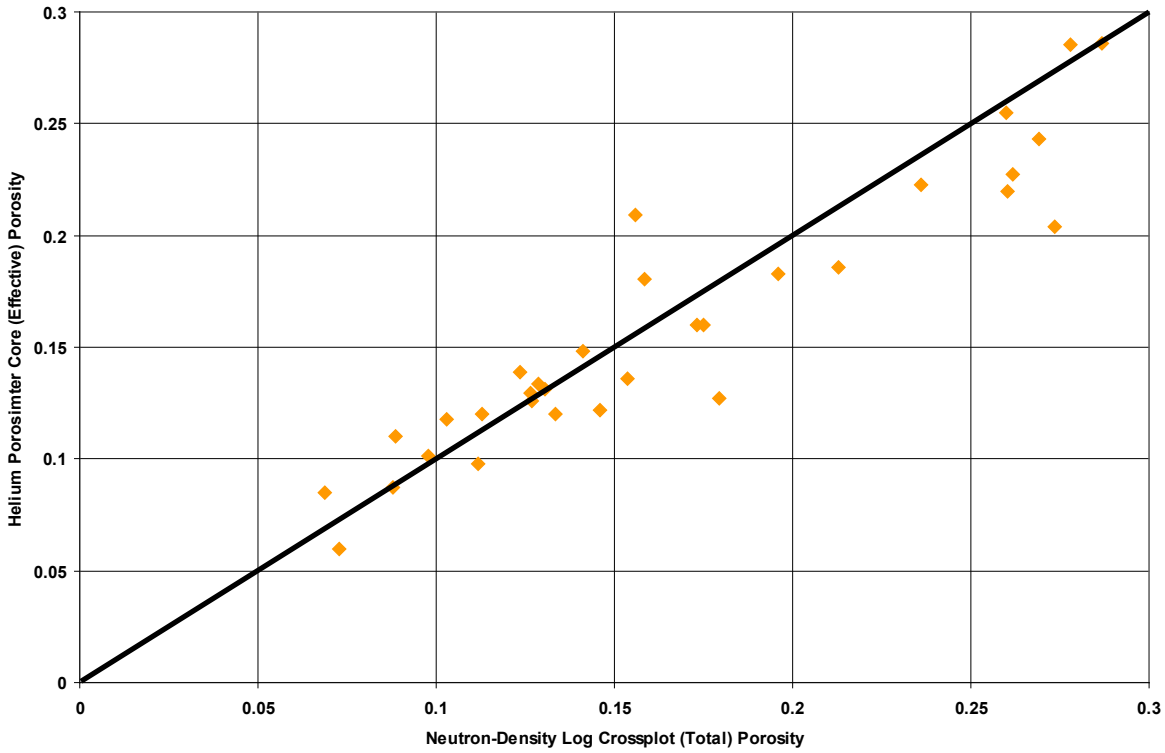


Figure 4a5. Crossplot of core permeability versus core porosity. Transforms were developed for three different grain sizes—fine grained, medium grained and coarse grained sandstone. (see frailey_completionreport_0310.xls for original plot)

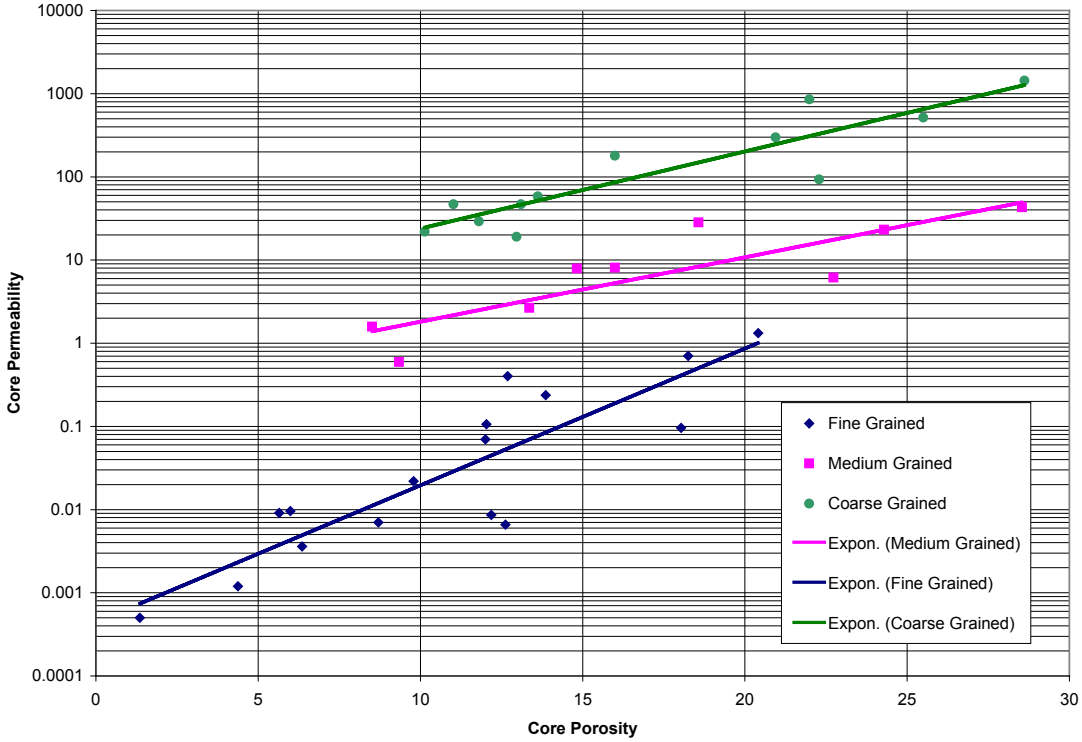


Figure 4a6: Qualitative derivative analyses of final pressure falloff test. Radial pressure response is indicated by a horizontal derivative trend. Two periods were measured during this test between 0.1 and 1 hours (PPNSTB) and 20 to 100 hours (STABIL). The first period corresponds to radial flow across the perforated interval; the second period corresponds to the larger thickness that would be between two much lower permeability sub-units e.g, the low perm granite wash at the base. The transition between the two radial responses (SPHERE) is a spherical flow period that is influenced by vertical permeability (or kv/kh). (The unit slope (UNIT SLP) indicating wellbore storage, identifies the end of wellbore storage influenced pressure data (ENDWBS) or pressure data that can be analyzed from reservoir properties.)

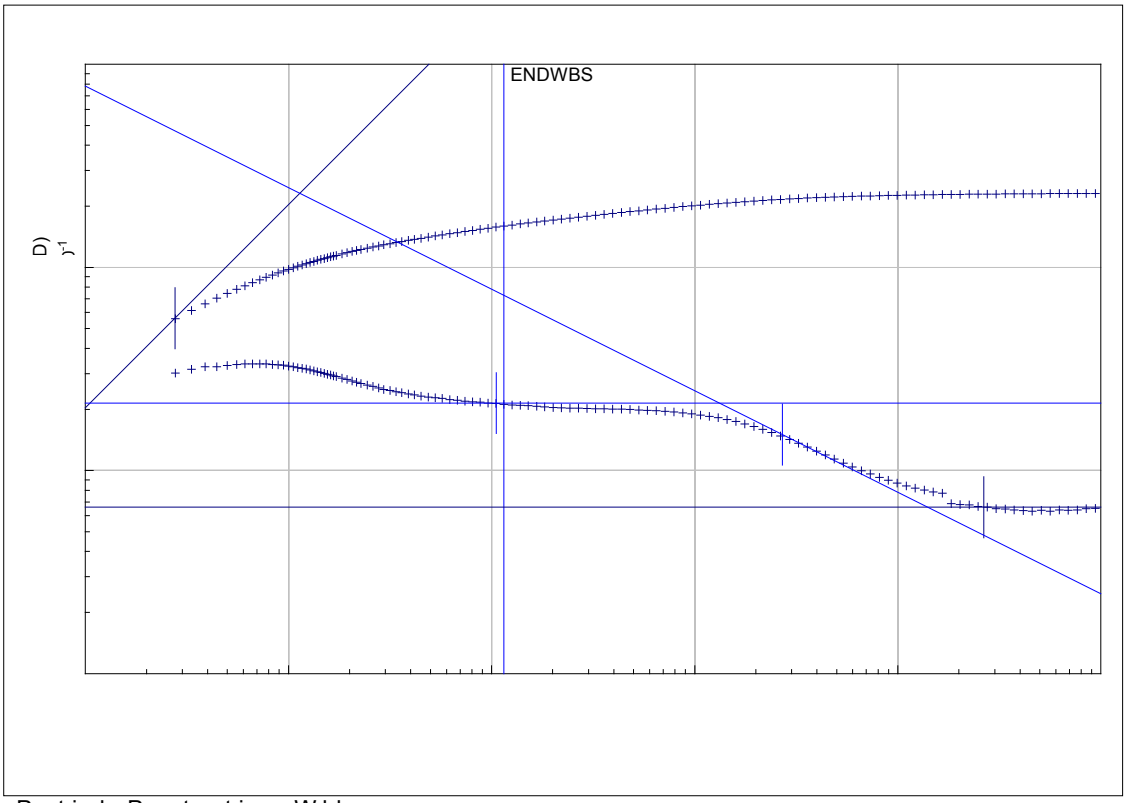


Figure 4a7: Overlay of pressure derivative of the three pressure falloff tests. The Green curve (upper pressure curve and bell shaped derivative) is the first falloff which had perforated interval of 7025-7050 ft MD. The pink (lower derivative curve) is the second falloff in the same perforated interval which had a modest acid treatment prior to the falloff. The dark blue (lower pressure curve middle derivative curve) was the third falloff tests for the perforated intervals of 6982-7012 and 7025-7050 ft MD and a second acid treatment over both perforated intervals. The difference between the green curve and the pink curve in the first 6 minutes is a result of the improvement to flow due to the acid treatment. The upper curves show the pressure difference and the lower curves show the derivative.

