Midwest Geological Sequestration Consortium

Drilling, Completion, and Data Collection Plans

Topical Report 4

An Assessment of Geological Carbon Sequestration Options in the Illinois Basin: Phase III

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SUBMITTED BY
Illinois State Geological Survey
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Disclaimer

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Executive Summary

The Illinois Basin – Decatur Project (IBDP) is managed by the Midwest Geological Sequestration Consortium (MGSC) and is led by the Illinois State Geological Survey (ISGS) at the University of Illinois. The project site is located on the Archer Daniels Midland Company (ADM) property in Decatur, Illinois, and is a fully integrated carbon capture and storage (CCS) project that uses CO_2 captured from the ethanol-producing fermentation process at the ADM corn-processing plant (Finley et. al., 2013). IBDP has a goal of injecting one million tonnes of CO_2 into the basal sands of the Mt. Simon Sandstone over a three-year period. This is a multi-faceted project, and this report details the planning and results of the drilling, completions, well testing, log data acquisition, and the Health, Safety, and Environment (HSE) aspects of the project.

Three deep wells were planned for the IBDP:

- The injection well: Injection Well #1 (CCS1);
- The monitoring well (both in-zone and above seal): Verification Well #1 (VW1); and
- The geophone monitoring well: Geophysical Monitoring Well #1 (GM1).

The detailed plans for these wells are attached to the appendices of this document. The wells were drilled successfully with little deviation from the original plans. The biggest change from the plan to execution was the need to adjust for larger-than-expected loss of circulation in the Potosi section of the Knox Formation. The completions reports also attached to this document detail the well constructions as they were actually built.

Injectivity testing was carried out, and the perforating plans were adjusted based on the results. Additional perforations and acidizing were performed as a result of the injectivity testing. The testing plans are detailed in this report along with the actual testing results. The injectivity testing results were used in the modeling and simulation efforts.

Detailed HSE plans were developed and implemented during the planning and execution phases of the project. The implementation included an HSE Bridging Document, which served to unify the HSE policies of the project partners and key subcontractors. The HSE plan and actual HSE results are presented in this document. There were no recordable HSE incidents during the project.

A detailed logging program was developed based on project needs. The log data were acquired in accordance with the plan, and both the plan and log results are presented in this report. Log data were heavily utilized by the research staff, modelers, reservoir engineers, and for technical and permitting efforts.

Several key lessons were learned during the project:

- Safety in operations and execution is paramount and is only achieved through proper planning and behavior control. The certainty of this was reinforced through implementation of this lesson and the resultant flawless HSE performance during the project.
- Losses of drilling fluid circulation were larger than anticipated within the Potosi Formation. Circulation was only recovered through cementing the loss zones.
- When possible, minimizing complexity in permit requirements and well designs is preferable.
- The size of the wells were outside of the standard experience and expertise typical within the basin, and therefore required substantial planning and ramp-up of contractors and partners to meet project objectives.
- With multiple stakeholders and research partners, establishing objectives and requirements early and adhering to change request procedures throughout the project are critical to manage competing data and sampling objectives that may be detrimental to overall progress.

The well construction and completion operations were successfully executed, with all wells built in a manner that achieved excellent wellbore integrity. Log planning involved a number of stakeholders and technical specialists.

Data collection from logging, coring, and testing was excellent. Time and effort spent with the associated contractors and suppliers to develop a well plan beyond normal scope proved highly successful, resulting in a well-construction and completion project that surpassed expectations. The world-class HSE results also demonstrate the commitment of all stakeholders in the project. The details follow in the body of this document

I. Drilling and Data Collection – Objectives

The Illinois Basin – Decatur Project (IBDP), adhering to the Statement of Project Objectives (SOPO) Section 5, proposed to develop detailed plans for the drilling process to include: Health, Safety, and Environment (HSE), completion procedures, and both open-hole and cased-hole data collection. The initial focus of the planned drilling and completion process centered on meeting or exceeding the Illinois Environmental Protection Agency (IEPA) Underground Injection Control (UIC) Class I (non-hazardous) requirements for data collection and well completion.

The open-hole and cased-hole data collection plans focused on the site characterization and modeling needs, but allowed for acquisition of additional data as necessary to meet permitting requirements and drilling program objectives. The requirements for drilling and data collection are broken down into three subtasks, detailed as follows, per SOPO Section 5 (Text in 5.1, 5.2, and 5.3 copied from SOPO):

IBDP SOPO Objective 5.1

Develop detailed plan for drilling, including Health, Safety, and Environment

Detailed plans will be developed for the drilling (including HSE) and completion process. The development of the drilling and completion process will be focused on meeting or exceeding IEPA UIC Class I (non-hazardous) requirements for data collection and well completion. The drilling program will include wellbore size, depths of surface and intermediate casing(s), and injection casing. Operationally, the drilling program will include mud density and additives anticipated to be required for lost circulation zones, drill bit types and sizes, coring bits and barrel specifications, planned DSTs, and log suites and intervals. The drilling program will include a description of the cementing procedure and will include types of cement and procedure for pumping and placing cement

IBDP SOPO Objective 5.2

Develop detailed plan for open-hole data collection

Detailed plans will be developed for open-hole data collection. The open-hole data collection will be based on the site characterization and modeling needs determined from Task 4; however, additional data may be necessary to meet permitting requirements and drilling program objectives.

IBDP SOPO Objective 5.3

Develop detailed plan for casing and cased-hole data collection

Detailed plans will be developed for cased-hole data collection. The cased-hole data collection will be based on the site characterization and modeling needs determined from Task 4; however, additional data may be necessary to meet permitting requirements and drilling program objectives. The compiled plans developed under Subtasks 5.1-5.3 will be submitted to DOE as a Topical Report.

II. Drilling and Data Collection – as Executed

A. Drilling and Data Collection Plans

Drilling Plans

Three deep wells were planned for the Illinois Basin – Decatur Project:

- The injection well – Injection Well #1 (CCS1),
- The monitoring well – Verification Well #1 (VW1), and
- The geophone monitoring well – Geophysical Monitoring Well #1 (GM1).

Detailed drilling plans for these three wells are attached in appendices A, B, and C respectively. Each plan provides details on wellbore and casing sizes and set depths and drilling fluid programs to be implemented, as well as lost circulation, bit, and coring plans. These plans also detail the wireline logging program, the testing program, and the cementing program.

Injectivity Testing Plan

The injectivity testing plan is detailed in Appendix D. The data generated from this testing were used to inform the final completion design as well as for updating and advancing subsequent models and simulations.

Initial stages (Phase I) of the CCS1 completion consisted of perforating the well and verifying that sufficient injectivity existed prior to final completion and hardware installation. Based on results of the injectivity (measured by a wireline production log), the decision was made to add additional perforations and to acidize the formation to remove any near-wellbore damage and to ensure all perforations were open.

The injection testing was subsequently modified from the original Statement of Project Objectives to use treated water rather than CO_2 to lower the risk, cost, and complexity of the injection test. An injectivity test using water was judged to be sufficient for the purposes of completion planning.

Completions Plans

Detailed completions plans for CCS1, VW1, and GM1 are attached in appendices E, F, and G, respectively. The plans provide details on the proposed intervals, size, and depth of perforations, frequency (shots/foot), and phase (orientation). The perforating plans were developed using the characterization and modeling outputs that have been highlighted in IBDP Topical Report 3 - Site Characterization, Modeling, and Monitoring. The plans also provide details of the tubing and downhole equipment employed.

HSE Plan

The HSE Bridging Document (see Appendix H) was developed to meet the need for a detailed plan for HSE of the drilling and completion processes. The HSE Bridging Document highlighted key areas of the HSE Management System from each of the principal operational companies, integrating the relevant procedures of each company and facilitating safe and efficient drilling and completions operations.

<u>Open-hole and Cased-hole Data Collection Plans</u>

The wireline open-hole and cased-hole logging programs for each of the wells is detailed in well plans in appendices A, B, and C. Key inputs to the selection of logging programs came from the following:

- Preliminary modeling and simulation results and recommendations from the modeling geologist and the simulation reservoir engineer.
- Additional stakeholder inputs and requirements collected during project meetings.
- IEPA UIC Class I (non-hazardous) requirements for data collection.
- Experience from the project team on similar projects.

A meeting was held to consolidate all of these requirements into a single data collection plan, and the results of this meeting are presented in Appendix I.

Coring was planned for the CCS1 and VW1 wells due to insufficient subsurface stratigraphic data. The core acquisition plan for the CCS1 well is detailed in Appendix A. The plan was to acquire approximately 240 feet of core in the Eau Claire Shale and the Mt. Simon Sandstone to better understand the stratigraphy and composition of the proposed caprock and reservoir. Based on the mud logs, core depths were determined by the geologist. This is summarized in Table 1.

Table 1 - CCS1 Planned Core Acquisition Depths

Core Formation	Length	Estimated Top of Formation
Eau Claire Shale	~120 feet	3,500 feet
Mt. Simon Sandstone	~120 feet	5,650 feet

The detailed core acquisition plan for VW1 is presented in Appendix B. The plan was to acquire approximately 820 feet of core through a variety of formations. The depth control for selecting the core was more detailed in VW1 due to information available from the drilling and logging of the CCS1 well. The core plan is summarized in Table 2.

Table 2 - VW1 Planned Core Acquisition Depth

Core Formation	Length	Estimated Top of Formation
New Albany Shale	30 feet	2,088 feet
Maquoketa Shale	60feet	2,611 feet
Knox Group	60 feet	3,477 feet
Potosi Dolomite	60 feet	4,361 feet
Eau Claire Shale to Mt. Simon Transition	200 feet	5,445 feet - 5,645 feet
Lower Mt. Simon	410 feet	6,690 feet – 7,100 feet

B. Drilling and Data Collection Results

The three wells were constructed very close to the planned objectives. The detailed completions reports are presented in appendices J, K, and L. Additionally, the figure in Appendix M shows a summary of the wells as built. Deviations of note between the plans and actual construction are highlighted in Part III of this report.

<u>Drilling and Completions Results for CCS1</u>

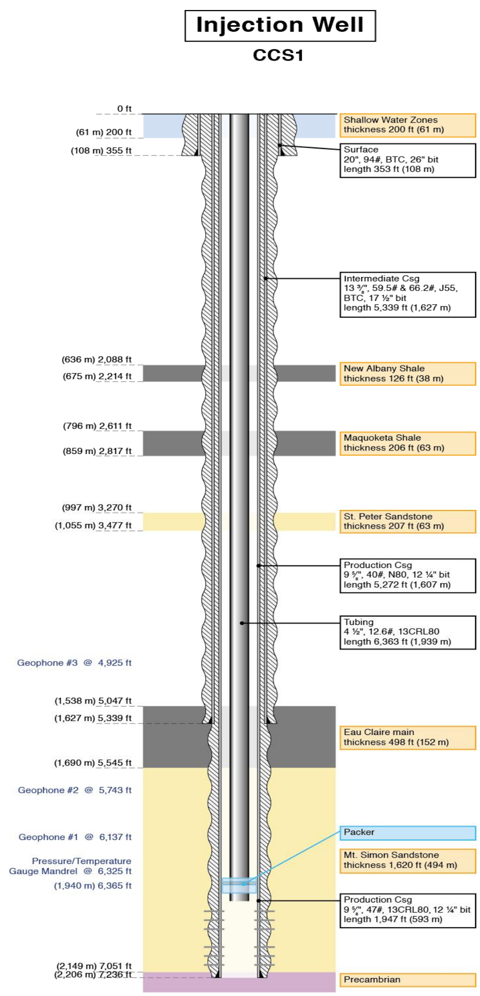


Figure 1— CCS1 Injection Well Details

CCS1 is located at 39˚ 52’ 37.06469” N and 88˚ 53’ 36.25685” W (NAD 83 coordinate system), which is 438 feet South and 1,332 feet East in the Northwest quadrant of Section 5 of Township 16 North and Range 3 East in Macon County, IL (See Figure 2). The well location’s ground elevation is 675.48 feet (NAVD 1988 coordinate system) above mean sea level (MSL).

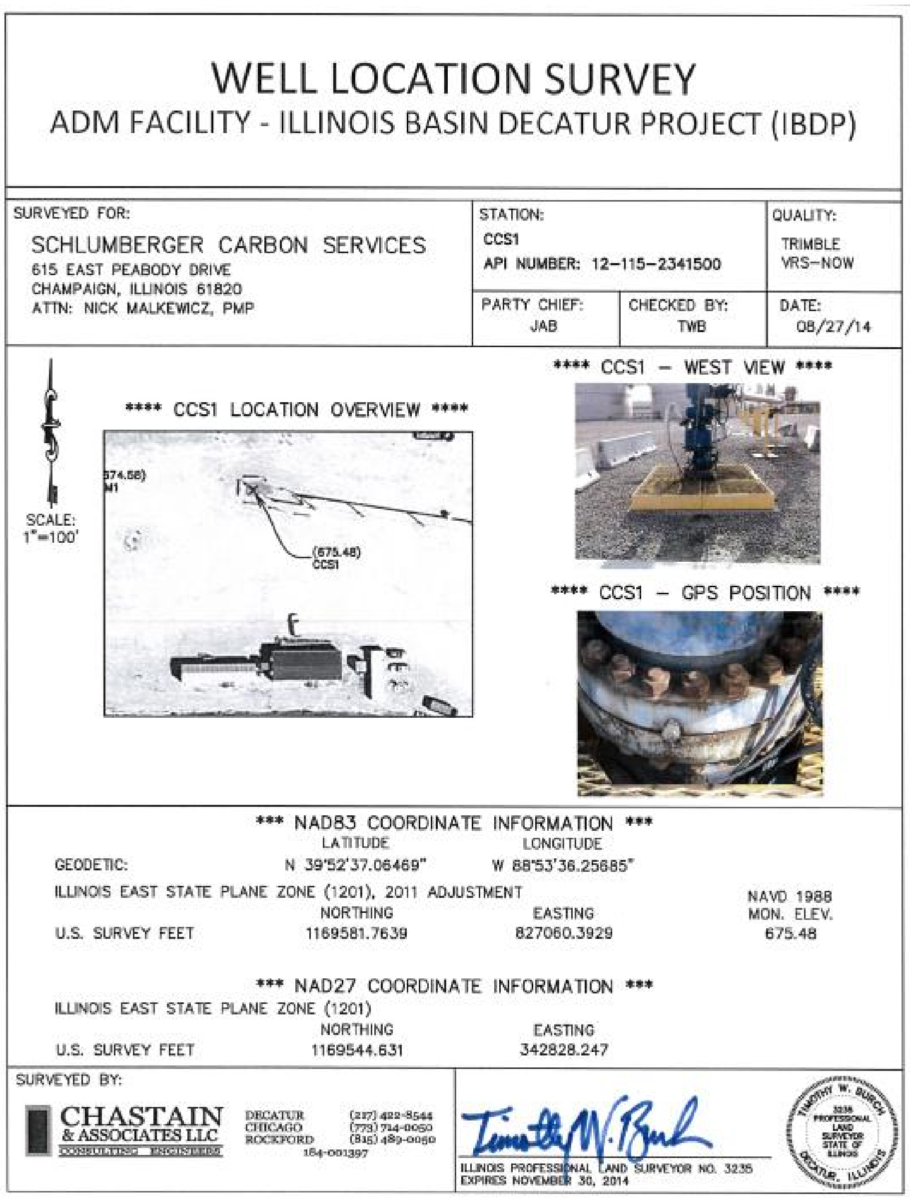


Figure 2 – CCS1 Location Survey Details

The well was drilled by Les Wilson, Inc. using their rig number 25, which has a kelly bushing elevation of 15 feet above ground level. The total well cost was approximately USD $6.6 million. The well was constructed in three sections: 1) surface; 2) intermediate; and 3) final. Initial drilling (“spudding”) of CCS1 began on February 14, 2009 and ended May 4, 2009. The Phase 1 completion was performed from September 18, 2009 to October 9, 2009. The Phase 2 completion was performed from November 10, 2009 to November 25, 2009.

The details of each section of the well are as follows:

Surface Section:

- The open-hole section was drilled from 0 – 355 feet using a 26-inch diameter bit.
- The casing was set from 0 – 355 feet using 20-inch diameter, 94 pounds per foot (lbs/ft), Grade H-40 8-round short round thread casing (STC).
- The casing was cemented to surface using Class A cement with a lead and tail mix.
- The drilling fluid used was water/gel with a weight of 9.7 pounds per gallon (ppg).

Intermediate Section:

- The open-hole section was drilled from 355 feet – 5,339 feet using a 17.5-inch diameter bit.
- Two grades of casing were set. The upper string of casing runs from 0 – 3,630 feet and is 13 3/8-inch in diameter, with a weight of 59.5 (lbs/ft), and grade of J-55 with a buttress type of threading. The lower string of casing runs from 3,630 feet - 5,339 feet and is 13 3/8-inch in diameter, with a weight of 66.17 lbs/ft, with a grade of J-55 and buttress type threading.
- Cementing was performed from total depth (TD) to surface in two stages. The first stage of cement runs from 3,715 feet – 5,339 feet and is a Class H blend of cement with a lead and tail mix. The second stage of cement runs from 0 – 3,715 feet and has a 35:65 Poz:H lead cement blend with a Class H tail cement.
- The drilling fluid used was water/gel with a weight of 9.1 ppg.
  Lost circulation zones were encountered at 4,562 feet and 5,017 feet of depth and were sealed using cement plugs after failed attempts to remediate with conventional lost circulation materials (LCM). A novel approach was developed to place two plugs in a manner that successfully avoided mud contamination.

Final Section:

- The open-hole section was drilled from 5,339 feet – 7,236 feet using a 12.25-inch diameter bit.
- The well was cored through the Eau Claire and Mt. Simon sections for a total recovered length of 90 feet. The retrieved core depth intervals were: 5,474 feet – 5,504 feet, 6,404 feet – 6,434 feet and 6,750 feet – 6,780 feet.
- Two grades of casing were set. The upper casing string runs from 0 – 5,272 feet and is 9 5/8-inch in diameter grade N-80 casing with 8-round LTC type threading. The lower string of casing runs from 5,272 feet – 7,219 feet and is 9 5/8 inches in diameter with a grade of L-80 13Cr80 with JFEBear™ style threading.
- Cementing was performed in one stage, with a lead cement slurry running from 0 – 4,170’ and is blended as 35:65 Poz:H class of cement. The tail slurry runs from 4,170’ – 7,219’ and is EverCRETE* CO_2 resistant cement.
- The drilling fluid used was a KCl-based xanthan polymer with a weight of 9.8 ppg.

Completion:

After drilling was complete, an extensive program of injectivity testing was performed. The details of this testing are summarized in the Injectivity Testing Results section of this report. The results of the injectivity testing led to the decision to add a second perforated interval to ensure the well would have sufficient injectivity capacity to inject the full rate necessary to achieve project injection goals.

- Cased-hole logs were run to confirm well integrity and develop baseline pulsed-neutron data.
- The well is perforated in the intervals from 6,977 feet – 6,978 feet, 6,982 feet – 7,012 feet and 7,025.5 feet – 7,050.5 feet (wireline depth), with six (6) shots per foot and a shot phasing of 60 degrees.
- After the perforating and injectivity testing, the injection tubing was run from 0 – 6,363 feet. The tubing is 4 ½ inches in diameter, with a weight of 12.6 lbs/ft and a grade of 13Cr85, with JFEBear™ type threading.
- The top of the packer is set at a wireline-referenced depth of 6,363.7 feet with the center of the sealing elements at 6,365 feet in depth. The packer used in the completion assembly is a seal bore, retrievable production type of packer. The packer is a QUANTUM MAX* HPHT gravel-pack system conditions Type III. The service tool for the packer is a Q-Max 13 chrome tool.
- A tubing mounted, down-hole pressure and temperature gauge is installed at a measured depth (MD) of 6,325 feet and is a Schlumberger NDPG-CA gauge.
- A four-component, tubing mounted, WellWatcher PS3* passive seismic sensing system is installed at three depths: 4,925 feet, 5,743 feet and 6,137 feet.
- A distributed temperature system (DTS) fiber optic cable that measures temperature every 1.624 feet within a thousandth of degree of accuracy every 5 seconds is installed on the tubing to a depth of 6,326 feet.
- The completion fluid is a brine with a weight of 9.4 ppg, with corrosion inhibitor and oxygen scavenger additives.

Drilling and Completions Results for VW1

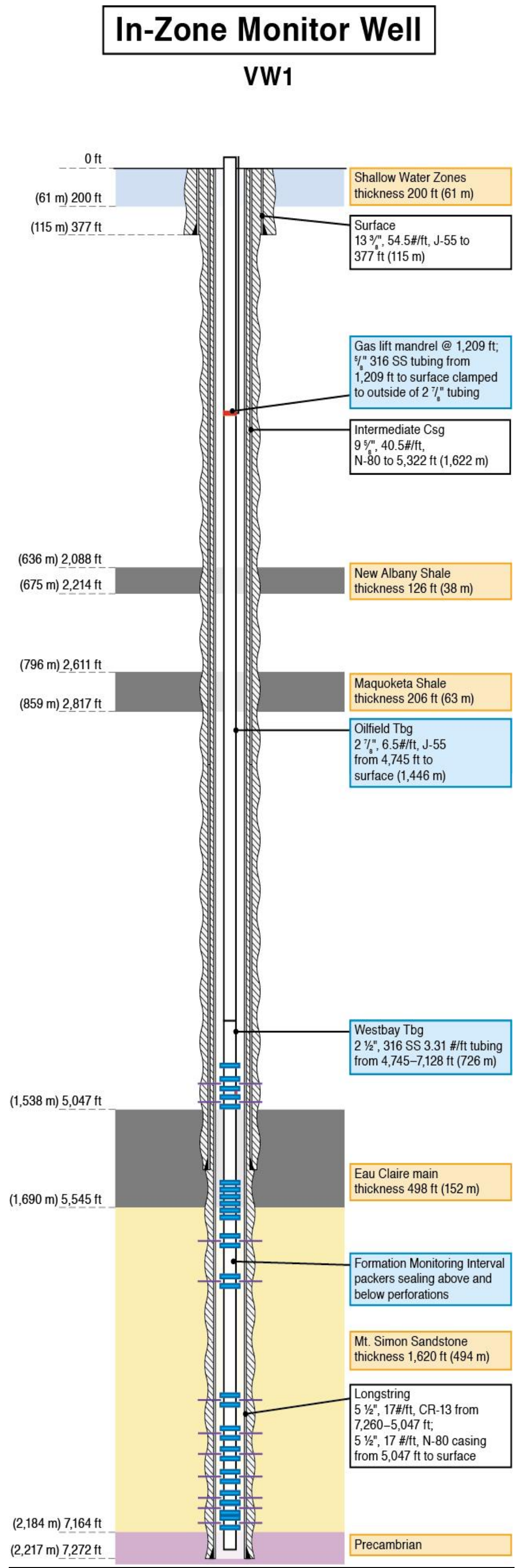


Figure 3 – VW1 In-Zone Monitoring Well Details

VW1 is located at 39˚ 52’ 47.22959” N and 88˚ 53’ 36.14288” W (NAD 83 coordinate system), which is 605 feet North and 1,175 feet East in the Southwest quadrant of Section 32 of Township 17 North and Range 3 East in Macon County, IL (see Figure 4). The well location’s ground elevation is 669.20 feet (NAVD 1988 coordinate system) above MSL.

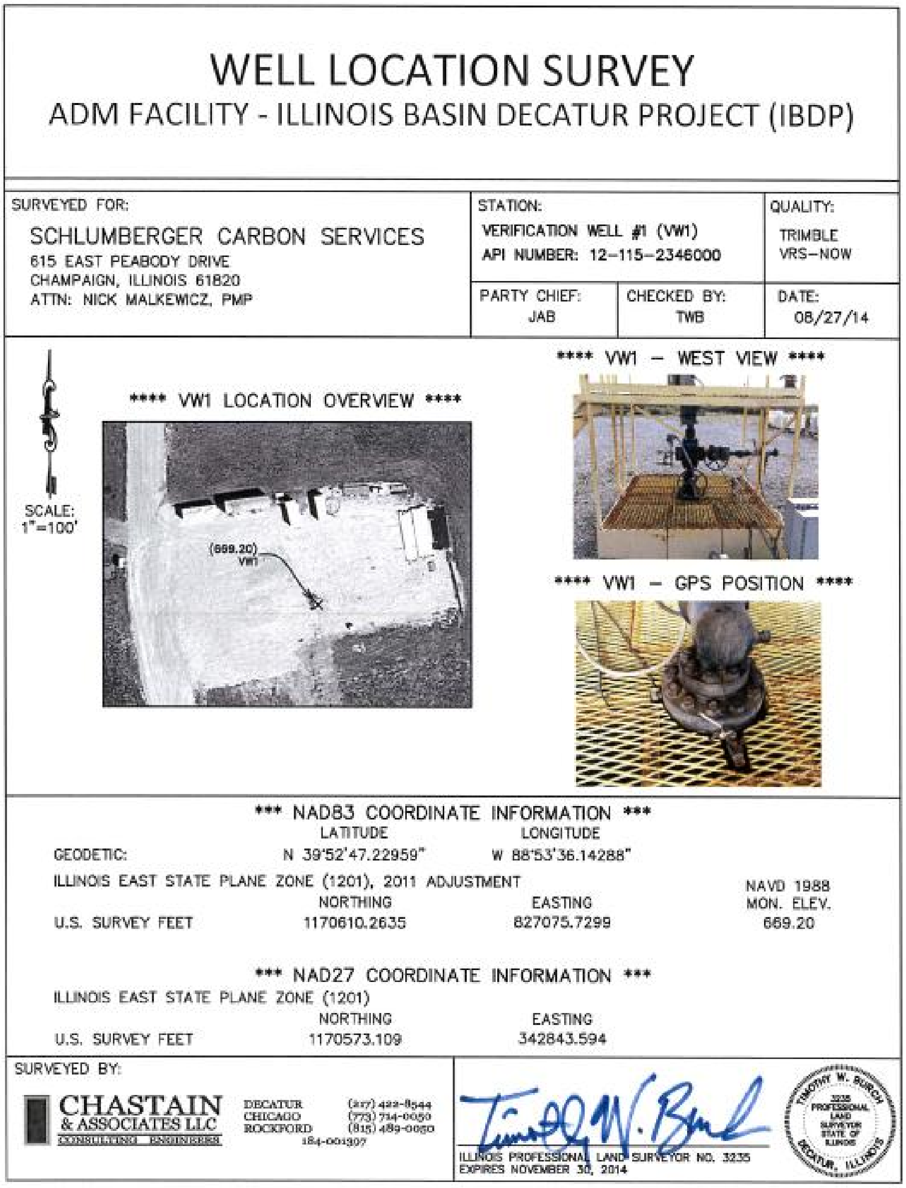


Figure 4 – VW1 Location Survey Details

The well was drilled by Pioneer Oilfield Services, LLC, using their rig number 15, which has a kelly bushing elevation of 15 feet above ground level. The total well cost was approximately USD $4.4 million. The well was constructed in three sections: 1) surface; 2) intermediate; and 3) final. Initial drilling (“spudding”) began on Sep 23, 2010, and finished on November 21, 2010. The completion was performed from April 28, 2011 to June 11, 2011.

The details of each section are as follows:

Surface Section:

- The open-hole section was drilled from 0 – 377 feet using a 17.5-inch diameter bit.
- The casing was set from 0 - 377 feet using 13 3/8-inch diameter casing, with a weight of 54.5 lbs/ft and grade of J-55, with STC style threading.
- The casing was cemented to surface using Class A cement with a lead and tail mix.
- The drilling fluid used was water/gel with a weight of 9.8 ppg.

Intermediate Section:

- The open-hole section was from 377 feet – 5,322 feet, using a 12.25-inch diameter bit.
- This section of the well was cored through the New Albany and Knox sections for a total length of 119 feet. The retrieved core depth intervals were: 2,132 feet – 2,159 feet, 4,218 feet – 4,264 feet, and 4,513 feet – 4,559 feet. The lost circulation zone was cored in this last interval.
- The casing runs from 0 – 5,322 feet and is 9 5/8-inches in diameter, with a weight of 40.5 lbs/ft and a grade of N-80, and LTC style threads.
- Cementing was performed from total depth to surface in two stages. The first stage of cement runs from 3,692 feet – 5,322 feet and is a Class H cement blend with a lead and tail mix. The second stage of cement runs from 0 – 3,692 feet is a 35:65 Poz:H lead cement blend with a Class H tail cement.
- The drilling fluid used was a dispersed gel with a weight of 9 ppg and a fluid viscosity of 50.
- A lost circulation zone was encountered at the depth of 4,460 feet. Based on the lessons learned in drilling CCS1, the lost circulation zone was sealed using cement plugs without any attempts to utilize LCM. Plug placement technique was refined so that circulation was restored after only three days of lost time compared to 10 days lost on CCS1.

Final Section:

- The open-hole section was drilled from 5,322 feet – 7,272 feet using an 8.5-inch diameter bit.
- This section of the well was cored through the Eau Claire and Mt. Simon sections for a total length of 588 feet. The retrieved core depth intervals were: 5,425 feet – 5,564 feet, 5,930 feet – 5,990 feet, and 6,680 feet – 7,069 feet.
- Two grades of casing were set. The upper casing string runs from 0 – 5,056 feet and is 5 1/2 inches in diameter, with a weight of 17 lbs/ft and a grade of J-55, with LTC style threads. The lower string of casing runs from 5,056 feet – 7,272 feet and is 5 ½ inches in diameter, with a weight of 17 lbs/ft and a grade of 13Cr85 with JFEBear™ style threads.
- Cementing was performed in one stage with a lead slurry running from 0 – 4,950 feet and is blended as 35:65 Poz:H cement. The tail slurry runs from 4,950 feet – 7,272 feet and is EverCRETE CO_2 resistant cement.
- The drilling fluid used was a KCl gel with a weight of 9.1 ppg and a fluid viscosity of 65.

Completion:

The VW1 well was completed to become both an in-zone and above-zone monitor well. Eight discrete sets of perforations were placed in the Mt. Simon formation. One set of perforations was placed below the Mt. Simon Formation in the Precambrian Formation, and two sets were placed above the caprock in the Ironton Galesville Formation. The completion centered around the installation of the Westbay* multilevel groundwater characterization and monitoring system that would provide the ability to monitor temperature and pressure in each of the 11 sets of perforations and provide the ability to sample formation fluids for geochemistry research.

- Cased-hole logs were run, confirming the well had excellent wellbore integrity. Baseline pulse-neutron logs were run as well.
- Perforation details are summarized in Table 3.

Table 3 - VW1 Perforation Details

Zone	Measurement Port (MD ft)	Perforation Top (MD ft)	Perforation Bottom (MD ft)	Formation Name	Shot Phasing (deg.)	Total Shots
11	4,917.0	4,917.5	4,920.5	Ironton-Galesville	60	18
10	5,001.1	5,000.7	5,003.7	Ironton-Galesville	60	18
9	5,653.3	5,653.8	5,657.3	Mt. Simon	120	11
8	5,839.8	5,840.4	5,843.9	Mt. Simon	120	11
7	5,415.6	6,416.2	6,419.7	Mt. Simon	120	11
6	6,631.7	6,632.3	6,635.8	Mt. Simon	120	11
5	6,719.7	6,720.3	6,723.8	Mt. Simon	120	11
4	6,837.3	6,837.1	6,840.6	Mt. Simon	120	11
3	6,945.0	6,945.6	6,949.1	Mt. Simon	120	11
2	6,982.4	6,983.0	6,986.5	Mt. Simon	120	11
1	7,060.6	7,061.2	7,064.2	Precambrian	60	18

- Once the zones were perforated, each zone was isolated using a packer and retrievable bridge plug. Extensive swabbing was performed to clean out invaded drilling fluids from the zone and to obtain a native formation fluid sample.
- The VW1 production tubing was run from 0 – 4,745 feet and is 2 7/8 inches in diameter, with a weight of 6.5 lbs/ft and a grade of J-55, and External Upset Ends (EUE) 8 rd threads. The proprietary Westbay tubing (detailed below) was run from 4,745 feet – 7,128 feet. The tubing deployment included a gas-lift mandrel installed at 1,209 feet with 5/8-inch stainless steel tubing run to surface and clamped outside of the 2 7/8 inch tubing. This gas-lift mandrel was to be used for establishing a temporary underbalanced condition in the well to allow for each monitor zone to be purged prior to sampling. This proved to be a useful tactic to purge each zone prior to sampling during the project.

- A Westbay system was installed on tubing from 4,745 feet – 7,128 feet and is 2 ½ inches in diameter, with a weight of 3.31 lbs/ft and a grade of 316 SS, with pin-up/box (captive nut) down and proprietary Westbay/ACME threading.
- The Westbay system consists of 28 packers set to straddle the perforated zones. The summary of the Westbay packer depths is presented in Table 4.

Table 4 - Summary of Westbay Packer Summary Depths

Packer #	Top Depth (MD ft.)	Packer #	Top Depth (MD ft.)	Packer #	Top Depth (MD ft.)
P1	7,081.4	P2	7,034.2	P3	7,003.3
P4	6,956.1	P5	6,918.7	P6	6,858.2
P7	6,811.0	P8	6,740.6	P9	6,693.4
P10	6,652.6	P11	6,605.4	P12	6,436.5
P13	6,389.3	P14	5,860.7	P15	5,813.5
P16	5,674.2	P17	5,627.0	P18	5,502.4
P19	5,456.6	P20	5,410.9	P21	5,365.2
P22	5,329.3	P23	5,283.5	P24	5,021.0
P25	4,973.8	P26[1]	4,937.9	P27	4,890.7
P28	4,823.8				
[1] Indicates packer did not inflate normally.					