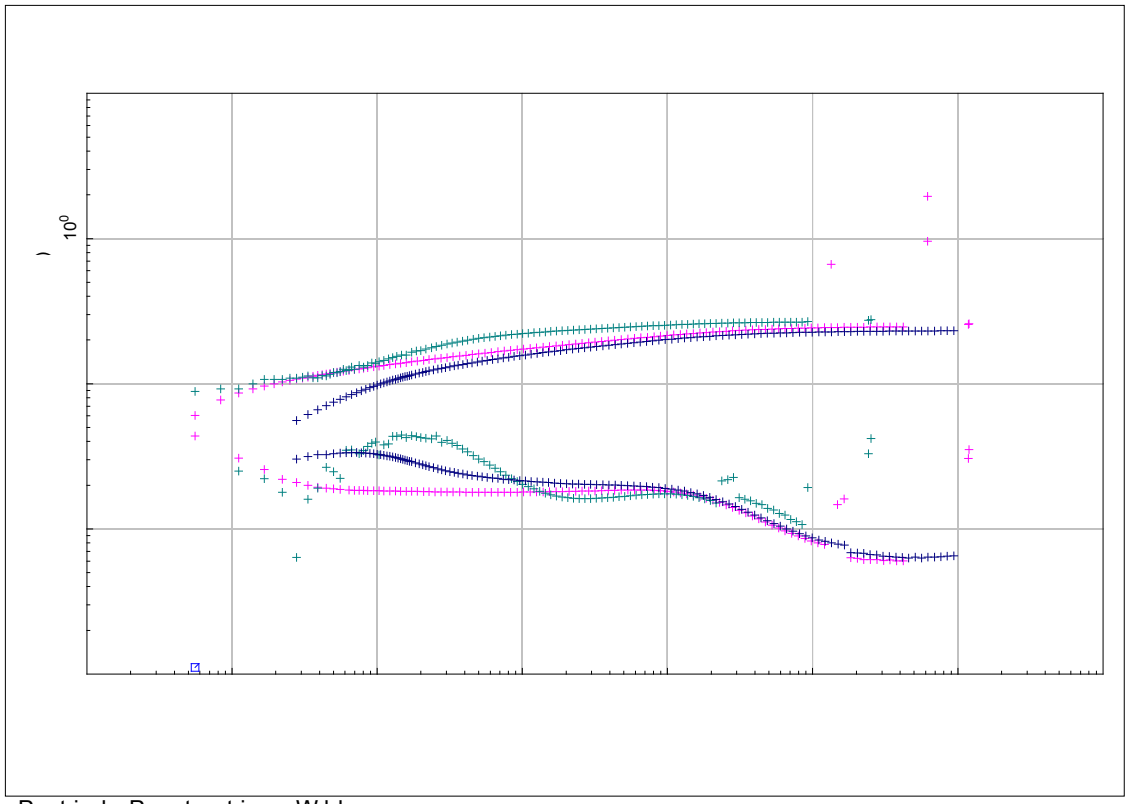
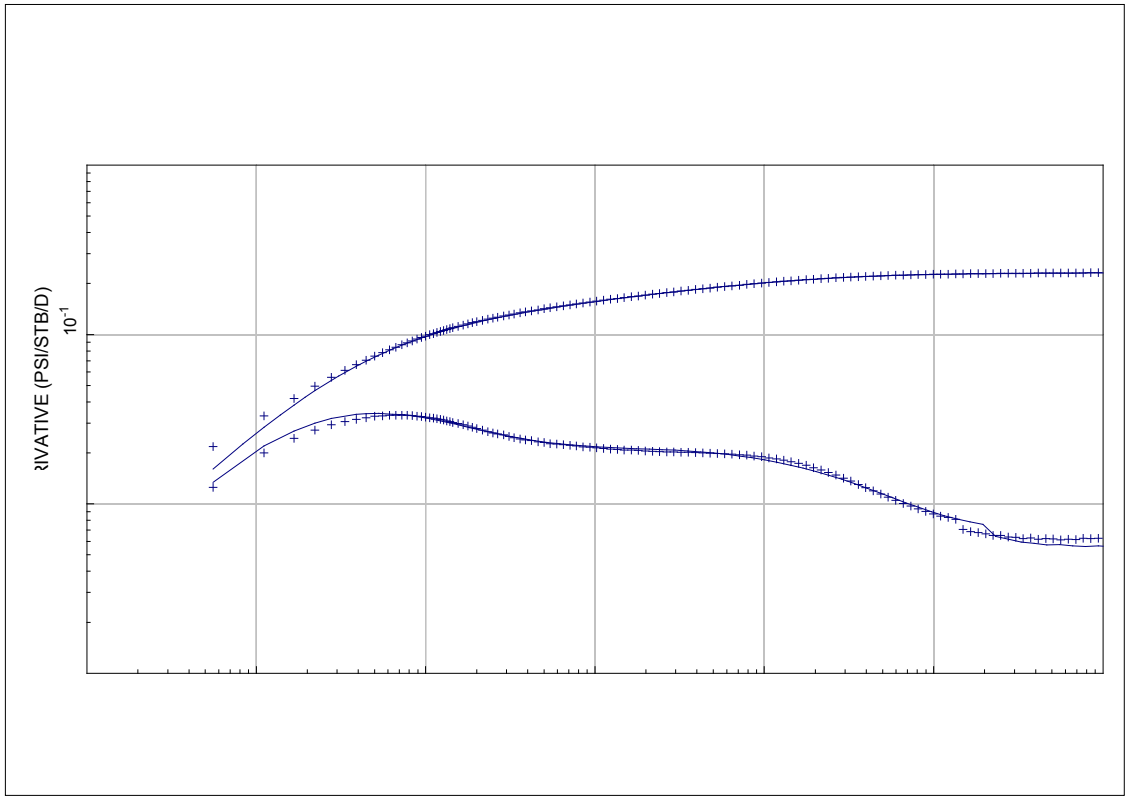


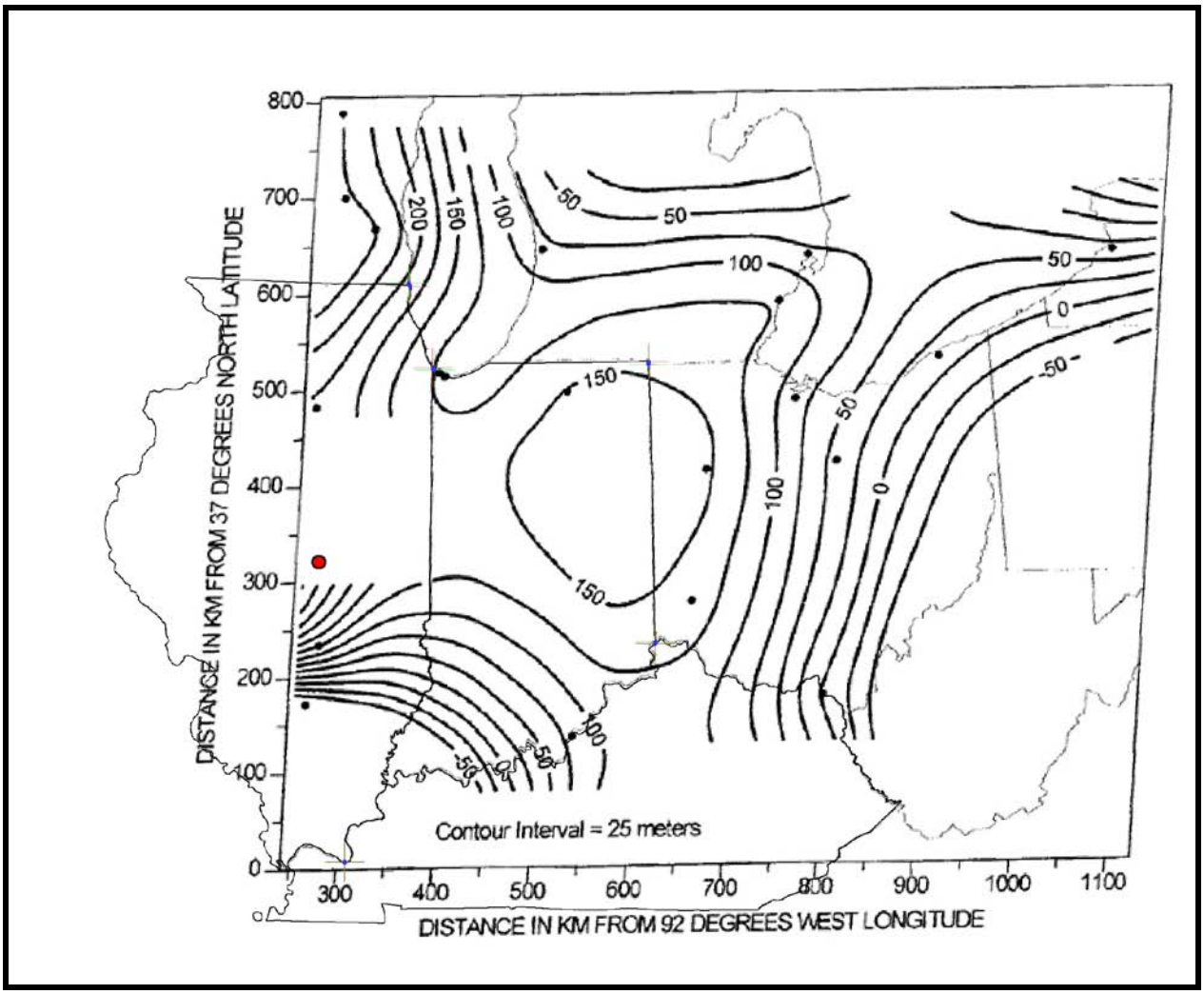
Figure 4a8: Nonlinear regression, or simulation history matching, of the of final pressure falloff test. Test data shown as + symbols and simulated data shown as line. The upper curve is the pressure difference and the lower curve is the derivative.



Partial Penetration Well

** Simulation Data **			Type-Curve Model Static-Data	
well. storage	= 0.0011457	BBLS/PSI	Perf. Interval	= 25.0 FEET
Skin(mech.)	= -0.85807			
permeability	= 184.58	MD	Static-Data and Constants	
Kv/Kh	= 0.013260		Volume-Factor	= 1.000 vol/vol
Eff. Thickness	= 75.000	FEET	Thickness	= 75.00 FEET
Zp/Heff	= 0.83330		Viscosity	= 1.300 CP
Skin(Global)	= 10.301		Total Compress	= .1800E-04 1/PSI
Perm-Thickness	= 13843.	MD-FEET	Rate	= -6100. STB/D

Figure 4a9. Potentiometric surface in the Mt. Simon Sandstone in Indiana, Ohio and surrounding states (modified from Gupta and Bair, 1997). The red dot shows the location of the ADM site in east-central Illinois. At the ADM site, the potentiometric surface was calculated to be 76 m above mean sea level.



Appendix XIII.B – Revised UIC Form 4d

7 UIC Form 4d, Area of Review

Last revised: 4/1/2010

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT APPLICATION

FORM 4d - AREA OF REVIEW

USEPA I.D. NUMBER ILD984791459
IEPA I.D. NUMBER 1150155136
UIC Well Number CCS #1

I. Radius of the Area of Review

A fixed radius of 2.5 miles was selected for the area of review.

II. Method of Radius determination

A fixed radius of 2.5 miles was selected for the area of review.

III. Map with information required by Section 730.114(a)(2) or 730.134(a)(2)

See the Feasibility Report for a discussion regarding maps of wells within the area of review. As discussed in the Feasibility Report, a total of 1,034 wells are known to be drilled within the area of review. The deepest well is 2,500 feet. Sixty-five oil wells within the Area of Review have been drilled to the depth range of 2,100 to 2,500 feet.

IV. Description of Anticipated Injection Fluid Movement during the Life of the Project

VIP reservoir simulator from Landmark Graphics (http://www.halliburton.com/ps/Default.aspx?navid=226&pageid=888&prodid=MSE%3a%3a1055451807810981) was used to estimate the plume migration around the proposed site. The proposal requires a minimum injection volume of 1.0 million metric tonnes (Mt). The geologic model was based on the open-hole well logs and the core analyses of CCS#1, verified with the water pressure transient injection falloff test. The structure was based on interpretation of two, 2-D seismic survey lines acquired prior to drilling the well and discussed in the Feasibility Report

The geologic model included the entire Mt. Simon from the base of the Eau Claire to the top of the granite. The Mt. Simon was divided into 108 vertical layers, with each layer being 15 feet thick.

For the simulation, CO_2 was injected at 0.333 Mt per year for three years. The lowest part of the Mt. Simon was used for injection. CO_2 could move vertically into higher parts of the Mt. Simon but not via the wellbore. Following three years of injection, two years of shut-in were also simulated.

Several models of varying model cell size and perforation strategies were used. Based on model results, the plume radius is expected to be approximately 1,500 feet. Because the injection interval is low within the gross thickness of the Mt. Simon, CO_2 flows upward from the injection interval. The CO_2 saturation increases below relatively lower permeability subintervals within the Mt. Simon. After three years of continuous injection into the lower part of the Mt. Simon and two years of shut-in, the CO_2 never reaches the caprock at the end of injection.

V. Wells Within the Area of Review

A. Tabulation of well data required by 730.114(a)(3) or 730.134(a)(3)

See the Feasibility Report for a tabulation of wells located within the 2.5 mile area of review.

B. Number of wells within 2 ½ miles of injection well penetrating within 300 feet of the uppermost injection zone which are:

1. *Properly plugged and abandoned – N/A*
2. *Temporarily abandoned – N/A*
3. *Operating– N/A*
4. *Improperly sealed, completed or abandoned– N/A*

As discussed in the Feasibility Report, there are no known wells within the 2.5 mile area of review that penetrate deeper than 2,500 feet. The depth to the top of the injection zone (Mt. Simon Sandstone) is 5,545 feet. Therefore, there are no known wells that penetrate within 300 feet of the uppermost injection zone.

C. Plugging affidavits for all plugged wells

See the Feasibility Report for the plugging affidavit for one plugged well located within the 2.5 mile area of review.

D. Proposed corrective action for unplugged wells penetrating the injection zone

See the Feasibility Report for a discussion of wells that required corrective action.

Appendix XIII.C – Revised UIC Form 4g

10 UIC Form 4g, Plugging and Abandonment

Last Revised: 3/31/2010

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT APPLICATION

FORM 4g - PLUGGING AND ABANDONMENT PROCEDURE

USEPA I.D. NUMBER ILD984791459
IEPA I.D. NUMBER 1150155136
UIC Well Number CCS #1

I. Description of Plugging Procedures, see instructions

The plugging and abandonment design reflects minimum requirements to sustain the integrity of the caprock to ensure CO_2 remains in the Mt. Simon. Any unforeseen changes necessary to plug and abandon this well will meet or exceed these requirements in terms of strength or CO_2 compatibility. Appendix E has the Engineering Technical Report signed and sealed by an Illinois Registered Professional Engineer.

A. Abandonment during construction

Removal of subsurface well features: There are three scenarios in which abandonment during well construction (or drilling) and completion while the wellbore is open or uncased: Drilling the Surface Hole (<300 ft MD), Drilling Intermediate Hole (<5,000 ft MD), and Drilling Long-String Hole (<7,500 ft MD).

During all three scenarios, the drill string (drill collars, drill pipe, and drill bit) is the most likely equipment in the hole. Every attempt will be made to recover all of this equipment prior to abandonment.

If drill pipe, drill collars and/or drill bit are not retrieved and must be abandoned in the wellbore, no unique plugging procedure is required and plugs will be placed as described in the UIC permit application (4g.I.C). The same procedure will be used in the scenario where any testing tool, such as a core barrel, drill stem test assembly, or non-radioactive well logging tool, cannot be retrieved or is abandoned in the well.

If a radioactive well log is lost in the hole (density and/neutron porosity), current Nuclear Regulatory Commission (NRC) regulations will be followed. A 300 foot, red cement plug will be placed immediately above the lost logging tool. An angled, kick-plate will be placed above this plug to divert any subsequent drilling that may coincidentally enter this wellbore. Current NRC regulations require that the surface casing remain extended above the ground surface with an informative ground plate welded to the pipe. The plate includes information about the well to identify what is in the hole.

Plug Placement Method: The method of placing the plugs is the **Balanced Plug** method. This is a basic plug spotting process that is generally considered more efficient and considered compliant with accepted industry practices.

B. Abandonment after injection

Removal of subsurface well features: Casing: All casing used in this well will be cemented to surface and will not be retrievable at abandonment after injection.

Tubing and Packer: After injection, the injection tubing and packer will be the only injection equipment in the cased hole. Every attempt will be made to remove the injection tubing and packer. If the packer cannot be released and removed from the cased hole, an electric line with tubing cutter will be used to cutoff the tubing above the single packer.

Plug Placement Method: The **Balanced Plug** placement method will be used. This is a basic plug spotting process that is generally considered more efficient and considered compliant with accepted industry practices.

C. Type and quantity of plugging materials, depth intervals

In addition to the proper volumes, placement of plugs on depths approved by the agency (the minimum requirements), all cement will be previously tested in the lab, a Schlumberger CemCADE will be performed using actual well information such as actual depth, temperature on bottom, hole conditions. During the plugging operations, both wet and dry samples will be collected for each plug spotted to ensure quality of the plug.

All casing will be cemented to surface and no casing will be retrieved. From the surface, at least 3 feet of all the casing strings will be cutoff well below the plow line and a blanking plate with the required permit information will be welded to the top of the cutoff casing.

D. Detailed plugging and abandonment procedures

Notifications, Permits, and Inspections (Prior to Workover or Rig Movement)

Notifications, Permits, and Inspections are the same for plug and abandonment during construction and post-injection.

1. Notify Illinois EPA 48 hours prior to commencing operations. Insure proper notifications have been given to all regulatory agencies for rig move.

2. Make sure all permits to P&A have been duly executed by all local, State & Federal agencies and ADM have written permission to proceed with planned ultimate P&A procedure.

3. Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks & ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.

4. Have copies of all government permits prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.

5. Make sure partners (U.S. DOE, IEPA and ADM) approvals have been obtained, as applicable.

6. Make sure all necessary forms for Schlumberger paperwork are on the rig, i.e., NPDES, safety meetings, trip sheets, etc.

Table 1: Plugging & Abandonment Contact List

Name	Department/Pos	Office	Fax	Mobile	Home
Paul Hughes, Jr., P.E.	Schlumberger-Operations	281-340-8658	281-285-0165	832-715-9060	281-781-8545
Robert J. Finley	ISGS Project Management	217-244-8389	217-333-2830	217-649-1744	217-384-6841
Tom Stone	ADM Project Engineer	217-424-5897			
Mark Carroll	ADM Environmental Coordinator	217-451-2720			
Kevin Lesko	Illinois Environmental Protection Agency	217-524-3271	217-524-3291		
	Federal Regulatory				

Volume Calculations

Volumes will be calculated for specific abandonment wellbore environment based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1. Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.

2. Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.

c. Plug length before the pipe is withdrawn.
d. Length of mud freefall in drill pipe.
e. Displacement volume required to spot the plug.

3. See generic calculations in Figure 51 and have Schlumberger cementer and wellsite supervisor both review calculations prior to spotting any plug.

Note: For each cementing operation the Schlumberger cementer and the wellsite supervisor will verify via the cementing handbook or iHandbook all calculations and have the Project Manager approve the manner and procedure for said cementing operations. Any amendments to the plugging program will require an exemption approved in writing from the Project Manager.

Plugging and Abandonment Procedure for "During Construction" Scenario:

<u>Pumping the Cement Job (Figure 52)</u>

1. Trip in Hole (TIH) to the desired depth (drill pipe tags the base of the desired plug depth).
2. Shut down circulating trip tank on wellbore.
3. Break circulation and condition mud as required. Circulate at least until the pit levels stabilize.
4. Mix and pump cement and spacers.
5. Displace with the predetermined mud volume.
6. Shut down cementing unit and allow mud to freefall.
7. Near the end of the freefall, begin pulling out. Check to verify if we are pulling dry or wet.

<u>Pulling Out of the Plug (Figure 52)</u>

8. Resume circulating trip tank on the wellbore. Slowly pull the drillstring out of the plug and continue trip out of hole (TOH) until 2-3 stands above the top of the plug. Slowly pump 5-10 bbls to clear the drill pipe. Run circulating trip tanks continuously.

9. Do not attempt to reverse circulate because of potential contamination of the cement plug and to avoid over-pressuring the wellbore annulus. TOH.

10. Waiting on cement (WOC) minimum 12 hours, make up bottom hole assembly (BHA) and TIH to tag plug and record same. If tag will hold 5-10K lbs weight, pull up, circulate 1-2 stands above and continue with next balanced plug (either in open hole or inside casing) to properly comply with all local, state and federal regulations governing P&A operations (Table in Form 4g.I.C).

11. After spotting of all plugs, pull out of hole (POOH) laying down all drill pipe and drill collars, break out BHA

12. Finish cutting off below plow line (or per local, state or regulatory guidelines) all casing, dump 2-5 sacks of G cement in surface hole below plow line and weld plate on top of casing stub. Place marker as required by agencies.

13. After rig is released, commence with restoring site to as original condition as possible or per local, state or federal guidelines.

14. Complete plugging forms and send in with charts and all lab information to all state, local or federal agencies, as is required.

Plugging and Abandonment Procedure for "After Injection" Scenario:

1. Mobilize workover (WO) or Plugging Rig Equipment. Give IEPA and DNR 48 hours notice before commencing operations.

2. Move in rig to ADM CCS#1 location. Notify the Project Coordinator before moving rig. Ensure all overhead restrictions (telephone, power lines, etc) have been adequately previewed and managed prior to move in and rig up (MI & RU). All CO_2 pipelines will be marked and noted to WO rig supervisor prior to moving in (MI) rig. Move rig onto location per operational procedures.

3. Conduct a safety meeting for the entire crew prior to operations, record date and time of all safety meetings and maintain records on location for review.

4. Make daily "Project Inspection" walks around the rig. Immediately correct deficiencies and report deficiencies during the regulatory discussion during morning meetings/calls. Maintain International Association of Drilling Contractors (IADC) or plugging reports daily at the WO rig log book or doghouse.

5. MI rig package and finish rigging up hoses, hydraulic lines, etc.

6. Open up all valves on the vertical run of the tree. Check pressures.

7. Rig up pump and line and test same to 2,500 psi. Fill casing with kill weight brine (9.5 ppg). Bleeding off occasionally may be necessary to remove all air from the system. Keep track and record volume of fluid to fill annulus (Hole should be full). If there is pressure remaining on tubing rig to pump down tubing and inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead then nipple up blowout preventers (NU BOP's). Monitor casing and tubing pressures.

8. If needed, if well is not dead nor pressure cannot be bled off of tubing, rig up (RU) slickline (SL) and set X-lock plug in X nipple located in X-Plug in tailpipe below packer. Circulate well with kill weight brine. Ensure well is dead. ND tree. NU BOP's and function test same. BOP's should have 4 ½"single pipe rams on top and blind rams in the bottom ram for 4 ½" Test BOP's as per local, state or federal provisions or utilize higher standard, 30 CFR250.616. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all TIW's, IBOP's choke and kill lines, choke manifold, etc. to 250 psi low and 3,000 psi high. **NOTE: Make sure casing valve is open during all BOP tests.** After testing BOPs pick up 4 ½ tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X- plug from well. Rig to pump via lubricator and keep well dead.

9. RU 4 ½" rig hydraulic tubing tongs for handling of production tubing. Pick back up on tubing string and pull seal assembly from seal bore. Pull hanger to floor and remove same. Circulate bottoms up with packer fluid.

10. POOH with tubing laying down same. **NOTE: Ensure well does not flow due to CO_2 "back flow"! Well condition is to be over-balanced at all times with at least 2 well control barriers in place at all times.**

    Contingency: If unable to pull seal assembly RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD. Several different sizes of cutters and pipe recovery tools should be on location due to possible tight spots in tubing.