Drilling and Completions Results for GM1

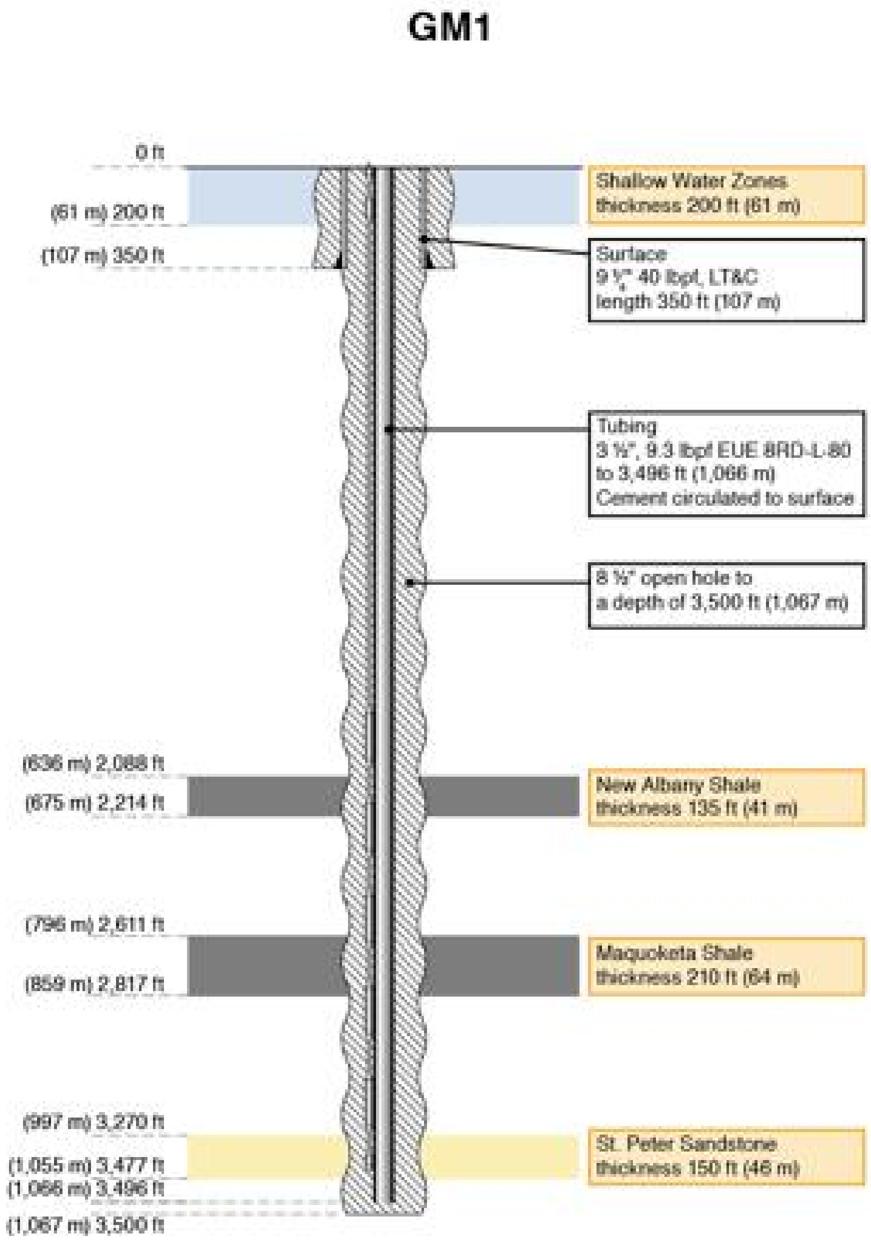
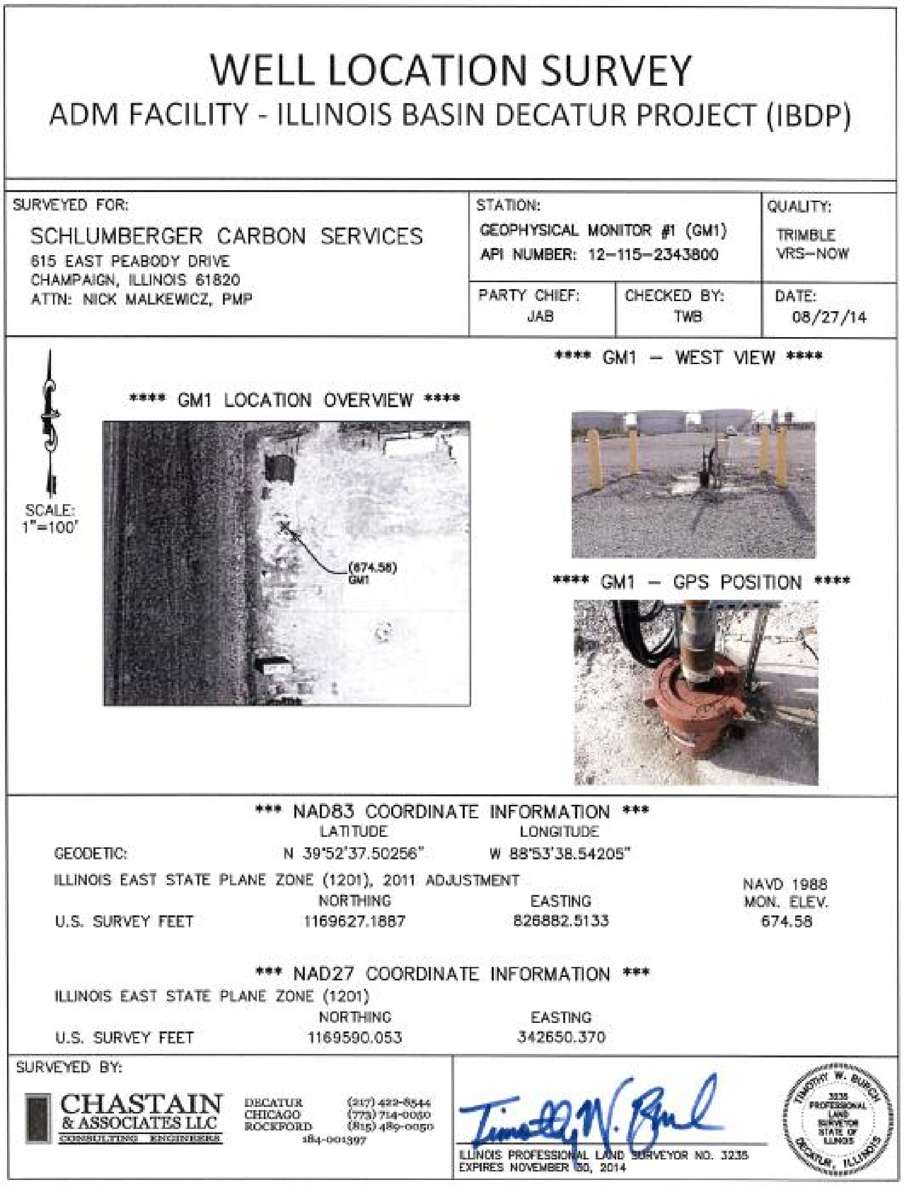


Figure 5 – GM1 Geophysical Monitoring Well Details

GM1 is located at 39˚ 52' 37.06469" N and 88˚ 53' 36.25685" W (NAD83 coordinate system), which is 390 feet South and 185 feet West of the Northeast corner of the Northwest corner of the Northwest corner of Section 5 of Township 16 North and Range 3 East in Macon County, IL (see Figure 6). The well location's ground elevation is 647.58 feet (NAVD 1988 coordinate system) above MSL.



WELL LOCATION SURVEY

ADM FACILITY - ILLINOIS BASIN DECATUR PROJECT (IBDP)

SURVEYED FOR:
SCHLUMBERGER CARBON SERVICES
615 EAST PEABODY DRIVE
CHAMPAIGN, ILLINOIS 61820
ATTN: NICK MALKEWICZ, PMP

STATION:
GEOPHYSICAL MONITOR #1 (GM1)
API NUMBER: 12-115-2343800

QUALITY:
TRIMBLE
VRS-NOW

PARTY CHIEF: JAB

CHECKED BY: TWB

DATE: 08/27/14

*** NAD83 COORDINATE INFORMATION ***

	LATITUDE	LONGITUDE	
GEODETIC:	N 39°52'37.50256"	W 88°53'38.54205"	

ILLINOIS EAST STATE PLANE ZONE (1201), 2011 ADJUSTMENT

	NORTHING	EASTING	NAVD 1988 MON. ELEV.
U.S. SURVEY FEET	1169627.1887	826882.5133	674.58

*** NAD27 COORDINATE INFORMATION ***

ILLINOIS EAST STATE PLANE ZONE (1201)

	NORTHING	EASTING
U.S. SURVEY FEET	1169590.053	342650.370

SURVEYED BY:
CHASTAIN & ASSOCIATES LLC
CONSULTING ENGINEERS
DECATUR (217) 422-8544
CHICAGO (773) 714-0050
ROCKFORD (815) 489-0050
184-001397

ILLINOIS PROFESSIONAL LAND SURVEYOR NO. 3235
EXPIRES NOVEMBER 30, 2014

TIMOTHY W. BURCH 3235 PROFESSIONAL LAND SURVEYOR STATE OF ILLINOIS DECATUR, ILLINOIS

Figure 6 – GM1 Location Survey Details

The well was drilled by Pioneer Oilfield Services, LLC, using their rig number 15, which has a kelly bushing elevation of 15 feet above ground level. The total well cost was approximately USD $4.0 million. The well was constructed in two sections: a surface section and a final section. Initial drilling ("spudding") began on October 29, 2009 and was finished on November 7, 2009. This well did not have a completion.

The details of each section are as follows:

Surface Section:

- The open-hole section was drilled from 0 - 351 feet using a 12.25 inch diameter bit.
- The casing was set from 0 - 350 feet using 9 5/8-inch diameter casing.
- Casing was cemented to surface using Class A cement.
- The drilling fluid used was water.

Final Section:

- The open-hole section was drilled from 351 feet – 3,500 feet, using an 8.5 inch diameter bit.
- The casing string runs from 0 – 3,496 feet and is 3 ½-inches in diameter, with a weight of 9.3 lbs/ft, EUE and a grade of L-80.
- Cementing was performed from total depth to surface and is Franklin blend of expansive cement, 10/10 FSS cement with 0.2% C-13 retarder and 1/8 pound per sack flake additives.
- The drilling fluid used was a water-based mud with a weight of 9.6 ppg and a fluid viscosity of 85.

Completion:

- 31 Geospace Technologies Corporation three component dual 10 Hz SMC-1850 geophones were run in on the casing and cemented in place. A perforating gun orienting device was added to the casing string for the option to perforate away from the geophones if an additional monitor well was needed. The geophone depths are summarized in Table 5.

Table 5 - GM1 Geophone Depths

Geophone Level	Depth (feet)	Geophone Level	Depth (feet)	Geophone Level	Depth (feet)
1	135	12	2,493	23	3,043
2	355	13	2,543	24	3,093
3	2,045	14	2,593	25	3,143
4	2,095	15	2,643	26	3,193
5	2,145	16	2,693	27	3,243
6	2,195	17	2,743	28	3,293
7	2,245	18	2,793	29	3,343
8	2,295	19	2,843	30	3,393
9	2,345	20	2,893	31	3,443
10	2,393	21	2,943		
11	2,443	22	2,993		

Injectivity Testing Results

Appendix N gives a detailed summary of the results of the step-rate injectivity testing which took place during the initial (Phase I) completion of CCS1. The injectivity testing results obtained during the Phase I completion were used to make the decision to increase the total perforated interval and to perform an acid treatment of the injection well to ensure the well would have sufficient injectivity capacity to inject the full rate necessary to achieve project injection goals.

The injectivity testing results were further used by the reservoir engineers, geologists, and other project research partners to perform modeling and simulation to confirm the CO_2 plume evolution conformed to expectations, and as data for numerous other related research projects.

The CCS1 step-rate test results are illustrated in Figure 7. The fracture propagation pressure is 4,966 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. The step rate test revealed a fracture pressure of 5,024 psig at 7,025 feet, which is a fracture gradient of 0.715 psi/ft.

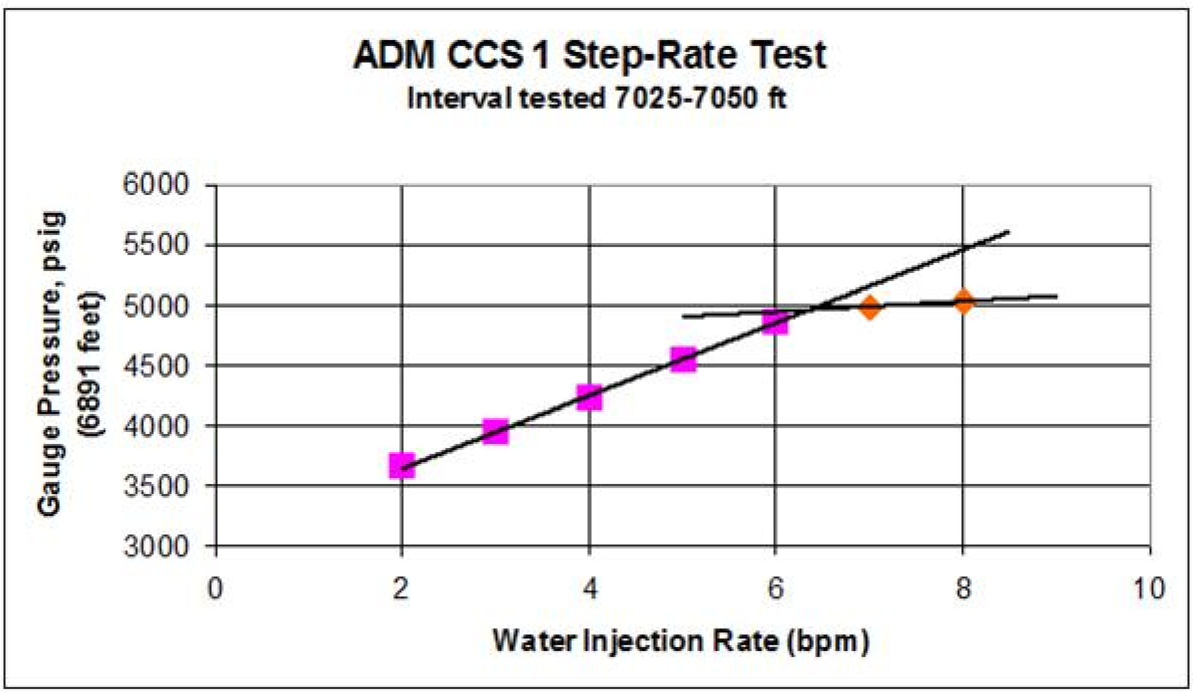


Figure 7 - CCS1 Step-Rate Test Results

In addition to the step rate test, two pressure falloff (PFO) tests were performed (Frailey, 2010). A PFO test involves two parts. During the first part of the test, the reservoir is stressed by injecting fluid, which changes the reservoir pressure. During the second part, the reservoir pressure is monitored as it returns to its pre-test pressure. The PFO tests performed on CCS1 were of varying duration and were conducted in September and October 2009 as part of the initial completion. The PFO tests used water treated with clay stabilizing potassium chloride substitute. These tests are summarized in Table 6.

Table 6 - PFO Tests on CCS1

Name	Rate / Length	Injection Length	Shut-in Period	Interval (feet)	Notes
PFO-1	1.5-2 bbl/min	2 hrs	19.5 hrs	7,025-7,050	First perforation
PFO-2	3.1 bbl/min	5 hrs	45 hrs	7,025-7,050	After acidizing
PFO-2	3.1-4.2 bbl/min and 4.2 bbl/min	6.5 hrs & 6.5 hrs	105 hrs	7,025-7,050 and 6,982-7,012	Second zone perforated and acidized for this test

Pressure transient analyses were performed on the data gathered from these PFO tests using pressure transient analysis software.

During the first PFO test, because only 25 feet of perforations were open in a very large vertical formation (gross thickness 1,505 feet), a partial penetration or partial completion effect was expected. The derivative of the falloff illustrated the partial penetration effect (see Figure 8). Two radial 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 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 period that is influenced by vertical permeability (or kv/kh).

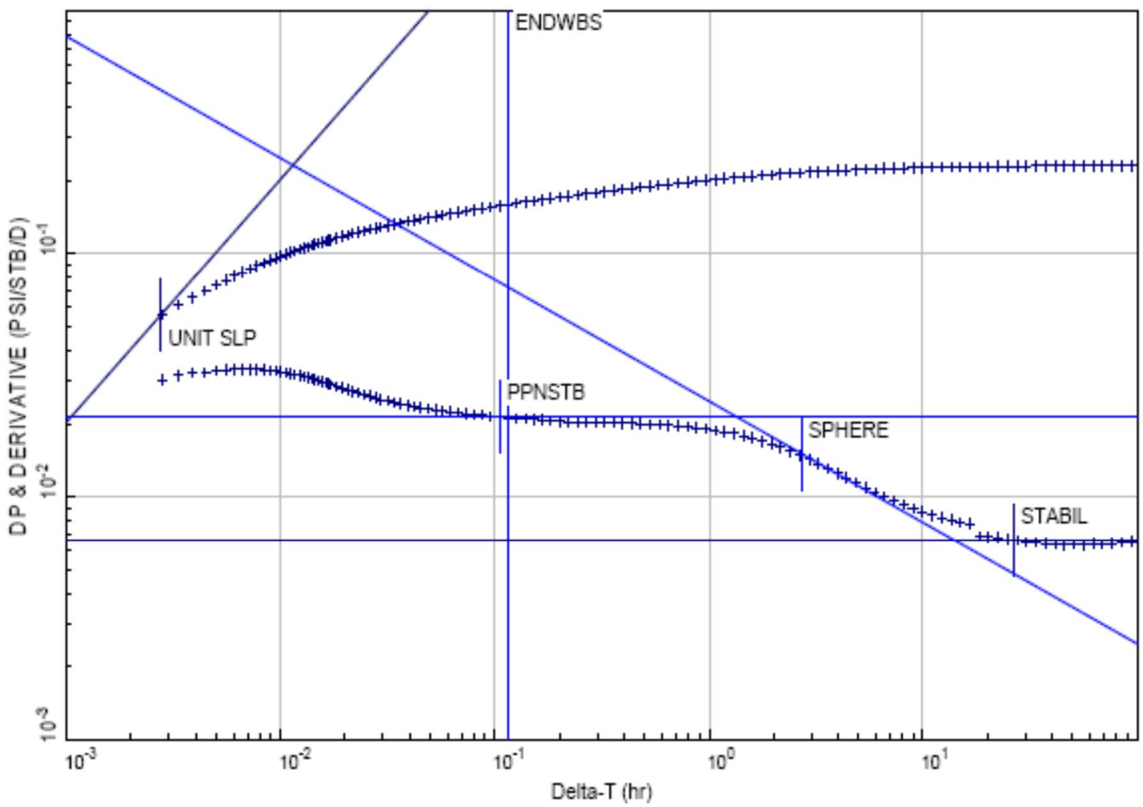


Figure 8 - Derivative Analyses of Final PFO Test

The derivatives of the three pressure falloff tests were overlain (see Figure 9). 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 indicate that the second set of perforations did not change the permeability estimated from the pressure transient tests. 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. The green curve (upper pressure curve and bell shaped derivative) is the first falloff (PFO-1). The pink (lower derivative curve) is the second falloff (PFO-2). The dark blue (lower pressure curve middle derivative curve) was the third falloff tests (PFO-3). The difference between the green curve and the pink curve in the first six (6) minutes is a result in the improvement to flow due to the acid treatment.

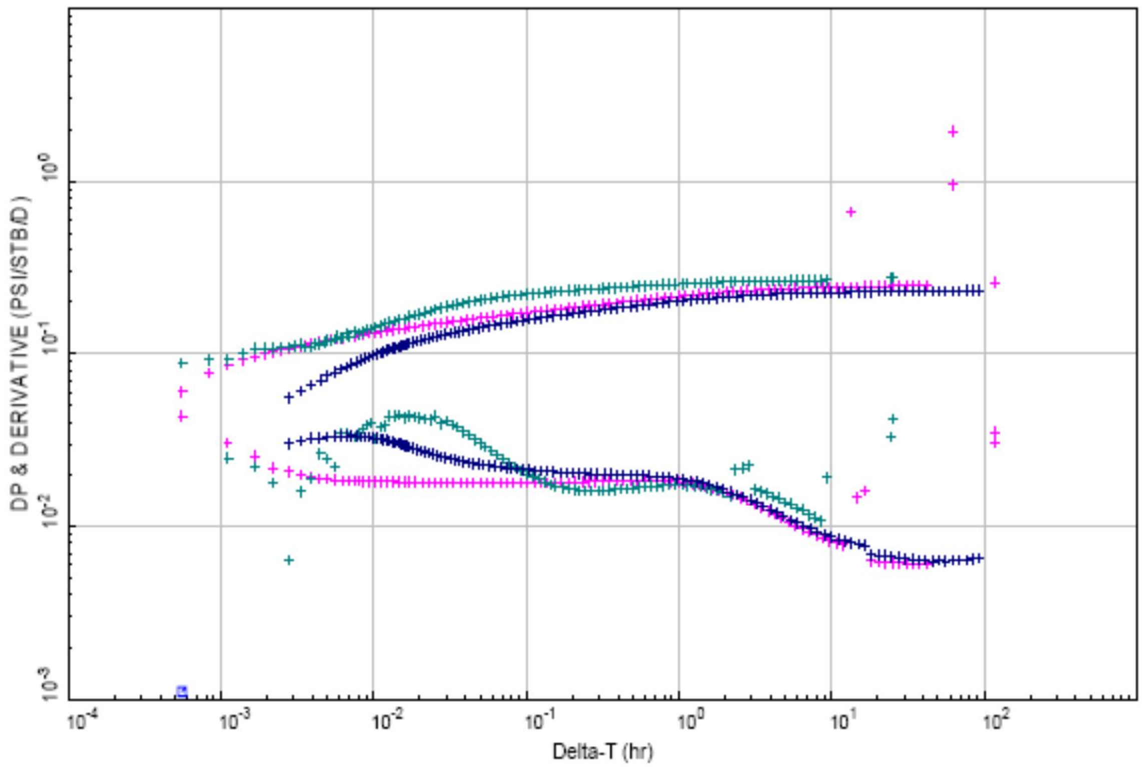
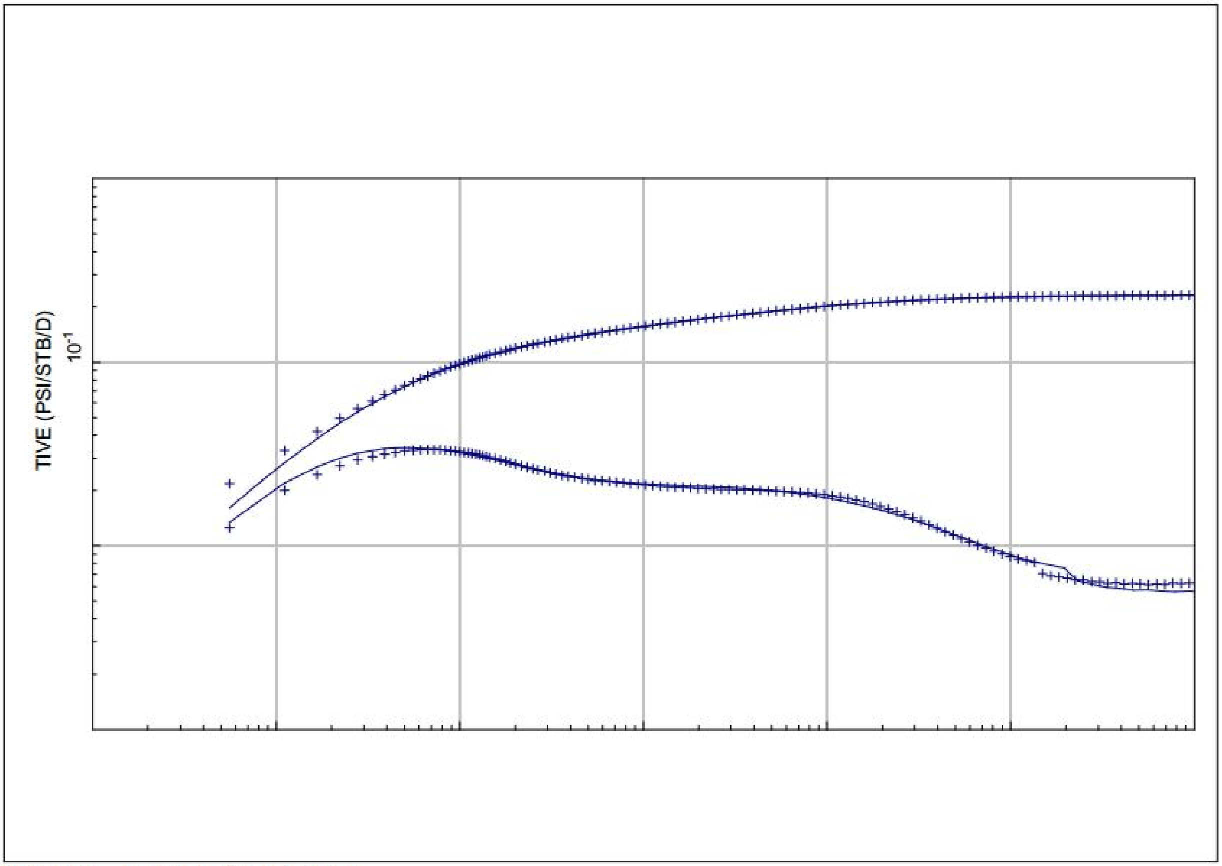


Figure 9 - Overlay of Pressure Derivative of the Three PFO Tests

Simulation of this pressure transient data using analytical solutions (see Figure 10), gave a permeability of 185 mD over 75 feet of vertical thickness. The transition period gave a vertical permeability over the 75 ft as 2.45 mD (kv/kh = 0.01326). Additionally, it is observed that the Mt. Simon initial pressure at CCS1 at 7,025 feet is about 3,200 psig. These results agreed well with log and core data.



Partial Penetration Well
** Simulation Data **
well. storage = 0.0011457 BBLS/PSI
Skin(mech.) = -0.85807
permeability = 184.58 MD
Kv/Kh = 0.013260
Eff. Thickness = 75.000 FEET
Zp/Heff = 0.83330
Skin(Global) = 10.301
Perm-Thickness = 13843. MD-FEET

Type-Curve Model Static-Data
Perf. Interval = 25.0 FEET

Static-Data and Constants
Volume-Factor = 1.000 vol/vol
Thickness = 75.00 FEET
Viscosity = 1.300 CP
Total Compress = .1800E-04 1/PSI
Rate = -6100. STB/D

Figure 10 – Non-linear Regression or Simulation History Matching of the Final PFO test.

HSE Results

Well drilling, completion and data collection involved numerous parties, and required good coordination between the site owner/operator (ADM), the drilling contractor, Schlumberger Carbon Services, ISGS, and other well-drilling and completion contractors.

It was recognized early in the project that HSE would require substantial coordination. As a result, Drill Well on Paper (DWOP) and Complete Well on Paper (CWOP) exercises were held, and all key contractors attended for all wells. HSE plans were discussed in detail during these exercises and plans modified to improve HSE performance. Expectations were also clearly set during these meetings. Job Safety Analysis (JSA) and/or Hazard Analysis and Risk Control (HARC) were performed prior to any actual work starting. Safety meetings were held regularly during ongoing operations. The continuous commitment to safety represented a substantial commitment of time and resources, but was integral to the exemplary HSE performance on the project. The following list summarizes the safety statistics for each of the wells:

- CCS1 and GM1 – Zero recordable incidents. Over 35,000 estimated man-hours for drilling and completion.
- VW1 - Zero recordable incidents. Over 17,000 estimated man-hours for drilling and completion.

Appendix O presents a detailed summary of HSE performance during the drilling, data collection, and completion of the three wells.

Open-hole and Cased-hole Data Collection Results for CCS1 and VW1

The detailed wireline open-hole logging program results are summarized in appendices P and Q. The detailed results of the cased-hole logging program are summarized in appendices R and S. Summary tables of all the logs run on each well are presented in Tables 7a, b, and c.

The open- and cased-hole logs provided key input into simulation and modeling efforts required to meet both research objectives and IEPA requirements. The logs verified both caprock and reservoir rock integrity and extent. The cased hole logging results verified mechanical integrity and provided a baseline for time-lapse, cased-hole logging which provided ground truth measurements to verify the accuracy of simulation and modeling efforts as well as to meet IEPA reporting requirements as specified in the permit.

Actual core recovery is detailed in the drilling and data collection portion of this document. Extensive core testing was performed, but the details of this testing are outside the scope of this report.

Table 7a – CCS1 Well Log Listing

Well	Date	Tool	Top	Bottom
CCS1	3/9/09	Platform Express* integrated wireline logging tool	352	3,541
CCS1	4/5/09	Platform Express	352	5,317
CCS1	4/5/09	High-Resolution Laterolog Array	352	5,317
CCS1	4/5/09	Sonic Scanner* acoustic scanning platform	352	5,317
CCS1	4/5/09	FMI* fullbore formation micro-imager	352	5,317
CCS1	4/5/09	CMR* Combinable Magnetic Resonance tool	352	5,317
CCS1	4/5/09	ECS* elemental capture spectroscopy sonde	352	5,317
CCS1	4/5/09	Hostile Environment Natural Gamma Ray Sonde	352	5,317
CCS1	4/5/09	MSCT* mechanical sidewall coring tool	352	5,317
CCS1	4/5/09	Cement Bond Log	50	352
CCS1	4/5/09	Directional Survey	352	5,317
CCS1	4/6/09	4 Arm Caliper	352	5,317
CCS1	4/26/09	Platform Express	5,339	7,221
CCS1	4/26/09	High-Resolution Laterolog Array	5,339	7,221
CCS1	4/26/09	Sonic Scanner	5,339	7,221
CCS1	4/26/09	FMI	5,339	7,221
CCS1	4/26/09	CMR	5,339	7,221
CCS1	4/26/09	ECS	5,339	7,221
CCS1	4/26/09	Hostile Environment Natural Gamma Ray Sonde	5,339	7,221
CCS1	4/26/09	MSCT	5,339	7,221
CCS1	4/26/09	MDT* modular formation dynamics tester	5,339	7,221
CCS1	4/26/09	VSI* Versatile Seismic Imager	5,339	7,221
CCS1	8/27/09	Cement Bond Log	50	7,142
CCS1	8/27/09	PS Platform Multifinger Imaging Tool	50	7,142
CCS1	8/27/09	Isolation Scanner* cement evaluation service	50	7,142
CCS1	8/28/09	RST* reservoir saturation tool	200	7,142
CCS1	8/28/09	Pressure, Temperature and Gamma Ray	200	7,142
CCS1	9/23/09	Perforation Record	6,700	7,133
CCS1	9/25/09	Correlation Log	0	7,050
CCS1	9/28/09	Production Log	6,900	7,070
CCS1	11/19/09	Casing Collar Locator - Junk Basket - Gauge	200	6,390
CCS1	9/19/11	RST	230	7,136
CCS1	9/19/11	Pressure Temperature	230	7,136

Table 7b – GM1 Well Log Listing

Well	Date	Tool	Top	Bottom
GM1	11/4/09	Platform Express	0	3,500
GM1	11/4/09	High-Resolution Laterolog Array	0	3,500
GM1	11/4/09	Directional Survey	3,498	346
GM1	2/3/10	Cement Bond Log	50	3,441
GM1	2/3/10	Pressure Temperature	20	3,441
GM1	11/15/10	Cement Bond Log	0	3,500
GM1	9/20/11	RST	230	3,431
GM1	9/20/11	Pressure Temperature	230	3,431

Table 7c – VW1 Well Log Listing

Well	Date	Tool	Top	Bottom
VW1	10/23/10	Platform Express	367	5,320
VW1	10/23/10	High-Resolution Laterolog Array	367	5,320
VW1	10/23/10	Sonic Scanner	367	5,320
VW1	10/23/10	FMI	367	5,320
VW1	10/23/10	CMR	367	5,320
VW1	10/23/10	ECS	367	5,320
VW1	10/23/10	Hostile Environment Natural Gamma Ray Sonde	367	5,320
VW1	10/23/10	MSCT	367	5,320
VW1	10/23/10	MDT	367	5,320
VW1	10/23/10	Spontaneous Potential	367	5,320
VW1	10/24/10	Cement Bond Log	0	367
VW1	11/15/10	Platform Express	5,306	7,264
VW1	11/15/10	High-Resolution Laterolog Array	5,306	7,264
VW1	11/15/10	Rt Scanner* triaxial induction service	5,306	7,264
VW1	11/15/10	Sonic Scanner	5,306	7,264
VW1	11/15/10	FMI	5,306	7,264
VW1	11/15/10	CMR	5,306	7,264
VW1	11/15/10	ECS	5,306	7,264
VW1	11/15/10	Hostile Environment Natural Gamma Ray Sonde	5,306	7,264
VW1	11/15/10	MSCT	5,306	7,264
VW1	11/15/10	PressureXpress* reservoir pressure while logging service	5,306	7,264
VW1	11/15/10	UCI* ultrasonic casing imager	0	5,306
VW1	11/16/10	Directional Survey	115	7,270
VW1	3/15/11	Cement Bond Log	50	7,120
VW1	3/15/11	Isolation Scanner	50	7,100
VW1	3/15/11	Pressure Temperature	50	7,150
VW1	3/15/11	RST	200	7,130
VW1	5/2/11	Perforation Record	6,635	7,064
VW1	5/2/11	PS Platform Multifinger Imaging Tool	0	7,140
VW1	5/2/11	Pressure Temperature	8	7,140
VW1	9/19/11	Pressure Temperature	230	7,114
VW1	9/19/11	RST	230	7,114

III. Drilling and Data Collection – Unanticipated Results

Drilling and Completions Plans – Unanticipated Results

- **Lost Circulation**
  While drilling CCS1 at a depth of 4,562 feet, drilling fluid circulation returns were lost in the Potosi section of the Knox Formation. The first attempts at lost circulation remediation consisted of mixing and administering several small batches of special purpose drilling fluid (“pills”). These pills were comprised of Lost-Circulation Material (LCM) built to 25 pounds per barrel (lbs/bbl.), two sodium silicate pills, and three Schlumberger fibrous pills. These attempts were ultimately unsuccessful, and necessitated the selective positioning (“spotting”) of two cement plugs in the well across the lost circulation zone. The cement plugs were successful in re-establishing drilling fluid circulation, and drilling proceeded. At a depth of 5,120 feet, additional seepage problems were encountered. The lost circulation was subsequently remediated by spotting another cement plug, and drilling proceeded to the total depth of the intermediate section. This methodology was applied to subsequent wells, and is also highlighted in Section IV of this report.

- **Insufficient Perforation**
  The Phase I scope for CCS1 included perforating, reservoir testing, and setting of the lower packer in preparation for the Phase II completion (installing injection tubing and completion hardware). At the time of the CCS1 completion, there was little information in the literature to correlate water injection with CO_2 injection. While the results obtained from opening the first 25-foot section in the Lower Mt. Simon Formation were promising, stakeholders made the unanimous decision to add additional perforations to ensure all project injectivity goals would be fully met. A small acid clean-up was performed in an attempt to establish injectivity across all perforations, and further reservoir testing was performed. Additional data were necessary to gain a better understanding of reservoir behavior and raise confidence in the ability of the reservoir and perforated interval to support the necessary injection volumes and rates.

- **Budget and Schedule Considerations**
  Although careful consideration was given to the funding requirements of the additional perforating, testing, rig time, and gauge rental necessary for the project, the planned budget proved inadequate to meet the additional cost of non-standard operations.

  Phase II of the completion required a larger rig to install the injection tubing and associated downhole hardware. Two issues arose that increased the time required to accomplish this phase. Given budget constraints, the original plan called for working 24 hours per day in order to reduce rental costs for the rig and other associated equipment. Upon startup, it became quickly apparent that due to weather conditions and operational intricacies, 24-hour operations posed an unacceptably high risk to personnel safety and successful operations. The decision was made to operate 12-hour days. Excess personnel and some equipment were immediately released in the move to 12-hour operations, but cost-per day could only be contained at around 70% of the 24-hour operations costs, while the total number of days required increased by nearly a factor of two. Additionally, a premature deployment failure of one of the permanent geophone levels required the entire tubing string to be pulled from the well for troubleshooting and remediation halfway into the installation. This failure further increased the total number of days required to complete the operation.

HSE Plans – Unanticipated Results

- There were no unanticipated results for HSE performance. The HSE Bridging Document was adhered to, and HSE performance was exemplary, with no lost time or recordable injuries during operations. Regular safety meetings were held, and the general safety attitude at the site was excellent.

Log Data Acquisition – Unanticipated Results

MDT sampling was complicated by the presence of LCM, which appeared to be plugging tool filters.

IV. Drilling and Data Collection – Lessons Learned

Drilling and Completions Plans Lessons Learned

1. The size and complexity of a CCS operation requires a unique set of technical skills and equipment which are not prevalent throughout the Illinois Basin or for the majority of land-based operations in the United States. As a result, greater training and preparation time was necessary, and a longer lead time was essential to order equipment that fulfilled operational requirements.

   Obtaining services and equipment in an economic environment where the oil and gas industry was utilizing nearly all available services and supplies was challenging and costly. In such an economic environment, vendors can be unwilling to mobilize or service projects outside their basin for a non-standard, limited-scope project, when they can service their traditional oil and gas customers and ensure greater certainty of future work.

   - **Lessons Learned**: 1) Similar highly complex and non-standard operations in the Illinois Basin will necessitate additional time and funding allocated in the project plan; 2) The costs to cover lost circulation remediation and complex completion were under-budgeted for the scope of work required; and 3) Extra funding and effort are necessary to sufficiently motivate vendors to mobilize outside of their traditional oil and gas customers when the market is at or near capacity.

2. Commercial contracts between project partners required more time than initially anticipated and had a significant impact on the project budget for the cost of supplies. Supplies – such as wellbore tubulars – can become relatively scarce when the oil and gas market utilization is at near-capacity levels, and result in much higher costs than anticipated. The project sponsor was approached, and the project budget was adjusted appropriately.

   - **Lesson Learned** – Market fluctuations in commodity prices can significantly impact the project budget and the length of time necessary to acquire essential supplies. Careful evaluation of the economic environment prior to budgeting is essential to the success of similar future projects, and flexibility in the project budget to allow for market fluctuations is highly desirable.

3. Planning for an increased margin of safety is essential in projects with non-standard operations, and adequate sizing of the equipment and its capacities are critical.

   - **Lessons Learned**: 1) For this project, a larger rig with larger handling tools and equipment would have made the operations safer and more efficient. Greater expenses for additional mobilization and day rate charges would also likely occur; 2) Blow-out preventers (BOPs) are required during the entire operation. Sufficient sub-structure under the rig is necessary to allow for a good fit. A larger rig would have helped to accommodate this; 3) A larger rig would typically have a de-sander and de-silters with larger capacities, and would have proved to be useful during the operation; and 4) A large, 7 feet by 7 feet cellar proved to be beneficial. This size was selected after careful consideration of the room required for BOPs, winterization equipment, cementing surface pipe, etc.

4. The presence of ADM's industrial support structure and personnel on site (and nearby) proved to be very beneficial. There was very good synergy maintained during the operations, and that proved useful in the drilling, completions, and data collection phases. ADM's support structure and on-site/nearby personnel were essential in performing fundamental but necessary support, including site set-up, acquisition of electricity, cleanup, procuring rentals, and many other tasks critical to the project's success.

    - **Lesson Learned** – Maintaining and leveraging the strengths and aid that all stakeholders can bring to the table provides for a mutually beneficial relationship for all project partners.