11. If successful pulling seal assembly then pick up 3 ½ or 4 ½ inch workstring and TIH with Quantum packer retrieving tools. If tubing was cut in previous step then skip this step. Latch onto Quantum packer and pull out of hole laying down same. If unable to pull Quantum pull work string out of hole and proceed to next step. Assuming tubing can be pulled with packer with no issues, run CBL or USIT to determine that there is no leakage around the wellbore above the caprock. If leakage is noted prepare cement remediation plan and execute during plugging operations. Set 9 5/8 inch cement retainer on wireline just in Eau Claire above the Mt Simon Formation (approximately 5250 feet). Trip into hole with work string and sting into cement retainer. Test backside to 750 psi for 30 minutes on chart. A successful test should have less than 10% bleed off over the 30 minute period. This will be considered a successful casing test. Establish injection with packer kill fluid at 0.5, 1, and 2 BPM not to exceed 2,000 psi injection pressure. Sting out of retainer.

12. With pipe stung out of retainer, Mix and pump 300 (63 bbls) sacks of Class "H" cement mixed at 15.6 ppg plus fluid loss additive as proposed by cementing company and actual downhole conditions (temperature, BHP, etc). Obtain fluid loss of less than 100 cc/30 min. Follow that with 500 (105 bbls) sacks Class H cement mixed at 15.6 ppg with dispersant. Circulate to within 5 bbls of end of work/tubing string, sting into retainer and finish mixing cement. Displace tubing and squeeze away 30 bbls of cement into the open perforations.. Note: Do not squeeze at higher pressures than 2,000 psi. Sting out of retainer and reverse out a minimum of 2 pipe volumes. **Note: Leave cement on top of retainer.**

13. POOH racking back work string. Shut down for 12 hours Go in hole (GIH) open ended. Tag up on cement on top of retainer and note same.

14. Circ well and ensure well is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug in 9 5/8 inch casing (approximately 175 sacks Class A or H). Pull out of plug and reverse circulate tubing. Repeat this operation until a total of 10 plugs have been set. If plugs are well balanced then the reverse circulation step can be omitted until after each third plug. Lay down work string while pulling from well. If rig is working daylights only then pull 10 stands and rack back in derrick and reverse tubing before shutting down for night. The following morning trip back in hole and tag plug and continue. After ten plugs have been set pull tubing from well and shut in for 12 hours. Trip in hole with tubing and tag cement top. Calculate volume for final plug. Pull tubing back out of well. Nipple down BOPs and cut all casing strings below plow line (min 3 feet below

ground level or per local policies/standards and ADM requirements). Trip in well and set final cement plug. Total of approximately 2660 sacks total cement used in all plugs. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded with well name onto lowest casing string at 3 ft.

15. File all plugging forms to local state, federal and other agencies as required.

Note: utilize all local, state or federal rules relative to P&A or at least 33% plus actual volumes or as approved previously by Illinois state agency or Federal agency.

E. Cost estimate for plugging and abandonment worst case scenario

Itemized P&A Costs	**During Construction**	**Post Construction***
a. Casing Evaluation: Mobilize equipment and crews from nearest district. Run multi-finger caliper for detailed inspection of the inner surface of the casing. Run Isolation Scanner for final condition of outer surface of casing and cement condition. Compare to baseline logs run before injection started.	N/A	$50,000
b. Evaluation of any problems discovered by the casing evaluation: Downhole video camera to get visual images of the questionable inner surfaces of the casing.	N/A	$20,000
c. Cost for repairing problems and cleanup of any groundwater or soil contamination: CO_2 as a vapor in soil would not result in contamination like a liquid. A formal "cleanup" may not be required, and the CO_2 would dissipate into the atmosphere. CO_2 into groundwater would like be the same as that in oil. For a period of time, the shallow groundwater may have a low concentration of CO_2 similar to a "flat" soft drink. With time the CO_2 will dissipate into the unsaturated soil and dissipate.	N/A	$40,000
d. Cost for cementing or other materials used to plug the well:	$37,000	$78,000
e. Cost for labor, engineering, rig time, equipment and consultants:	$157,000	$157,000

f. Cost for decontamination of equipment:	N/A	N/A
g. Cost for disposal of any equipment:	N/A	$2,000
Tubing would be sold as scrap metal and worst case cost would be trucking services only.		
h. Estimated sales tax:	$2,000	$2,000
Our review shows there is no state sales tax for this kind of work.		
i. Miscellaneous and minor contingencies (20%):	$10,000	$10,000
j. Total	$206,000	$359,000

* Post Construction cost is for 1/1/08; if the well was abandoned 30 years from now, assuming 3% annual inflation the worst case P&A would be 2.43 times greater or $873,370.

Figure 51: Plugging Volume Calculations

VOLUME CALCULATIONS

1. CAPACITIES

Determine the following capacities:

Annular capacity between drillpipe and hole (V_{ANN})	ft^3/ft and ft/bbl
Hole or casing capacity (V_{CAPOH})	ft^3/ft
Drillpipe or tubing capacity (V_{CAPDP})	ft^3/ft and bbl/ft

2. NUMBER OF SACKS OF CEMENT

Determine the number of sacks of cement required for a given length of plug (sx):

N_{SX} = L_{PLUG} X V_{CAPOH} / slurry yield

Where:

N_{SX} = number of sacks of cement, sx

L_{PLUG} = length of cement plug, ft

V_{CAPOH} = capacity of open hole or casing, ft^3/ft

Slurry yield = cement yield, ft^3/sk

3. SPACER VOLUME BEHIND SLURRY

Determine the spacer volume to be pumped behind the slurry to balance the plug (bbls):

$V_{TAILSPACER}$ = V_{ANN} X $V_{LEADSPCR}$ X V_{CAPDP}

Where:

$V_{TAILSPACER}$ = spacer volume to be pumped behind the slurry to balance the plug, bbls

V_{ANN} = annular capacity, ft/bbl

$V_{LEADSPCR}$ = spacer volume to be pumped ahead of cement plug, bbls

V_{CAPDP} = drill pipe capacity, bbl/ft

Figure 51: Plugging Volume Calculations, contd.

VOLUME CALCULATIONS, CONTINUED

4. PLUG LENGTH

Determine the plug length (ft) before the drill pipe is withdrawn (ft):

L_{PLUG} = (N_{SX} X slurry yield) / (V_{ANN} + V_{CAPDP})

Where:

L_{PLUG} = length of cement plug before the DP is withdrawn, ft

N_{SX} = number of sacks of cement, sx

Slurry yield = cement yield, ft^3/sk

V_{ANN} = annular capacity, ft^3/ft

V_{CAPDP} = drill pipe capacity, ft^3/ft

5. LENGTH OF FREEFALL IN DRILL PIPE

Determine the length of mud free fall in drill pipe (ft):

L_{FF} = TD (1 – MW)

Where:

L_{FF} = length of free fall inside the drill pipe, ft

TD = depth, ft

MW = mud density, pPG

6. DISPLACEMENT VOLUME

Determine displacement volume required to spot the plug (bbl):

V_{DISP} = [(L_{DP} – L_{PLUG} – L_{FF}) X V_{CAPDP}] – $V_{TAILSPCR}$

Where:

V_{DISP} = displacement volume required to spot cement plug, bbls

L_{DP} = length of drill pipe, ft

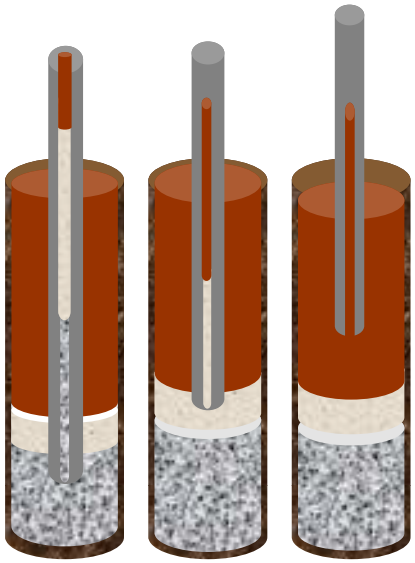
L_{PLUG} = length of cement plug, ft

L_{FF} = length of freefall, ft

V_{CAPDP} = drill pipe capacity, bbl/ft

$V_{TAILSPCR}$ = spacer volume to be pumped behind the slurry to balance the plug, bbls

Figure 52: Schematic of pumping the cement job using the balanced plug method.
The mottled grey is cement, the white is spacer, and the brown is mud. In the first graphic, the first spacer has already been pumped, and they are pumping in the cement. In the 2nd graphic, they have displaced most of the cement (don't want to contaminate the cement, so leave a little in pipe at this stage), pulled the end of the pipe up into the space, and are displacing the end of the cement and putting more spacer fluid in between the mud and the cement. In the 3rd graphic, they are circulating mud to clean the pipe and casing of any cement before it sets.



Appendix M – Seismic Interpretation and Processing Figures

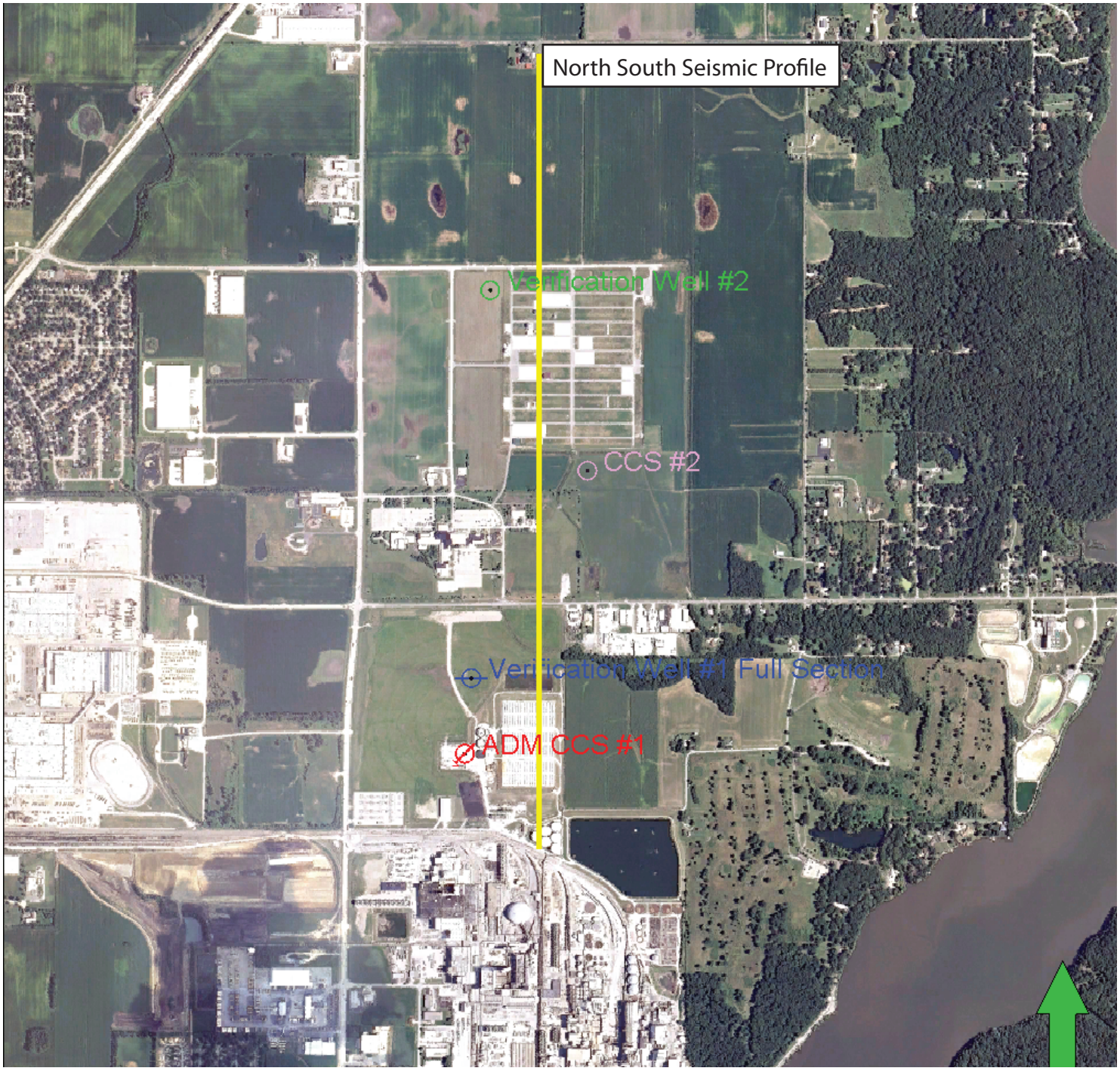


Figure M-1: Map View which shows the location of the North-South Seismic Profile seen in Figure M-2. The existing wells (CCS#1 and Verification Well #1) are located just west of this line. The proposed ICCS wells (CCS#2 and Verification Well #2) straddle this line.

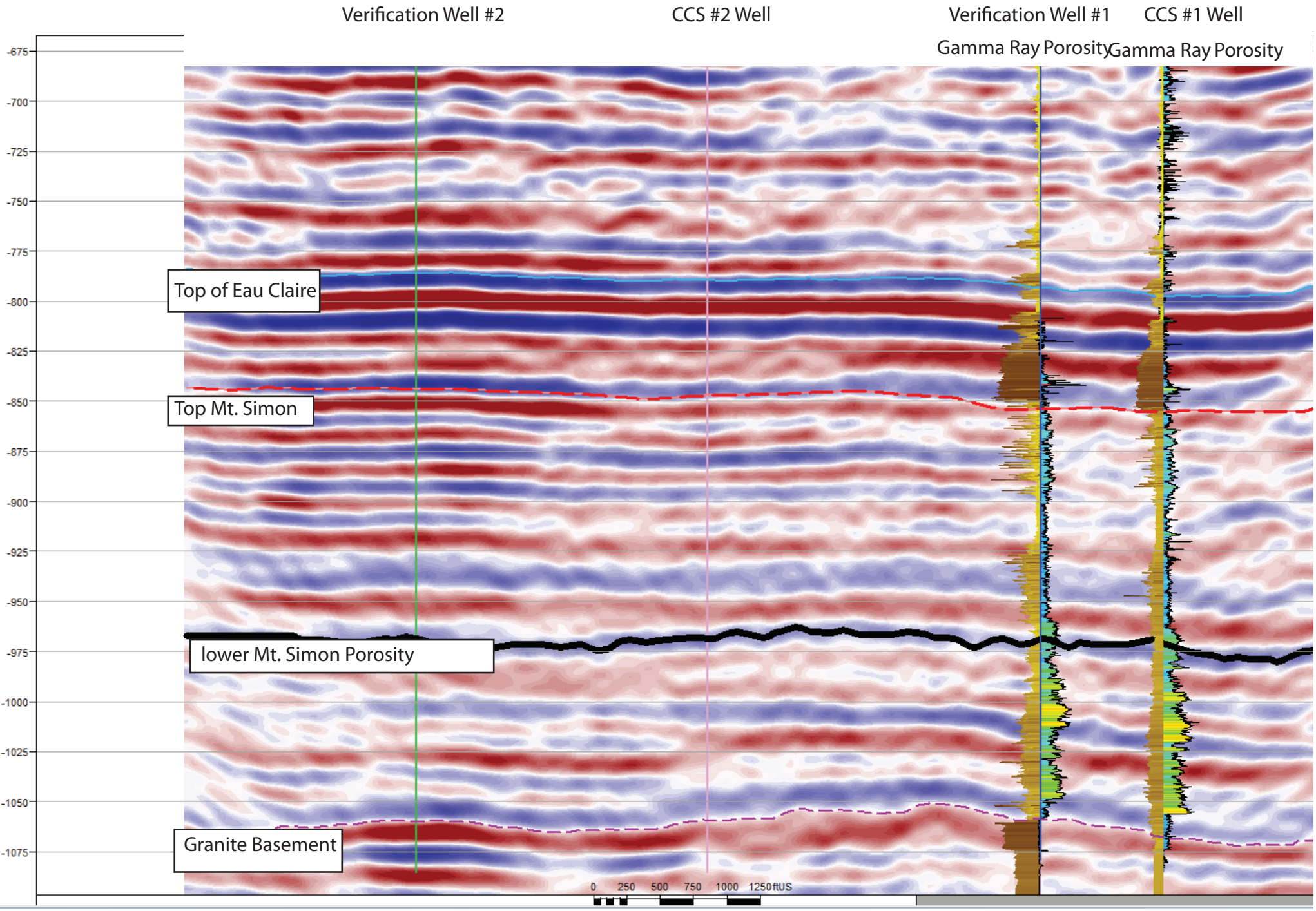


Figure M-2 - Interpreted North to South seismic line which is part of ADM ICCS 3D Seismic Survey. The location of this line is shown in Figure M-1. North is to the left. The Petrel software shows the Gamma Ray curves (brown with higher values to the left) and Porosity data (multi-colored with higher values to the right) for CCS#1 and Verification Well #1. The black line shows the approx. position of the top of the higher porosity section in the lower part of the Mt. Simon formation.

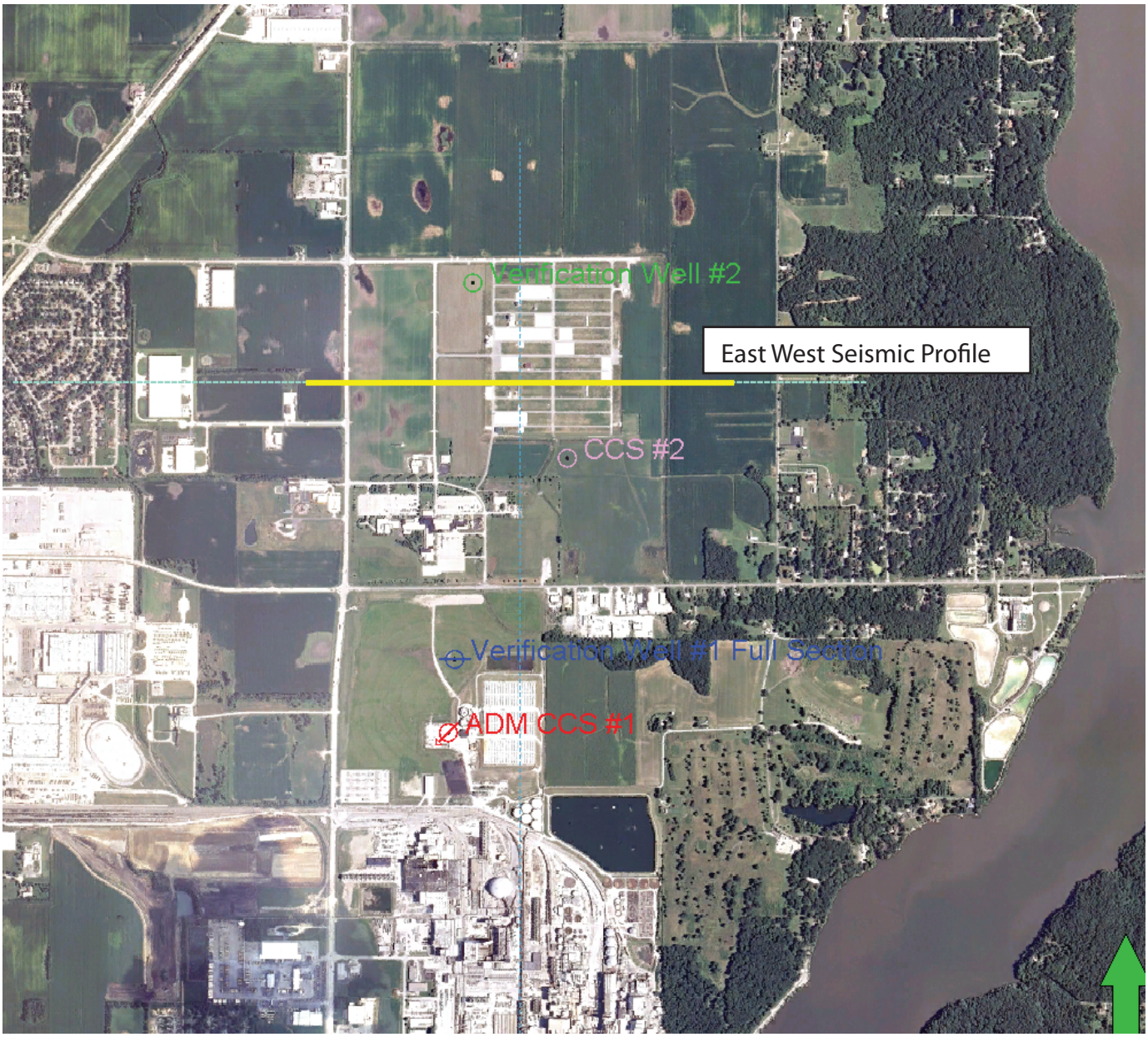


Figure M-3: Map View which shows the location of the East-West Seismic Profile seen in Figure M-4. The proposed injection well (CCS#2) is located just south of this line and the proposed observation well (Verification Well #2) is located just north of this line.