5. Contract stipulations required the contracted drilling company to have a person certified through either the International Well Control Forum (IWCF) or the International Association of Drilling Contractors (IADC) onsite at all times, and to maintain the pressure control equipment onsite in accordance with IWCF/IADC standards. Although Schlumberger Carbon Services required current well control certifications, local customs had not previously done so. This disparity led to additional costs and training time to bring onsite personnel current in well control certifications.

    - **Lesson Learned** – For future projects, committing to a well control plan and clearly communicating all expectations prior to the project start would lead to greater efficiency. Including extra time and funding for training requirements would be highly desirable.

6. The project encountered a significant and substantial loss of circulation while drilling through the Potosi interval of the Knox Group. After numerous and varied attempts to control the lost circulation through mud additives (LCM, pills, etc.), a cement lost circulation plug proved to be the most effective method to restore lost circulation in this formation.

    - **Lesson Learned** – Cement plugs proved to be the most effective solution for restoring lost circulation in the Potosi interval of the Knox Group.

7. Installation of PS3 geophones on the injection well tubing was complex and a previously unproven application of the technology. During downhole installation, the package deployed prematurely, necessitating a visual inspection to gauge potential damage to the system. Upon removal for troubleshooting, it was discovered that one of the geophones in the system had suffered terminal damage, further complicating the completion procedure. The remainder of the system was eventually installed successfully.

    - **Lesson Learned** – Future projects could benefit from carefully selecting technologies that balance research and regulatory objectives with operational considerations.

8. The geophone well (GM1) proved to be very useful, providing a relatively inexpensive permanent seismic string that could be used for microseismic monitoring and 3-Dimensional Vertical Seismic Profiling (3D VSP). The ability to orient perforations in GM1 allowed for additional above-zone fluid and/or pressure monitoring, had it become necessary. The ability to run RST logs and temperature logs in this well provided valuable options to prove no CO_2 had migrated above the caprock. The use of perforating in a nearby well as a sound source to check the geophone orientation was a successful tactic, and is likely to be incorporated into future projects whenever possible.

   - **Lesson Learned** – A nearby well with an above-zone geophone array for 3D VSP surveys and option for perforating for sampling and pressure measurements is a valuable tool in a CCS project. Geophone orientation shots to confirm geophone orientation and processing algorithms also proved highly beneficial.

9. Core collection during drilling proved to be relatively straightforward. Coordinating and executing the analysis plan between all stakeholders was quite challenging due to varied and frequently changing requirements. Additionally, results from core analysis took a substantial amount of time to receive.

   - **Lesson Learned** – A carefully crafted and documented core acquisition and analysis plan with stringent change control practices would have resulted in greater efficiency. Additionally, wait times to receive core analysis results were much longer than expected. For similar future projects, it may be beneficial to hire a coordinator to track analysis frequently, to respond quickly, and to manage, plan, and coordinate competing requests.

10. The installation of the Westbay string for pressure and temperature monitoring and the ability to take fluid samples is a very valuable technology to fulfill research requirements, but the technology is complex and was previously unproven in deep environments. Ongoing operations revealed that while the technology is sound, as utilized in this project, remedial operations may be required due to a high frequency of failure. In its current state, this technology requires substantial support if it is to be deployed at greater depths.

    - **Lesson Learned** – Future projects could benefit from carefully selecting technologies that balance research and regulatory objectives with operational considerations.

11. The well permitting process for this project did not deviate from the inherently slow pace of well permitting in general, and allowing adequate processing time in the plan was crucial. Additionally, when applying for a permit, it was found to be preferable to meet (rather than exceed) the regulatory requirements. The permit application submitted included some items that may have exceeded regulatory requirements for permit issuance; as a result, the project had to maintain additional operating condition requirements to avoid violation.

    - **Lesson Learned** – During the permitting process for this project, budgeting sufficient schedule time to accommodate for delays and planning for slow responses and multiple clarification requests was critical. For similar future projects, the aid of a professional permit writer familiar with the permit-issuing organization would likely be very helpful for both advice and the development of the permit application.

12. The annular pressure monitoring system required modifications to work properly. A pressure vent needed to be added, and the brine level fluctuation needed to be more tightly controlled than initially expected. Additionally, at startup there were wider-than-expected temperature swings due to seasonal temperature changes. An accumulator pressure vessel type system to account for annular volume changes due to seasonal temperature changes and well pressure fluctuations would have been a better choice for the project parameters.

    - **Lesson Learned** – A simple and proven annular pressure monitoring system – such as an accumulator pressure vessel type system – could provide a more useful solution for future projects.

13. The well designs for this project were complex. In general practice, complexity of well design often leads to complex operations and the potential for greater exposure to loss events.

    - **Lesson Learned** – Carefully considering the value added through additional instrumentation or complexity – and balancing this against the additional cost and risk exposure introduced – can prove to be a challenging, but necessary task for non-standard operations.

14. A Drill Well on Paper (DWOP) exercise was held for the IBDP project April 9-10, 2008. All major partners and vendors participated, and local personnel contributed numerous valuable suggestions – resulting in over 50 action items. This meeting proved very valuable in refining the well drilling plans. A follow-up Complete Well on Paper (CWOP) exercise was held in September 2009, just prior to starting completion activities.

    - **Lesson Learned** – Involving as many partners and vendors as possible when preparing to drill and/or complete wells is highly beneficial to the process, as is holding DWOP and CWOP exercises.

15. The final perforating program was heavily dependent on data acquired from well drilling and injectivity test results. The perforation decisions had to be made quickly, but required input from multiple data sources and multiple stakeholders. Careful planning of the perforation scheme was critical for project success, and giving this task the importance and complexity it required led to correct decision making.

    - **Lesson Learned** – Carefully planning the perforating scheme with focus on scheduling constraints and the dependent tasks proved to be a successful tactic. Knowing the decision workflow before operations began was very useful as well, and was covered in the CWOP exercise held during the project.

16. The gas-lift mandrel installed on the VW1 completion proved to be an excellent economic and effective solution to the required purging of each monitor zone prior to sampling. This

was used frequently in the early stages of the project to aid in obtaining uncontaminated samples from each monitor zone.

- **Lesson Learned** – Gas-lift is an excellent solution for creating an underbalanced condition when multi-zonal sampling is needed.

HSE Plans Lessons Learned

1. A safety meeting was held before initial drilling (spudding) began, at which all key operational team members reviewed the well plans and the HSE Bridging Document. This represented a substantial investment of time and money but was deemed worth the expenditure, as it facilitated operation-wide cooperation by both the operational team and the team leads representing key stakeholders.

    - **Lesson Learned** – Investing in and fully utilizing pre-spud operational safety meetings can provide project-wide cooperation and foster teamwork throughout the operation.

2. Illinois winters proved to be more challenging than expected. The rigs utilized had very little winterizing, and as a result, operations were delayed when temperatures were below freezing.

    - **Lesson Learned** – Future IBDP projects that span winter months could benefit from utilizing better-winterized rigs, planning additional time for completion, and establishing secondary operational plans.

Log Data Acquisition Lessons Learned

1. The wireline-deployed MDT used for formation fluid sampling provided several challenges. The formations tested exhibited high permeability and porosity, resulting in significant drilling fluid contamination into the formation. Contamination is routinely removed during MDT testing through pumping the contaminated fluids out of the formation, in a process known as formation clean-up. The MDT operator uses the resistivity monitor within the MDT to monitor the resistivity of the pumped fluid. Once resistivity stabilizes, the fluid is deemed to be primarily native formation fluid. This is an acceptable method for oilfield applications, but proved to be less than adequate for the IBDP project, where obtaining samples with the lowest levels of contamination possible was a top priority. As a result, higher-than-typical pump times were necessary to get the minimal levels of contamination requested. Additionally, even with the substantial pumping time for cleanup, it was difficult to ascertain the degree of cleanup using resistivity readings alone. As such, the additional employment of mud dyes may have been beneficial, as mud dyes can provide a more precise indication of the level of contamination than resistivity readings, and could provide a more accurate assessment of the level of formation clean-up.

    Frequent requirement changes by multiple stakeholders provided another challenge during MDT testing. A written plan published prior to MDT testing and a formal procedure to propose changes to it would have been beneficial and ensured greater satisfaction in meeting all stakeholder objectives.

- **Lessons Learned** – 1) When clean, pristine samples are paramount, higher-than-standard pumping operational costs for collecting formation fluid samples will likely be incurred. The use of mud dyes may be indicated; 2) Planning sampling operations earlier and implementing a formal procedure for requesting changes would have proved beneficial; and 3) MDT sampling may not be the optimal choice if LCM is needed or substantial drilling fluid invasion is expected as occurred in this project. In similar future projects, drill stem tests or cased-hole sampling may be considered as a better option when the use of LCM would potentially interfere with MDT sampling.

2. With any drilling operations there are challenges and sacrifices made in balancing between optimal well construction and optimal log data for petrophysical analysis. Key choices such as casing set point, hole size, and other parameters may be different when selecting to optimize for well logs versus selecting to optimize for well performance. After careful and thorough discussion, the decision was made to optimize for well performance. As a result, while log data overall was excellent, it was nonetheless lacking in some intervals of the wells. Better logs in some of these intervals would have been helpful in subsequent data analysis and modeling efforts. If future project constraints allow, it might be beneficial to plan an additional well which is optimized for data collection.

    - **Lesson Learned** – Balancing between well-performance optimization and the acquisition of well log data is a necessary, but challenging feature of non-standard operations, and both early decision making and timely communication of operational choices to all relevant stakeholders is essential.

* Mark of Schlumberger

VI. References Cited and Associated Articles and Abstracts

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

Finley, Robert J., Scott M. Frailey, Hannes E. Leetaru, Özgür Senel, Marcia L. Couëslan, and Scott Marsteller, 2013, Early operational experience at a one-million tonne CCS demonstration project, Decatur, Illinois, USA. 11th International Conference on Greenhouse Gas Control Technologies, Extended Abstract, Kyoto, Japan.

VII. Appendices

Table of Contents — Appendices

ISGS/ADM Well #1 –CCS
Final Well Plan-PTH Jr

ADM WELL #1-CCS
MGSC/ISGS/ADM PROJECT

WELL PLAN

Decatur, Illinois

ADM WELL #1 - CCS

WELL PLAN

Prepared by: PT Hughes, Jr., P.E. SCHLUMBERGER CARBON SERVICES ________________________ (signature) Date:	Agreed by: Les Wilson Drilling ________________________ (signature) Date:
Approved by: Scott Marsteller Schlumberger Carbon Services Project Manager ________________________ (signature) Date:	Agreed by: ISGS Project Committee Leader ________________________ (signature) Date:
Approved by: Ron Peterson ADM ________________________ (signature) Date:	Approved by: Tom Stone ADM ________________________ (signature) Date:

WELL PLAN DISTRIBUTION

ADM WELL #1 – CCS

DECATUR, ILLINOIS

ADM plant site:

1 – ADM Project Coordinator – ADM
1- ADM HSE Manager - ADM

ISGS:

1 – ISGS Project Committee Leader - ISGS
1- Chief Geologist-ISGS
1 – Assistant ISGS Project Committee Leader - ISGS
1 - Operations/Logistics Superintendent - ISGS

SCHLUMBERGER- Champaign, Illinois & Wellsite:

1 – SCS Project Manger - Schlumberger
1 – SCS Drilling/Logistics Coordinator - Schlumberger
1 – Project File - Schlumberger
1 - Drilling Engineer-SCS
1 - Engineer in Charge (wellsite) - Schlumberger
1 - Drilling Wellsite Supervisor - Schlumberger
1 – Mud logger – wellsite
1 – Wellsite geologist - Consultant
1 - Drilling Contractor - Office (Edited)
1 - Drilling Contractor - Well Site (Edited)

I N D E X

GENERAL INFORMATION

ADM WELL #1 - CCS

GENERAL WELL DATA

Well Name and Number	:	ADM WELL #1 - CCS
Classification	:	Exploratory - Straight Hole for CCS
Country	:	Macon, Co., Illinois
Area	:	ADM Plant site property
License/Permit #-	:	……..
Operator	:	ADMa
UTM Coordinates (or T-R-S)		
Surface	:	X = **8737:0** Y = 22287:5 3/8
Bottom hole	:	Vertical well
Geographic Coordinates		
Surface	:	……… W ………………. S
Bottom Hole	:	……… W ………………. S
KB	:	assumed 665 feet (to be surveyed in after rig move)
GL	:	assumed 650 feet (to be surveyed in after rig move)
Objectives	:	Drill thru Mt Simon & Into Pre-Cambrian
Est. Total depth	:	7,900 ft TVD
Drilling Contractor	:	Les Wilson Drilling, Rig #25
Drilling Fluids and Engineering	:	MI/SWaco/Schwartz Drilling Fluids
Cementing Services	:	Schlumberger
Electric Logging Services	:	Schlumberger
Mud Logging Services	:	Exploration Mud Logging-Jim Eader
Surface Test Equip. & Service	:	Schlumberger
Down Hole Test Tools & Service	:	Schlumberger
Completion Rig	:	TBD (in 2009)
Directional Drilling Contract	:	N/A(but teledrift/multishot- Smith International or Pason from Les Wilson))
AFE Number	:	0802888

GENERAL DRILLING OUTLINE

1. Move rig from Northern Alabama (indicated previous location) to ADM wellsite, Decatur, Illinois. Spot rig, rig up rig and auxiliary over pre-constructed cellar with pre-drilled rathole & mousehole as well as having 30 or 36 inch conductor pre-set and cemented prior to MI & RU. Rig will be on day work after the ADM Well Site Supervisor and SCS Well Engineer have accepted the rig and the 26" retip bit has been picked up. 30 in conductor pipe to be for sure pre-set and cemented. Prior to spud, ensure an exemption is in place and approved by PM as to no diverter nor Hydril while drilling the 26" surface hole.

2. Complete drilling rat and mouse hole (if not already pre-drilled). Accept rig after rig audit and acceptance checklist is complete and all crews & operational staff have undergone thorough QHSE training beforehand. M/U slick BHA with 9 or 9 ½" inch DC, monel and drill vertically to 350 ft into the Limestone (see offset ADM well drilled to 2135 ft!) (good casing seat is required!) with a retip 26 in mill tooth bit. Run Pason or multishot (or teledrift!) at 150-175 feet TVD to ensure we have good record of azimuth & deviation for future use. **NOTE**: No pilot hole is deemed necessary. Drill with as much WOB as possible monitoring torque in sandstone/surface shale zones very carefully. Ensure 9-1/2 in drill collars are in string. Drill slick, with as much weight as will be allowed, maintaining as straight a hole as practical, keeping 800-835 GPM, and 45-55 surface rpm. Control drill this part of the hole! No electrical logs planned for this section. (verify with Project manager prior to spud!)

3. At TD, drop multishot after C&C hole, POOH, racking back BHA (if possible). RU floor to run 20 inch casing with casing running tool if possible. Tac weld each joint. Run and cement 20" casing to surface. Perform top cement job if cement is not circulated to surface. (have macaroni string on location with proper XO, etc). Conventional float equipment to be utilized from Davis-Lynch
4. Install and test 20" 3M x 13-5/8" 3M wellhead and BOP stack (verify with Les Wilson Drilling on exact inventory to be used) with base plate.

5. Drill out with a 17 ½" hole, holding vertical angle to the planned casing point into the Eau Claire expected at -, -4250 SS, or approximately 4,920 TVD. A comprehensive logging program (see below details) will be used for this section. Conditioning trips may be needed and will be decided on at the field level, with input from the Schlumberger PMT and the ISGS and other earth scientists engaged in the project.

6. Run and cement 13 3/8" "protection" casing in one (1) stage as per attached detailed cementing programs.

7. Hang the casing in full tension, install and test 13-5/8" 3M x 11" 5M wellhead and BOP stack (check with Les Wilson Drilling as to exact inventory to be used).

8. Drill a 12 ¼" straight hole, holding angle as close to vertical as possible, with multishots or teledrift (pason) shot surveys no farther apart than 250-350 feet, or on each bit trip. Record same. (This is to be carefully controlled and if needed, the SCS WSS can adjust according to drilling criteria encountered.) It is very important to keep the hole as reasonably straight as possible.

During the 12 ¼" hole section, it is contemplated that 4, 60 ft cores will be taken or 8-30 foot cores at least; 60 feet in the Eau Claire, and 180 feet in the Mt Simon. All cores are to be picked by the WS Geologist, mudlogger in close communication with the SCS Project Manager and the ISGS Manager for the Project (Rob Finley) and other ISGS science personnel.

9. At TD, expected at -6450 (7,120 TVD) plus 65-100 ft of rathole in Precambrian! +/- condition well to be comprehensively logged as directed and per below wireline plan. After the logging/testing program has been completed a string of 9 5/8" casing will be run and cemented according to the attached detailed plan. (scheduled to be in 1 stage). Hang at least 70% of weight on slips, NU back up & test same.

Rig is to be released to 2nd well or MVV well, after plug is bumped, 1 master valve is installed, and rig ready for release!

WORK TO BE PERFORMED AFTER DRILLING RIG IS MOVED OFF:

While waiting on cement (minimum 72-90 hours), pick up 4½" drill pipe OR CLEAN OUT STRING to clean out the 9 5/8" casing with rig's 6 ½" DC or BHA that is deemed appropriate. Run 8 ½ or 8 ¾" bit, casing scraper and junk basket and clean out to the float collar or through shoe track, depending on where we TD and get casing down to & requirements for rathole. Plan now is to bump plug with a filtered 3% KCl packer fluid. (TBD prior to cementing the 9 5/8" casing).

Circulate hole clean. Pull out of hole laying down drill pipe or work string and bottom hole assembly. RU and run either a USIT or CBL & possible other logs/technology. Log as directed.

Install a used master valve with gauge on top of well head. Rig down and move rig off. Well will be completed in 2009!

GEOLOGIC PROGRAM

Page No.

1.0 GEOLOGICAL PROGNOSIS

OBJECTIVES

The ADM Well #1 – CCS well is intended to be a CCS well drilled on the ADM plant site property in order that 1 MM tones of liquid CO2 can eventually be injected into the Mt Simon formation at site. The main objectives for the drilling and wellbore integrity of this well construction phase include:

1. To MI, RU, drill & MO with no safety nor environmental incidents. This is the main objective of the well construction mission!

2. Ensure the wellbore is as straight as possible
3. Ensure the larger casing strings (hole sizes) are drilled with minimal formation invasion and to obtain world-class cement jobs per the appropriate plans
4. Drill adequate hole sections to where all of the testing, wireline logs and coring that is planned can ultimately be performed and that the data collection, core recoveries, etc are maximized so future sub-surface workscope can be performed by other skill sets
5. 100% core recovery

ANTICIPATED ADM WELL #1 – CCS
FORMATION TOPS

KB = est to be 670 + 14 feet**** (TBD after well is staked & rig MI)

Formation	Top (feet) Datum (sea level)	Thickness (feet)	Best Estimate Measured Depth
Surface Elevation			670
Colchester Coal	-150		820
New Albany	-1410	135	2080
Lingle to Maquoketa	-1540	420	2210
Maquoketa	-1960	210	2630
Trenton to St. Peter	-2180	460	2850
St. Peter	-2640	150	3310
Knox to Eau Claire	-2780	1470	3450
Eau Claire	-4250	500	4920
Mt. Simon	-4750	1690	5420
Precambrian	-6450		7120

NOTE:
There is no well control for 17 miles
The Eau Claire, Mt. Simon and Precambrian tops have a range.
Best estimate for Eau Claire is between 4,500 to 5,500 feet
Best estimate for Mt. Simon is between 5,000 to 6,000 feet
Best estimate for Precambrian is between 6,000 to 7600 feet
The thickness was estimated from the regional maps and are best estimates

2.0 POTENTIAL DRILLING HAZARDS

SURFACE TO 350 feet (MD): Spudding in clay/sandy formations tends to be very easy drilling with high ROP's after enough DC weight has been picked up. Expect drilling rates of up to 60 - 90 FPH, if allowed to drill in that fashion. (see some of the well performance recaps & drilling curves on wells that have been studied) Some zones of water influx may occur while drilling from 150-300 feet (MD). From surface to 400 feet (MD), hole bridging may occur if there are extended periods without circulation or tripping. Adequate mud weight per the plan and continuous minimum GPM to keep the hole clean are mandatory while drilling the surface hole and running surface casing to avoid water influx. Drill string vibration may also be experienced due to large –size hole being cut but no shock sub is deemed to be necessary for this short interval. Several high gel sweeps to ensure bridging is kept to a minimum should be considered. Keeping the hole straight in the upper section is another main driver, so the well ultimately will end up as straight as reasonably practical!

350 feet TO -3500 feet +/--per ISGS (MD):

Between this interval, hole bridging may occur if there are extended periods without circulation or tripping. Short trips every 400-750 feet are mandatory to ensure drill string does not pack off. Again, with larger than normal BHA and hole sizes, ensure hole is cleaned faster than ROP.

Potential zones of water influx may require raising the mud weight. However, the lower the MW the faster the section can generally be drilled. (See detailed drilling fluids program)

3,500-(4,000) to TD (7,900 Ft +/-):

Below 3,500 feet, through the Eau Claire and through the Mt Simon, we will be drilling a series of non-reactive shales with the Mt Simon being for the most part striated sandstone, some expected to be porous and highly permeable. In some of the shaly zones, sloughing has been common. Tight hole problems have been experienced, but were cured by keeping water loss at a minimum, by using mud weights controlled and by making planned wiper trips. Many reports from wells (closest is 17-38 miles away and structurally higher than the ADM well) reveal that while tripping out the first few stands pulled tight, and when running back in the hole, washing and reaming were necessary to get down to TD.

The Wellsite Geologist and the Drilling Supervisor must coordinate their determination of final well TD to ensure proper log coverage and rat hole in the Mt Simon section necessary for logging operations to pick up Precambrian as well as for completion details (to be in 2009).

OVERPRESSURING: NO high pressures are anticipated.

3.0 MUD LOGGING PROGRAM AND MONITORING EQUIPMENT

Mud Logging Services will be performed from spud to TD. Since data gathering is of utmost importance, sample catching and lithology confirmation is of utmost importance. The mudlogging and daily geological review of lithology will require careful and meticulous coordination between the Wellsite Geologist, mudloggers, WSS and the senior ISGS geological representative. The geologists, mudloggers and sample catchers will provide 24 hour coverage. The unit will monitor, record and/or plot the following at a minimum:

Lithology

Percentage Log	Visible Porosity
Interpretative Log	Calcimetry

<u>Shows</u>

Total Gas ("Hot-Wire")	Chromatograph (C_1-C_5)
Cuttings Gas	Visible Sample Shows

<u>Drilling Parameters</u>

Depth (MD,TVD,lagged,)	Rate of penetration (ROP)
RPM	Weight on bit (WOB)
Total bit revs	Torque
Hook load	Pumpstrokes/min.
Pump pressure	Standpipe pressure
Casing pressure	Pit-volume totalizer (PVT)
Mud weight in/out	Mud temperature in/out
Mud flow	Mud gains/losses
Stands done/to go	Pull rate
Total pump strokes	Mud volume pumped

In addition to the above capabilities, the following special equipment will be provided and maintained by the Mud Logging Company:

Intercom system linking the logging unit to the rig floor, drilling office, drilling supervisor's cabin.

Two, remote CRT screens, in the Drilling Supervisor's Cabin and the rig floor, to be connected with the Data Acquisition System.

External alarm for the PVT and a high quality binocular microscope for the Wellsite Geologist/ISGS and Schlumberger use.

NOTE: The draw works sensor will monitor <u>all</u> pipe movements, including drilling, connection, tripping, casing and fishing operations.

3.2 <u>GENERAL INSTRUCTIONS</u>

The wellsite geologist along with the input and approval of the Senior ISGS representative has the responsibility for the complete geologic evaluation of the well, with special emphasis on determining the lithology, coring points, TD, etc and recording all pertinent data. In their absence, the contracted logging geologists/mudloggers assume this responsibility. The following general instructions will assist in the performance of these duties:

- The mudlog (1:500 scale) and worksheets will be prepared and kept up-to-date at all times. The mudlog will be completely updated at the end of each 12 hour tour. Field prints will be available at all times. All drilling parameter and gas data (if any) will be recorded on CD's in ASCII format.

- Carbide checks will be run daily and recorded on the log and worksheets.

- No Calcimetry tests are to be run. (per ISGS DWOP meeting)

- If unusual drilling conditions such as abrasive formation (chert, sharp sand or pyrite), metal in the cuttings, or loss of pump pressure or an increase in pump strokes (indications of possible washouts) are detected, immediately notify **both** the Driller and the Schlumberger/ADM Drilling Supervisor.

- If unexplained gas cut mud, mud loss or pit volume increases are noted, instruct the Driller to check for flow and start shut-in procedures if necessary, and then notify the Schlumberger/ADM Drilling Supervisor and the Wellsite Geologist.

- Monitor hole fill-up on all trips and immediately advise the Driller and the Schlumberger/ADM Drilling Supervisor of any discrepancies.

- The Wellsite Geologist will maintain an "interpretative" progress log which will include drilling rate, interpreted lithology, lithologic descriptions, visual porosity, coal, oil and gas shows (if any), mud data, bit data, cores, casing, and formation tops. This log should be at both a 1" & 2":500 scale on reproducible film. (per ISGS)

3.1• The mudlog will be kept up-to-date at all times. In addition to the normal information, the logger should record bit, footage, rotating hours, and mud data (including mud losses) and the drilling parameters (WOB, RPM). Weight and RPM changes that affect the penetration rate should always be noted on the log at the depth they occur. Mud salinity and thiocyanate tracer (if any used) concentrations will be recorded on the log and worksheets. The drilling rate scale must be identified every 500'. The scale should be selected to best fit the range of drilling rates typical expected or seen in the area, without having to change scales or plot on a backup scale. The drill rate will be recorded in minutes/foot in five-foot increments from or as directed by the Wellsite Geologist and the ISGS surface to TD. Log scales to match 2 inch: 100 feet and 5 inch: 100feet "standard electric log" scale. For readability, limited or no annotations on the 2 inch scale. Copies of logs: number and format (media) of logs as required. Recommend gamma ray and SP on the left side of the log, and one resistivity and one porosity curve on the right side. Other log designs can be provided as required by the operator or the ISGS. Mud Logger will provide 2 copies of well data base as requested, on appropriate media. (per ISGS-DWOP meeting)

- **Only software approved by the ISGS and Schlumberger/ADM will be permitted on PCs.**

Notes per ISGS & DWOP:

ISGS recommends (2 sets) 10' samples from surface, and 5' samples in zones of interest. One set should be in a large sample bag equivalent to at least 4X standard Illinois Basin sample bags. The second set would be a "standard sized sample" used for on site purposes. Samples to be bagged and marked with hole and depth. Other samples will be collected as needed, i.e. Oil or gas shows, circulating samples, etc. ISGS indicated that they would pick up the samples periodically for transport to ISGS facilities and that they wanted wet bagged samples only no heat lamps or dried samples. ISGS has the facilities and desire to process and distribute samples as needed. Recommend drilling company catch samples as per standard Illinois Basin operation. (In a conversation with Mr. Verdayne Seals of Les Wilson Drilling on April 10, 2008, he indicated that Les Wilson could collect the samples).

3.3 CIRCULATING INSTRUCTIONS

- Circulate any rapid increase of ditch gas (or coal/oil shows) until the source can be identified. This does not apply to trip gas, connection gas or other such predictable occurrences, if encountered.

- Circulate after all operations which could affect the evaluation of any prospective zones, such as after high trip gas or excessive drilling operations such as freeing stuck pipe.

- Circulate bottoms up before any trips when drilling below the 20 in.

3.4 SAMPLE COLLECTION

See above 3.1 per ISGS – DWOP meeting of April 2008

FULL DIAMETER CORES

4-60 foot full diameter cores are planned for this well.

Sidewall Cores (Optional)

Label and hand carry as follows:

Jar Label	Sample Box Label	Final Destination
ADM	ADM	ISGS
Well Name	Well Name	c/o Rob Finley, Univ of Illinois
Depth	Samples #	Champaign, Illinois

Hand carry the SWCs on your return from the well or make other secure arrangements per ISGS/Project requirements, if this is the case.

3.6 SUMMARY OF REQUIRED OUTPUT

Mudlogging output to the ISGS, ADM and Schlumberger Carbon Services will include the following:

1) Daily geologic reports summarizing daily operations, key intervals, lithologies, oil shows and drilled gas, sent by cc:mail to all the personnel listed in the distribution list and to the Drilling Supervisor at the wellsite as well as to the Engineer in charge via e-mail.

   Note:The CD with the daily report will contain only the data for that day's report.

2) A formation log at 1": 100 & 2": 100 ft scale. This log will record drill rate, percentage lithology, interpreted lithology, ditch gas curve, chromatographic data, cuttings analysis, oil shows and pertinent engineering data. Additional information for inclusion may be requested by the wellsite geologist or the ISGS.

3) Four weekly field prints of the Formation Log. One copy remains at the wellsite and the other 3 copies are sent to the ISGS and ADM Subsurface Management Team, Champaign, Illinois. A copy of the Formation Evaluation log in 1":100 scale should be printed out to compare to the electric logs.

4) Mud Logger will provide 2 copies of well data base as requested, on appropriate media. One copy of the final well report and the final formation evaluation log within 10 days after the TD of the well or when the mudlogging unit is demob from the location. The Schlumberger Carbon Services Project Management Team, namely the Project Manager, the senior ISGS Geologic representative and the SCS Engineer in Charge (if needed), will review and edit these products, and when approved by the ISGS & the SCS Project Manager, 2 copies of the final well report & 2 copies each of the formation evaluation logs (Scale 1:100 & 2:100) will be sent to the ISGS, c/o Rob Finley, at the University of Illinois, Champaign, Illinois for subsequent distribution.

5) One copy of the final well report on CD in MicroSoft Word/Excel format.

6) One copy of the Formation Evaluation data on CD in ASCII format.

4.0 GEOLOGIC REPORTING

4.1 MORNING GEOLOGIC REPORT

The morning geologic report will be completed at 0600 hours (or as dictated by the ISGS or SCS) with the activities and results of the last 24 hours. The written report should be done in the Schlumberger Carbon Services WEMS or report form system. General instructions for use of this system follow:

1. The Schlumberger Carbon Services WEMS (Well Engineering Management System) or report system to be used will be successfully loaded onto the Mudloggers and WSS PCs. All Mudlogging PCs must remain virus free. <u>UNAUTHORIZED SOFTWARE WILL NOT BE RUN ON THESE PCs</u>. All outside CD's & diskettes must be checked for viruses prior to performing any disk operations.

2. The wellsite geologists and mudloggers are responsible for the following 4 reports:

- GEOLOGIC SUMMARY REPORT (Daily Geologic Report)
- FORMATION TOPS REPORT (Formation Tops Report)
- OPEN HOLE LOGS REPORT (Open Hole Logging Summary)
- CORING REPORT (As needed)

3. The day's reports will be completed, exported onto CD or diskette/memory stick, and given to the wellsite Drilling Supervisor before 6:00 am. The memory stick/diskette will contain only 1 file, with only that day's reports. The Drilling Supervisor must be told which reports are included that day's file.

4. Never send an edited report forward without firstly checking with the wellsite geologist and/or drilling supervisor (to make any corrections to the reports). If any revision is required in the field, they can be incorporated later and changes for input into the system.

A telephone report will be made to the following at least every morning:

SCS Project Manager
SCS Well Architect

at 0800 hours. This will permit clarification of the morning report and discussion of wellsite activities. If the Wellsite geologist is not present, the mud logging geologist will report. When drilling through objective formations, radio/telephone contact with the SCS Project Manager and the SCS Well Architect will be kept open at all times, continuously.

4.2 AFTERNOON GEOLOGIC REPORT

The afternoon telephone report will be a complete geologic report using the same format as the morning report, but with a 1500 hours cutoff. The afternoon oral report will be made at 1515 hours. If the Wellsite geologist nor WSS is present, the mud logging geologist will report.

4.3 INSTRUCTIONS AND FORMATS

Descriptions of Cuttings Samples: For each described interval, the average and the range of the ROPs will be given. The lithologies will be listed in descending order of percentages. The format for lithologic description follows:

ROCK TYPE	**SHOW DESCRIPTION (if any occur):**
COLOR	OIL IN MUD-Percent
HARDNESS/INDURATION	ODOR-Intensity
GRAIN SIZE	VIS. STAIN- Percent, Color, Distribution
GRAIN COMPOSITION	NAT. FLUOR- Percent, Color, Distribution
TEXTURE - Shape, Round, Sorting	CUT FLUOR- Type, Rate, Intensity, Color

MATRIX - Percent, Type RES. RING - Thickness, Color, Fluor
CEMENT - Percent, Type
POROSITY - Percent, Type
ACCESSORY MINERALS
FOSSILS/FRAGMENTS

Gas Reporting: For each interval described in the geologic reports, gas measurements will be reported as follows:

BG (Background gas): xx units
Maximum TG (Total Gas) at xxxx'
C_1 - C_5 ppm

Remarks Section: The remarks section of each report should/will include the following information:

Preliminary Formation Tops - MD, TVD relative to prognosis and offset wells (relative to base maps prepared by ISGS)
Mud Data - Mud weight, chlorides, additives
Carbides - Depth, Mud weight, Gas Units, Actual vs theoretical lag time
Surveys - Depth, deviation angle and deviation azimuth, if any, TVD

Trip and connection gas (if any) - Amount, Chromatographic Analysis
Comments - Any other pertinent observations or data including mudloggers equipment that is not working properly.

4.4 WIRELINE REPORTING

During wireline logging operations, the Daily Report will be modified as follows:

Operations Section:

Tools run - main log interval, repeat section interval, failures

Total depth - Driller's & Logger's, Bottom hole temperature

Casing Depth - Driller's & Logger's

Mud resistivity data and temperatures

SFTs (if any) - # of attempted pressure measurements, pressures obtained, supercharged readings, dry tests, and seal failures

SWCs - # attempted, recovered, misfired, and lost

CSSs - # stations attempted, obtained, record quality (Optional)

Interpretation Section:

Formation Tops - Measured depth, TVDSS, if the case

Correlations - Tops relative to prognosis, key well correlation points

Reservoir Intervals - Top and base, Net reservoir,

SFTs - Depth, hydrostatic pressures, formation pressure, duration

CSSs - Depth of station, TWT (Optional)

All - Note any problems with logging run

5.0 CORING PROGRAM

5.1 4-60 FOOT (OR 8 30 FOOT) CONVENTIONAL CORES ARE PLANNED – (See detailed coring program below. Note that coring points are not exactly known at this time and will be decided on lithology and expertise at the rigsite!)

CONTENTS

1.0 INTRODUCTION

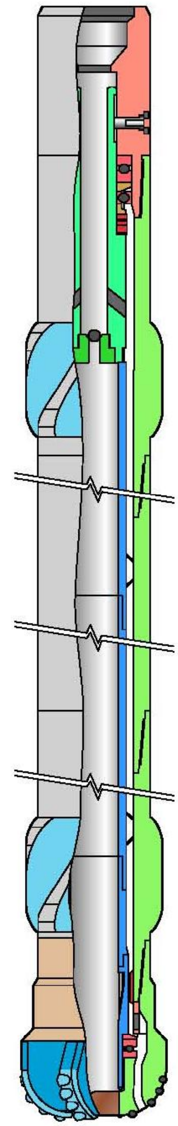
This program is a full description of core operation (coring, core processing, core preservation, well site gamma ray, transportation) for the cores to be cut in the ADM Well #1 –CCS well in Decatur, Illinois. A total of 240 feet of core will be taken into the following formations:

Zone	TVD	Formation
Eau Claire	3,500 ft +/-	Shale
Mt Simon	5650, 5900, 7750 ft +/-	Sandstone

The drilled hole will be 12 1/4" and either a full 6 ½" or 4" OD during coring. This should ease the trip down avoiding the reaming of any tight spots. The hole will have an inclination of probably no more than 2-3 degrees, but the multishot/teledrift information to coring points should be reviewed prior to coring to optimize coring BHA & subsequent recovery. This should help the stabilization of the barrel to assist in full recovery. (This is dependent on the core company proposal and experience that can be found in the area in regards to coring.)

No major problems are expected, except picking the optimum core points and having the equipment on site.

2.0 TENTATIVE CORING EQUIPMENT (to be finalized in DWOP or prior to spud)



2.1 Core Barrel 6 1/2" or 5 7/8"(TO CUT A 4" OD Core)

The coring concept has been specifically designed to enable the retrieval of longer, higher quality cores. Faster penetration rates, reduced incidence of core jamming, improved reliability and reduced core damage are four of the benefits offered by this system. (ultimate coring head & barrel will be adjusted so that local experience is captured and utilized in order for core recovery to be 100%. This might include cutting a 6" or 5 7/8" with say a 8 ¾ core head to retrieve a 4" OD core and as well cutting only 30 foot cores at a time rather than 60 foot—TBD when we get closer to spud and discuss details with successful coring company.