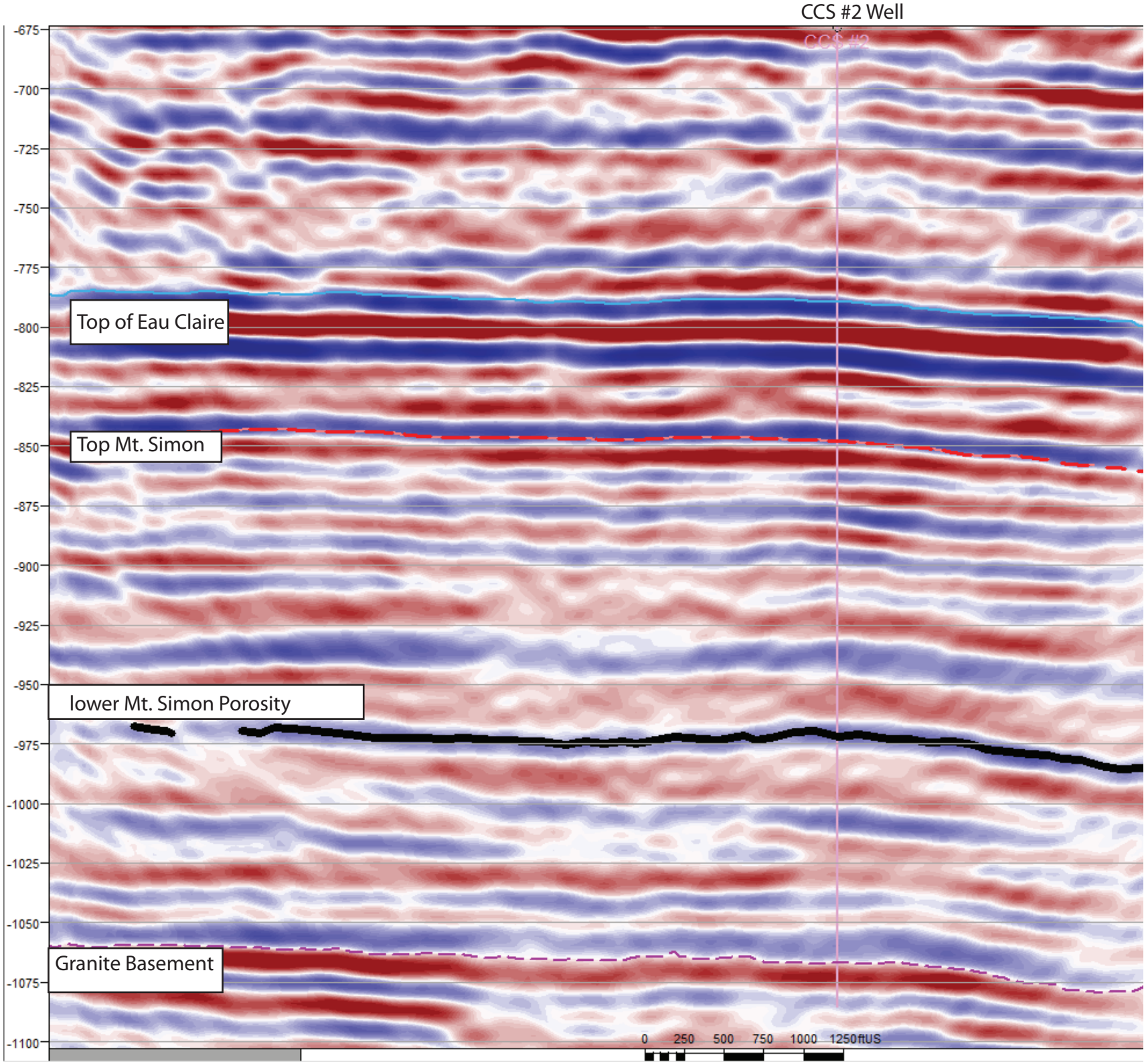


Figure M-4 - Interpreted East to West seismic line which is part of ADM ICCS 3D Seismic Survey. The location of this line is shown in Figure M-3. West is to the left. The location of the proposed ICCS injection well (CCS#2) is marked. The black line shows the approx. position of the top of the higher porosity section in the lower part of the Mt. Simon formation.

The figures below show some of the acquisition details, example cross sections, and processing details for the ICCS 3D Seismic data acquired in Jan 2011. The processing was completed in August 2011. Interpretation was initiated in August 2011. Some of the interpreted results from the Petrel 3D model are captured above in Figures M1 through M-4.