Stabilization is one of the most important factors governing a successful coring operation.

The majority of core barrel systems are unable to properly transmit the weights on bit required for modern coring operations. Without the outer barrel correctly stabilized, bending within the well bore will occur. This is evident from the polished areas found on the outer tubes between the stabilizers after retrieving the core barrel. The deflection of the barrel impinges wear on the well bore (overgauge hole) and produces eccentric bit rotation (poor quality, undergauge core).

Corebarrel length will be 60 feet unless we find in the Illinois Basin, that 30 foot barrels are better from a recovery perspective and HSE perspective-weight? Gas trapping?, etc)

2.2 Inner Tube System

The Thin Sleeve System will probably be decided to be the best inner assembly system for our application. The Thin Sleeve System (to be determined prior to spud) is a two part inner barrel system. A specially designed inner barrel carries within it a second thin walled tube. A connection enables the tool joint to be broken and disengaged without rotating the thin inner tubes, a feature, which eliminates torsional damage to the core during the breakout. The box connector contains six ribs that retain the inner tubes, centrally within the outer barrel. Time is saved during the lay down process as no cradle is used. The core is laid down safely inside the TSS steel inner barrel without any risk of bending.

Barrel Length

- The strength of the formation, and presence of sharp changes in lithology mechanical properties will limit the length of core that can be cut. (now planned at a maximum of 60 foot cores and maybe 30 foot)
- Barrel length should be limited to the longest core that can be cut in order to minimize potential problems, barrel flex, vibration, rig floor handling time and the need for re-running of inner barrels (60 or 30 feet in this case).
- If hole conditions are ideal, we will core with a 60 feet barrel. (Due to rig capabilities & HSE issues. Possibly 30 foot cores will be taken if it is decided that this will result in better core recoveries)
- The coring BHA will be a stiff packed assembly (four stabs-TBD by coring operator), it is therefore recommended that the hole is finished with an equally stiff BHA before running the core barrel to maximize the chance of trouble free tripping.
-

Core Catcher

- Plan to use conventional spring catchers.
- In case of very soft sand encountered in the Mt Simon, the FINGER CATCHER SYSTEM should be/will be available on site.
- All catchers and pilot shoes should be inspected / certified OK by core hand before use (these have been seen to fail in use before.)

2.3 Corehead (TBD)

The corehead to be used will be 8 ½" (or 6 1/2") diameter to cut cores. This very well might end up, however, having to be a 8 ¾" core head, with 5 7/8" OD barrel, with the result of retrieving only a 4 inch OD core. At the time of finishing the final well program, the core company has not been decided, so this is one (1) option still that is undecided

A core head such as the **MCP662**, 6 blades, throat and face discharge, low invasion, PDC 13mm. This corehead has been successfully used in many areas like what will be drilled in the Decatur area. The throat discharge will help to clean shale and should increase the ROP in these sections.

Two Core Heads of this type will be available on the rig.

Low Invasion Core Bit (TBD after core company is selected)

Specifications

TYPE OF CUTTER: PDC

NUMBER OF CUTTERS: 24

SIZE OF CUTTERS: 13 mm

RIB NUMBER: 6

SETTING: Overlap

PROFILE: Round

BODY: Tungsten Carbide Matrix

JUNK SLOTS: 6

GAUGE: Carbide & Natural Diamond

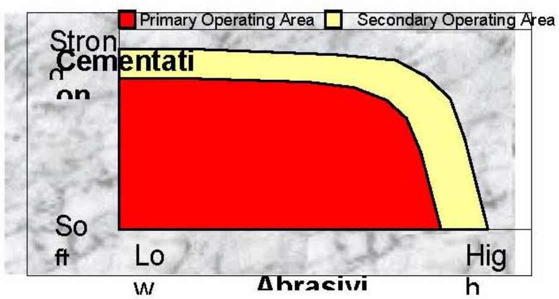
FLUID FLOW CONTROL: Sculptured Flow Channel

ROCK TYPE: Clay, Shale, Sandstone

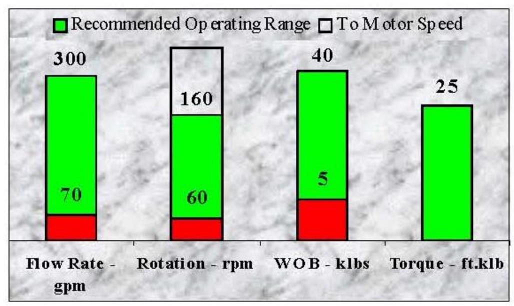
Total Flow Area 0.74 in^2

FEATURES: Low Fluid Invasion

Throat Discharge (6 paths)



Application



Generic/Best practices-Procedures during Coring for ADM Well #1 - CCS

1. Drop ball – when ball has seated take SCRs.

2. Commence coring with low weight and RPM until at least 2 feet are cored.
3. When coring is established to the satisfaction of the coring engineer, increase parameters to recommended levels for coring assembly.

- Aim for constant weight on bit with no sharp increases in WOB (this may lead to premature jamming and short cores).
- Do not allow weight to drill off while coring a high ROP (in heterogeneous formation a large variation in ROP can be expected) if the corehead breaks out of a slow coring shale into fast coring soft sand and weight on bit is not maintained, the sand will wash out and the core will fail and probably jam (short cores and poor recovery).
- Aim for low to moderate RPM (60 – 90 RPM) to avoid any chance of early core breakage or jamming due to core barrel vibration.
- Mud flow rate for face discharge coreheads should be kept constant.
- If mud flow rate is raised to increase ROP in slow coring claystone sections it must be done gradually, and must be reduced as soon as high ROP sandstone sections are encountered constant (suggested flowrate in 12 ¼" hole 250 – 350gpm).
- ROP, torque and standpipe pressure trends are valuable indicators of coring performance. The coring engineer will record parameters every foot.
- Cuttings must be monitored for signs of rock flour at all times in order to check for milling of soft sandstone with a jammed core barrel.

Coring Termination

- Coring should be terminated when barrel is full (i.e. core is within one foot of top of barrel) or when evidence of jamming has occurred (drop in torque or erratic torque, very low ROP, erratic pump pressure). Barrel must not be over-filled; core will fail in compression if barrel is overfilled.
- If coring is about to be terminated (3 feet before full barrel) and ROP is high, consider reducing mudflow rate to minimum safe rate to ensure full gauge core in catcher.
- It is not recommended to spin the barrel at higher rpm to "burn core in", the inner barrel may rotate with the outer, causing core damage.
- If the core appears to be finishing in harder rock, or to have packed off (low ROP) then coring should be terminated at normal flow rate.
- Circulation after coring should be performed in a way that minimizes the risk of soft sandstone core being washed from the catcher. (if this be the case encountered in the Mt Simon)

Bottom Hole Assembly

The following BHA should be filled in by coring company:

Item	Length	ID	OD	Top Thread	Bottom

					Thread
Corehead					
Stabilizer					
Outer Tube					
Stabilizer					
Outer Tube					
Stabilizer					
Outer Tube					
Stabilizer					
Top Section					

- Corehead MCP 662 (TBD)
- Core Barrel 60 feet x 4 ½"IF (TBD)
- Float Sub (4 ½" IF) ,the internal valve will provided by coring company if requested
- Cross Over (4 ½" IF x 4 ½" XH), provided by coring company if requested
- Drill Collars (enough to get 25-37 Klbs on bottom)
- Heavy Weight Drill Pipe and Jar
- Drill String

The BHA drawings will be given on the rig site by the engineer before running into the hole.

Gamma Ray Logger (TBD still by the ISGS & Earth Scientists)

(If) Gamma ray logging will be carried out directly on the core once laid down. Data will be handed over the ISGS geology department in Ascii format and graphs will be emitted at the required scale.
The Gamma Ray will be used with a shield in order to reduce high back ground readings.

Core cutting/boxing/Transportation

Cores will be cut into 3 feet cores and placed in single wooden boxes. ISGS to determine where cores are to be transported and to what lab. The people involved in this process are aware of the paramount importance of this step. Great care should be taken for loading and unloading but also for the transportation.

6.0 WIRELINE LOGGING PROGRAM

Intermediate run 3500 - 350 ft.
Platform Express
Sonic Scanner

FMI (selected intervals)
CMR (selected intervals)
ECS
Rotary cores
MDT or PressureXpress pressure/mobility in St Peter Sand
MDT (possible) water sample in St Peter Sand

TD run 7900 - 3500
Platform Express
Sonic Scanner
FMI
CMR
ECS
Rotary cores
MDT: mini-frac in Eau Claire shale
pressure/mobility in Mt Simon Sand
water samples in Mt Simon Sand (possible) and St peters? (TBD)

We also need to specify the cement logging on the Intermediate string
Intermediate: USIT / CBL
TD: Isolation Scanner / CBL

6.1 LOG SURVEY SUMMARY

The required surveys, intervals, and the final log formats are detailed below. If required, change track scales to avoid excessive use of backup scales. No surface logs will be run in this well. Call out of the Schlumberger Wireline unit and personnel will be coordinated with the Schlumberger Carbon Services Project Manager and the ADM Drilling Supervisor. **A minimum 72 hour notice is requested, with a 4-day notice preferred**. Fresh water based mud will be used in this well.

Note: The ADM Wellsite supervisor will not allow Schlumberger Wireline logging services to start a job if the appropriate fishing tools are not on location.

ADM WELL #1 - CCS

DRILLING PROCEDURES

INTRODUCTION

The ADM Well #1 – CCS will be located on property owned at the ADM plant site in Decatur, Macon

County, Illinois and is scheduled to be drilled as a CCS well capable of having 1,000,000 or more tones of liquid CO2 injected into it, eventually over a 3 year period. The well is pegged to be drilled to a TD of approximately 7,900 feet +/- TD in Precambrian.

No major drilling related problems are expected to be encountered. However, several of the formations contain reactive shales that may cause tight hole conditions. The reactive shale problems can usually be remedied by a combination of increasing the mud weight and scheduled wiper trips. There is no known surface gas in the area (ADM well drilled 0.66 miles away in the 1980's experienced no problem to 2,225 feet (7 days). Water flow from sections in the surface hole can possibly be expected but is not expected.

These drilling procedures provide general guidelines and a description of items such as drilling fluids, casing, cementing, bits and hydraulics program, well control. However, this program is only a guideline and the Schlumberger Carbon Services Project Manager and the ADM Wellsite Supervisor (WSS) along with the other members of the Project TEAM must always be cognizant of safety, cost, and penetration rates through continuous consultation with the SCS Project Manager and the SCS Well Architect as well as other members of both the ISGS staff and the various service companies involved in the project! "The 'we is smarter than the I'…so let's capture the best practices from everyone and apply here.

A. <u>RIG MOVE</u>

The rig mobilization is not very clear as of the writing of this Drilling Program. As of mid-January the Les Wilson Rig 25 was drilling wells in Pennsylvania but in March moved to Illinois. We are attempting to get clarification on how/when the rig can commence mob, after permits are obtained, tubulars bought and all contracts in place. As of the writing of this program, a definite surface location has been picked and is noted as X & Y coordinates on the front of the Well Plan Program as noted.

Rig will be considered ready to drill when the rat and mouse holes are drilled, all rig components have been rigged up and tested, including desilter, desander, cellar jets, water lines and derrick is leveled and a comprehensive crew QHSE training has been completed. Rig will be on dayrate once the rig is accepted by the SCS/ADM WSS. It is also planned, that a workover rig/rathole digger will preset and install the conductor pipe and grout same prior to the rig MI.

<u>SURFACE HOLE</u> - 26" HOLE - 20" CASING AT ± 350-400 feet MD

Directional Control: Vertical well
Survey Interval: Single shot/teledrift every 150 feet- and or on each bit trip. Teledrift or gyro at casing point

The purpose of the surface casing is to isolate and protect fresh water aquifers (the deepest planned to be covered is located at 150 feet +/- TVD). It is also necessary for regulatory purposes, as well as to provide sufficient integrity to safely shut in the well in an emergency situation. This surface pipe is also intended to provide some shoe integrity for kick tolerance and integrity against anti-broaching.

The formations to be encountered while drilling the surface hole are basically, some scattered coal seams possibly, much sandstones and claystone. Some zones of water influx may occur while drilling around 150 feet +/- . If water influx occurs weight up to control flow while jetting cellar, if needed, to avoid washout below the rig sub-base, MW of 8.4 – 8.7 ppg may be required but is not expected. This interval is expected to be drilled with water and gel easily.

1. No pilot hole is contemplated on being drilled firstly.
2. Tag cement bottom of 30" conductor (preset prior to rig arriving). If we do not have good cement in surface, perform top job with 1.660" OD internal joint tubing between 30"casing and 36 "hole, clean out cement and drill vertically new hole slowly until enough hole has been drilled to accommodate BHA. Resume drilling under normal conditions with up to 650 GPM, and 80-100 rpm, to maintain as near vertical hole as possible.

3. Drill under WSS´s recommendations. Use water based mud, with weight 8.4-8.7, Vis=47-55 sec/qt.

4. Circulate and condition hole at TD, and make wiper trip to 30" casing shoe. Run back to bottom, circulate hole clean with a hi-vis pill and spot a hi-vis pill on bottom.

5. Rig up 20" tools, run 20" casing and cement as per program. Upon reaching bottom, reciprocate while circulating hole clean (watch drag while reciprocating casing. Comply with section guidelines and rig capacity).

   Note: **Do not treat <u>(thin and lower YP)</u> and circulate excessively to treat mud prior to cementing casing.**
   During cementing job have mud engineer check on cement returns to surface using Phenolphalein.
   Report number of bbls of contaminated and good cement returns to surface.
   Use PDC drillable floating equipment, if possible.

6. After cementing, drain 20" conductor casing.

7. Wait on cement a minimum of 6 hrs (watch surface samples).

8. Slack off 20" casing. Make rough cut on 20" and 30" casing. Lay down same.

   Note: Watch for water flow, if water flow is encountered, weld plate on top of 20" casing and around 20" casing. Install 2" valve and pump cement between 20" and 30" casing. <u>Have steel plate donut prefabricated for 20" x 30" annulus to save time</u>.

9. If good cement is not circulated to surface, perform a top job (neat) with 1.660" OD internal joint tubing (macaroni string) between 20" and 30" casing.

10. Make final cut on 20" casing as needed for space out. (Cellar is to be 7' X 7' X 7', so use WH & BOP drawings to ensure proper placement of initial starting head!)

Note:- Objective on final space out is to have top flange on tubing head ± no more than 1-2 feet above ground level, depending on final substructure height and completion program.
Record the distance between the RKB and the top the flange.

11 Weld and test section "A", 20" by 13-5/8" - 3M slip-on C-22 wellhead (SOW). (Check final wellhead design before spud date & ensure all sections and including extra slips are on-site before spud for all casing strings).

12. Test head to 1,000 psi (20", 94 lb/ft, K-55, BTC, collapse is 2,110 psi).

Note: If the wellhead has internal seal, the only weld necessary is to the outside bottom. Excessive preheat temperature will damage internal seal. Be sure to check condition of seal. If necessary, an internal weld can be made if wellhead does not test. Annular valve on well head should be oriented as per requirements for completion and subsequent injection operations dictate. Annular valve on "TC" tubing spool will stack up on top of valve on casing head. Alignment pin in "TC" tubing spool should be located 90 degrees counter clock wise from catwalk. (check with UWE and geophones-RVSP, requirements)

2. Install blowout preventors, bell nipple and flowlines.

3. Make up and run test plug. R/U Schlumberger pump truck and lines. Test lines to ± 3,500 psi and test BOP stack as follows:

   (a) Blind rams, pipe rams, choke manifold and lines, stand pipe, upper and lower kelly cock to 250 psi and 3000 psi. Each test will be for 5 minutes.
   (b) Hydril - Annular to 250 psi. and 1,500 psi, for 5 minutes.

Note: Have Schlumberger lines tested and ready while rig crew is installing BOP's, so that Schlumberger WSV is waiting on rig, instead of rig waiting on Schlumberger WSV.

All tests are to be with water and recorded on a chart. Casing valve on 20" casing head needs to be open during test. ALL TESTS ARE TO BE WITNESSED BY Schlumberger/ADM WELL SITE SUPERVISOR.
<u>To save time, pretest as much BOP equipment as possible concurrently with other rig activity, test choke manifold during trip, etc</u>.
Subsequent BOP tests are to be every fourteen (14) days but not in conflict with other drilling policies-best practices. Record BOP tests on all well reports.

2. Pull out of hole and lay down test plug.

3. Install and lock down wear bushing in casing head.

<u>C. PROTECTION HOLE</u> - 17-1/2" HOLE - 13-3/8" CASING AT ± 3,500 Ft TVD

P/U 17 1-2" , 2JS (IADC-515X) bit, monel, large DC & HvyWt BHA. Ensure ROP is commensurate with straight hole provisions, taking teledrift/multishot/Pason surveys +/- 250-300 feet. Ensure that if RPM cannot be achieved by rig's rotary (or Top drive), that we have option for downhole motor.

The main purposes of this section/casing is to cover and protect reactive shales so as to prevent from getting stuck, while coring in the 12 ¼" hole, as well this adds another seal during CO2 injection and will allow the technology that needs to be run inside the 9 5/8" X 4 ½" tubing, when well is completed. (RVSP's, micro-seismicity, etc)

The mud system will be a low solids, ND system utilizing rig solids control equipment and possible calcium carbonate for seepage/lost returns, if encountered (a contingency plan will be prepared for this and is included in the drilling fluids program)

Note: Run screens inside drill pipe while drilling with any bit.

2. Tag top of cement or float collar. Drill cement, wiper plugs, float collar, cement, float shoe and 10' of new formation.

Note: If any problem is suspected, plans to test casing must be implemented.

3. Pull back to 20" casing shoe and perform a Formation Integrity Test (FIT) to an Equivalent Mud Weight (EMW) of 9.7-9.9 ppg. If EMW is less than 9.5 ppg, consult with the Schlumberger/ADM Drilling Supervisor and the SCS Well Architect or Engineer in Charge before proceeding.

Note: See FIT & LOT PROCEDURES for details.(to be provided on project PC and attached to final version of well plan)

4. Drill ahead holding angle at 0 degrees to 13 3/8" casing point expected at ± 3,500-4,000 feet TVD. Hopefully the plan is to drill partially through the Eau Claire shale, before setting protection pipe.

Note:- Drill with caution while drilling inside casing.
- Wiper trips every 24 hours or 200-400 feet drilled are recommended.
- Sweep the hole properly

5. Circulate & condition hole, perform a wiper trip to 20" casing shoe. Trip back to bottom, condition hole clean, TOH-SLM.

Note: Log as planned in this section. This may require another wiper trip, depending on what TD is reached and ease/difficulty of the logging program. Decision to make wiper trip is with WSS, rig manager & wellsite geologist, with consultation with the SCS Project Manager

6. Pull wear bushing.

Note: Changing of rams to 13 3/8" will not be necessary due to past experience in the area, the use of annular BOP should be enough to cover any emergency. Prepare Change Order or Deviation from Norm paperwork.

7. Run and cement 13 3/8" casing as per programmed 1-stage cementing proposal. Upon reaching bottom with casing reciprocate while circulating until hole is clean (watch drag while reciprocating). Cement per plan. After cementing ensure casing is aligned properly in order to work slips into bowl and activate. Ensure that the annular area close to the surface is adequately centralized to assist in this endeavor.

Note: - Do not treat <u>(thin or lower YP</u>) and circulate excessively to treat mud prior to cementing casing.

8. Pick up BOP's and set slips with full string weight (full tension or at least 80%). Cut 13 3/8" casing, install and test tubing head to 2,500 psi. Re-install and test BOP's as follows:

   (a) Blind rams, pipe rams, choke manifold and lines, stand pipe, upper and lower kelly cock to 250 psig and 3,000 psig for 5 min.

   (b) Hydril/Annular to 250 psig and 1,500 psig for 5 min.

1. Install and lock down wear bushing in casing head.

D. <u>INJECTION HOLE</u> – 12-1/4" HOLE – 9 5/8" casing to TD +/- 7,900 FT TVD

Directional Control: Teledrift/multishot/Pason survey Interval every 300-400 feet and/ or on bit trips

Due to the fact that this is our "formation of interest" we have to be careful with mud weights, formation invasion (all drilling fluid properties) and our best drilling practices. Adjust mud weight only on an as-needed basis to hole conditions.

1. Trip in hole with 12 1/4", F47H (IADC=627Y) rock bit, from bit company inventory (contingency bits to be left at rigsite in case different types are needed) and a Packed Under-gauge BHA, tag cement or Float Collar.

2. Drill cement, wiper plugs, float collar, cement, float collar and ± 7-10 feet of new formation. Circulate hole clean and pull back to 9-5/8" casing shoe. This FIT will be accomplished with the existing mud system, then displaced after the FIT to the FloPro mud system and after any core is taken in eh Eau Claire to "break the new system" in prior to drilling into the Mt Simon.

   Note: If any problem is suspected, plans to test casing must be implemented

3. Perform a FIT to 13.0 ppg EMW per same procedures mentioned before. If EMW is less than 12.5 ppg, consult with Schlumberger Carbon Services Well Architect and the SCS Project Manager in Charge of the PMT before proceeding.

4. Continue, drilling the U/L Eau Claire shale into the upper Mt Simon with optimized bit program per plan from ± 3,500-4,000 ft +/- to TVD into Pre-cambrian expected to be at between 5,900-7,900 ft

TVD, controlling deviation every ± 200-400 feet or as directed by WSS, depending on well conditions.

5. Full diameter , 30 or 60 foot cores (240 ft total in the Mt Simon) will be taken in the Eau Claire and the Mt Simon, as picked by the Wellsite geologist and the senior ISGS geological personnel.

Note: - Run Drill Pipe screens while drilling with bits. Make sure Rig personnel are aware of this matter.

- Sweep the hole properly.
- Wipe the hole every 24 hrs/250 meters whichever is first.

6. Once top of Pre-cambrian is tagged, attempt to drill with existing bit in hole. If little to no progress is reached, POOH, change bit to drill enough rathole of Pre-cambrian, C&C, , make wiper trip to 9-5/8" shoe, POOH to log well as planned. Run to bottom and condition hole to log. Drop EMS directional survey and POOH-SLM for logs.

7. Run logs as per geological program.

Note: - If logging takes over 24 hours, make a conditioning trip.
- Observe the well at all times while logging, keep hole full.
- **Report all mud losses and gains.**

8. Perform a conditioning trip with the same BHA prior to running 9 5/8" casing.

9. Run 9 5/8 casing, per casing running procedures. If hole conditions permit, reciprocate casing while circulating and **do not lower YP**.

Note: Change of rams to 9 5/8" would not be necessary due to past experience in the area, the use of annular BOP should be enough to cover any emergency. However, if appreciable amounts of gas are encountered while drilling, arrange to have 2 sets of rams on location, just in case.

10. Cement casing per procedures.

Note: See CASING AND CEMENTING PROCEDURES.

<u>CASING CLEANING PROCEDURES (for the 9 5/8" casing, this will be performed after th drilling rig is released and when /after the USIT/CBL's are run after the rig is moved off!)</u>

1. *While waiting on cement 6 hours, pick up enough 4½" DP and 6 ½"drill collars (or BHA that is racked back if suitable)to clean out the 9 5/8" casing. Run in hole with 8-1/2" bit and clean out to the top of the float collar, if needed (TBD after well is TD'd, logged, casing run to TD to analyze how much, if any, rathole needs to be available for completion efforts in the Mt Simon. If shoe track is set into the Pre-cambrian, maybe no drilling of shore track is necessary. Allow suitable cleaning, etc to run USIT/CBL & other possible casing wireline tools)*

2. *TIH with 9-5/8" casing scrapers properly spaced out with junk basket, etc. Hole will already be displaced with KCl during cementing operation, to allow future completion operations.*

3. *Prior to POOH , LD, circulate clean, filtered KCl in hole. .*

4. *Pull out of hole, laying down drill pipe and bottom hole assembly. Prepare to release rig*

5. *Remove BOP's and install used master valve with gauge on top of well head.*

6. *Rig down and move drilling rig. Prior to releasing rig, ensure steel wellhead protector is in place.*

F. <u>GENERAL GUIDELINES</u>

1. Make sure Material Transfers are made on all items when received or dispatched from the well. Report the arrival and departure date of rental equipment for cost control.

2. As soon as possible while rigging up, place the 20" casing on the pipe rack (arrange different method if workover rig is to be used prior to drilling rig arrival). Clean the threads, visually inspect for damage, and tally. It is expected that the 20" will not be magnetic particle inspected. Rack the 13 3/8" and 9-5/8" casing in such a way that they can be drifted and inspected prior to use, if necessary, on location. After the 20" casing is run, place the 13 3/8" on the rack and prepare for running.

3. While casing is on the racks, find all Buttress triangle marks. Clean and paint an arrow mark pointing to the Buttress triangle mark, so that when casing is run, the mark can be easily seen and assist in ensuring the buttress threaded casing is properly torqued to the triangle mark.

4. The MINIMUM BARITE WEIGHTING RESERVE at nightfall should allow for increasing the mud weight two lbs/gal in 17-½" hole and one lb/gal in 12-1/4" hole, but in any case <u>it will not be less than</u>

5. <u>1000 sacks.</u> Minimum inventory of a sized calcium carbonate as a weighting/loss return agent to be used per drilling fluids specialist and WSS. The addition of sodium thyocianate should also be considered while drilling the Mt Simon, for verification of filtrate.

6. Plan ahead on all material requirements as this is a logistical sensitive well. Transportation is limited and will be very difficult to arrange. The nearest supply store is far away, even in an emergency.

7. Make every effort to have bits dressed with the proper size nozzles, spare stabilizers checked and ready, tools calipered and measured, etc. to prevent unnecessary losses of time.

8. Check Drilling Contractor's or inventory of fishing tools carefully to ensure they have tools to catch anything that goes through the rotary.

9. At least one week prior to any cementing operation send in a sack of the cement and a 5-gallon can of the water that will be used on the job, for lab testing. Lab tests must be run on the water and cement for thickening time, free water, required additives and compressive strength. Ensure same source of water for each cement job!

10. Formation pressures are expected to be normal to T.D. However, pressure anomalies may occur particularly as a result of local abnormalities. Swab and surge pressures must be watched carefully. Be prepared for well kicks. Special attention must be taken while drilling the surface hole because there will not be a diverter installed.

11. All crews must practice BOP practice drills while drilling and trip drills must be duly noted in the WEMS or comparable report and IADC morning report forms. Thereafter, BOP drills are to be run at least weekly for each crew or on trips and reported on the daily drilling report.

12. **BOP Equipment shall be tested at least every fourteen- (14) days or per SCS Drilling Policy**. Rams shall be operated each trip and the operation noted on the reports. Test as much of BOP equipment as possible concurrent with other rig operations to minimize testing time.

13. Take a "Reduced Flow Rate" with at least 2 separate pumps daily and note the SPM and pressure on the reports and drilling recorder.

14. Keep a "Full Opening Safety Valve" and an "Inside BOP" on the rig floor at all times with proper x-overs to all connections of the drill string and/or tubing.

15. Use the Trip Tank to fill hole on trips. Monitor hole and fill carefully. Report any mud losses or gains.

16. Run Drill Pipe Protector Rubbers on the drill pipe that is inside casing. Do not run protectors below casing into open hole.

17. The mud and hydraulic programs are meant as guides. However, proposed changes must be discussed with the ADM Drilling Supervisor and the SCS Well Architect/Engineer in Charge prior to

any major changes that will affect the MOC process. To maximize hole cleaning keep circulating rates at 650-830 GPM in 17-½" hole, 500-620 GPM in 12-1/4" hole.

Optimize bit hydraulics by properly sizing nozzles, not maximizing circulation rate.

18. Do not take deviation surveys right on bottom. Always keep enough open hole below the bit to allow breaking stuck pipe free going downward.

19. Report the Shock Sub and Drilling Jar serial numbers and cumulative running hours on the morning report. Make notation on initial drilling report, when all jars are picked up the down setting wt.

20. Make sure all BHA´s that go through the rotary table are correctly calipered I.D., O.D. and length. A downhole schematic of the BHA must be kept current. Note on schematic if pin has API relief groove and box has API bore back. Gauge stabilizers each trip.

21. Make sure all pit level indicators alarms and multi-pen drilling recorder is working at all times. Discrepancies must be reported on the daily drilling report.

22. **On the 17-1/2" hole have 50 bbl of 9.0 ppg premixed kill mud, in case a water flow is encountered**.

23. Measure pipe (SLM) on a trip prior to reaching casing setting points, important formation tops and when POOH for cores or drill stem tests. If the pipe strap should be off more than 1-foot/1000 feet of depth, strap the pipe again to confirm the difference prior to making depth corrections.

24. Keep an inventory of all drill pipe on location. If measurements should become in question, the number of joints in the hole can easily be determined.

25. Solids control equipment must be kept in top operating condition. Keep finest screens possible on the shale shaker. Report screen sizes on morning report. Efficiency checks for all SCE should be made at least twice a week and duly reported on the daily morning report.

26. Upon returning to bottom after all trips, wash a minimum of 2 joints to bottom.

27. After every trip when circulation is started, start the Degasser and run it at least until after bottoms

are circulated up. This will not only ensure the Degasser operates properly, but will help condition the mud.

28. Coordinate operations closely with the mud loggers and Wellsite Geologist. Check with the Wellsite Geologist prior to tripping for the possible need to circulate up critical samples.

29. The Rig Toolpusher and the ADM Drilling Supervisor should be on the rig floor for the first ten stands out of the hole and the last ten stands in the hole on all trips and any other times hole problems are present.

30. Report all safety meetings and response brigade drills/training on daily drilling report and radio report.

31. Report WOB, rotary RPM, pump pressure, SPM, TORQUE, for each drilled interval on daily drilling report.

32. Use bit nozzles on all bit runs whether drilling, conditioning or reaming. Every bit run through the rotary should be capable of drilling additional hole even on conditioning trips while logging.

33. Report all non-functioning contractor and service company equipment each day on drilling report.

34. Recover and save for future requirements the jet nozzles from all rock and PDC bits. Nozzles are both expensive and in short supply. Ensure PDC bit breakers are on location.

35. Keep caustic soda and soda ash under lock in secured mud storage. Keep tight inventory control on these items (per SCS Policy).

36. The ADM Drilling Supervisors will maintain a current directional drilling chart and drilling time charts at their respective work site. On drilling time curve, days, rotating hours, cost, torque and mud properties will be plotted current. Torque and mud data trends are a useful tool in detecting hole or mud problems.

37. Check Drilling Contractor's drill pipe hard banding. Do not run newly hard-banded tool joints inside 9-5/8" protective casing. Critical area for casing wear is directional build area.

<u>**BHA PLAN**</u>

1. PHASE I: 17-1/2" HOLE.

After spudding the well and running and cementing the 20" (30"conductor was pre-set) drill out of the 20" as follows:

17-1/2" ROCK BIT + 9"A-962 PPK MOTOR(if rotary cannot be achieved) + 9 1/2" XO + 9 1/2" FS + 3 (9 1/2") DC + 8"XO + 3 (5" or 4 ½") HWDP + 6-3/4"JARS + 15 (5" or 4 ½") HWDP

Note: This BHA is expected to hold the angle vertical as can be.

The 2JS rock bit is recommended and if no chert is encountered it is possible to cut the 17 ½" hole with 1 bit. If not, then a 2nd , 4JS is planned.

2. PHASE II: 12-1/4" HOLE

Lay down 9 1/2 in collars, while WOC. P/U the same BHA as before but with 8 in collars. (without motor if rpm can be achieved with rig equipment)

This BHA is expected to maintain the vertical angle.

DRILLING FLUIDS PROGRAM

DEPTH MD / TVD (feet)	HOLE SIZE	CASING	MUD SYSTEM
350-400	26"	20"	GEL / WATER
350-4,000	17-1/2"	13-3/8"	BTS
7,900 +/-	12-1/4"	9-5/8"	FLOPRO

CRITICAL MUD PROPERTIES :

DEPTH MD (feet)	MUD WT. (ppg)	YP lb/100sf	FLUID LOSS c.c.	pH	0.3 RPM
0 - 400	*8.4 - 8.6	25 - 51	N.C.	8.0 - 9.0	N.C.
400 – 3,500	8.4 - 9.0	9 - 20	N.C. - 12.0	8.5 - 9.5	NC
3,500-7,900	*9.0-9.3	25 - 45	</= 8.0	9.2 - 9.9	80-130,000

- The mud weight may need to be raised if a water flow occurs.

Detailed Drilling Fluids Proposal
For

ADM Well #1 - CCS
Decatur, Illinois (ADM Plant)
Macon County, IL.
Projected T.D. - +/-7,900'

Hole Size and Casing Program

Interval I

30" Conductor Pipe – pre-driven or set prior to spud
Set (30'-60')

Interval II
Drill 26" Hole to (350'-400' +/- (M.D.)) – Set 20" Casing

Interval III
Drill 17 ½" Hole to (3500'-4500' +/- (M.D.)) – Set 13 3/8" Casing

Interval IV
12 ¼" Hole to 7,900' +/- (M.D.) – Set 9 5/8" Casing

Interval Discussion

Interval I

This interval will be drilled with a port-a-drill rig. If any viscosity is needed for this interval we recommend spud mud with a 45+ sec/1000cc viscosity.

Hole Volume for 36" hole at T.D. (+/-60')	-	77.8 bbl.
Pit Volume	-	200.0 bbl.
Total Volume at T.D. (+/-60')	-	277.8 bbl.

Estimated Product Consumption
Caustic Soda – 0.25 lb. /bbl. * 277.8 bbl. = 69.5 lb.
Soda Ash - 0.25 lb. /bbl. * 277.8 bbl. = 69.5 lb
MI Gel - 15.0 lb. /bbl. * 277.8 bbl. = 4,167.0 lb.
Lime - 0.50 lb. /bbl. *277.8 bbl. = 138.9 lb.

If spud mud is needed for this interval estimated products will vary.

Interval II

Drill 26" Hole to (350'-400' +/- (M.D.)) – Set 20" Casing

We recommend using spud mud for this interval. Spud mud with a 45+ sec/1000cc viscosity.

Hole Volume for 26" hole at T.D. (+/-400' M.D.) with 15% washout increase - 311.0 bbl.
Pit Volume - 600.0 bbl.

Total Volume at T.D. (+/-400' M.D.) - 911.0 bbl.

Estimated Product Consumption
Caustic Soda – 0.25 lb. /bbl. * 911.0 bbl. = 227.8 lb.
Soda Ash - 0.25 lb. /bbl. * 911.0 bbl. = 227.8 lb.
MI Gel - 15.0 lb. /bbl. * 911.0 bbl. = 13,665.0 lb.
Lime - 0.50 lb. /bbl. *911.0 bbl. = 455.5 lb.

Interval III

Drill 17 ½" Hole to (3500'-4000' +/- (M.D.)) – Set 13 3/8" Casing

We recommend using a gel/chemical mud system for this hole interval with filtrate control. We will mud up the system after drilling out the cement plug with freshwater along with 5 feet of new hole so we do not contaminate the mud system with cement.

Mud Up Volumes

17 ½" Hole volume at 400' -	160.0 bbl.
Pit Volume -	600.0 bbl.
Total Volume -	760.0 bbl.

Estimated Product Consumption
Caustic Soda – 0.25 lb. /bbl. * 760.0 bbl. = 190.0 lb.
Soda Ash - 0.25 lb. /bbl. * 760.0 bbl. = 190.0 lb.
MI Gel - 18.0 lb. /bbl. * 760.0 bbl. = 13,680.0 lb.
Quebracho - 0.25 lb. /bbl. * 760.0 bbl. = 190.0 lb.
Caustilig - 0.50 lb. /bbl. * 760.0 bbl. = 380.0 lb.
Fed Pac - 0.50 lb. /bbl. * 760.0 bbl. = 380.0 lb.

Maintenance Treatments from 400' to 1400' – 5 days of drilling (200' per day)

Caustic Soda – 100 lb.
Soda Ash - 100 lb.

MI Gel - 1500 lb.
Quebracho - 100 lb.
Caustilig - 100 lb.
Fed Pac - 25 lb.
Total - 5 days

@ 1400' we will need to pretreat for Anhydrite Contamination:

Caustic Soda – 200 lb.
Soda Ash - 300 lb.
Quebracho - 300 lb.

Caustilig - 200 lb.

Maintenance Treatments from 1400' to 5000' – 18 days (200' per day)

Caustic Soda – 100 lb.
Soda Ash - 100 lb.
MI Gel - 1500 lb.
Quebracho - 100 lb.
Caustilig - 100 lb.
Fed Pac - 25 lb.
Total 18 days

Prior to coring the Eau Claire:
We will need to pretreat with Caustilig and Fed Pac to drop the filtrate in the mud.
Caustilig – 200 lb.
Fed Pac - 100 lb.

Interval IV

12 ¼" Hole to Est TD =7,900' +/- (M.D.) – Set 9 5/8" Casing

We recommend using a FloPro system for this hole interval. We will mud up the system after drilling out the cement plug with freshwater along with 5 feet of new hole so we do not contaminate the FloPro system with cement. When we get the cement drilled out and the hole has been displaced and pits cleaned out we will fill the hole and pits with clean freshwater and while circulating the system we will mud up with FloPro.

<u>Mud Up Volumes</u>

12 1/4" Hole volume at 5000'	-	894.5 bbl.
Pit Volume	-	600.0 bbl.
Total Volume	-	1,494.5 bbl.

<u>Estimated Product Consumption</u>
Soda Ash – 0.25 lb./bbl. * 1,494.5 bbl. = 373.6 lb.
Myacide – 5.0 gal./100.0 bbl. * 1,494.5 bbl. = 74.7 gal.
FloVis – 1.0 lb./bbl. * 1,494.5 bbl. = 1,494.5 lb.
FloTrol – 5.0 lb./bbl. * 1,494.5 bbl. = 7,472.5 lb.
SafeCarb 40 – 10 lb./bbl. * 1,494.5 bbl. = 14,945.0 lb.
SafeCarb 20 – 10 lb./bbl. * 1,494.5 bbl. = 14,945.0 lb.

Maintenance treatments from 5000' to 8000' – 15 days (200' per day)

We will use a 100 bbl. premix tank to build batches of the FloPro system and then bleed it into the active system to compensate for the new hole volume made and for jetting purposes.

100 bbl. Premix Tank

Estimated Product Consumption
Soda Ash – 0.25 lb./bbl. * 100.0 bbl. = 25 lb.
Myacide – 5.0 gal./100.0 bbl. * 100.0 bbl. = 5.0 gal.
FloVis – 1.0 lb./bbl. * 100.0 bbl. = 100.0 lb.
FloTrol – 5.0 lb./bbl. * 100.0 bbl. = 500.0 lb.
SafeCarb 40 – 10 lb./bbl. * 100.0 bbl. = 1000.0 lb.
SafeCarb 20 – 10 lb./bbl. * 100.0 bbl. = 1000.0 lb.

We recommend bleeding the 100 bbl. premix tank into the active system over 400' of new drilled hole. For every 400' of new hole we figured it to be 60 bbl. of new fluid and if needed to jet the shale tank which would be approximately 40 bbl. of fluid. At that rate if the hole does not take any abnormal amount of fluid we should be able to maintain the system by mixing 8 to 9 100 bbl. premix tank fulls of the FloPro fluid. (9 tank fulls)
We will also need to add Myacide to the active system each day for polymer protection – 1.0 gal./100 bbl. * 1,494.5 bbl. = 14.9 gal –

KCL Water for Filling the 9 5/8" Casing at end of Well (or after drilling rig is moved off)

Casing Volume at 8000' – 744.0 bbl.
KCL - 11.2 lb./bbl. * 744.0 bbl. = 8,332.8 lb.
KOH (Caustic Potash) – 0.50 lb./bbl. * 744.0 bbl. = 372.0 lb.

Product	Purpose for Mud System
MI Gel	Viscosifier
Caustic Soda	Alkalinity Control
Soda Ash	Hardness Contamination
Quebracho	Deflocculent
Caustilig	Fluid loss control/Deflocculent
Fed Pac	Fluid loss control
Lime	Viscosity Flocculent
Cottonseed Hulls	Loss Circulation
Fed Seal	Loss Circulation
Cedar Fiber	Loss Circulation
Mica	Loss Circulation

MI Bar	Weighting Material

Product	Purpose for FloPro System
Soda Ash	Alkalinity Control
Myacide	Bactericide
FloVis	Viscosifier
FloTrol	Fluid loss control
SafeCarb	Fluid loss control and loss circulation
Mix II	Loss Circulation

Loss Circulation Material, Amount. if needed in the Gel/Chemical Mud

Cottonseed Hulls – 2.5 lb. /bbl.
Fed Seal – 2.5 lb. /bbl.
Cedar Fiber – 2.5 lb. /bbl.
Mica Coarse – 2.5 lb. /bbl.
Cottonseed Hulls – 3.75 lb. /bbl.
Fed Seal – 3.75 lb. /bbl.
Cedar Fiber – 3.75 lb. /bbl.
Mica Coarse – 3.75 lb. /bbl.

Cottonseed Hulls – 5.0 lb. /bbl.
Fed Seal – 5.0 lb. /bbl.
Cedar Fiber – 5.0 lb. /bbl.
Mica Coarse – 5.0 lb. /bbl.

Cottonseed Hulls – 6.25 lb. /bbl.
Fed Seal – 6.25 lb. /bbl.
Cedar Fiber – 6.25 lb. /bbl.
Mica Coarse – 6.25 lb. /bbl.
Total – 25 lb. /bbl.

NOTES FOR THE 17 1/2"HOLE SECTION

1. Spud this section with water.
2. Use drill solids to weight the system up as much as possible
3. Maintain soda ash, freeing additive and LCM on location for contingency.
4. Mud checks will be made at the flow line and pits while drilling. Flow line checks will be recorded on the daily drilling report and these values will be used to estimate product additions.

5. After the wiper trip, before running casing, raise the mud weight if there are hole stability problems.

6. Wiper trips to the shoe are excellent indicators of hole conditions. A wiper trip will be made every 300 meters or 24 hours. Whichever comes first. Circulate the hole clean following a 100-bbl sweep. The mud engineer will be at the shakers during bottoms up to determine when the hole is clean.

CASING AND CEMENTING PROGRAM

Schlumberger

CemCADE* well cementing recommendation for Surface Csg

Operator	**: Battelle**	**Well**	**: Unknown**
Country	:	Field	: CO2 Disposal
State	: Illinois		
Prepared for	**:**	**Location**	**:**
Proposal No.	:	Service Point	: Inez
Date Prepared	: 01-25-2008	Business Phone	: 606-298-2200
		FAX No.	:

Prepared by : Fred Peters
Phone : 304-549-9733
E-Mail : fredpeters@cebridge.net

well description

Configuration	**Casing**	**Stage : Single**	**Rig Type : Land**
Csg/Liner	MD : 300.0 ft	OD : 20 in	Weight : 94.0 lb/ft
Landing Collar MD		295.0 ft	
Casing/liner Shoe MD		300.0 ft	
Mud Line		0.0 ft	
Total MD		300.0 ft	
BHST		60 degF	
Bit Size		26 in	
Mean OH Diameter		26.000 in	
Mean Annular Excess		100.0 %	
Mean OH Equivalent Diameter		30.854 in	
Total OH Volume		277.4 bbl (including excess)	

DESIGN EXECUTE EVALUATE

* Mark of Schlumberger

Section 1: fluid sequence

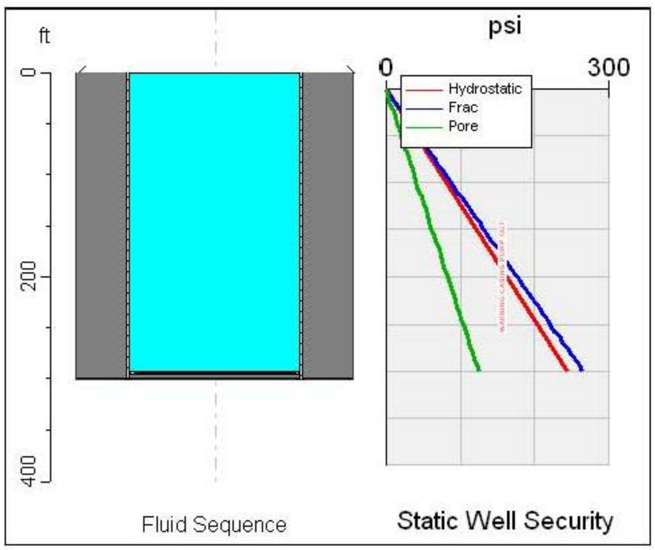
Original fluid	Brine	8.35 lb/gal
	k : 2.09E-5 lbf.s^n/ft2	n : 1.000
Displacement Volume	104.8 bbl	
Total Volume	267.5 bbl	
TOC	0.0 ft	

Fluid Sequence

Name	Volume (bbl)	Ann. Len (ft)	Top (ft)	Density (lb/gal)	Rheology	
Water	0.0	0.0	0.0	8.33	viscosity:1.000 cP	
Class A 2%	162.6	300.0	0.0	15.60	Pv:85.000 cP	Ty:15.00 lbf/100ft2
Water	104.8		0.0	8.33	viscosity:1.000 cP	

WARNING : CASING PUMP OUT

Static Security Checks :		
Frac	0 psi	at 0.0 ft
Pore	0 psi	at 0.0 ft
Collapse	403 psi	at 295.0 ft
Burst	2110 psi	at 0.0 ft
Csg.Pump out	-5 ton	



Section 2: pumping schedule

Pumping Schedule

Name	Flow Rate (bbl/min)	Volume (bbl)	Stage Time (min)	Cum.Vol (bbl).	Inj. Temp. (degF)	Comments
Water	5.0	0.0	0.0	0.0	80	Start water ahead
Class A 2%	5.0	162.6	32.5	162.6	80	Start slurry
Pause	0.0	0.0	2.0	0.0	80	Shut down, drop top plug
Water	5.0	100.0	20.0	100.0	80	Start displacement
Water	1.0	4.8	4.8	104.8	80	Reduce rate to bump plug
		Total	**00:59 hr:mn**	**267.5 bbl**		

Dynamic Security Checks :

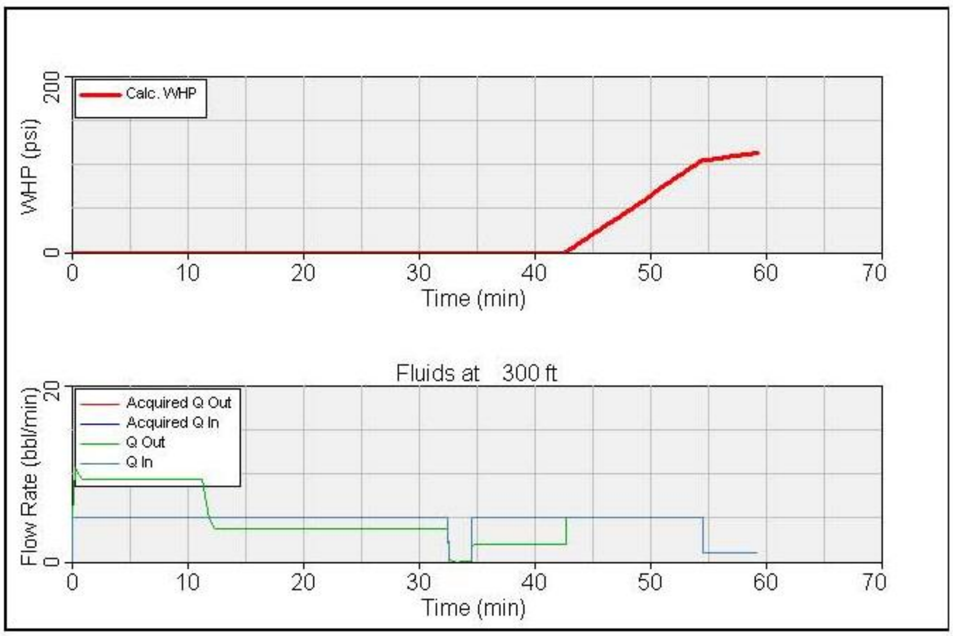
Frac	0 psi	at 0.0 ft
Pore	0 psi	at 0.0 ft
Collapse	403 psi	at 295.0 ft
Burst	1997 psi	at 0.0 ft

Temperature Results

BHCT	80 degF	Simulated Max HCT	(degF)
Simulated BHCT	(degF)	Max HCT Depth	(ft)
CT at TOC	(degF)	Max HCT Time	(hr:mn:sc)

Static temperatures :

At Time	(hr:mn)	(hr:mn)	Geo. Temp.
Top of Cement	(degF)	(degF)	(degF)
Bottom Hole	(degF)	(degF)	(degF)



Section 3: fluid description

Class A 2% DESIGN

Fluid No	: 2	Density	: 15.60 lb/gal
Rheo. Model	: BINGHAM	P_v	: 85.000 cP
At temp.	: (degF)	T_y	: 15.00 lbf/100ft2
		Gel Strength	: (lbf/100ft2)

DESIGN

BLEND		SLURRY			
Name	: A	Mix Fluid	: 5.230 gal/sk	Job volume	: 162.6 bbl
Dry Density	: 197.27 lb/ft3	Yield	: 1.20 ft3/sk	Quantity	: 763.11 sk
Sack Weight	: 94 lb	Solid Fraction	: 41.6 %		

BASE FLUID					
Type	: Fresh water	Density	: 8.32 lb/gal	Base Fluid	: 5.230 gal/sk

Additives

Code	Conc.	Function
D130	0.250 lb/sk blend	Lost circ
S001	2.000 %BWOC	Accelerator

Thickening Time	Schedule	( )	(Bc)	at	(hr:mn)
Compressive Strength	Schedule	( )	(psi)	at	(hr:mn)

Schlumberger

CemCADE* well cementing recommendation for Intermediate Csg

Operator	**: Battelle**	**Well**	**: Unknown**
Country	:	Field	: CO2 Disposal
State	: Illinois		
Prepared for	**:**	**Location**	**:**
Proposal No.	:	Service Point	: Inez
Date Prepared	: 01-25-2008	Business Phone	: 606-298-2200
		FAX No.	:

Prepared by : Fred Peters
Phone : 304-549-9733
E-Mail : fredpeters@cebridge.net

* Mark of Schlumberger

well description

Configuration	**Casing**	**Stage : Single**	**Rig Type : Land**
Prev.String	MD : 300.0 ft	OD : 20 in	Weight : 94.0 lb/ft
Csg/Liner	MD : 5000.0 ft	OD : 13 3/8 in	Weight : 61.0 lb/ft
Landing Collar MD		4920.0 ft	
Casing/liner Shoe MD		5000.0 ft	
Mud Line		0.0 ft	
Total MD		5000.0 ft	
BHST		105 degF	
Bit Size		17 1/2 in	
Mean OH Diameter		17.500 in	
Mean Annular Excess		50.0 %	
Mean OH Equivalent Diameter		19.234 in	
Total OH Volume		1689.0 bbl (including excess)	

Section 4: fluid sequence

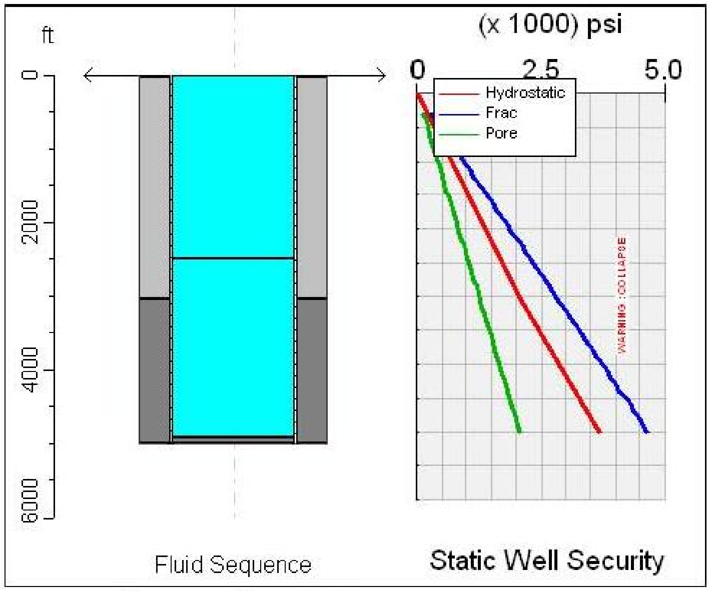
Original fluid	Mud	9.00 lb/gal	
	Pv : 20.000 cP		Ty : 5.00 lbf/100ft2
Displacement Volume	748.6 bbl		
Total Volume	1701.2 bbl		
TOC	34.1 ft		

Fluid Sequence

Name	Volume (bbl)	Ann. Len (ft)	Top (ft)	Density (lb/gal)	Rheology	
Water	20.0	34.1		8.33	viscosity:1.000 cP	
Int Lead	555.5	2999.3	34.1	13.30	Pv:30.000 cP	Ty:10.00 lbf/100ft2
Int Tail	377.1	1966.7	3033.3	15.60	Pv:85.000 cP	Ty:20.00 lbf/100ft2
Water	368.0		2501.3	8.33	viscosity:1.000 cP	
Water	380.6		0.0	8.33	viscosity:1.000 cP	

WARNING : COLLAPSE AND BURST

Static Security Checks :		
Frac	82 psi	at 300.0 ft
Pore	74 psi	at 300.0 ft
Collapse	-84 psi	at 4920.0 ft
Burst	3090 psi	at 0.0 ft
Csg.Pump out	29 ton	



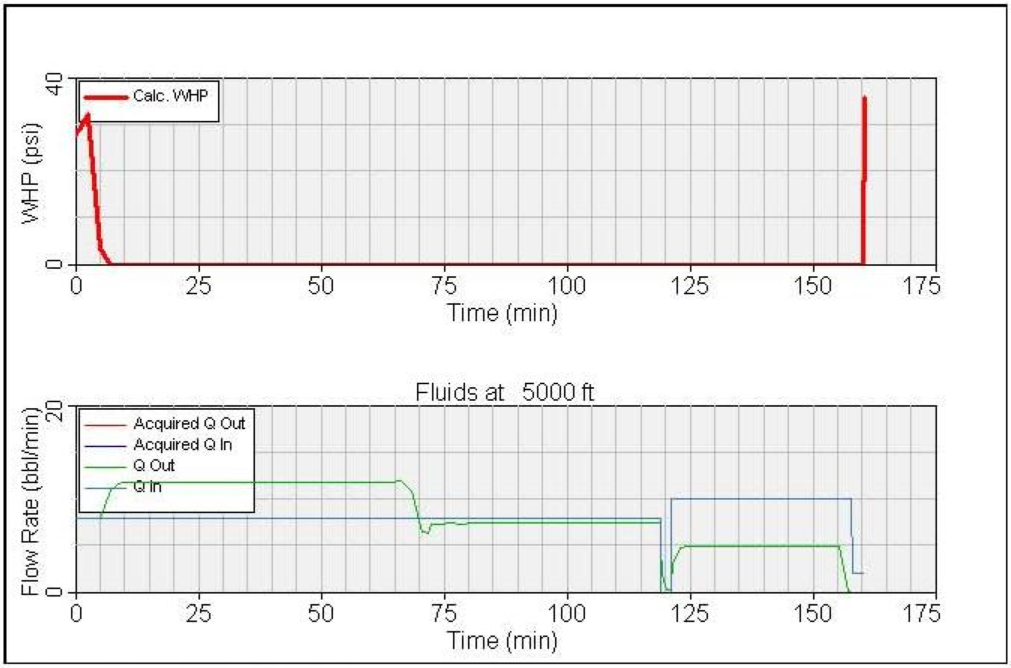
Section 5: pumping schedule

Pumping Schedule

Name	Flow Rate (bbl/min)	Volume (bbl)	Stage Time (min)	Cum.Vol (bbl).	Inj. Temp. (degF)	Comments
Water	8.0	20.0	2.5	20.0	80	Start water ahead
Int Lead	8.0	555.5	69.4	555.5	80	Start lead slu9rry
Int Tail	8.0	377.1	47.1	377.1	80	Start tail slurry
Pause	0.0	0.0	2.0	0.0	80	Shut down, drop top plug
Water	10.0	368.0	36.8	368.0	80	Start displacement
Water	2.0	5.1	2.5	373.1	80	Reduce rate to bump plug
		Total	**02:40 hr:mn**	**1325.7 bbl**		

Dynamic Security Checks :

Frac	139 psi	at 300.0 ft
Pore	16 psi	at 300.0 ft
Collapse	778 psi	at 1567.1 ft
Burst	2963 psi	at 4920.0 ft



Section 6: fluid description

Int Lead DESIGN

Fluid No : 2
Rheo. Model : BINGHAM
At temp. : (degF)

Density : 13.30 lb/gal
P_v : 30.000 cP
T_y : 10.00 lbf/100ft2
Gel Strength : (lbf/100ft2)

DESIGN

BLEND
Name : 5050pozA
Dry Density : 176.01 lb/ft3
Sack Weight : 84 lb

SLURRY
Mix Fluid : 7.579 gal/sk
Yield : 1.52 ft3/sk
Solid Fraction : 33.3 %

Job volume : 555.5 bbl
Quantity : 2053.07 sk

BASE FLUID
Type : Fresh water
Density : 8.32 lb/gal
Base Fluid : 7.579 gal/sk

	Additives	
Code	**Conc.**	**Function**
D020	6.000 %BWOC	Extender
D046	0.200 %BWOC	Antifoam
S001	2.500 %BWOC	Accelerator

Thickening Time Schedule ( ) (Bc) at (hr:mn)
Compressive Strength Schedule ( ) (psi) at (hr:mn)

Int Tail DESIGN

Fluid No	: 3	Density	: 15.60 lb/gal
Rheo. Model	: BINGHAM	Pv	: 85.000 cP
At temp.	: (degF)	Ty	: 20.00 lbf/100ft2
		Gel Strength	: (lbf/100ft2)

DESIGN

BLEND		SLURRY			
Name	: A	Mix Fluid	: 5.234 gal/sk	Job volume	: 377.1 bbl
Dry Density	: 197.27 lb/ft3	Yield	: 1.19 ft3/sk	Quantity	: 1784.93 sk
Sack Weight	: 94 lb	Solid Fraction	: 41.0 %		

BASE FLUID					
Type	: Fresh water	Density	: 8.32 lb/gal	Base Fluid	: 5.234 gal/sk

Additives

Code	Conc.	Function
D046	0.200 %BWOC	Antifoam
D065	0.500 %BWOC	Dispersant
D167	0.250 %BWOC	Fluid loss

Thickening Time	Schedule	( )	(Bc)	at	(hr:mn)
Compressive Strength	Schedule	( )	(psi)	at	(hr:mn)

Schlumberger

CemCADE* well cementing recommendation for Long String

Operator	**: Battelle**	**Well**	**: Unknown**
Country	:	Field	: CO2 Disposal
State	: Illinois		
Prepared for	**:**	**Location**	**:**
Proposal No.	:	Service Point	: Inez
Date Prepared	: 01-25-2008	Business Phone	: 606-298-2200
		FAX No.	:

Prepared by : Fred Peters
Phone : 304-549-9733
E-Mail : fredpeters@cebridge.net

well description

Configuration Casing		**Stage : Single**	**Rig Type : Land**
Prev.String	MD : 5000.0 ft	OD : 13 3/8 in	Weight : 61.0 lb/ft
Csg/Liner	MD : 7500.0 ft	OD : 9 5/8 in	Weight : 40.0 lb/ft
Landing Collar MD		7420.0 ft	
Casing/liner Shoe MD		7500.0 ft	
Mud Line		0.0 ft	
Total MD		7500.0 ft	
BHST		130 degF	
Mean OH Diameter		12.250 in	
Mean Annular Excess		25.0 %	
Mean OH Equivalent Diameter		12.823 in	
Total OH Volume		399.3 bbl (including excess)	

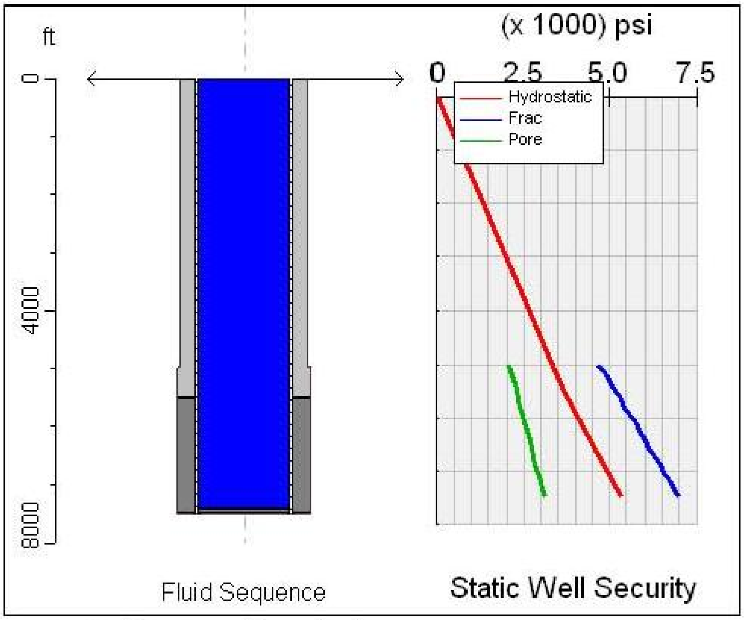
Section 7: fluid sequence

Original fluid	Mud	9.00 lb/gal	
	Pv : 15.000 cP		Ty : 5.00 lbf/100ft2
Displacement Volume	562.6 bbl		
Total Volume	1053.8 bbl		
TOC	0.0 ft		

Fluid Sequence

Name	Volume (bbl)	Ann. Len (ft)	Top (ft)	Density (lb/gal)	Rheology	
Water	0.0	0.0	0.0	8.32	viscosity:1.000 cP	
LS Lead	345.6	5500.0	0.0	12.80	Pv:35.000 cP	Ty:10.00 lbf/100ft2
LS Tail	145.5	2000.0	5500.0	15.80	Pv:110.000 cP	Ty:25.00 lbf/100ft2
Water	562.6		0.0	8.32	viscosity:1.000 cP	

Static Security Checks :		
Frac	1351 psi	at 5000.0 ft
Pore	1247 psi	at 5000.0 ft
Collapse	801 psi	at 7420.0 ft
Burst	5730 psi	at 0.0 ft
Csg.Pump out	58 ton	



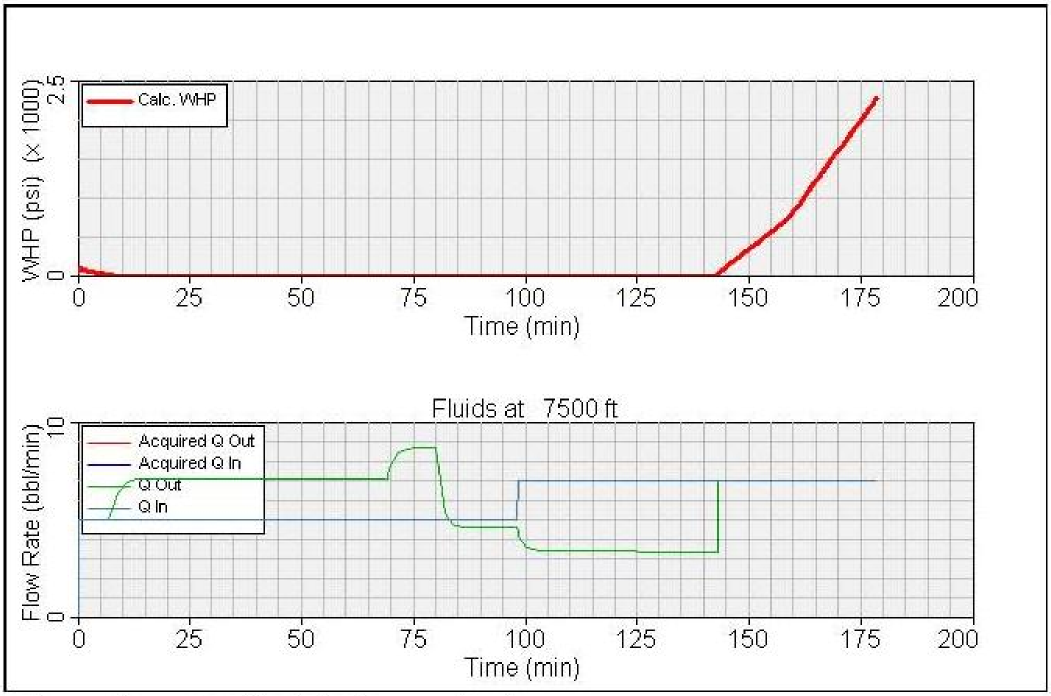
Section 8: pumping schedule

Pumping Schedule

Name	Flow Rate (bbl/min)	Volume (bbl)	Stage Time (min)	Cum.Vol (bbl).	Inj. Temp. (degF)	Comments
Water	5.0	0.0	0.0	0.0	80	Start water ahead
LS Lead	5.0	345.6	69.1	345.6	80	Start lead slurry
LS Tail	5.0	145.5	29.1	145.5	80	Start CO2 taul slurry
Pause	0.0	0.0	0.0	0.0	80	Shut down, drop top plug
Water	7.0	558.0	79.7	558.0	80	Start displacement
Water	7.0	4.6	0.7	562.6	80	Reduce rate to bump plug
		Total	**02:58 hr:mn**	**1053.8 bbl**		

Dynamic Security Checks :

Frac	1231 psi	at 5000.0 ft
Pore	260 psi	at 5000.0 ft
Collapse	801 psi	at 7420.0 ft
Burst	3463 psi	at 0.0 ft



Section 9: fluid description

LS Lead DESIGN

Fluid No : 2
Rheo. Model : BINGHAM
At temp. : (degF)

Density : 12.80 lb/gal
P_v : 35.000 cP
T_y : 10.00 lbf/100ft2
Gel Strength : (lbf/100ft2)

DESIGN

BLEND
Name : 35:65 Poz:A
Dry Density : 183.88 lb/ft3
Sack Weight : 87 lb

SLURRY
Mix Fluid : 10.994 gal/sk
Yield : 1.97 ft3/sk
Solid Fraction : 25.4 %

Job volume : 345.6 bbl
Quantity : 985.13 sk

BASE FLUID
Type : Fresh water
Density : 8.32 lb/gal
Base Fluid : 10.657 gal/sk

Additives

Code	Conc.	Function
D020	6.000 %BWOC	Extender
D013	0.100 %BWOC	Retarder
D044	10.000 %BWOW	Salt
D046	0.200 %BWOC	Antifoam
D065	0.200 %BWOC	Dispersant
D167	0.200 %BWOC	Fluid loss

Thickening Time	Schedule	( )	(Bc)	at	(hr:mn)
Compressive Strength	Schedule	( )	(psi)	at	(hr:mn)

LS Tail DESIGN

Fluid No	: 3	Density	: 15.80 lb/gal
Rheo. Model	: BINGHAM	P_v	: 110.000 cP
At temp.	: (degF)	T_y	: 25.00 lbf/100ft2
		Gel Strength	: (lbf/100ft2)

DESIGN

BLEND		SLURRY			
Name	: Low T CO2	Mix Fluid	: 3.400 gal/sk	Job volume	: 145.5 bbl
Dry Density	: 157.50 lb/ft3	Yield	: 1.09 ft3/sk	Quantity	: 749.88 sk
Sack Weight	: 100 lb	Solid Fraction	: 58.3 %		

BASE FLUID

Type	: Fresh water	Density	: 8.32 lb/gal	Base Fluid	: 3.010 gal/sk

Additives

Code	**Conc.**	**Function**
D080	0.160 gal/sk blend	Dispersant
D168	0.200 gal/sk blend	Fluid loss
D175	0.030 gal/sk blend	Antifoam
D153	0.100 %BWOC	Antisettling

Thickening Time	Schedule	( )	(Bc)	at	(hr:mn)
Compressive Strength	Schedule	( )	(psi)	at	(hr:mn)

CASING AND CEMENTING PROCEDURES

CASING STRING:

13-3/8" Float Shoe, Conventional, Buttress
80' (2 Jt.) 13-3/8" 68 lb/ft., K-55, R-3, BTC
13-3/8" Float Collar, Conventional, Buttress
520' (13 joints) 13-3/8" 68 lb/ft, K-55, R-3 BTC

MATERIALS & EQUIPMENT:

1 13-3/8" Float Shoe, Davis Lynch, BTC (PDC drillable)

1 13-3/8" Float Collar, Davis Lynch, BTC (PDC drillable - non rotating)

4 Thread Lock Compound - Thread lock bottom 3 joints

3 Thread Lubricant - API Modified

1 Circulating Head - Swage, 2" Union x 13-3/8" Buttress

1 13-3/8" Side Door Elevator, 150 ton capacity.

1 13-3/8" Rotary Slips

1 Set of 250 Ton Elevator Links, 144" long

1 Power Casing Tongs with 13-3/8" heads. (Torque to buttress triangle mark)

2 Rotary Tong heads to fit 13-3/8" casing

1 13-3/8" Single Joint Pick-Up Elevator and Protector

10 Centralizers, 13-3/8" x 18". (Install one around stop collar + 6 feet above shoe, one around next coupling, one on every third coupling next 10 jts (TBD by hole section after well sections are TD'd & log information is inputted into the CemCade/Centralizer Program

5 Stop Rings, 13-3/8"

1 Surface Fill Line, 3" with quick opening valve

1 Cementing Head - Plug Container 13-3/8", Buttress

2 Cementing Plugs - Top and Bottom, 13-3/8" PDC drillable - non rotating.

2 Casing Coupling 13-3/8" "K-55", BTC, for emergency replacement should a joint be damaged while running.

1 Pressure Recorder - Connected to record all circulating and cementing pressures.

1 Drift Mandrel 12.259" O.D.

1 3" - 4" fill up line on rig for running casing

RUNNING & CEMENTING PROCEDURES:

1. Inspect, clean threads, tally and rabbit casing on the pipe racks. Use a 12.259" casing drift. Mark all Buttress thread triangle torque marks on pin end with white paint while casing is on rack. Tack weld the bottom side of the coupling on the bottom four (4) joints while on the rack (3 spots, 2" long). Have hot work permit before welding.

2. Cut drilling line as required and RIH to condition hole for casing. Make a conditioning trip and circulate the hole clean. POOH.

3. Rig up to run casing. Thread Lock the float shoe and connections up past float collar. Torque casing to Buttress triangle mark on casing. Fill casing while running. Float equipment is not automatic fill up.

   Note: Use casing crew tongs and CONTRACTOR (if he has them) casing tools to run casing. Do not use casing crew single joint pick up elevators.

4. Install cementing head adapter in last joint in V-door. Pick up the last joint and install cementing head at the stabbing board. Break circulation slowly and wash last joint to bottom. Have sufficient lines connected to allow reciprocating casing a 40 foot stroke. Rig up kelly hose for circulating and chicksan hose for cementing. The 13-3/8" shoe should be set two to three feet off bottom.

5. Circulate and condition mud.

6. Pump Mud Flush ahead.

7. Drop bottom plug, load top plug.

8. Mix and pump cement as outlined. (The final slurry mix will depend upon lab results with actual mix water and cement).

9. Release the top plug while still pumping cement. Allow for at least 10' of cement to be located above the top plug at the conclusion of pumping. Displace with rig pumps at a 15 BPM or higher rate. Slow down displacement just prior to bumping plug and bump with +/- 1000 psi above final displacement pressure. **Maximum allowable pressure on 13-3/8" casing is 2400 psi**. Do not exceed 70 % of the burst rating.

   Note: If plug does not bump after the theoretic displacement, over displace the half of float joints (one joint) only.

10. Land the 13-3/8" casing so the collar of the next to last joint will be approximately 24" below

ground level. Objective on final space out is to have top flange on tubing head +/- 6" below ground level (**check with FINAL DIAGRAM**!)

11. Wait on cement three to six to eight (6-8) hours, until cement will support the weight of the casing. Watch the cement surface samples.

12. Cut off the 20" conductor and back out the 13-3/8" landing joint.

13. Weld and test 13-3/8" x 13-5/8" slip on weld, C-22 well head.

    Note: Head has internal seal, therefore the only weld necessary is to the bottom. <u>Make sure that the Contractor uses acetylene bottles not carbide generator to preheat head.</u>

14. Check the cement level in the 13-3/8" x 20" annulus and <u>if cement is not at surface, a top job will be required.</u>

15. Install and test BOP stack.

RECOMMENDATIONS FOR PLUG AND CASING SHOE DRILL OUT - DAVIS LYNCH NON-ROTATING PDC DRILLABLE.(if needed)

1. Apply a thread-locking compound to the last four casing thread connections and to the floating equipment threads. This will help prevent the shoe joint from backing off during drill out.

2. Release the top cementing plug while still pumping cement. Allow for at least 10 ft of cement to be located above the top plug at the conclusion of pumping.

3. Go in the hole with regular bottom hole assembly (stabilized for open hole drilling) and the PDC bit that is planned for the next section of hole to be drilled. It is recommended to use the parameters listed below to drill out the float equipment and non-rotating wiper plugs.

a. <u>Drilling Parameters - Anti-Rotational Cement Plugs Wiper Plugs</u>

1. RPM's = 80 to 100
2. Circulating rate 336 - 420 GPM
3. Weight on bit = 2000 to 4000 lbs.
4. Torque - normal

b. <u>Lock Down Anti-Rotation Float Equipment</u>

1. RPM's 80 to 100

2. Circulating rate 336 - 420 GPM
3. Weight on bit = 2000 to 4000 lbs
4. Torque = Normal

Flush the bit of any rubber or cement after every 1 to 2 inches of penetration by pulling up the drill string 2 to 3 feet and circulating at 336 - 420 GPM on the down stroke.