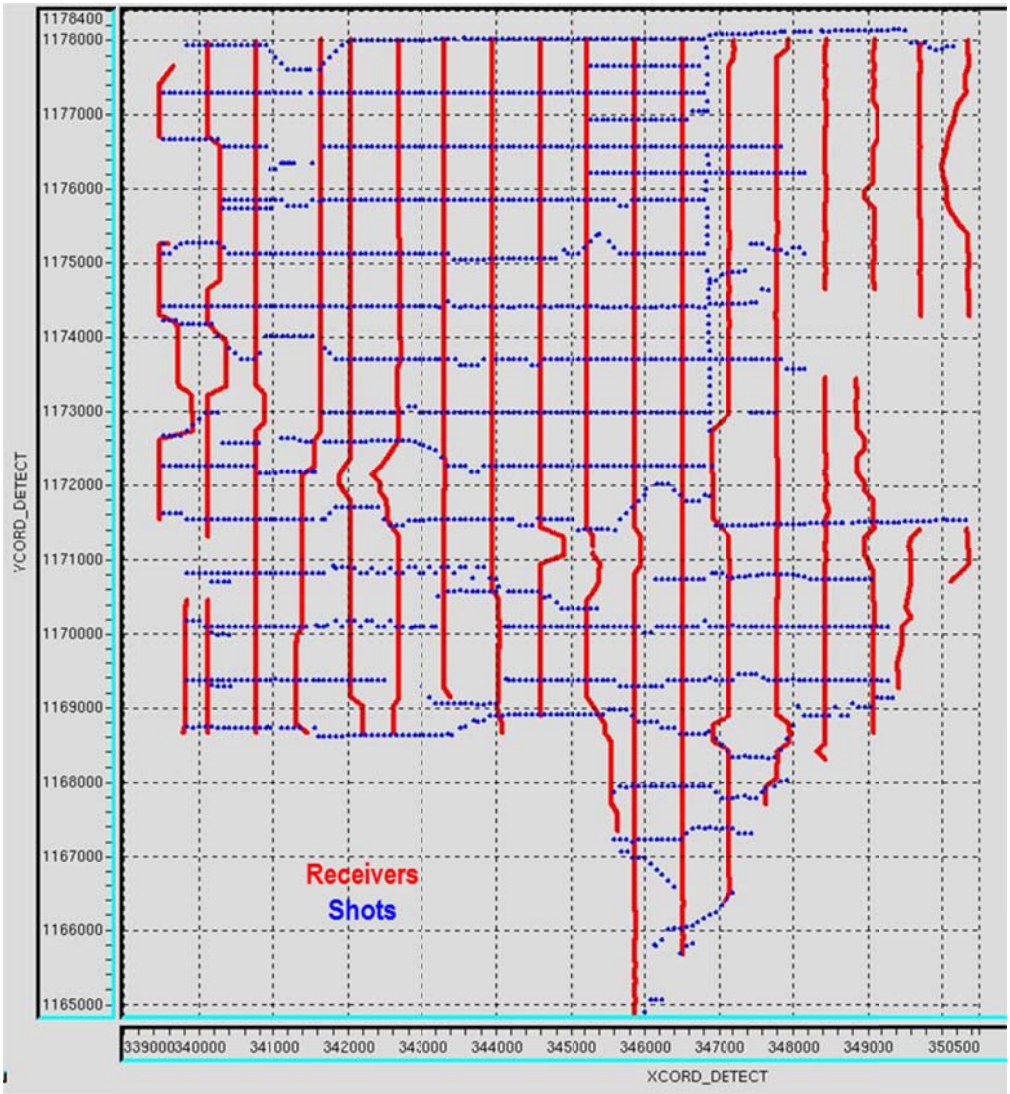


Figure M-5 - Shot and Receiver Locations

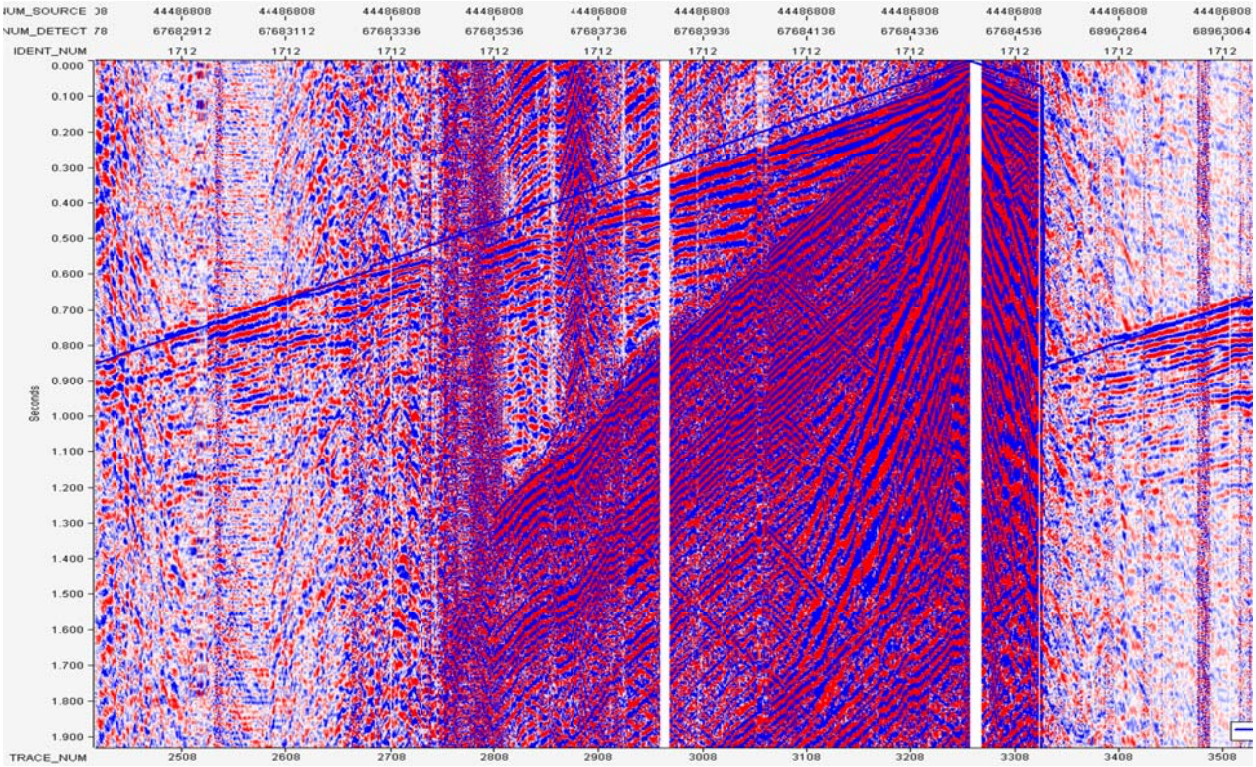


Figure M-6 - Raw Shot example

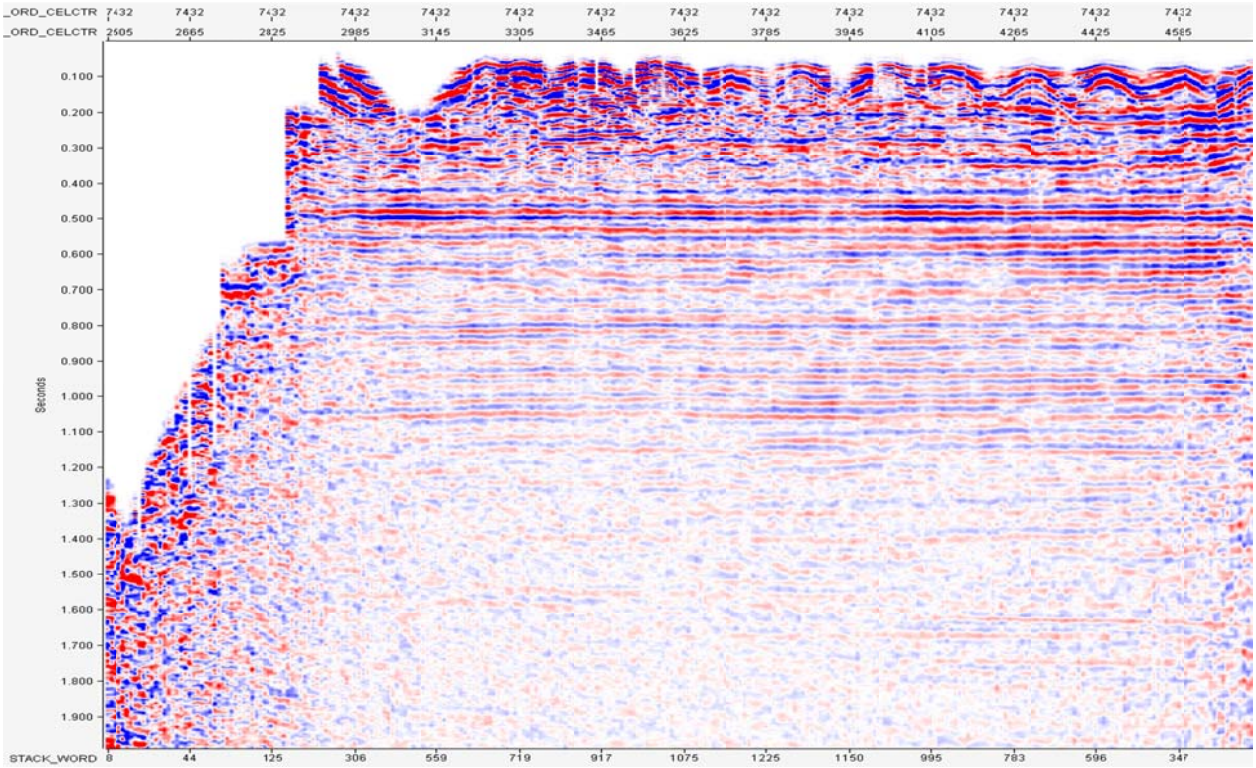


Figure M-7 - Brute Stack with AGC, IL 7432

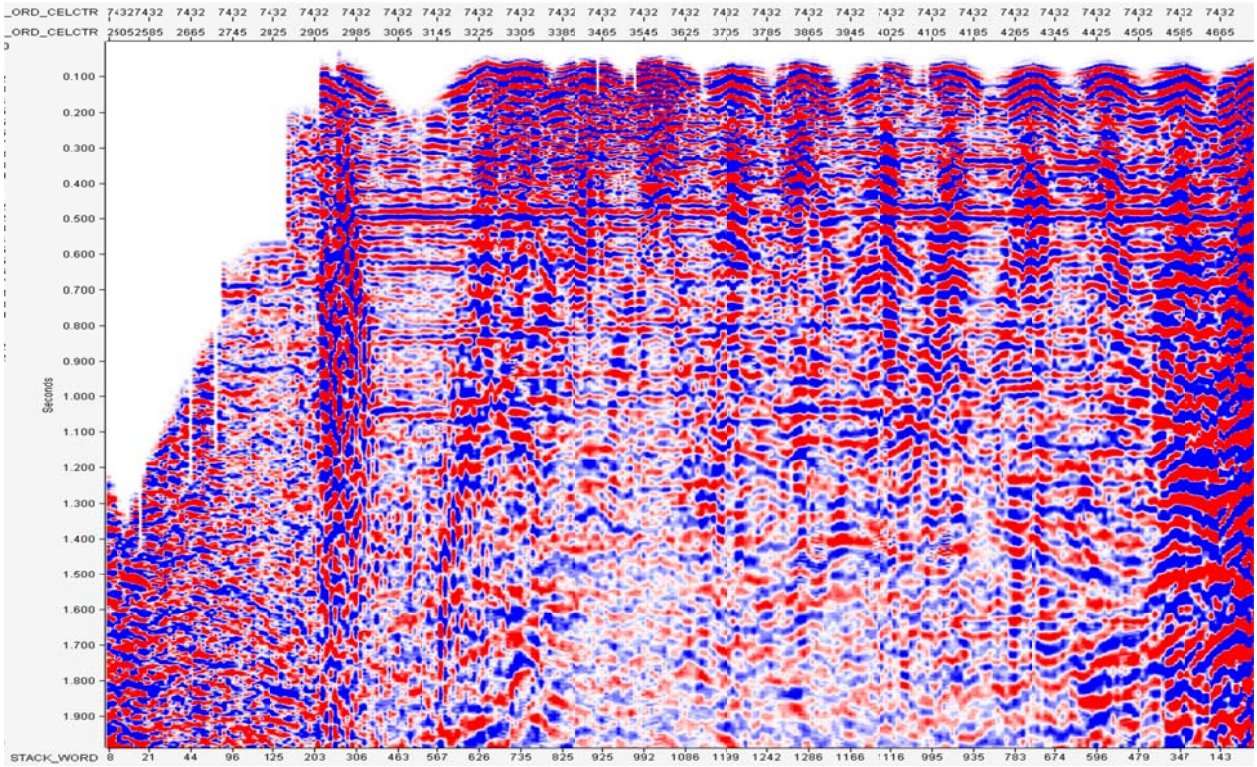


Figure M-8 - Stack Before Decon

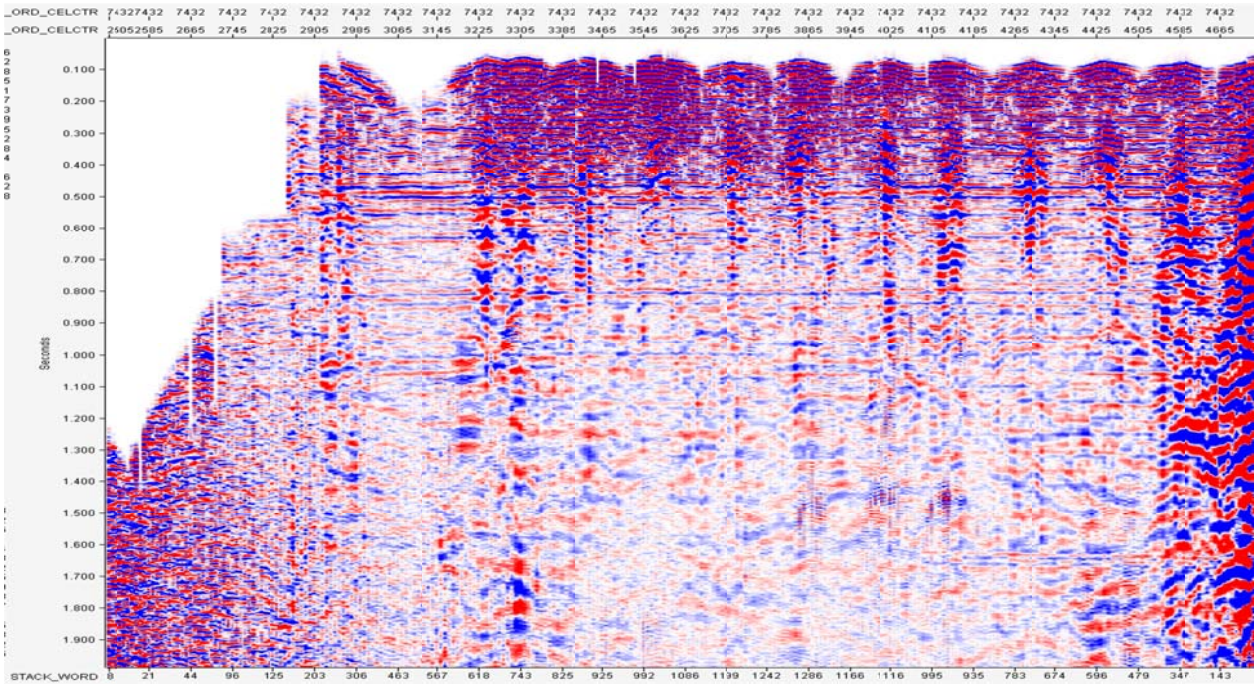


Figure M-9 - Stack After Decon

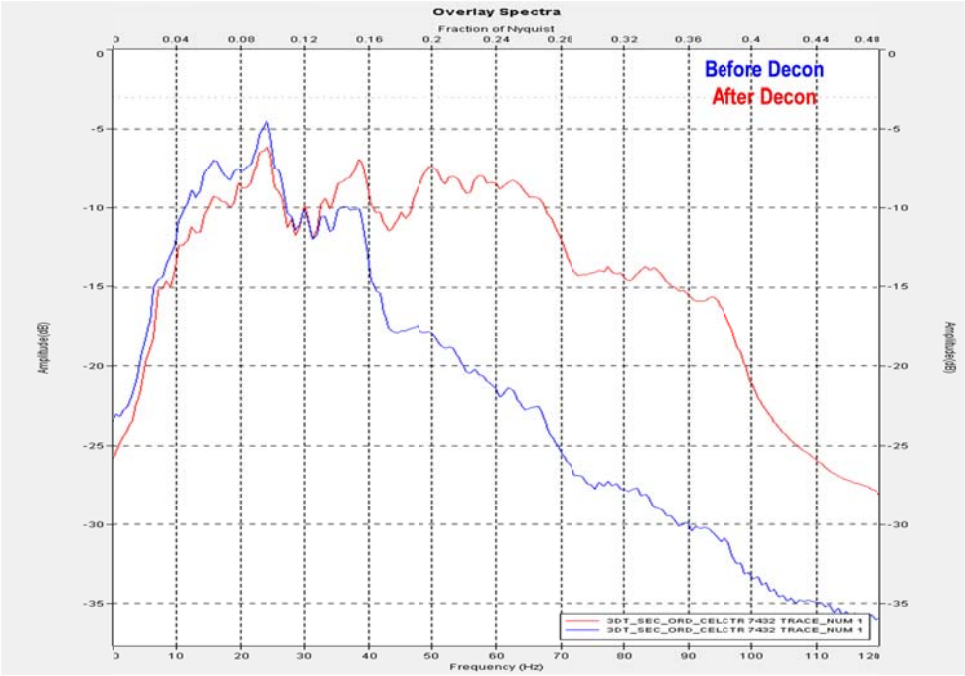


Figure M-10 - Spectra Before and After Decon

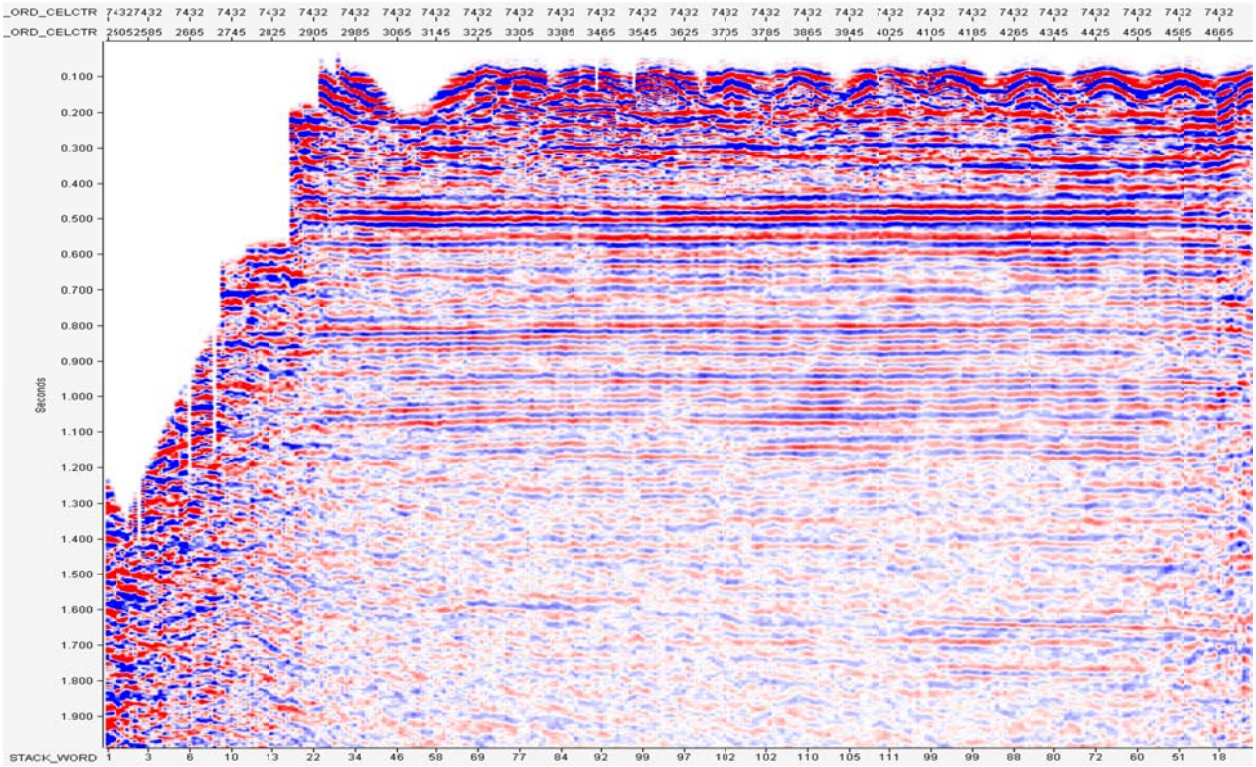


Figure M-11 - Stack with Elevation and Refraction Statics

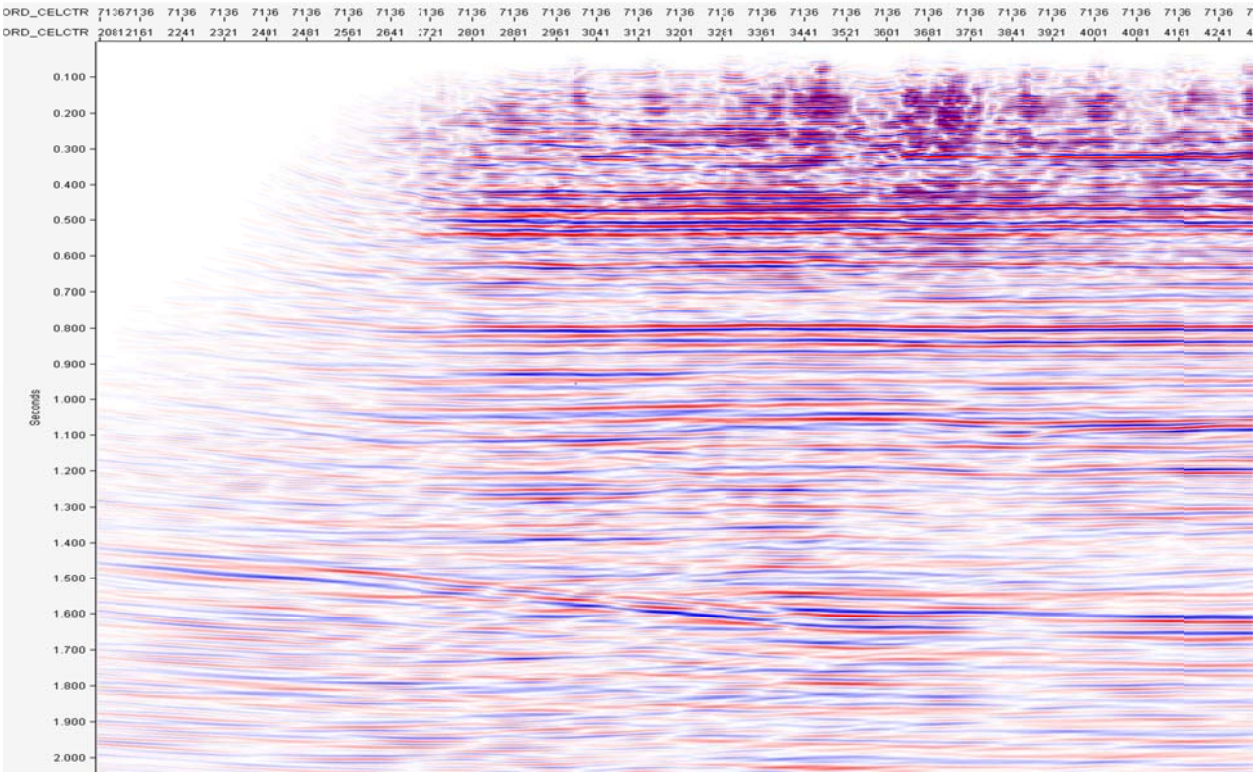


Figure M-12 - Stack with Stacking Velocities

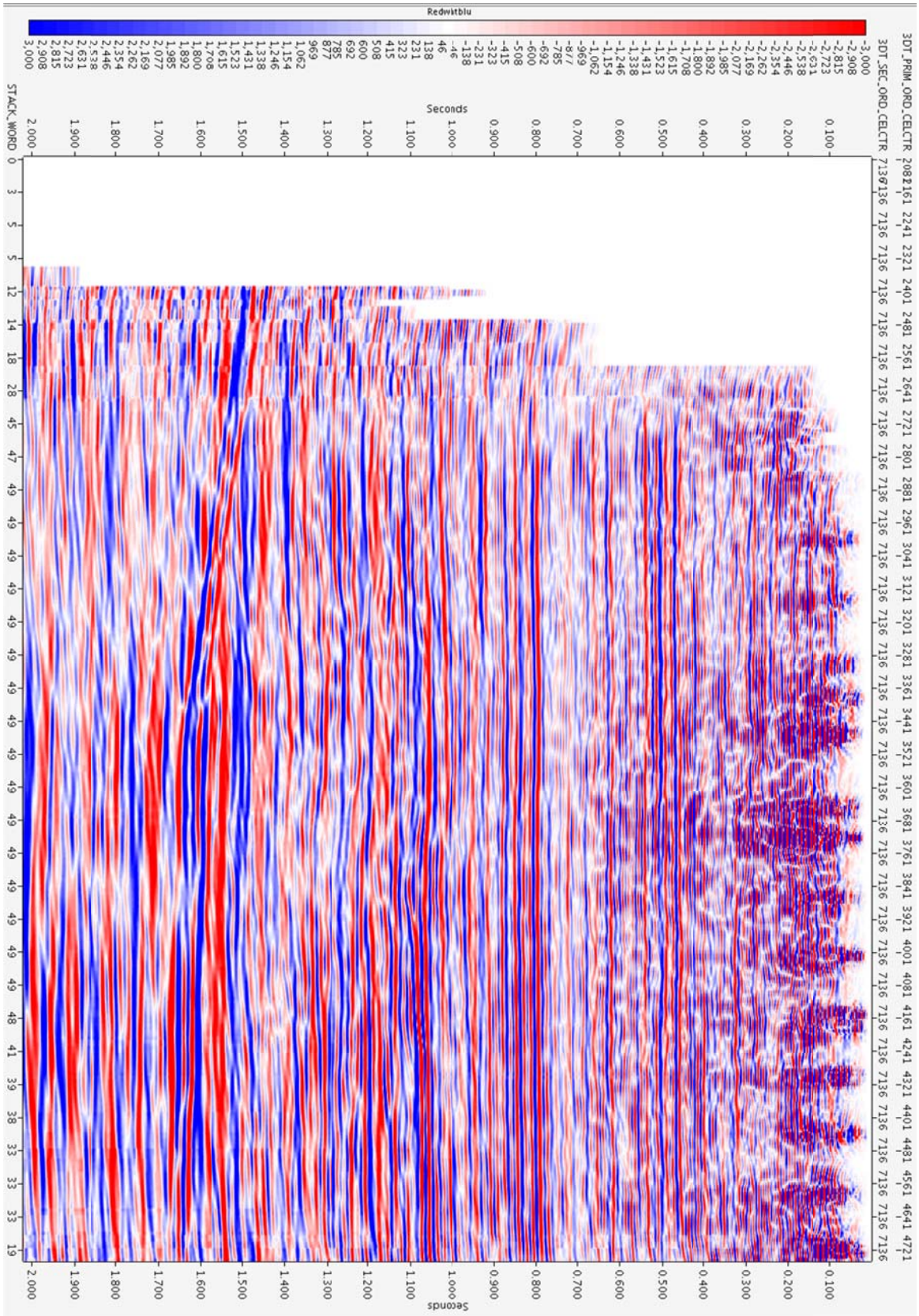


Figure M-13 – Final enhanced migrated volume without interpretation (Inline 7136)

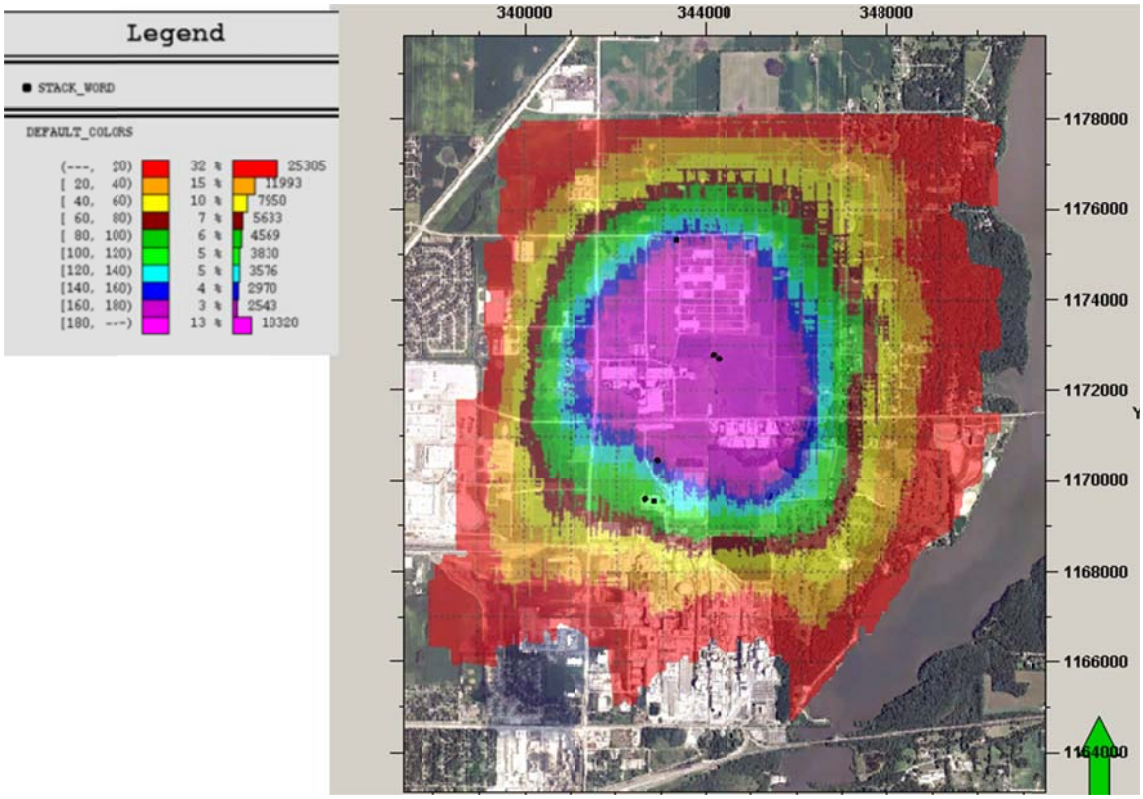


Figure M-14 - Fold Coverage map of ICCS 3D Seismic data acquired in Jan 2011. Adequate fold coverage exists out to the outer yellow ring.