4. If the drill pipe and/or rotary table should start to jump, backlash, or act erratically, temporarily change one or more of the following drill-out parameters: WOB, bit speed, or circulation rate. Resume drilling with original parameters once normal operations are observed.

5. If the penetration rate ceases and cannot be reinstated using the above procedures, recover the bit for inspection.

6. Do not by-pass shale shaker while drilling out. PDC bit shaves wiper plugs resulting in small particles which plug pump suctions, pump valves and bit nozzles.

CASING STRING: (FINAL DESIGN BASED ON ACTUAL PURCHASE & TD OF HOLE)

9-5/8" Float Shoe, Davis Lynch, Buttress, PDC Drillable
80' (2 jts) 9-5/8", 53.5 lb/ft, P-110, BTC, R-3
9-5/8" Float Collar, Davis Lynch, Buttress, PDC Drillable, non-rotating
1,428' (34 jts) 9-5/8", 47 lb/ft, N-80, BTC, R-3
504' (12 jts) 9-5/8", 47 lb/ft, S-95, BTC, R-3
6,152' (146 jts) 9 5/8", P-110, BTC, R-3

MATERIALS & EQUIPMENT

1 9-5/8" Float Shoe, Buttress (PDC drillable)

1 9-5/8" Float Collar, Buttress (PDC drillable)

4 Thread Locking Compound

40, 9-5/8" Centralizers – TBD when hole sections are drilled and CemCade is run)

20, 9-5/8" Stop Rings

3 Thread Lubricant, API Modified

1 Circulating Head, 2" Union x 9-5/8_" Buttress Thread

1 Power Casing running tool (or Tongs w/9-5/8" heads)

1 9-5/8" 350 ton Elevator Links 144” long

1 9-5/8" 350 ton Spider w/top guides

1 Set 350 ton Elevator Links 144" long

1 9-5/8" Side Door Casing Elevators, 150 ton capacity

1 9-5/8" Rotary Casing Slips

1 9-5/8" Single Joint Pick-Up Elevator

3 9-5/8" Quick Removal Thread Protectors (Provided by casing crew)

2 Rotary Tong Head for 9-5/8" Casing

2 9-5/8" Casing Coupling - P-110, BTC

1 Cementing Head Plug Container, Buttress w/QC adapter

2 Cementing Plugs - Top and Bottom (PDC drillable, non rotating)

1 Surface fill line to permit fast fill of casing

1 Pressure Recorder, connected to record all circulating, cementing and displacement pressures.

1 Drift Mandrel 8.50" O.D.

1 3" - 4" fill up line on rig floor

1 13-5/8" 3m X 11" 3M tubing head FMC-TC-ECC (check inventory)

2 10-¾" X 9-5/8" pack-offs

1 9-5/8" x 12" C-22 hanger (TBD)

RUNNING & CEMENTING PROCEDURES:

1. With adequate lead time, place casing on pipe racks. Inspect, clean threads, tally and drift casing with 8.500" and 8.625” drift mandrels. Clean and mark all Buttress Triangle Torque marks with white paint. (VERIFY ANY SPECIAL HANDLING TOOLS IF CR13 IS TO BE RUN)

2. Haul bulk cement as required and store at location. Results of lab test will determine necessary additives for cement. Verify latest Cemcade with lab results!

3. Cut drilling line as required and string to 10 lines. RIH and condition hole for casing. Make short trip if considered necessary. POOH.

3. Rig up to run 9-5/8" casing. Pull wear bushing from 13-5/8" casing spool. Install 9-5/8" rams in BOP.

   Note: Use PRE-AGREED TO, SPECIAL TORQUE-TURN, CASING RUNNING TOOL to run casing. Do not use casing crew's single joint pick-up elevators.

5. Use Thread Lock on all threads from shoe to float collar. Run 2 joints between float shoe and float collar. (verify at TD as to path forward on this- depending on rathole & amount of Precambrian cut!) Make sure the shoe joint is full of mud. Torque casing to the "Buttress Triangle" mark on the casing.

6. Install centralizers on the middle of the first joint and on each of the collars on first 15 joints then each every (2) two joints. (Schlumberger Centralizer/CemCade program to be run on all casing beforehand)

7. Casing running speed should not exceed 30 seconds/joint.

8. The float equipment is not automatic fill. Fill casing with 4" fill line while running.

9. Change to 350 ton Elevator/Spider before going below the 13-5/8" surface casing shoe.

10. Install the cementing head quick connect adapter in the last joint of casing in V-door. Pick up the last joint and install cementing head at the stabbing board. Rig kelly hose for circulating. Break circulation and wash last joint to bottom. Rig up cementing lines with sufficient hose to allow reciprocating the casing a full 40 foot stroke, depending on rig's capabilities, allowing centralizers to overlap on each stroke.

11. Circulate and condition mud until hole is cleaned up. Reciprocate the casing a full 40' stroke throughout the circulating period.

12. Test cement lines. Pump mud flush. Drop bottom plug. Mix and pump cement as outlined. The final slurry will be determined from lab tests.

13. Drop top plug. Displace cement with mud using rig pump at as high a rate as possible. If hole conditions will allow, continue reciprocating the casing until the plug bumps, or at least until the cement is above the primary zones of interest. Slow pump rate just prior to bumping plug. Bump plug with +/- 1000 psi above final displacing pressure. **Maximum allowable pressure on the 9-5/8" casing is 4800 psi**. Release pressure and check float equipment.

    Note: If plug does not bump after theoretic displacement, displace half of the float joints (one joint) only.

14. Install the 12" x 9-5/8" type C-22 casing hanger (check inventory) and have replicated equipment at all times on location and hang 9-5/8" casing in full tension.

15. Pick up BOP stack, cut off 9-5/8" casing and install the 11" 3,000 psi x 13-5/8" - 3000 psi Tubing Spool, FMC type TC-ET (check with T3 Energy eq diagram, specs). Pressure test the secondary pack off to 2500 psi. Nipple up stack and test to 3000 psi with the test plug.

16. Follow same drill out procedures as per 13-5/8" casing, except utilize where possible, Rig's BHA (DC) and 9 5/8" casing scraper, etc. Drill track show if necessary (TBD when well has been cemented). After this, USIT/CBL will be run, used master valve with gauge NU & rig released. Drill/clean out with a used 8 ½" bit if in inventory.

Appendix B -- Well Plan for VW1

SCHEDULE C

WELL PLAN/WORK SCOPE

ADM MMV Well #1
Final Well Plan/Work Scope-PTH Jr

ADM MMV WELL #1
MGSC/ISGS/ADM PROJECT

WELL PLAN/WORK SCOPE

Decatur, Illinois

WELL PLAN/WORK SCOPE FOR TURNKEY RFQ

INDEX

GENERAL INFORMATION

ADM MMV WELL #1

GENERAL WELL DATA

Well Name and Number	:	ADM MMV WELL #1
Classification	:	Monitoring Well for CCS #1 Well
Country	:	Macon, Co., Illinois
Area	:	ADM Plant site property
License/Permit #-	:	UIC-012-ADM
Operator	:	ADM
UTM Coordinates (or T-R-S)		
Surface	:	X = **???** Y = ???
Bottom hole	:	Vertical well
Geographic Coordinates		
Surface	:	……..W ………………..S
Bottom Hole	:	……..W ………………..S
KB	:	assumed 665 feet (to be surveyed in after rig move)
GL:	:	assumed 650 feet (to be surveyed in after rig move)
Objectives	:	Safely drill thru Mt Simon & Into Pre-Cambrian, 100% core recovery, hole conditions to allow for good log data, excellent cement to surface on all strings.
Est. Total depth	:	7,200 ft TVD
Drilling Contractor	:	TBD
Drilling Fluids and Engineering	:	Drilling contractor choice
Cementing Services, Surface	:	Drilling contractor choice
Cementing Services, Inter, Long	:	Schlumberger

Electric Logging Services	:	Schlumberger
Mud Logging Services	:	Drilling contractor choice
Surface Test Equip. & Service	:	NA
Down Hole Test Tools & Service	:	NA
Completion Rig	:	TBD (well will be completed with special downhole tools)
Directional Drilling Contract	:	N/A (teledrift/multishot- per drilling contractor)
AFE Number	:	NA

GENERAL DRILLING OUTLINE

1. Successful Sub-contractor will Move rig to ADM MMV Well #1 wellsite, Decatur, Illinois. Spot rig, rig up rig and auxiliary over pre-constructed cellar with pre-drilled rathole & mousehole (at sub-contractor's election) as well as having 30 or 36 inch conductor pre-set and cemented prior to MI & RU(at sub-contractor's election). Rig will be on Turnkey work after Contractor's representative has gone through the acceptance checklist and all personnel have attended the QHSE indoctrination. If sub-contractor elects to not pre-set conductor pipe, then they will have to make adequate provisions to pump out the cellar while drilling the surface hole.

2. Complete drilling rat and mouse hole (if not already pre-drilled). Accept rig after rig audit and acceptance checklist is complete and all crews & operational staff have undergone thorough QHSE training beforehand. M/U slick BHA with 9 or 9 ½" inch DC (or at election of sub-contractor), monel and drill vertically to 350-375 ft into the Limestone (see offset ADM CCS Well #1 data, attached) (good casing seat is required!) with a 17 ½" in mill tooth bit or bit selected by sub-contractor. Run Pason or multishot (or teledrift!) at 150-175 feet TVD to ensure we have good record of azimuth & deviation for future use. **NOTE**: No pilot hole is deemed necessary. Drill with as much WOB as possible monitoring torque in sandstone/surface shale zones very carefully. It is suggested to utilize 9-1/2 in drill collars in the string to keep BHA as rigid as possible, but this is not mandatory. Drill slick, with as much weight as will be allowed, maintaining as straight a hole as practical. Control drill this part of the hole! After the limestone has been confirmed, circulate & condition hole, POOH & RU Schlumberger REW. A Triple combo will be run in this section of hole (see attached logging schedule and allotted time Contractor will require to allow for rig up, logging, rig down in each section)

3. At TD, drop multishot after C&C hole, POOH, racking back BHA (if possible). RU floor to run 13 3/8" inch casing with casing running tool if possible. Tac weld bottom 2 joints. Run and cement 13 3/8" casing to surface. Perform top cement job if cement is not circulated to surface. (have macaroni string on location with proper XO, etc). Conventional float equipment to be utilized.

4. Install and test 13-5/8" 3M X 11"3M wellhead and BOP stack (13 5/8" 5M stack). Test hi/lo per API, recording same.

5. Drill out with a 12 1/4" bit, holding vertical angle to the planned casing point into the Eau Claire expected at +/- , 5,310-5,320. During this interval, there will be full-diameter cores taken (see core schedule). A comprehensive logging program (see below details) will be used for this section. Conditioning trips may be needed and will be decided on at the field level, with input from the Schlumberger and the successful sub-contractor. Logs must reach bottom to full fill the terms & conditions of the agreement/Well Plan/Work Scope.

6. Run and cement 9 5/8"protection casing as per attached detailed cementing programs.

7. Hang the casing in full tension, install and test 13-5/8" 3M x 11" 5M wellhead and BOP stack. NOTE: this interval will be cored and immediately after setting casing & drill-out, coring operations will begin again, after a casing FIT/LOT is performed. (See coring details)

8. Drill out with a 8 ¾" or 8 ½" bit, holding angle as close to vertical as possible, with multishots or teledrift (pason) shot surveys no farther apart than 250-350 feet, or on each bit trip. Record same. (This is to be

carefully controlled and deviation control is paramount-see terms and conditions of proposed agreement) It is very important to keep the hole as reasonably straight as possible. During the 8 3/4" hole section, it is planned on quite a few full diameter cores, so please duly note the exact core points and requirements in the "Coring Schedule", attached. All core points will be confirmed by Schlumberger with advise from mud logger and possibly some of the ISGS geologists.

9. At TD, expected at 7,200' TVD or 30 ft into the pre-Cambrian condition well to be comprehensively logged as directed and per below wireline plan. After the logging/testing program has been completed a string of 5 ½"" casing will be run and cemented according to the attached detailed plan. (scheduled to be in 1 stage). Hang off in l slips, make rough cut, place bucket on top, ND BOP's, prepare to release rig & move off, per obligations under the terms and conditions of the contract. If a 2nd well is to be drilled, then the plan will be to skid rig over to pre-built cellar for well #2, RU & commence to drill well #2 in same fashion.

GEOLOGIC PROGRAM

1.0 GEOLOGICAL PROGNOSIS

OBJECTIVES

The ADM MMV Well #1 is intended to be a monitoring well to monitor the CO2 being injected into the injection well (CCS Well #1) drilled on the ADM plant site property in order that 1 MM tones of liquid CO2 can eventually be injected into the Mt Simon formation at site. The main objectives for the drilling and wellbore integrity of this well construction phase include:

1. To MI, RU, drill & MO with no safety or environmental incidents. This is the main objective of the well construction mission!
2. Ensure the wellbore is as straight as possible
3. Ensure the larger casing strings (hole sizes) are drilled with minimal formation invasion and to obtain world-class cement jobs per the appropriate plans
4. Drill adequate hole sections to where all of the testing, wireline logs and coring that is planned can ultimately be performed and that the data collection, core recoveries, etc are maximized so future sub-surface workscope can be performed by other skill sets
5. 100% core recovery

ANTICIPATED DEPTHS FOR ADM MMV WELL #1

FORMATION TOPS

BASED ON CCS WELL #1

KB = 15 feet

Formation Name	MD from KB	Subsea from KB
Stark Shale	360.00	330.00
Chapel Coal	441.00	249.00
Herrin	606.00	84.00
Springville	647.00	43.00
Springfield Coal	647.00	43.00
Excello Shale	700.00	-10.00
Mecca Qu Sh	825.00	-135.00
Seelyville Coal	844.00	-154.00
Carrier Mills Sh	879.00	-189.00
Logan Qu Shale	902.00	-212.00
Renault	1,275.74	-585.74
Aux Vases	1,290.47	-600.47

Ste. Genevieve	1,326.88	-636.88
St. Louis	1,376.07	-686.07
Borden	1,528.94	-838.94
Burlington-Keoku	1,838.00	-1,148.00
Chouteau	2,068.23	-1,378.23
New Albany	2,088.01	-1,398.01
Lingle	2,213.84	-1,523.84
Moccasin Springs	2,240.37	-1,550.37
Maquoketta	2,611.10	-1,921.10
Galena	2,816.86	-2,126.86
Platteville	2,945.18	-2,255.18
Glenwood	3,240.39	-2,550.39
St. Peter	3,269.52	-2,579.52
Shakopee	3,476.03	-2,786.03
Knox	3,476.79	-2,786.79
New Richmond	3,861.93	-3,171.93
Oneota	3,930.40	-3,240.40
Potosi	4,360.76	-3,670.76
Davis	4,896.05	-4,206.05
Ironton	4,928.03	-4,238.03
Eau Claire	5,047.17	-4,357.17
Eau Claire Lime Base	5,220.61	-4,530.61
Eau Claire Shale	5,346.54	-4,656.54
Mt. Simon	5,544.66	-4,854.66
Granite Wash	7,051.03	-6,361.03
Precambrian	7,164.69	-6,474.69

2.0 POTENTIAL DRILLING HAZARDS FOR SUB-CONTRACTOR INFORMATION

SURFACE TO 350-375 feet (MD): Spudding in clay/sandy formations tends to be very easy drilling with high ROP's after enough DC weight has been picked up. Expect drilling rates of up to 60 - 90 FPH, if allowed to drill in that fashion. (see some of the well performance recaps & drilling curves on wells that have been studied) . From surface to 350 feet (MD), hole bridging may occur if there are extended periods without circulation or tripping. Adequate mud weight per the plan and continuous minimum GPM to keep the hole clean are mandatory while drilling the surface hole and running surface casing to avoid water influx. Drill string vibration may also be experienced due to large –size hole being cut; shock sub is deemed to be necessary for this short interval, but it is up to the sub-contractor to decide this! Several high gel sweeps to ensure bridging is kept to a minimum should be considered. Keeping the hole straight in the upper section is another main driver, so the well ultimately will end up as straight as reasonably practical!

350 feet TO -3500 feet +/-:

Between this interval, hole bridging may occur if there are extended periods without circulation or tripping. Short trips every 400-750 feet are recommended to ensure drill string does not pack off. Again, with larger than normal BHA and hole sizes, ensure hole is cleaned faster than ROP. Fresh water influx may occur at 1000 -1200 feet

Potential zones of saltwater influx may exist in the St Peters which might require raising the mud weight. However, the lower the MW the faster the section can generally be drilled. (See detailed drilling fluids program)

3,500-(4,000) to TD (7,200 Ft +/-):

Below 3,500 feet, through the Eau Claire and through the Mt Simon, we will be drilling a series of non-reactive shales with the Mt Simon being for the most part striated sandstone, some expected to be porous to medium-porous. Below the St Peters the Knox section will be hard dolomite especially the Ptosi section. In the CCS well, we encountered some lost returns, which might be present in the MMV well. The lost were apparently due to the presence of some karst like features in the dolomite. This section is to be cored. The drilling of the Eau Claire and Eau Claire shale proved to be very fast, including the Mt Simon, where only 2-12 ¼" bits were used to drill the complete section! (see proposed bit program, but sub-contractor can decide which IADC code bits he wishes to use. After TD was reached in the CCS well #1, we spent 6 days logging, with no wiper trips and all logs got to within 4-6 ft of bottom, with an extremely gauge hole. Key here is to optimize rheology of drilling fluid system, maintain optimum gpm and WOB. On trips, note pu weight and watch carefully POOH for the 1st few stands, then ensure reaming when you go back to bottom. Care must be taken to not de-stabilize the Eau Claire shale section. This laminated shale will start to come apart of allowed to.

OVERPRESSURING: NO high pressures are anticipated. See drilling fluids recap from the CCS well #1

3.0 MUD LOGGING PROGRAM

3.1 WELL MONITORING AND EQUIPMENT

Mud Logging Services will be performed from the **base of the 13 3/8"** (350-375 ' +/-) to TD. Since data gathering is of utmost importance, sample catching and lithology confirmation is of utmost importance. The mudlogging and daily geological review of lithology will require careful and meticulous coordination between the mudlog Geologist & other mudloggers, and the Schlumberger representatives along with the ISGS geological representative. The geologists, mudloggers and sample catchers will provide 24 hour coverage. The unit will monitor, record and/or plot the following at a minimum:

Lithology

Percentage Log	Visible Porosity
Interpretative Log	Calcimetry

Shows

Total Gas ("Hot-Wire")	Chromatograph (C_1-C_5)

Cuttings Gas	Visible Sample Shows

Drilling Parameters

Depth (MD,TVD,lagged,)	Rate of penetration (ROP)
RPM	Weight on bit (WOB)
Total bit revs	Torque
Hook load	Pumpstrokes/min.
Pump pressure	Standpipe pressure
Casing pressure	Pit-volume totalizer (PVT)
Mud weight in/out	Mud temperature in/out
Mud flow	Mud gains/losses
Stands done/to go	Pull rate
Total pump strokes	Mud volume pumped

In addition to the above capabilities, the following special equipment will be provided and maintained by the Mud Logging Company:

Intercom system linking the logging unit to the rig floor, drilling office, drilling supervisor's cabin (could be walkie-talkies).

External alarm for the PVT and a high quality binocular microscope for the ISGS & mudlogging company Geologist and Schlumberger representative use. Note: The mudlogging company chosen by the sub-contractor should have at least 1 geologist on the crew with the complementary mudlogging crew for a 24/7 operation.

NOTE: The draw works sensor will monitor all pipe movements, including drilling, connection, tripping, casing and fishing operations. This can also be performed by the Pason or Totco electronic, internet system, which is required under the terms and conditions of the agreement

3.2 GENERAL INSTRUCTIONS

The mudlog geologist and the mudloggers, with vast experience in the basin, along with the input and approval of the ISGS and Schlumberger representative has the responsibility for the complete geologic evaluation of the well, with special emphasis on determining the lithology, coring points, TD, etc and recording all pertinent data. In their absence, the contracted logging geologists/mudloggers assume this responsibility. The following general instructions will assist in the performance of these duties:

- The mudlog (1:500 scale) and worksheets will be prepared and kept up-to-date at all times. The mudlog will be completely updated at the end of each 12 hour tour. Field prints will be available at all times. All drilling parameter and gas data (if any) will be recorded on CD's in ASCII format.
- Carbide checks will be run daily and recorded on the log and worksheets.
- No Calcimetry tests are to be run.

- If unusual drilling conditions such as abrasive formation (chert, sharp sand or pyrite), metal in the cuttings, or loss of pump pressure or an increase in pump strokes (indications of possible washouts) are detected, immediately notify **both** the Driller and the Schlumberger representative and the other key service providers such as the drilling fluids engineer.
- If unexplained gas cut mud, mud loss or pit volume increases are noted, instruct the Driller to check for flow and start shut-in procedures if necessary, and then notify the sub-contractor's representative, tool pusher or both along with the Schlumberger representative.
- Monitor hole fill-up on all trips and immediately advise the Driller and the tool pusher or sub-contractor's onsite representative of any discrepancies.
- The mudloggers and mud log Geologist will maintain an "interpretative" progress log which will include drilling rate, interpreted lithology, lithologic descriptions, visual porosity, coal, oil and gas shows (if any), mud data, bit data, cores, casing, and formation tops. This log should be at both a 1" & 2":500 scale on reproducible film.

Mud Log

The mudlog will be kept up-to-date at all times. In addition to the normal information, the logger should record bit, footage, rotating hours, and mud data (including mud losses) and the drilling parameters (WOB, RPM). Weight and RPM changes that affect the penetration rate should always be noted on the log at the depth they occur. Mud salinity and thiocyanate tracer (if any used) concentrations will be recorded on the log and worksheets. The drilling rate scale must be identified every 500'. The scale should be selected to best fit the range of drilling rates typical expected or seen in the area, without having to change scales or plot on a backup scale. The drill rate will be recorded in minutes/foot in five-foot increments from or as directed by the Wellsite Geologist and the ISGS surface to TD. Log scales to match 2 inch: 100 feet and 5 inch: 100feet "standard electric log" scale. For readability, limited or no annotations on the 2 inch scale. Copies of logs: number and format (media) of logs as required. Mud Logger will provide 6 copies of well data base as requested, on appropriate media, as well as paper copies and all final reports on a CD delivered to the Schlumberger Project manager within 10 working days after the rig moves off or the mudlogger is released.

3.3 CIRCULATING INSTRUCTIONS

- Circulate any rapid increase of ditch gas (or coal/oil shows) until the source can be identified. This does not apply to trip gas, connection gas or other such predictable occurrences, if encountered.
- Circulate after all operations which could affect the evaluation of any prospective zones, such as after high trip gas or excessive drilling operations such as freeing stuck pipe.
- Circulate bottoms up before any trips when drilling below the 13 3/8 in.

3.4 SAMPLE COLLECTION

Schlumberger requires (2 sets) 10' samples from the base of the surface pipe, and 5' samples in zones of interest. Other samples will be collected as needed, i.e. Oil or gas shows, circulating samples, etc. Recommend drilling company catch samples as per standard Illinois Basin operation. Sub-contractor or mudlogger to furnish sample bags for all the collected samples required.

3.5 SAMPLE IDENTIFICATION AND DISTRIBUTION

Samples to be bagged and marked with hole and depth. Samples are to be periodically transported to the ISGS trailer for further review and subsequent transport to the ISGS or to Schlumberger's offices, in Champaign, Illinois. One(1) wet bagged samples as well with no heat lamps applied to the 1 bag of cuttings.

3.6 SUMMARY OF REQUIRED OUTPUT

Mudlogging output to Schlumberger Carbon Services will include the following:

1) Daily geologic reports summarizing daily operations, key intervals, lithologies, oil shows and drilled gas, sent by cc:mail to all the personnel presented by Schlumberger via e-mail.

   Note: The CD with the daily report will contain only the data for complete well at the end of the well.

2) A formation log at 1": 100 & 2": 100 ft scale. This log will record drill rate, percentage lithology, interpreted lithology, ditch gas curve, chromatographic data, cuttings analysis, oil shows and pertinent engineering data. Additional information for inclusion may be requested by the Schlumberger representative or the ISGS.
3) Four weekly field prints of the Formation Log. One copy remains at the wellsite and the other 3 copies are sent to the ISGS and Schlumberger Management Team, Champaign, Illinois. A copy of the Formation Evaluation log in 1":100 scale should be printed out to compare to the electric logs.
4) Mud Logger will provide 2 copies of well data base as requested, on appropriate media. Four (4) copies of the final well report and the final formation evaluation log within 10 days after the TD of the well or when the mudlogging unit is demob from the location. The Schlumberger Carbon Services Project Management Team, namely the Project Manager, will review and edit these products, and when approved by the ISGS & the SCS Project Manager, 4 copies of the final well report & 4 copies each of the formation evaluation logs (Scale 1:100 & 2:100) will be sent to the ISGS, c/o Rob Finley, at the University of Illinois, Champaign, Illinois for subsequent distribution.
5) One copy of the final well report on CD in MicroSoft Word/Excel format.
6) One copy of the Formation Evaluation data on CD in ASCII format.

4.0 GEOLOGIC REPORTING

4.1 MORNING GEOLOGIC REPORT

The morning geologic report will be completed at 0600 hours (or as dictated by the Schlumberger representative) with the activities and results of the last 24 hours. The written report should be done in the Schlumberger Carbon Services report form system(example to be provided) or any acceptable "executive summary" that canb be prepared by the mudlogger (geologist). General instructions for use of this system follow:

1. The mudloggers (geologist) are responsible for the following 4 reports:

- GEOLOGIC SUMMARY REPORT (Daily Geologic Report)
- FORMATION TOPS REPORT (Formation Tops Report)
- OPENHOLE LOGS REPORT (Open Hole Logging Summary)
- CORING REPORT (As needed)

2. The day's reports will be completed, exported onto CD or diskette/memory stick or sent via email to the SCS Project Manager and any other personnel such as ADM, ISGS, etc that will be provided in writing after award of the project before 7:00 am.
3. Never send an edited report forward without firstly checking with the Schlumberger representative/Project Manager (to make any corrections to the reports). If any revision is required in the field, they can be incorporated later and changes for input into the system.

A telephone report will be made to the following at least every morning to:

SCS and/or ISGS personnel (list to be provided after award of Project) at 0800 hours. This will permit clarification of the morning report and discussion of wellsite activities. If the Wellsite geologist is not present, the mud logging geologist will report. When drilling through objective formations, radio/telephone contact with the SCS Project Manager and the SCS Well Architect will be kept open at all times, continuously.

4.2 AFTERNOON GEOLOGIC REPORT

The afternoon telephone report will be a complete geologic report using the same format as the morning report, but with a 1500 hours cutoff. The afternoon oral report will be made at 1515 hours. The mud logging geologist or a mudlogger will report.

4.3 INSTRUCTIONS AND FORMATS

Descriptions of Cuttings Samples: For each described interval, the average and the range of the ROPs will be given. The lithologies will be listed in descending order of percentages. The format for lithologic description follows:

ROCK TYPE

COLOR
HARDNESS/INDURATION
GRAIN SIZE
GRAIN COMPOSITION
TEXTURE - Shape, Round, Sorting
MATRIX - Percent, Type RES.
CEMENT - Percent, Type
POROSITY - Percent, Type
ACCESSORY MINERALS
FOSSILS/FRAGMENTS

SHOW DESCRIPTION (if any occur):

OIL IN MUD-Percent
ODOR-Intensity
VIS. STAIN- Percent, Color, Distribution
NAT. FLUOR- Percent, Color, Distribution
CUT FLUOR- Type, Rate, Intensity, Color
RING - Thickness, Color, Fluor

Gas Reporting: For each interval described in the geologic reports, gas measurements will be reported as follows:

BG (Background gas): xx units

Maximum TG (Total Gas) at xxxx'

C_1 - C_5 ppm

Remarks Section: The remarks section of each report should/will include the following information:

Preliminary Formation Tops - MD, TVD relative to prognosis and offset wells (relative to base maps prepared by ISGS)

Mud Data - Mud weight, chlorides, additives

Carbides - Depth, Mud weight, Gas Units, Actual vs theoretical lag time

Surveys - Depth, deviation angle and deviation azimuth, if any, TVD

Trip and connection gas (if any) - Amount, Chromatographic Analysis

Comments - Any other pertinent observations or data including mudloggers equipment that is not working properly.

4.4 WIRELINE REPORTING

During wireline logging operations, the Daily Report will be modified as follows:

Operations Section:

Tools run - main log interval, repeat section interval, failures

Total depth - Driller's & Logger's, Bottom hole temperature

Casing Depth - Driller's & Logger's

Mud resistivity data and temperatures

SFTs (if any) - # of attempted pressure measurements, pressures obtained, supercharged readings, dry tests, and seal failures

SWCs - # attempted, recovered, misfired, and lost

CSSs - # stations attempted, obtained, record quality (Optional)

Interpretation Section:

Formation Tops - Measured depth, TVDSS, if the case

Correlations - Tops relative to prognosis, key well correlation points

Reservoir Intervals - Top and base, Net reservoir,

SFTs - Depth, hydrostatic pressures, formation pressure, duration

CSSs - Depth of station, TWT (Optional)

All - Note any problems with logging run

5.0 CORING PROGRAM

5.1 EXTENSIVE CORING ARE PLANNED – (See detailed coring program below. Note that coring points are ESTIMATES. Note excellent formation tops provided by virtue of the drilling & testing of the nearest well to depth, that being the ADM CCS Well #1, approximately 800 ft to the South. Mud logs are attached to this tender document as well as formation tops.

1.0 INTRODUCTION

This program is a full description of core operation (coring, core processing, core preservation, well site gamma ray, transportation) for the cores to be cut in the ADM MMV Well #1 in Decatur, Illinois. A total of 240 feet of core will be taken into the following formations:

CORING DETAILS FOR MMV WELL #1

Below you will find the anticipated core depths and lengths of core required under the turnkey commercial quote. Please note that some of the full-diameter cores will be taken in the 12 ¼" section as well as the 8 ½" or 8 ¾" section. Since core recovery is of paramount importance, it will be left up to the successful Sub-contractor and his corer to determine the best method to core (eg, 60 ft barrels, pdc core head or diamond, etc.). Core barrel should have aluminium sleeves, catcher and once the core(s) are layed down in the V-door/catwalk, the sub-contractor needs to get a fork lift and move the cores to a convenient spot on the location, then allow a third party to mark, cut, and box the cores. This cutting, boxing, etc is not part of the sub-contractor's work scope. Only getting the core out of the V-door/catwalk and on the ground on location, then sub-contractor can either go back in hole and continue to cut core, or ream or drill ahead, as per plan. Every effort should be taken to ensure 100% recovery of the cores to be taken!

Final coring depths will be the call of the ISGS Geologist who will work with the wellsite geologist to insure project core objectives are met.

Core formations & lengths		**Est top of formation**
New Albany	– 30′	2,088′
Maquoketa	– 60′	2,611′
Knox	– 60′	3,477′
Potossi	– 60′	4,361′

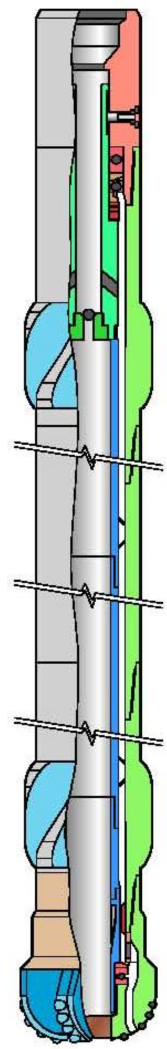
After this last series of cores in the Potossi, we will ream/drill to between 5,310-5,320 ′, log, set pipe & cement. After we drill out and perform a LOT, we will resume coring as follows:

Lower Eau Claire		
To Upper Mt Simon	– 200′	5,445 - 5,645′
Lower Mt Simon	– 410′	6,690 - 7,100′

Where shown, we are looking at 30 ft or 60 ft core barrels, with continuous coring at the discretion of the sub-contractor in terms of whether 60 ft or 30 ft barrels should be used. All time, to core, retrieve barrels, lay down, etc are to be part of the turnkey quote and/or per the Commercial Quote, if additional coring is requested by Contractor.

No major problems are expected except possible loss of circulation in the Ptsosi dolomite sectionThe coring performed on the CCS Well #1 entailed 3-30 ft cores of which there was 100% recovery. Note instructions in the tender documents in terms of what obligations sub-contractor has in coring. Cutting, boxing and transport are not part of the tasks/commercial requirement; only laying down the barrel out of the way, so the cutters, geologists, etc can cut, mark and then transport.

2.0 TENTATIVE CORING EQUIPMENT (this is an example only for sub-contractor. Actual proposal is to be proposed by sub-contractor in the Commercial Quote)



2.1 Core Barrel 6 1/2" or 5 7/8"(TO CUT A 4" OD Core)

The coring concept has been specifically designed to enable the retrieval of longer, higher quality cores. Faster penetration rates, reduced incidence of core jamming, improved reliability and reduced core damage are four of the benefits offered by this system. (ultimate coring head & barrel will be adjusted so that local experience is captured and utilized in order for core recovery to be 100%. This might include cutting a 6" or 5 7/8" with say a 8 ¾ core head to retrieve a 4" OD core and as well cutting 30 or 60 foot cores at a time, depending on what sub-contractor and his coring sub-contractor recommend and as approved by SCS. Excellent recoveries and coring rate were experienced while coring the CCS Well #1!

Stabilization is one of the most important factors governing a successful coring operation.

The majority of core barrel systems are unable to properly transmit the weights on bit required for modern coring operations. Without the outer barrel correctly stabilized, bending within the well bore will occur. This is evident from the polished areas found on the outer tubes between the stabilizers after retrieving the core barrel. The deflection of the barrel impinges wear on the well bore (overgauge hole) and produces eccentric bit rotation (poor quality, undergauge core).

Core barrel length will be 30-60 feet unless rig is capable of taking 90 foot cores.

2.2 Inner Tube System

The Thin Sleeve System or aluminium sleeve barrels will be required for application; this is partly due to best practices as experienced while coring the CCS Well #1 (core report is on mudlog and daily drilling reports attached!). The Thin Sleeve System is a two part inner barrel system. A specially designed inner barrel carries within it a second thin walled tube. A connection enables the tool joint to be broken and disengaged without rotating the thin inner tubes, a feature, which eliminates torsional damage to the core during the breakout. The box connector contains six ribs that retain the inner tubes, centrally within the outer barrel. Time is saved during the lay down process as no cradle is used. The core is laid down safely inside the TSS steel inner barrel without any risk of bending.

Barrel Length

- The strength of the formation and presence of sharp changes in lithology mechanical properties will limit the length of core that can be cut. (now planned at a maximum of 60 foot cores and maybe 30 foot, but to be proposed by sub-contractor as to his choice & best practice)
- Barrel length should be limited to the longest core that can be cut in order to minimize potential problems, barrel flex, vibration, rig floor handling time and the need for re-running of inner barrels (60 or 30 feet in this case).
- If hole conditions are ideal, sub-contractor should consider coring with a 60 feet barrel. (Due to rig capabilities & HSE issues.)
- The coring BHA will be a stiff packed assembly (stabs-TBD by coring operator), it is therefore recommended that the hole is finished with an equally stiff BHA before running the core barrel to maximize the chance of trouble free tripping.

Core Catcher

- Plan to use conventional spring catchers.
- In case of very soft sand encountered in the Mt Simon, the FINGER CATCHER SYSTEM should be/considered by sub-contractor and be available on site.
- All catchers and pilot shoes should be inspected / certified OK by core hand before use (these have been seen to fail in use before.)

2.3 Corehead (AS PROPOSED BY SUB-CONTRACTOR/CORING COMPANY)

The corehead to be used will be 8 ½" OR 8 ¾" diameter to cut cores. This very well might end up, however, having to be a 8 ¾" core head, with 5 7/8" OD barrel, with the result of retrieving a 4 inch OD core. Sub-contractor to make his proposal, however.

A core head such as the **MCP662**, 6 blades, throat and face discharge, low invasion, PDC 13mm. This corehead has been successfully used in many areas like what will be drilled in the Decatur area. The throat discharge will help to clean shale and should increase the ROP in these sections.

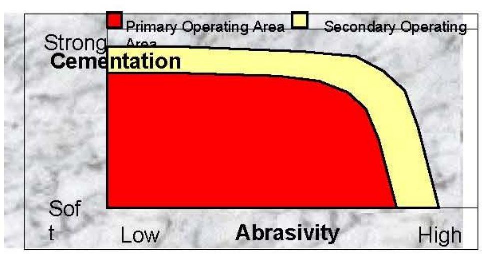
Two Core Heads of this type should be available on the rig.

Low Invasion Core Bit (see example below)

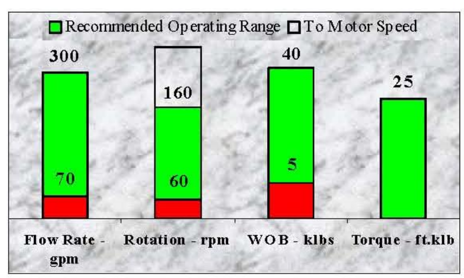
Specifications

TYPE OF CUTTER:	PDC
NUMBER OF CUTTERS:	24
SIZE OF CUTTERS:	13 mm
RIB NUMBER:	6
SETTING:	Overlap
PROFILE:	Round
BODY:	Tungsten Carbide Matrix
JUNK SLOTS:	6
GAUGE:	Carbide & Natural Diamond
FLUID FLOW CONTROL:	Sculptured Flow Channel
ROCK TYPE:	Clay, Shale, Sandstone
Total Flow Area	0.74 in²
FEATURES:	Low Fluid Invasion

Throat Discharge (6 paths)



Application



Generic/Best practices-Procedures during Coring for ADM Well #1 – CCS Well(for sub-contractor information only)

1. Drop ball – when ball has seated take SCRs.

2. Commence coring with low weight and RPM until at least 2 feet are cored.
3. When coring is established to the satisfaction of the coring engineer, increase parameters to recommended levels for coring assembly.

- Aim for constant weight on bit with no sharp increases in WOB (this may lead to premature jamming and short cores).
- Do not allow weight to drill off while coring a high ROP (in heterogeneous formation a large variation in ROP can be expected) if the corehead breaks out of a slow coring shale into fast coring soft sand and weight on bit is not maintained, the sand will wash out and the core will fail and probably jam (short cores and poor recovery).
- Aim for low to moderate RPM (60 – 90 RPM) to avoid any chance of early core breakage or jamming due to core barrel vibration.
- Mud flow rate for face discharge coreheads should be kept constant.
- If mud flow rate is raised to increase ROP in slow coring claystone sections it must be done gradually, and must be reduced as soon as high ROP sandstone sections are encountered constant (suggested flowrate in 12 ¼" hole 250 – 350gpm).
- ROP, torque and standpipe pressure trends are valuable indicators of coring performance. The coring engineer will record parameters every foot.
- Cuttings must be monitored for signs of rock flour at all times in order to check for milling of soft sandstone with a jammed core barrel.

Coring Termination

- Coring should be terminated when barrel is full (i.e. core is within one foot of top of barrel) or when evidence of jamming has occurred (drop in torque or erratic torque, very low ROP, erratic pump pressure). Barrel must not be over-filled; core will fail in compression if barrel is overfilled.
- If coring is about to be terminated (3 feet before full barrel) and ROP is high, consider reducing mudflow rate to minimum safe rate to ensure full gauge core in catcher.
- It is not recommended to spin the barrel at higher rpm to "burn core in", the inner barrel may rotate with the outer, causing core damage.
- If the core appears to be finishing in harder rock, or to have packed off (low ROP) then coring should be terminated at normal flow rate.
- Circulation after coring should be performed in a way that minimizes the risk of soft sandstone core being washed from the catcher. (if this be the case encountered in the Mt Simon)

Bottom Hole Assembly

The following BHA should be filled in by coring company and a core report to be furnished to SCS after coring operations:

Item	Length	ID	OD	Top Thread	Bottom

					Thread
Corehead					
Stabilizer					
Outer Tube					
Stabilizer					
Outer Tube					
Stabilizer					
Outer Tube					
Stabilizer					
Top Section					

- Corehead MCP 662 (TBD)
- Core Barrel 60 feet x 4 ½"IF (TBD)
- Float Sub (4 ½" IF) ,the internal valve will provided by coring company if requested
- Cross Over (4 ½" IF x 4 ½" XH), provided by coring company if requested
- Drill Collars (enough to get 25-37 Klbs on bottom)
- Heavy Weight Drill Pipe and Jar
- Drill String

The BHA drawings will be given on the rig site by the engineer before running into the hole.

Gamma Ray Logger (TBD but at sole cost of Contractor)

(If) Gamma ray logging will be carried out directly on the core once laid down. Data will be handed over to the SCS representative.

The Gamma Ray will be used with a shield in order to reduce high back ground readings.

Core cutting/boxing/Transportation (at sole cost/task by Contractor)

Cores will be cut into 3 feet cores and placed in single wooden boxes. SCS whom will perform the cutting, marking and boxing then subsequent transport of the cores. No sub-contractor involvement is required; only for sub-contractor to get the core barrel out of the V-door, catwalk and to a spot on the location where the cores can be cut, marked & boxed!

6.0 WIRELINE LOGGING PROGRAM (see below logging program and the hours that SCS wishes to be included in the commercial proposal)

ADM MMV WELL #1- Logging Times Required and logs to be run under turnkey pricing

Suite/Run #	Top Interval	Bottom Interval	Service	Time to use for RFQ
1a	0	350	Triple Combo	4
2a	350	5210	PEX-HRLA	7
2b	0	5210	FMI-Sscan (w/CBL in surface)	10
2c	350	5210	MDT (Mini-frac, Pre-tests)	18
2d	350	5210	MSCT (60 cores, 2 runs)	15
3a	5210	7200	PEX-HRLA-CMR-ADT-GPIT	9
3b	5210	7200	MRScanner	9
3c	0	7200	CBL	7
			Total Estimated Time (hrs) =	**79**

Note: Hours of rig and spread rate required to run the above logs

is to be built into the turnkey price (not the Schlumberger logging service cost). Unused hours from previous logging runs can be used in subsequent runs.

ADM MMV WELL #1

DRILLING PROCEDURES/WORK SCOPE -DETAIL

INTRODUCTION

The ADM MMV Well #1 will be located on property owned at the ADM plant site in Decatur, Macon County, Illinois and is scheduled to be drilled as a monitoring well to monitor the CO_2 being injected into the CCS Well #1, injection well drilled and completed in 2009. The well will be drilled to a TD of approximately 7,200 feet +/- TD with 30 ft cut of Pre-Cambrian.

No major drilling related problems are expected to be encountered. However, several of the formations contain reactive shales that may cause tight hole conditions. The reactive shale problems can usually be remedied by a combination of increasing the mud weight and scheduled wiper trips. There is no known surface gas in the area (ADM CCS Well #1 and a shallow (200 ft MVA well approximately 90 ft NE from the CCS well encountered no gas). No water flow from sections in the surface hole can are expected. Lost circulation was encountered in the offset well at 4200-4300 feet requiring the setting of cement plugs to heal. The Ironton – Galesville will possibly seep a little as well.

These drilling procedures provide general guidelines and a description of items such as drilling fluids, casing, cementing, bits and hydraulics program, well control. However, this program is only a guideline and the successful sub-contractor that the work will be awarded to is free to amend or improve on the detail of drilling procedures, best practices, etc. The below are only minimum obligations, tasks that need to be performed to comply with the terms and conditions of the agreement for the turnkey tasks.

A. LOCATION BUILDING/SUBSEQUENT RIG MOVE

The successful sub-contractor will be obligated to build the location suitable for the rig that he is proposing, but the location is expected to be at least 95 ft X 125 ft . Sub-contractor to build cellar out of cement. Cellar is to be 6' X 6' X 6', at least or larger depending on what sub-contractor's rig requirements are for BOP's, etc. Top of bradenhead should be 2-6 inches below surface of cellar (verify BOP stack heights, etc!)It is suggested that a well-compacted, level location suitable for the sub-contractor's rig be built and maintained throughout the drilling of the well. The main access to the CCS well already exists and will be maintained by ADM/SCS up to the CCS Well #1. During the pre-bid, site visit, this can be confirmed. Rig mobilization, rig up, tear down and demob will be on the successful sub-contractor based on the Commercial Quote. ADM/SCS will procure all the necessary permits to allow the drilling of the well and allow access to the ADM site. Final X/Y coordinates and DF, GL will be at SCS cost after the rig has moved on and after spud. Saying this, however, it is clear at the time of preparing these tender documents that more than likely the location for the MMV well will be to the North or Northwest of the CCS Well #1, in the open field between the CCS Well #1 and the College.

Rig will be considered ready to drill when the rat and mouse holes are drilled, all rig components have been rigged up and tested, including desilter, desander, cellar jets, water lines and derrick is leveled and a comprehensive crew

QHSE training has been completed. (SCS will sponsor this and is scheduled to be ½ - ¾ of a day training at the ISGS trailer at the CCS Well #1 wellsite. Sub-contractor needs to build this cost into his/her proposal.

SURFACE HOLE – 17 ½ " HOLE – 13 3/8" CASING AT ± 350-375 feet MD

Directional Control: Vertical well

Survey Interval: Single shot/teledrift every 150 feet- and or on each bit trip. Teledrift or gyro at casing point

The purpose of the surface casing is to isolate and protect fresh water aquifers (the deepest planned to be covered is located at 150 feet +/- TVD). It is also necessary for regulatory purposes, as well as to provide sufficient integrity to safely shut in the well in an emergency situation. This surface pipe is also intended to provide some shoe integrity for kick tolerance and integrity against anti-broaching.

The formations to be encountered while drilling the surface hole are basically, some scattered coal seams possibly, much sandstones and claystone. No known water influx is expected based on the drilling of several shallow wells in/around the site including the CCS Well #1. This interval is expected to be drilled with water and gel easily.(see drilling fluids requirements below)

1. No pilot hole is contemplated on being drilled.

2. Drill under sub-contractor's recommendations. Use water based mud, with weight 8.4-8.7, Vis=47-55 sec/qt.

3. Circulate and condition hole at TD, and make wiper trip. Run back to bottom, circulate hole clean with a hi-vis pill and spot a hi-vis pill on bottom. Log surface hole as indicated. GIH, C&C prior to POOH to run pipe.

4. Rig up 13 3/8" tools, ensuring that power tongs are used in order to properly torque casing to proper make-up & run 13 3/8" casing and cement as per program. Upon reaching bottom, reciprocate while circulating hole clean (watch drag while reciprocating casing. Comply with section guidelines and rig capacity).

   Note: **Do not treat (thin and lower YP) and circulate excessively to treat mud prior to cementing casing.**

   During cementing job have mud engineer check on cement returns to surface using Phenolphalein.

   Report number of bbls of contaminated and good cement returns to surface.

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5. After cementing, drain 13 3/8" surface casing.

6. Wait on cement a minimum of 8 hrs (watch surface samples).

7. Slack off 13 3/8" casing. Make rough cut on 13 3/8" casing. Lay down same.

8. If good cement is not circulated to surface, perform a top job (neat) with 1.660" OD internal joint tubing (macaroni string) between 13 3/8" and 17 ½"hole.

9. Make final cut on 13 3/8" casing as needed for space out. (Cellar is to be 6' X 6' X 6', at least or larger depending on what sub-contractor's rig requirements are for BOP's, etc. Top of bradenhead should be 2-6 inches below surface of cellar (verify BOP stack heights, etc!)

   Note:- Objective on final space out is to have top flange on tubing head ± no more than 2-4 feet above ground level, depending on final substructure height and completion program.

   Record the distance between the RKB and the top the flange.

10. Weld and test section "A", 13 3/8" by 11" - 3M slip-on C-22 wellhead (SOW). (Check final wellhead design before spud date & ensure all sections and including extra slips are on-site before spud for all casing strings).

11. Test head to 1,000 psi

    Note: If the wellhead has internal seal, the only weld necessary is to the outside bottom. Excessive preheat temperature will damage internal seal. Be sure to check condition of seal. If necessary, an internal weld can be made if wellhead does not test. Annular valve on well head should be oriented as per requirements for completion and subsequent injection operations dictate. Annular valve on "TC" tubing spool will stack up on top of valve on casing head. Alignment pin in "TC" tubing spool should be located 90 degrees counter clock wise from catwalk.

12. Install blowout preventers, bell nipple and flowlines.

    Test BOP stack as per API and IADC best practices <u>To save time, pretest as much BOP equipment as possible concurrently with other rig activity, test choke manifold during trip, etc</u>.

    Subsequent BOP tests are to be every fourteen (14) days but not in conflict with other drilling policies-best practices. Record BOP tests on all well reports.

13. Install and lock down wear bushing in casing head.

<u>INTERMEDIATE HOLE</u> – 12 1/4" HOLE – 9 5/8" CASING AT ± 5,310-5,320 Ft TVD

P/U 12 ¼", per sub-contractor- bit, monel, large DC & HvyWt BHA. Ensure ROP is commensurate with straight hole provisions, taking teledrift/multishot/Pason surveys +/- 250-300 feet. Ensure that if RPM cannot be achieved by rig's rotary (or Top drive), that we have option for downhole motor.

The main purposes of this section/casing is to cover and protect reactive shales so as to prevent from getting stuck, while coring in the 12 ¼" hole & 8 ½" hole sections below the 9 5/8", as well this adds another seal for the monitoring well during CO2 injection into the CCS Well #1.

The mud system will be a closed loop, low solids, ND system utilizing rig solids control equipment and possible calcium carbonate for seepage/lost returns, if encountered (a contingency plan will be prepared for this and is included in the drilling fluids program)- see attached proposed drilling fluids propgram.

Note: Run screens inside drill pipe while drilling with any bit.

2. Tag top of cement or float collar. Drill cement, wiper plugs, float collar, cement, float shoe and 10' of new formation.

Note: If any problem is suspected, plans to test casing must be implemented.

3. Pull back to 9 5/8" casing shoe and perform a Formation Integrity Test (FIT) to an Equivalent Mud Weight (EMW) of 10.-11.0 ppg. If EMW is less than 9.5 ppg, consult with the Schlumberger representative and the SCS Well Architect or Engineer in Charge before proceeding.

Note: See FIT & LOT PROCEDURES for details.(to be provided on project PC and attached to final version of well plan)

4. Drill ahead holding angle at 0 degrees to 9 5/8" casing point expected at ± 5,310-5,320 feet TVD. The plan is to drill partially through the Eau Claire shale, before setting protection pipe. Note that extensive full-diameter coring will transpire in the 12 ¼" hole section (see coring details)

Note:- Drill with caution while drilling inside casing.

- Wiper trips every 24 hours or 200-400 feet drilled are recommended.
- Sweep the hole properly

5. Circulate & condition hole, perform a wiper trip to 13 3/8" casing shoe. Trip back to bottom, condition hole clean, TOH-SLM.

Note: Log as planned in this section. This may require another wiper trip, depending on what TD is reached and ease/difficulty of the logging program. Decision to make wiper trip is with the sub-contractor and the SCS representative or the SCS Well Architect along with the SCS Project Manager

6. Pull wear bushing.

Note: Changing of rams to 9 5/8" will not be necessary due to past experience in the area; the use of annular BOP should be enough to cover any emergency. Prepare Change Order or Deviation from Norm paperwork.

7. Run and cement 9 5/8"" casing as per programmed 1- cementing proposal. Upon reaching bottom with casing reciprocate while circulating until hole is clean (watch drag while reciprocating). Cement per plan. After cementing ensure casing is aligned properly in order to work slips into bowl and activate. Ensure that the annular area close to the surface is adequately centralized to assist in this endeavour. Cement returns are expected to surface.

   Note: - Do not treat (thin or lower YP) and circulate excessively to treat mud prior to cementing casing.

8. Pick up BOP's and set slips. Cut 9 5/8" casing, install and test casing head to 1,500 psi. Re-install and test BOP's as follows:

   (a) Blind rams, pipe rams, choke manifold and lines, stand pipe, upper and lower kelly cock to 250 psig and 3,000 psig for 5 min.

   (b) Hydril/Annular to 250 psig and 1,500 psig for 5 min.

9. Install and lock down wear bushing in casing head.

D. LONG STRING HOLE SECTION– 8 ½" HOLE – 5 ½" casing to TD +/- 7,200 FT TVD

Directional Control: Teledrift/multishot/Pason survey Interval every 300-400 feet and/ or on bit trips

Due to the fact that this is our "formation of interest" we have to be careful with mud weights, formation invasion (all drilling fluid properties) and our best drilling practices. Adjust mud weight only on an as-needed basis to hole conditions.

1. Trip in hole with 8 ¾'' or 8 ½"", -rock bit, from bit company inventory (contingency bits to be left at rigsite in case different types are needed) and a Packed Under-gauge BHA, tag cement or Float Collar.

2. Drill cement, wiper plugs, float collar, cement, float collar and ± 7-10 feet of new formation. Circulate hole clean and pull back to 9-5/8" casing shoe. This FIT will be accomplished with the existing mud system. See detailed drilling fluids requirments.

   Note: If any problem is suspected, plans to test casing must be implemented

3. Perform a FIT to 13.0 ppg EMW per same procedures mentioned before. If EMW is less than 12.5 ppg, consult with Schlumberger Carbon Services Well Architect and the SCS Project Manager in Charge of the PMT before proceeding or a SCS representative.

4. Continue, drilling the U/L Eau Claire shale into the upper Mt Simon with optimized bit program per plan from ±

5,310-7,200 ft +/- to TVD into Pre-cambrian expected to be at between 7180-7,200 ft TVD, controlling deviation every ± 200-400 feet or as deemed necessary to maintain proper verticality of well.

5. Full diameter, 30 or 60 foot cores will be cut in the 8 ½" section (see detailed coring requirements).

Note: - Run Drill Pipe screens while drilling with bits. Make sure Rig personnel are aware of this matter.

- Sweep the hole properly.
- Wipe the hole every 24 hrs/250 meters whichever is first.

6. Once top of Pre-cambrian is tagged, attempt to drill with existing bit in hole. If little to no progress is reached, POOH, change bit to drill enough rathole of Pre-cambrian, C&C, , make wiper trip to 9-5/8" shoe, POOH to log well as planned. Run to bottom and condition hole to log. Drop EMS directional survey and POOH-SLM for logs.

7. Run logs as per geological program.

Note:

- Make a conditioning trip if required. Note logging times preferred by SCS
- Observe the well at all times while logging, keep hole full.
- **Report all mud losses and gains.**

8. Perform a conditioning trip with the same BHA prior to running 5 ½" casing (see detailed casing program attached to tender).

9. Run 5 ½" casing, per casing running procedures. If hole conditions permit, reciprocate casing while circulating and **do not lower YP**.

Note: Change of rams to 5 ½" will not be necessary due to past experience in the area, the use of annular BOP should be enough to cover any emergency. However, if appreciable amounts of gas are encountered while drilling, arrange to have 2 sets of rams on location, just in case.

10. Cement casing per procedures. Cement returns are expected to surface.

Note: See CASING AND CEMENTING PROCEDURES.

F. <u>GENERAL GUIDELINES</u>

1. Plan ahead on all material requirements as this is a logistical sensitive well. Transportation is limited and will be very difficult to arrange. The nearest supply store is far away, even in an emergency.

2. Make every effort to have bits dressed with the proper size nozzles, spare stabilizers checked and ready, tools calipered and measured, etc. to prevent unnecessary losses of time.

3. Check Drilling Contractor's or inventory of fishing tools carefully to ensure they have tools to catch anything that goes through the rotary.

4. Formation pressures are expected to be normal to T.D. However, pressure anomalies may occur particularly as a result of local abnormalities. Swab and surge pressures must be watched carefully. Be prepared for well kicks. Special attention must be taken while drilling the surface hole because there will not be a diverter installed.

5. All crews must practice BOP practice drills while drilling and trip drills must be duly noted in the WEMS, Pason or Totco or comparable report and IADC morning report forms. Thereafter, BOP drills are to be run at least weekly for each crew or on trips and reported on the daily drilling report.

6. **BOP Equipment shall be tested at least every fourteen- (14) days or per SCS Drilling Policy**. Rams shall be operated each trip and the operation noted on the reports. Test as much of BOP equipment as possible concurrent with other rig operations to minimize testing time.

7. Take a "Reduced Flow Rate" with at least 2 separate pumps daily and note the SPM and pressure on the reports and drilling recorder.

8. Keep a "Full Opening Safety Valve" and an "Inside BOP" on the rig floor at all times with proper x-overs to all connections of the drill string and/or tubing.

9. Use the Trip Tank to fill hole on trips. Monitor hole and fill carefully. Report any mud losses or gains.

10. The mud and hydraulic programs are meant as guides. However, proposed changes must be discussed with the SCS Well Architect/Engineer in Charge or the Project Manager or his representative prior to any major changes that will affect the MOC process. <u>To maximize hole cleaning keep circulating rates at 650-830 GPM in 17-½" hole, 500-620 GPM in 12-1/4" hole.</u>

    Optimize bit hydraulics by properly sizing nozzles, not maximizing circulation rate.

11. Do not take deviation surveys right on bottom. Always keep enough open hole below the bit to allow breaking stuck pipe free going downward.

12. Report the Shock Sub and Drilling Jar serial numbers and cumulative running hours on the morning report. Make notation on initial drilling report, when all jars are picked up the down setting wt.

13. Make sure all BHA´s that go through the rotary table are correctly calipered I.D., O.D. and length. A downhole schematic of the BHA must be kept current. Note on schematic if pin has API relief groove and box has API bore back. Gauge stabilizers each trip.

14. Make sure all pit level indicators alarms and multi-pen drilling recorder is working at all times. Discrepancies must be reported on the daily drilling report.

15. **On the 17-1/2" hole have 50 bbl of 9.0 ppg premixed kill mud, in case a water flow is encountered.**

16. Measure pipe (SLM) on a trip prior to reaching casing setting points, important formation tops and when POOH for cores or drill stem tests. If the pipe strap should be off more than 1-foot/1000 feet of depth, strap the pipe again to confirm the difference prior to making depth corrections.

17. Keep an inventory of all drill pipe on location. If measurements should become in question, the number of joints in the hole can easily be determined.

18. Solids control equipment must be kept in top operating condition. Keep finest screens possible on the shale shaker. Report screen sizes on morning report. Efficiency checks for all SCE should be made at least twice a week and duly reported on the daily morning report.

19. Upon returning to bottom after all trips, wash a minimum of 2 joints to bottom.

20. After every trip when circulation is started, start the Degasser and run it at least until after bottoms are circulated up. This will not only ensure the Degasser operates properly, but will help condition the mud.

21. Coordinate operations closely with the mud loggers and sub-contractor's representative onsite (toolpusher?). Check with the mudloggers and the SCS Well Architect or Project manager prior to tripping for the possible need to circulate up critical samples.

22. The Rig Toolpusher should be on the rig floor for the first ten stands out of the hole and the last ten stands in the hole on all trips and any other times hole problems are present.

23. Report all safety meetings and response brigade drills/training on daily drilling report and radio report.

24. Report WOB, rotary RPM, pump pressure, SPM, TORQUE, for each drilled interval on daily drilling report.

25. Use bit nozzles on all bit runs whether drilling, conditioning or reaming. Every bit run through the rotary should be capable of drilling additional hole even on conditioning trips while logging.

26. Report all non-functioning contractor and service company equipment each day on drilling report.

27. Recover and save for future requirements the jet nozzles from all rock and PDC bits. Nozzles are both expensive and in short supply. Ensure PDC bit breakers are on location.

28. Keep caustic soda and soda ash under lock in secured mud storage. Keep tight inventory control on these items (per SCS Policy).

29. The sub-contractor's Drilling Supervisors or representative will maintain a current directional drilling chart and drilling time charts at their respective work site. On drilling time curve, days, rotating hours, cost, torque and mud properties will be plotted current. Torque and mud data trends are a useful tool in detecting hole or mud problems. (This is offered via either Pason or Totco electronic system)

30. Check Drilling Contractor's drill pipe hard banding. Do not run newly hard-banded tool joints inside 9-5/8" protective casing. Critical area for casing wear is directional build area.

SUGGESTED BHA'S

SUGGESTED BHA PLAN (sub-contractor can amend as he sees fit)

1. PHASE I: 17-1/2" HOLE.

17-1/2" ROCK BIT + 9 1/2" XO + 9 1/2" FS + 3 (9 1/2") DC + 8"XO + 3 (5" or 4 ½") HWDP + 6-3/4" JARS + 15 (5" or 4 ½") HWDP

Note: This BHA is expected to hold the angle vertical as can be.

The 2JS rock bit is recommended and if no chert is encountered it is possible to cut the 17 ½" hole with 1 bit. If not, not, then a 2nd , 4JS is planned.

2. PHASE II: 12-1/4" HOLE

Lay down 9 1/2 in collars, while WOC. P/U the same BHA as before but with 8 in collars.

This BHA is expected to maintain the vertical angle.

SUGGESTED DRILLING FLUIDS PROGRAM

DRILLING FLUIDS PROGRAM

DEPTH MD / TVD (feet)	HOLE SIZE	CASING	MUD SYSTEM
350-375	17 1/2"	13 3/8"	GEL / WATER
375-5,310	12 ¼"	9 5/8"	BTS (or sub-contractor proposal)
5,310-7,200' +/-	8 1/2"	5 ½"	BTS(or sub-contractor proposal)

CRITICAL MUD PROPERTIES :

DEPTH MD (feet)	MUD WT. (ppg)	YP lb/100sf	FLUID LOSS c.c.	pH	0.3 RPM
0 - 375	*8.4 - 8.6	25 - 51	N.C.	8.0 - 9.0	N.C.
375 – 5,310	8.4 - 9.0	9 - 20	N.C. - 12.0	8.5 - 9.5	NC
5,310-7,200	*9.0-9.3	25 - 45	</= 8.0	9.2 - 9.9	80-130,000

- The mud weight may need to be raised if a water flow occurs.

Detailed Minimum Requirements for Drilling Fluids For

ADM MMV Well #1
Decatur, Illinois (ADM Plant)
Macon County, IL.
Projected T.D. - +/-7,200'

Hole Size and Casing Program

Interval I

Drill 17 ½" Hole to (350'-375' +/- (M.D.)) – Set 13 3/8" Casing

Interval II

12 ¼" Hole to 5,310-5,320 +/- (M.D.) – Set 9 5/8" Casing

Interval III

8 ½ " Hole to TD expected to be 7,200 ft TVD or 30 ft into Pre-Cambrian – Set 5 ½" Casing

Interval Discussion

Interval I

Drill 17 ½" Hole to (375' +/-(M.D.)) – Set 13 3/8" Casing

SCS recommends using spud mud for this interval. Spud mud with a 45+ sec/1000cc viscosity.

<u>Estimated Mud Up Volumes – Perfect Hole</u>

Hole Volume for 17 ½" hole at T.D. (+/-375' M.D.) – 114.8 bbl.

Pit Volume -	400.0 bbl.
Total Volume -	514.8 bbl.

<u>Mud Properties to be maintained for Interval I</u>

Viscosity – 45+ sec/1000cc

Weight – 8.6 to 9.2 ppg

pH – 10.0 to 10.5

Interval II

Drill 12 ¼" Hole to (5320' +/-(M.D.)) – Set 9 5/8" Casing

SCS recommends watering back the spud mud used for the surface hole to drill out the cement plug and 5 feet of new hole. Once that is done we recommend jetting, cleaning all pits, and displacing the hole with freshwater and drilling down to 1600' with good clean freshwater. If you can get below the St. Louis section from 1376' to 1528' with freshwater you can avoid anhydrite contamination and mixing numerous amounts of chemical to fight it. Once you know that we are out of the St. Louis section, mud up just prior to drilling the Borden section and this will allow to build a thin filter cake to take care of any small seepage problems that may occur. SCS recommends using a gel/chemical mud system for this hole interval with filtrate control.

Estimated Mud Up Volumes

12 ¼" Hole Volume at 1600' – 240.1 bbl.

Pit Volume - 500.0 bbl.

Total Volume - 740.1 bbl.

Minimum Mud Properties to be maintained for Interval II

Viscosity – 45+ sec/1000cc

Weight – 8.6 to 9.2 ppg

pH – 10.0 to 10.5

Filtrate – 6.0 to 8.0 cc

Plastic Viscosity – 15 to 20 cP

Yield Point – 8 to 10 lb/100 ft^2

Gel Strength

10 second – 0 to 2 lb/100 ft^2

10 minute – 4 to 8 lb/100 ft^2

Interval III

Drill 8 ½ " Hole to (7200' +/-(M.D.)) – Set 5 ½" Casing

For this interval SCS WOULD LIKE THE SUB-CONTRACTOR TO PROPOSE the drilling fluid. On the offset well MI's Flo-pro system was utilized with excellent results however this extreme might not be required. The system must protect the reactive Eau Claire shale and provide low invasion of the Mt. Simon. Pore pressure is expected to be 9.0 ppg in the Mt Simon.

Estimated Hole Volume at 5300' – 408.5 bbl.

Pit Volume - 500.0 bbl.

Total Volume - 908.5 bbl.

Minimum Mud Properties to be maintained for Interval III

Viscosity – 45+ sec/1000cc

Weight –9.0to 9.4 ppg

pH – 10.0 to 10.5

Filtrate – 6.0 to 8.0 cc

Plastic Viscosity – 15 to 20 cP

Yield Point – 8 to 10 lb/100 ft^2

Gel Strength

10 second – 0 to 2 lb/100 ft^2

10 minute – 4 to 8 lb/100 ft^2

When you get the cement drilled out and the mud is in good shape continue to drill ahead. Continue the normal maintenance treatments as before with interval II.

Note: Sub-contractor to provide his/her detailed mud program as he/she wishes to propose in the Commercial Proposal, but at least minimum rheological properties as reflected above need to be maintained. As well, please note that this has to be a "closed loop" mud system, and this has cost implications for sub-contractor's Commercial Proposal. It is also suggested that sub-contractors review the drilling reports and mud logs from the CCS Well #1, as this is very close to the proposed MMV well #1.

NOTES FOR THE 17 1/2"HOLE SECTION

1. Spud this section with water.

10. Use drill solids to weight the system up as much as possible

11. Maintain soda ash, freeing additive and LCM on location for contingency.

4. Mud checks will be made at the flow line and pits while drilling. Flow line checks will be recorded on the daily drilling report and these values will be used to estimate product additions.

5. After the wiper trip, before running casing, raise the mud weight if there are hole stability problems.

6. Wiper trips to the shoe are excellent indicators of hole conditions. A wiper trip will be made every 300 meters or 24 hours, whichever comes first. Circulate the hole clean following a 100-bbl sweep. The mud engineer will be at the shakers during bottoms up to determine when the hole is clean.

CASING AND CEMENTING PROGRAM

CASING AND CEMENTING PROCEDURES

The following cement prognosis is based upon planned well conditions. Actual cement design will be based on actual hole conditions and could be modified at the actual time of cementing. Sub-contractor to provide the cost per the below parameters and also who the sub-contractor is proposing to cement the strings listed below in the Commercial Quote.

Surface Pipe (13 3/8"):

Cement 350 feet 13 3/8 casing in 17 ½ open hole using 75% excess. Cement volume required 425 cu. ft. Cement with 360 sacks Class A, 1% CaCl2, ¼ #/sk flake mixed at 15.6 ppg and a yield of 1.18 ft3/sk. Cement head and top plug required. Float equipment to be a Guide shoe, float collar, and 4 centralizers with one stop ring. Displace cement with fresh water. Two single pump cement units or one double pump cement unit required.

Intermediate Casing (9 5/8"):

Cement 9 5/8 inch casing in 12 ¼ open hole to +/- 5300 feet returning cement to surface. Volume to be hole size plus 45% excess. Cement proposal to be in two options.

Option 1 Cement in one stage using 910 sacks of lead 65-35 Cement-Poz, 4% Gell, 10 % BWOW salt, 5#/sk Kolite, .2% Dispersent, .2% fluid loss control agent, .2% anti-foam agent. Cement density 12.7 ppg, Yield 2.15 ft3/sk, and water ratio 11.81 gal/sk. Tail in with 415 sacks Class H cement. Cement density 16.2 ppg, Yield 1.09 ft3/sk, and water ratio 4.62 gal/sk. Cement using cement head with top and bottom plugs. Run 30 bbls Mud Spacer and 20 bbls Chemical wash ahead of cement. Float equipment to consist of a float collar and a float shoe with a minimum of 25 centralizers and one stop ring.

Option 2 will require a stage cementing collar as well.

Option 2 is to cement in two stages with stage collar at 3850 feet. First stage to consist of 20 bbls Mud Spacer and 20 BBl Chemical Wash. Lead slurry consist of 280 sacks Class H with .04 gal/sk Retarder with cement density of 15.6 ppg and yield of 1.18 cu ft/sk with a water ratio of 5.20 gal/sk . Tail in with 300 sks Class H with .04 gal/sk retarder with cement density of 16.2 ppg and a yield of 1.09 cu ft/sk. Water ratio is 4.62 gal/sk. Drop opening bomb and open stage collar. Circulate six hours and cement second stage with 815 sacks of the lead slurry in Option 1 above and tail in with 100 sacks Class H cement mixed at 16.2 ppg and a yield of 1.09 cu ft /sk. In both cases cement will be displaced with mud.

Both cases require two double pump cementers. Approximately 24 hours after cementing operations are finished the cement pump truck will be used to perform an FIT and shoe tests.

Note: Schlumberger will be providing cement and all horsepower and all accessories to cement the long string (5 ½"). All sub-contractor needs to do is to provide the time to run the pipe, time to cement, hang off, ND BOP's, RD, etc. 5 ½" cementing program to be delivered before TD is reached, but the string will be cemented to surface.

CASING AND CEMENTING PROCEDURES

CASING STRING:

13-3/8" Float Shoe, Conventional, STC

375' 13-3/8" 61 lb/ft., K-55, R-3, LTC plus extra joints

13-3/8" Float Collar, Conventional, LTC

SUGGESTED MATERIALS & EQUIPMENT:

1 13-3/8" Float Shoe, Davis Lynch, STC (PDC drillable)

1 13-3/8" Float Collar, Davis Lynch, STC (PDC drillable - non rotating)

4 Thread Lock Compound - Thread lock bottom 3 joints

3 Thread Lubricant - API Modified

1 Circulating Head - Swage, 2" Union x 13-3/8" STC

1 13-3/8" Side Door Elevator, 150 ton capacity.

1 13-3/8" Rotary Slips

1 Set of 250 Ton Elevator Links, 144" long

1 Power Casing Tongs with 13-3/8" heads. (Torque to buttress triangle mark)

2 Rotary Tong heads to fit 13-3/8" casing

1 13-3/8" Single Joint Pick-Up Elevator and Protector

10 Centralizers, 13-3/8" x 18". (Install one around stop collar + 6 feet above shoe, one around next coupling, one on every third coupling next 10 jts (TBD by hole section after well sections are TD'd & log information is inputted.

5 Stop Rings, 13-3/8"

1 Surface Fill Line, 3" with quick opening valve

1 Cementing Head - Plug Container 13-3/8", STC

2 Cementing Plugs - Top and Bottom, 13-3/8" PDC drillable - non rotating.

2 Casing Coupling 13-3/8" "K-55", STC, for emergency replacement should a joint be damaged while running.

1 Pressure Recorder - Connected to record all circulating and cementing pressures.

1 Drift Mandrel 12.259" O.D.

1 3" - 4" fill up line on rig for running casing

SCS SUGGESTED RUNNING & CEMENTING PROCEDURES:

1. Inspect, clean threads, tally and rabbit casing on the pipe racks. Use a 12.259" casing drift.

2. Tack weld the bottom side of the coupling on the bottom four (4) joints while on the rack (3 spots, 2" long). Have hot work permit before welding.

3. Cut drilling line as required and RIH to condition hole for casing. Make a conditioning trip and circulate the hole clean after logging operations cease. POOH.

4. Rig up to run casing. Thread Lock the float shoe and connections up past float collar. Torque casing to optimum manufacturer specifications with power tongs. Fill casing while running. Float equipment is not automatic fill up.

5. **Note**: Use casing crew power tongs and CONTRACTOR (if he has them) casing tools to run casing. Do not use casing crew single joint pick up elevators.

6. Install cementing head adapter in last joint in V-door. Pick up the last joint and install cementing head at the stabbing board. Break circulation slowly and wash last joint to bottom. Have sufficient lines connected to allow reciprocating casing a 40 foot stroke. Rig up kelly hose for circulating and chicksan hose for cementing. The 13-3/8" shoe should be set two to three feet off bottom.

7. Circulate and condition mud.

8. Pump Mud Flush ahead. (follow cementing program as mentioned previously)

9. rop bottom plug, load top plug.

10. Mix and pump cement as outlined. (The final slurry mix will depend upon lab results with actual mix water and cement).

11. Release the top plug while still pumping cement. Allow for at least 10' of cement to be located above the top plug at the conclusion of pumping.

    Maximum allowable pressure on 13-3/8" casing is 2400 psi. Do not exceed 70 % of the burst rating.

    Note: If plug does not bump after the theoretic displacement, over displace the half of float joints (one joint) only.

12. Land the 13-3/8" casing so the collar of the next to last joint will be approximately 24" below ground level. Objective on final space out is to have top flange on tubing head +/- 2-4 above GL (ground level) (**check with FINAL DIAGRAM**!)

13. Wait on cement six to eight (8) hours, until cement will support the weight of the casing. Watch the cement surface samples.

14. Cut off the 13 3/8" surface pipe and back out the 13-3/8" landing joint. (or cut for SOW bradenhead)

15. Weld and test 13-5/8" X 11" 3M# slip on weld, C-22 well head.

    Note: Head has internal seal, therefore the only weld necessary is to the bottom. Make sure that the Contractor uses acetylene bottles not carbide generator to preheat head.

16. Check the cement level in the 13-3/8" X 17 ½" annulus if possible and if cement is not at surface, a top job will be required.

17. Install and test BOP stack.

18. Go in the hole with regular bottom hole assembly (stabilized for open hole drilling) and the PDC bit that is planned for the next section of hole to be drilled. It is recommended to use the parameters listed below to drill out the float equipment and non-rotating wiper plugs.

19. If the drill pipe and/or rotary table should start to jump, backlash, or act erratically, temporarily change one or more of the following drill-out parameters: WOB, bit speed, or circulation rate. Resume drilling with original parameters once normal operations are observed.

20. If the penetration rate ceases and cannot be reinstated using the above procedures, recover the bit for inspection.

21. Do not by-pass shale shaker while drilling out. PDC bit shaves wiper plugs resulting in small particles which plug pump suctions, pump valves and bit nozzles.

CASING STRING: (FINAL DESIGN BASED ON ACTUAL PURCHASE & TD OF HOLE)

9-5/8" Float Shoe, Davis Lynch, LTC, PDC Drillable

5,320 ' - 9-5/8", 40 ppf & 43.50 ppf (see casing design), LTC, R-3

9-5/8" Float Collar, Davis Lynch, Buttress, PDC Drillable, non-rotating

SUGGESTED MATERIALS & EQUIPMENT

1 9-5/8" Float Shoe, LTC (PDC drillable)

1 9-5/8" Float Collar, LTC (PDC drillable)

4 Thread Locking Compound

40, 9-5/8" Centralizers – TBD when hole sections are drilled

20, 9-5/8" Stop Rings

3 Thread Lubricant, API Modified

1 Circulating Head, 2" Union x 9-5/8_" LTC Thread

1 Power Casing running tool (or Tongs w/9-5/8" heads)

1 9-5/8" 350 ton Elevator Links 144" long

1 9-5/8" 350 ton Spider w/top guides

1 Set 350 ton Elevator Links 144" long

1 9-5/8" Side Door Casing Elevators, 150 ton capacity

1 9-5/8" Rotary Casing Slips

1 9-5/8" Single Joint Pick-Up Elevator

3 9-5/8" Quick Removal Thread Protectors (Provided by casing crew)

2 Rotary Tong Head for 9-5/8" Casing

2 9-5/8" Casing Coupling – N80 or >, LTC

1 Cementing Head Plug Container, LTC w/QC adapter

2 Cementing Plugs - Top and Bottom (PDC drillable, non rotating)

1 Surface fill line to permit fast fill of casing

1 Pressure Recorder, connected to record all circulating, cementing and displacement pressures.

1 Drift Mandrel 8.50" O.D.

1 3" - 4" fill up line on rig floor

1 13-5/8" 3m X 11" 3M tubing head FMC-TC-ECC or per sub-contractor Commercial Quote (check inventory)

1 9-5/8" x 12" C-22 hanger (TBD)

SUGGESTED RUNNING & CEMENTING PROCEDURES:

1. With adequate lead time, place casing on pipe racks. Inspect, clean threads, tally and drift casing with 8.500" drift mandrels. No special casing other than OCTG will be utilized, thus no special handling procedures are required.

2. Haul bulk cement as required and store at location. Results of lab test will determine necessary additives for cement. Verify with lab results!

3. Cut drilling line as required and string to 10 lines. RIH and condition hole for casing. Make short trip if considered necessary. POOH.

4. Rig up to run 9-5/8" casing. Pull wear bushing from 13-5/8" casing spool. Install 9-5/8" rams in BOP.
   Note: Use PRE-AGREED TO, POWER TONGS TO PROPERLY TORQUE ALL TUBULARS.

5. Use Thread Lock on all threads from shoe to float collar. Run 2 joints between float shoe and float collar. (verify at TD as to path forward on this- depending on rathole & amount of hole cut) Make sure the shoe joint is full of mud. Torque casing to the optimum torque.

6. Install centralizers on the middle of the first joint and on each of the collars on first 15 joints then each every (2) two joints.

7. Casing running speed should not exceed 30 seconds/joint.

8. The float equipment is not automatic fill. Fill casing with 4" fill line while running.

9. It is suggested to change to 350 ton Elevator/Spider before going below the 13-5/8" surface casing shoe.

10. Install the cementing head quick connect adapter in the last joint of casing in V-door. Pick up the last joint and install cementing head at the stabbing board. Rig kelly hose for circulating. Break circulation and wash last joint to bottom. Rig up cementing lines with sufficient hose to allow reciprocating the casing a full 40 foot stroke, depending on rig's capabilities, allowing centralizers to overlap on each stroke.

11. Circulate and condition mud until hole is cleaned up. Reciprocate the casing a full 40' stroke throughout the circulating period.

12. Test cement lines. Pump mud flush (fulfill above mentioned cementing program). Drop bottom plug. Mix and pump cement as outlined. The final slurry will be determined from lab tests.

13. Drop top plug. Displace cement with mud using rig pump at as high a rate as possible. If hole conditions will allow, continue reciprocating the casing until the plug bumps, or at least until the cement is above the primary zones of interest. Slow pump rate just prior to bumping plug. Bump plug with +/- 1000 psi above final displacing pressure. **Maximum allowable pressure on the 9-5/8" casing is 4100 psi**. Release pressure and check float equipment.
    Note: If plug does not bump after theoretic displacement, displace half of the float joints (one joint) only.

14. Install the 12" x 9-5/8" type C-22 casing hanger-or as proposed by sub-contractor (check inventory) and have replicated equipment at all times on location and hang 9-5/8" casing in full tension.

15. Pick up BOP stack, cut off 9-5/8" casing and install the 11" 3,000 psi x 13-5/8" - 3000 psi Tubing Spool, FMC type or per sub-contractor Commercial Quote. Pressure test the secondary pack off to 1500 psi. Nipple up stack and test to 3000 psi with the test plug.

16. Follow same drill out procedures as per 13-5/8" casing, except utilize where possible, Rig's BHA (DC), etc. Drill track show if necessary. Drill/core as per plan to TD. 5 ½" running and cementing procedures will be provided before reaching TD.

ADM MMV WELL #1

BASIS OF DESIGN (BOD)

For Drilling MMV Well

casing design and hole size

GOALS:

To provide all prospective sub-contractors that will be providing turnkey Commercial Quotes, the tubular that will be required as a minimum for the MMV Well #1. The design parameters and general discussions are to assist sub-contractor in his/her preparation of their Commercial Quote. Please note that sub-contractor should take into account extra joints in the event of galling while make-up, with possible return of unused tubular from your provider. As well, please make note that since this is a partially, DOE-sponsored project, USA-content is required.

17 ½" Hole / 13 3/8" Surface Casing

- Placed at 350-375 ft MD in order to seal off fresh water bearing formations from the shallow aquifer located near surface around 100-125 ft +/- as part of the permitting process.
- Provide shut-in capability and kick tolerance for pressure events above the Eau Claire/Mt Simon, if any.
- 17 1/2" hole drilled in one run (optimal condition)
- Obtain casing pressure test to 300 psi for 5 mins / 1350 psi for 10 mins.
- Obtain Formation Integrity Test of 9.5-9.9 ppg EMW
- Allow installation of BOP stack

12-1/4" Hole / 9 5/8" Intermediate/Protection Casing

- Properly engineered hole size to provide fast drilling through the formations above the Eau Claire and into the Eau Claire shale where intermediate casing will be set & cemented to surface but to not wash out the formations and to provide an adequate hole size for logging, coring and subsequent running of a long string of 9 5/8" casing.
- Provide mechanical containment and zonal isolation of the open hole above the Mt Simon.

- To provide a hole size to facilitate open hole logging measurements required to effectively evaluate the open hole sections
- More effective drilling criteria for the Mt Simon after drilling commences below the 9 5/8"
- Provide shut-in capability and kick tolerance for pressure events into shallower zones.
- To provide mechanical support and zonal isolation to shales and swelling clays drilled down to the top of the Mt Simon.
- Obtain Formation Integrity Test of 12 – 12.5 ppg equivalent mud weight. (Perform LOT (Leak off test) for future reference.
- To provide a hole with minimum DLS for protection of plume migration and protection of the injection process integrity.
- Obtain casing pressure test to 300 psi for 5 mins / 1500 psi for 10 mins
-

8 1/2" Hole / 5 ½" Long string

- Provide mechanical containment and zonal isolation of the main reservoir (Mt Simon) for supercritical CO_2 monitoring.
- Properly engineered hole size to provide fast drilling through the Mt Simon zone of interest but suitably sized hole so as to not wash out the formation and to provide an adequate hole size for logging, coring and subsequent running of a long string of 5 1/2" casing.
- Allow a suitable ID for the complex completion of the well once the well has been drilled and completion commences.
- Maintain well bore stability allowing for good cement job.

Design Policies / Standards

Policies set out in the SLB/SCS operations manual must be met as a minimum. Some of these casing policies are as follows:

- All surface, intermediate, and production casing will be pressure tested prior to drilling out the shoe track or perforating. Subsequently, such tests will be repeated whenever the integrity of the casing is in doubt (long rotating hours, high dogleg severity, etc.) A pressure test will be conducted on the production casing/ liner prior to running completion.

- Well control will be maintained while running casing through maintenance of fluid column, barriers, and surface well control.

- The casing installed in any well shall be designed to withstand burst, collapse, tension, bending, buckling or other stresses that are known to exist or that may reasonably be expected to exist.

- The performance properties of any casing shall be considered to be those listed for that casing in the American Petroleum Institute's API Bulletin on Performance Properties of Casing, Tubing, and Drill Pipe, API BUL 5C2, nineteenth edition, October 1984.

- Minimum design factors:

Design Loads	Surface / Intermediate Casing, Drilling Liners	Production Casing Liners	Tubing
Collapse	1.0	1.1	1.125
Burst:			
Normal Service	1.1	1.1	1.1
Critical Service	1.25	1.25	1.25
Tension:			
Pipe Body	1.3	1.3	1.3
Connection	1.5	1.5	1.3
Compression	1.3	1.3	1.3
Triaxial	1.25	1.25	1.25

- The casing installed in any well shall be designed to withstand collapse loading based on the following assumptions:
    1. The hydrostatic head of the drilling fluid in which the casing is run acts on the exterior of the casing at any given depth;
    2. subject to the casing is 1/3 evacuated; and
    3. The production casing is completely evacuated.
    4. The effect of axial stresses on collapse resistance shall be taken into account.
    5. The effect of temperature deration and casing wear shall be taken into account.

- Any casing/liner that creates an annular space with the production tubing shall be treated as a production casing / liner.

- The casing installed in any well shall be designed to withstand tensile loading based on the following assumptions:
    1. The weight of casing is its weight in air; and
    2. The tensile strength of the casing is the yield strength of the casing wall or of the joint, whichever is the lesser.

Casing Design assumptions

In designing the casing for the ADM MMV Well #1, the following assumptions were made:

- A 5% casing wear due to BHA rotation is assumed on all casing design with consecutive hole sections.
- Wall Tolerance of 87.5% is assumed as per API standards.
- Temperature deration is taken into account on the design of the 13 3/8" and 9 5/8" casing strings. This option directs TDAS (Schlumberger proprietary casing/tubing design software) to the appropriate yield strength vs. temperature relationship in deeper casing strings (not expected in the ADM MMV Well #1).
- The 13 3/8" casing is being proposed and engineered to be required to comply with Schlumberger casing design standard (IPM-WELL-S029) to pass a 1/3 evacuation loading on collapse. (This standard is well above the standard as utilized in normal oil and gas general best practices and engineering discipline.)
- The 9 5/8" casing string will have to pass evacuation loading to approximately 1500 ft. (The 9 5/8" long string will be cemented to surface for extra protection and to preserve the integrity of the long range goals of the monitoring and of injecting liquid CO2 in the CCS Well #1)
- The casing is designed to offer the most cost effective, engineering-wise acceptable option to the Project, designed to preserve the integrity of the monitoring operation(s) for the life of the R&D project. In the event that the casing recommended is not available, casing selection should be based on what other technical options are available and what might be "on the ground" but in no event meet lesser design parameters. If need be, sub-contractor is advised to seek guidance from the SCS Project Manager, if tubular as designed are not available. (Exceeding standard designed criteria)
- The kick tolerance for the 13 3/8" and 9 5/8" casings will comply with the minimum SLB standards. The KT and MASP are calculated as follows (example):

  13 3/8" Casing: Assuming fracture EMW of 13ppg at 1000ft (ex), 9.2ppg mud, and a 25bbl kick, then:

$$(MASP)_{LOT} = 0.052 \times (EMW_{LOT} - MW_{(in\ hole)}) \times TVD_{shoe}$$

$$(13 - 9.2) \times 996 \times 0.052$$

$$197 \text{ psi}$$

$$KT = [MASP_{LOT} - (MW_{(in\ hole)} \times 0.052 \times H_i)] / 0.052 / TVD_{shoe}$$

$$= [197 - (9.2 \times 0.052 \times 100) / 0.052 / 996$$

$= 3.09$ ppg

9 5/8" Casing: Assuming FIT EMW of 12ppg, 10.5ppg mud, and a 25bbl kick, then:

$(MASP)_{FIT} = 0.052 \times (EMW_{FIT} - MW_{(in\ hole)}) \times TVD_{shoe}$

$(12 - 10.5) \times 7000 \times 0.052$

546 psi

$KT = [MASP_{FIT} - (MW_{(in\ hole)} \times 0.052 \times H_i)] / 0.052 / TVD_{shoe}$

$= [546 - (10.5 \times 0.052 \times 171) / 0.052 / 7000$

$= 1.24$ ppg

IMPORTANT OFFSET CONSIDERATIONS

The following are considerations by virtue of having drilled successfully the closest well that being the ADM CCS Well #1 to depth as well as, which we have given all sub-contractors key drilling results and the shallow "geophone" well that was drilled and completed in 2009 as well (see drilling reports, bit records, etc). It is suggested, but not mandatory, for all sub-contractors to review this data prior to submitting their commercial quote. Any other information that may be needed can be requested of the SCS Project manager.

Casing design

TDAS was the program utilized to perform casing string design. A design summary is shown below(note minimum tubular factors):

HOLE SIZES AND CASING PROGRAM (RT-MSL ft): 675 ft +/-				**WELL TYPE: Vertical**
Hole Size (in.)	Casing O.D. (in.)	Setting Depth (ft TVD BRT)	Design FIT value EMW	Casing Seat Justification

17 ½"	13 3/8 "	4000-5000'	9.3-9.6 ppg	Seal off shallow aquifer at ~100-125 ft TVD Seal off potential bothersome shales and to provide a good casing seat for kick tolerance and good , general oilfield engineering practices.
12 ¼ "	9 5/8 "	5,310-5,320 TVD	9.4-9.9 ppg	Seal off the Knox, Eau Claire, offer protection for longer monitoring of the carbon dioxide that will be injected into the Mt Simon in the CCS Well #1.
8 ½"	5 ½"	7,200 ' TVD	9.4-9.9 ppg	Seal off the Mt Simon, offer protection for longer monitoring of the carbon dioxide that will be injected into the Mt Simon in the CCS Well #1.

casing specification

Casing	Specification	Performance		
		Burst	Collapse	Body YS (1000 lbs)
Surface	13 3/8" OD, 61 ppf, K55, STC	3,090 psi	1,540 psi	962 lbs
Protection	9 5/8" OD, 40 ppf N80, LTC (5,500 FT) & 43.50 ppf, N80, LTC (1,700 ft)	5,750 psi 6,330 psi	3,090 psi 3,810 psi	916 lbs 1005 lbs
Production	5 ½" OD, 17 ppf, N80, LTC	7740 psi	6290 psi	390 lbs

LOAD CASES

CASING STRING: 13-3/8" Surface Casing								
LOAD CASE	Pressure Profile		Temp.	Wear	Minimum Design Factor			
	Internal	External	Profile*	(%)	Burst	Coll	Tens	Triax
Axial weight in air								
Axial running load 5 ft/s								
Burst	3090 psi	PP	Drilling		> 100	3.98	> 100	>6.65
Pressure Test	1500 psi	PP	Drilling		> 100	3.98	> 100	>6.65
Collapse	1/3 Evac	Drilling Fluid	Drilling		> 100	3.98	> 100	>6.65
As Cemented	9.2 ppg Mud	Cement	Cementing		> 100	3.98	> 100	>6.65

CASING STRING: 9-5/8" Production Casing								
LOAD CASE	Pressure Profile		Temp.	Wear	Minimum Design Factor			
	Internal	External	Profile *	(%)	Burst	Coll	Tens	Triax
Axial weight in air								
Axial running load 5 ft/s								
Burst	Tubing leak - static	PP	Drilling	5	2.03	1.09	3.55	1.64
Pressure Test	1700 psi	PP	Drilling	5	2.03	1.09	3.55	1.64
Tubing Leak- static	Res Pr – Gas Grad	PP	Prod	5	>2.03	1.09	3.55	1.64
Collapse	100% Evac	10.5 ppg mud (max)	Drilling	5	>2.03	>1.09	>3.55	>1.64
Cementing and Landing	10.5 ppg mud	Cement to next string or surface	Cmtg	5	>2.03	>1.09	>3.55	>1.64
Full Evacuation (NA)	Gas gradient	10.5ppg mud (max)	Drilling	5	>2.03	>1.09	>3.55	>1.64

*Design temperature profile (Undisturbed, Drilling, Cementing, WOC, Production)

profile (Undisturbed, Drilling, Cementing, WOC, Production)

design envelope

Casing	Design Pressure Test	Design KT in next hole section

13 3/8"	1350 psi	25 bbls with 0.5 ppg kick intensity
9 5/8"	2700 psi	25 bbls with 0.5 ppg kick intensity

other considerations

Drilling hazards in the ADM MMV Well area (Decatur, Illinois) in general are not of a sufficiently severe nature to require a great deal of contingency planning in the casing design. A standard casing string configuration has been selected. Only OCTG tubular are required. For sub-contractors, please note that it possible that the tubular listed might not be "on the ground" and alternative designs might be needed to make your Commercial Quotes. It is advised, if this is the case, to notify the SCS Project Manager and we can visit the availability/design issues, in case the tubular cannot be sourced. It very well might be that heavier wall or different threads might be sourced and in this case, might be acceptable. The longstring (5 ½") will be sourced by the sub-contractors but will be cemented by Schlumberger. Provisions have been made in the design of the 5 ½" string for completion purposes, as there will be some special completion techniques utilized in the completion of the well.

The casing setting depths have been chosen such that adequate trip margins, kick tolerance are available and that rig operations can be carried out in a safe and efficient manner.

Using the proposed casing setting depths, the estimated formation fracture gradient at the surface shoe and the estimated mud weight the kick tolerance at section TD is predicted as 20-35 barrels with 1.5 ppg kick intensity. The general acceptable limits on kick tolerance are as follows:

Hole size	Development
>= 12 ¼"	50 bbls
< 12 ¼"	25 bbls

* i.e. a formation pressure 0.5 ppg higher than the mud density.

The load cases address the probable conditions, which the particular casing string could be exposed to over the life of the well.

SUGGESTED BIT & HYDRAULICS PROGRAM

The below bit program is based on what SCS believes the well can be drilled with. It is up to the sub-contractor to propose and utilize his/her own design keeping in mind SCS's preferred contractors for key services.

1. BITS SUMMARY & HYDRAULICS

1.1 Bit Summary

Bit No.	Size	Condition	Company	Type	Model	IADC
1	17 1/2"	Retip	Rental	Tricone	Retip	117
2	12 ¼"	New	TBD by sub-contractor	PDC/Tricone	TBD by sub-contractor	517X
3	12 ¼"	New	TBD by sub-contractor	PDC/Tricone	TBD by sub-contractor	547Y
4	8 ½"	New	TBD by sub-contractor	PDC/Tricone	TBD by sub-contractor	627Y
3	8 ½"	New	TBD by sub-contractor	PDC/Tricone	TBD by sub-contractor	627Y
4	8 ½"	New	TBD by sub-contractor	PDC/Tricone	TBD by sub-contractor	637Y

1.2 Contingency Bits

Sub-contractors can furnish their own bit programs which might include, PDC, button or conventional tricone bit technology.

Attach proposed bit/hydraulics program with the Commercial Quote as well as the provider.

No.	Size	Condition	Company	Type	Model	IADC

1.3 Recommended Hydraulics(based on CE F1000's-sub-contractors each need to revise per their pump inventory/specs/outputs)

Bit size	in	17 1/2"	12 1/4"	8 1/2"
Liner size	in	6"	6"	6"
Stroke length	in	10"	10"	10"
Max pressure 90%	psi	3000	3000	3000
Maximum strokes	SPM	120	120	120
Displacement (95%)	bbl/stk	0.083	0.083	0.083
Measured depth	ft	375'	375-5310'	7200'
Mud weight	ppg	8.6	9.3-9.6	9.3-9.6
Flow Rate	gpm	837	653	490
Surface pressure	psi	1350	2540	2424
Nozzles	/ 32 in	4x20	3x20	3 x 16
TFA	in^2	1.227	0.920	0.589
Jet impact force	lb	947	2143	1722
Bit pressure loss	psi	372	397	702
HSI	HSI	0.756	1.283	3.744

Hydraulics calculations for the 8 ½" hole can/should be optimized so as to not washout hole & to maintain as gauge a hole as possible. Note as well, the above does not include reaming activities after cutting cores. Worse scenarios are shown in the table above.

Appendix C -- Well Plan for GM1

Dedicated Geophone Well Details

Location	Sec 5, T16N,R3E, Macon County, Illinois	
Surface Casing		9 5/8" 40lbf LT&C
	Hole size	12.25"
	Cement detai	Class A, 2% CaCl2
	Float equip	Guide shoe, float collar,
Hole size		8.5"
Mud Type		Fresh gel
TD		3500
Logs		Triple Combo
Tbg run as casing		3.5" 9.3 #/ft, EUE L-80
Cement		Self Stress or Franklin 10-10 FSS
Notes		Run casing head and casing adapter for 3.5 inc
		Land tubing in casing head

Formation tops

		Log
West Franklin	460	460
Renault	1276	1279
Aux Vases	1290	1294
St. Louis	1376	1374
Borden	1529	1530
Burlington - Keokuk	1838	1840
Choteau	2069	2066
New Albany	2086	2085
Devonian	2215	2215
Silurian	2246	2246
Maquoketa	2550	2611
Trenton	2816	2814
Platteville	2945	2945
Joachim	3229	3229
Glenwood	3253	3253
St. Peter	3278	3277
Shakopee	3472	3472
TD	3500	

Drilling Prognosis Geophysical Well # 1

1 Move in and rig up rig.
Rig up closed system for returns. Rain for Rent to supply
2 two de-watering boxes
Spud with 12 1/4 bit and drill surface hole to 355 ft. Eight
joints of 9 5/8" N-80 LT&C casing totaling 375ft will be
3 moved to location
Condition hole to run surface casing and run deviation
4 survey
5 Rig up to run surface casing

Run 9 5/8 casing.Use power tongs to make up casing.
Cement casing with Class A cement,1/4# flake and 2%
CaCl2. Be prepared to take cement returns into steel pit
6 and dilute with water and sugar to haul away.
Nipple up casing head and flange for annular to surface
casing. Casing head will be screw on Larkin style with 10
3/4 " threads for top cap. Screw on adapter flange for
7 11" 3000 psi flange.
Wait on cement eight hours. Cut off casing and nipple
up BOP stack and flowlines. Test surface casing and
8 BOP to 1000 psi.
Drill 8.5 " hole to 3500 ft maintaining directional control
every 400 ft as per rig contract. Take 10ft samples out
from under surface casing to TD. See front page for
9 formation tops.
Condition hole for logging and take deviation survey
10 prior to tripping out of hole.
11 Run triple combo logs TD to surface
12 Trip back in hole and condition mud to run casing
13 Trip out of hole laying down drill pipe
Rig up to run 3 1/2" tubing with geophone array.
Separate running procedure will be provided. Land
tubing so that top collar is eight inches above casing
14 head.

Cement 3 1/2 tubing using Franklin's 10-10 FSS cement
system mixed at 14.2 ppg. Run hole volume based on
caliper log plus 20%. Run 20 bbls mud flush and 50 bbl
water ahead of cement. Displace with fresh water and
bump plug to 500 psi over circulating pressure. Check
15 floats and if holding leave tubing open if floats hold.

Appendix D -- Injectivity Testing Plan

Test Procedure ADM CCS#1

Note: The procedure below was just meant to be a guide to flow of events that will take place. Due to the uncertainty as to how the well will react we can say that the well is to be perfed at 7024-7049 and two VIT holes at 6976, ELAN log depth. Please note that the ELAN must be correlated to the cased hole logs previously run and to the open hole Density log. At least two injection tests will occur, one of which will contain a step rate test to obtain fracturing pressure. The first injection test will also determine if a small 1500 gal 15% HCL clean up acid job will be performed or not. The ultimate outcome of the test will be to determine if the first set of perforations will be adequate or if more perfs are required. After all fluid testing and fall offs are finished a stabilized BHT log will be run as well as a spinner survey while performing a small injection test. All injection fluids will be fresh water with 2 gal/1000 gal. Scott Frailey will; be on location to conduct injection tests starting at noon Thursday.

1. Pick up test packer on 3 ½'' work string with 2 7/8'' x 2.25'' F-nipple just above the packer. Clamp tandem memory gauges to tubing above packer.
2. TIH with 3 ½'' work string to approximately 7000'.
3. Set packer and close rams to isolate annulus.
4. Rig up Schlumberger pumping equipment and ERS lubricator and SRO equipment to well. If possible rig to isolate ERS lubricator without laying down in case acidizing is necessary.
5. Pressure test lines and lubricator to 4000 psi.
6. Lower SRO gauge in well to 10-15' above F- nipple. Run tandem memory gauges below SRO for backup.
7. Fill annulus and pressure to 500 psi. Watch pressure fall off to insure VIT perfs are open.
8. Begin injection down tubing. If a fluid other than fresh water is used then the bypass on the packer will be opened and injection fluid will be spotted to the end of the tubing. Close bypass and establish injection rate of 1- 1.5 BPM while monitoring downhole pressure. Continue to inject until bottom hole injection pressure stabilizes.

Increase rate to 3 BPM while monitoring bottom hole injection pressure and allow injection pressure to stabilize. If bottom hole injection pressure is 4200 psi or greater then prepare to acidize. If lower than 4200 psi then proceed with injection test Step XX.

9. Shut down injection and watch fall off for 30 minutes.
10. Remove SRO from well and isolate in lubricator if possible.
11. Rig to acidize as follows.
12. Pump 500 gallons 3% NHCL4 water with 10% mutual solvent and 2 gal/1000 gal surfactant. Follow with 500 gallons 15% HCL with 3 gal/1000 corrosion inhibitor, 2 gal/1000 surfactant, 100 gal/1000 gal mutual solvent, 10 lbs/1000 gallons iron reducing agent, and 25gal/1000 gallons iron chelating agent. Follow with alternating stages of 3% NHCL4 water and 15% HCL until a total of 1500 gallons of 3% NHCl4 and 1500 gallons of 15% HCL is pumped. Over flush with 1000 gallons 3% NHCL4 and displace to bottom perforation. Start injection rate at approximately 1 BPM and as acid is on the perforations increase rate as possible to stay below 4400 psi bottom hole injection pressure. Shut down and monitor pressure for 30 minutes.
13. Lower SRO assembly back into well as before. Monitor pressure until stable
14. Reestablish injection rate of 1-1.5 BPM while monitoring downhole injection pressure. Begin step rate test by injecting at constant rate for one hour. Increase rate in 1 BPM increments while monitoring downhole pressure. Continue step rate test until fracture pressure is obtained. Shut down and record instant shut in pressure and five minute fall off. Calculate frac gradient. Re-establish injection rate at .25 BPM higher rate than the rate at which fracture pressure occurred. Establish fracture extension pressure and repeat shut and recalculate frac gradient. This will now establish maximum bottom hole injection pressure for the duration of testing.
15. Continue injection at 3.5 BPM for 6 - 8 hours or until pressure is stable. (At this point if injection is deemed to be insufficient additional perforations may be required so test will be stopped and perforation will be added. Test procedure for combined perforations will be substituted from this point forward.)
16. Shut down and record pressure fall off overnight or 12 hours.
17. After 12 hours fall off resume injection at 5 BPM while monitoring downhole injection pressure. Do not exceed the fracture pressure established in previous test. Inject 8 – 12 hours at constant rate.

18. Shut in and record fall off for 48 hours.
19. After shut in is finished rig down test equipment, remove SRO, and release packer.
20. Trip out of hole with tubing and test packer and memory gauges. Recover data from memory gauges. Continue with completion.

Notes: All injection rates are estimates at this time. Actual rates and pressures will depend on well conditions encountered. This procedure is meant to be a framework for the test with actual detailed steps established as information is garnered at each step.

Fluid to be pumped will be fresh water with 2 gal/1000 gal B – 292 Clay Stabilizer.

Appendix E -- Completions Plan for CCS1

Phase 1 Completion Procedure ADM CCS #1

1. Move in completion unit. Hold ½ day safety orientation meeting with all personnel at site. Continue to rig up completion unit and nipple up adapter spool and BOPs. Rig up support equipment and off load work string. Spot xx frac tanks.
2. Pressure test BOP and Casing to 1700 psi
3. Pick up 8.5'' bit and two casing scrapers. Pick up and tally 3 ½ '' 9.3# EUE N-80 work string.
4. Trip in hole to +/- 7130 PBTD. Circulate hole clean with 9.5 ppg brine. Change to fresh water.
5. Trip out of hole standing back work string.
6. Swab well down 1500 feet surface.
7. Rig up Schlumberger to well. Make a temp/ gauge ring run into well
8. Go in hole with xxx perforating gun and perforate interval xxx using xxx charges with .xxx entry hole. Lay down perforating gun and check shots.
9. Rig pump to well. Pump 25 bbls. Completion brine while keeping injection pressure at 1000 psig or below. (Optional)
10. Pick up Team treating packer and trip in hole on 3 ½'' tubing. Run 2.25 X 2 7/8 F- nipple one joint above packer. Have ret BP on location.
11. At this point well will either be acidized by following a separate procedure or be ready for injection testing using the separate testing procedure. If a VIT test is to be performed a separate procedure will follow but that test will be conducted at this time as well. Plan to acidize.
12. After monitoring fall off pressure open by pass on packer and circulate well with completion brine.
13. Release packer and trip out of hole.
14. Pick up Quantum lower completion and trip in hole on 3 1/2 '' work string. Gauge ring may not be required depending upon OD of test packer.
15. Set packer at xxx. Test annulus to 1000 psig and record. Quantum setting procedure on separate document.
16. Pull above Quantum and circulate hole with final completion brine. Recipe to follow. Leave 100 bbls completion brine in frac tank on location.
17. Pull out of hole laying down 3 ½'' work string.

18. Rig up slick line and set X blanking plug with memory gauge carrier and two memory gauges below plug in 3.313X nipple in lower completion. Rig down slick line, nipple down BOPs and install tree cap.
19. Move out all equipment.

Notes:

This is probably not the final but gives a good plan of the work flow and what will be accomplished in Phase 1 of the completion.

The density of the completion brine will be reviewed and modified after additional pressure data is obtained..

The cement evaluation showed that the cement job was good and that PBTD was adequate to proceed with the completion without further intervention.

The PMIT and USIT both showed the interior of the casing to be very clean with no cement film therefore a regular casing scraper run should be adequate.

The temperature log on the RST was abnormally low at 122 F and does not match the open hole temperatures recorded therefore an additional temperature run will be required. A wireline gauge ring can be run at this time.

The Les Wilson completion rig has a 225,000 lb rated derrick that was last inspected two years ago. Derrick is down rated to 164,000 lbs.

Acidizing plan if needed is developed in separate document

Matrix Acidizing

Company: Schlumberger Carbon Services

Well Name: ADM CCS #1 1

Field:

County:

State: IL

Date: 9/10/2009

Well Location:

API Number:

Proposal Number: 1

Contact: Mr. Jim Kirksey

Made By: Robert Holicek

Service from District: Inez, KY

District Phone:

Objective: Contingency for acidizing the desired CO_2 injection interval.

Schlumberger

EXECUTIVE SUMMARY

Enclosed are our recommendations for Schlumberger intervention on the referenced well. The proposal includes well data, design data, materials and resources requirements and cost estimates. The purpose of our services is to perform a Matrix Acidizing treatment.

Schlumberger has established a safety policy to which all Schlumberger personnel must adhere. A pre-job safety meeting will be held with customer representatives and other on location personnel to familiarize everyone with existing hazards and safety procedures. We would appreciate close cooperation between the customer representative and the Schlumberger representative to ensure a safe operation.

The estimated total cost of our services is **$ 52,780.70**.* All costs are estimates only. Actual costs will be determined by time, material and equipment used during treatment. Taxes are not included. All work will be subject to Schlumberger then-current General Terms and Conditions or to the terms and conditions of a Master Service Agreement if one is in force between Schlumberger and Customer. This quote is valid for a period of thirty (30) days from the date submitted.

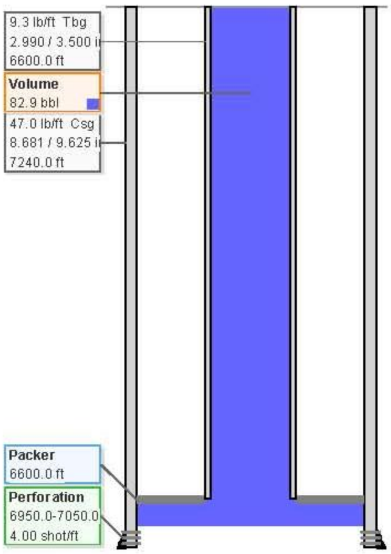
Thank you for considering Schlumberger.
Please do not hesitate to contact me with any questions or concerns.

Sincerely,

Robert Holicek
281 285 1950
rholicek@slb.com

*This value is book price for materials only. Equipment and personnel requirements need to be confirmed with the actual service district.

WELL DATA



Casing

OD	ID	Top Depth	Bottom Depth	Weight	Grade
9.625 in	8.681 in	0.0 ft	7240.0 ft	47.0 lb/ft	P110 13Cr

Tubing

OD	ID	Top Depth	Bottom Depth	Weight	Grade
3.500 in	2.990 in	0.0 ft	6600.0 ft	9.3 lb/ft	N80 13Cr

Packer

OD	ID	Depth
8.681 in	3.500 in	6600.0 ft

Perforations

Treatment Interval: 100.0 ft

Top Depth	Bottom Depth	Shot Density
6950.0 ft	7050.0 ft	4.00 shot/ft

3

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BACKGROUND INFORMATION

This proposal is for an acid treatment in a CO_2 injection well. The proposal is based on the reservoir data provided and represents a best-recommendation considering the information provided. When pursuing any acid stimulation the following factors should be considered:

- Formation damage
- Treatment fluid selection & schedule
- Interval coverage/Placement Technique
- Flowback & recovery of treatment fluids

Each of these aspects has special consideration for the subject well, and will be covered as follows.

FORMATION DAMAGE:

Formation damage can be from several sources such as polymers from gelled-fluids, scale, organic deposits, migrating fines, emulsions, bacterial slime, etc. The potential formation damage to be treated in this well is a combination of **carbonate** and **polymer** material present from the drill-in fluid (DIF). Other formation damage types are ruled out, or considered minor for the following reasons:

1. Fines migration is not considered because the reservoir sand has an extremely low clay content (99.4% Quartz+Feldspars) and also the well has not produced therefore fines migration is extremely unlikely
2. Organic deposits are not consired because the injection interval is a salt-water bearing formation.
3. Emulsions are not considered because there should be no hydrocarbon-water interactions in this water-bearing formation
4. Bacterial slime is not considered assuming proper bacteriacides/biocides have been used in the drilling and completion fluids
5. Scale is of moderate concern because it is a saline formation, however a treatment aimed at carbonate and polymer damage inherently will also treat scale.

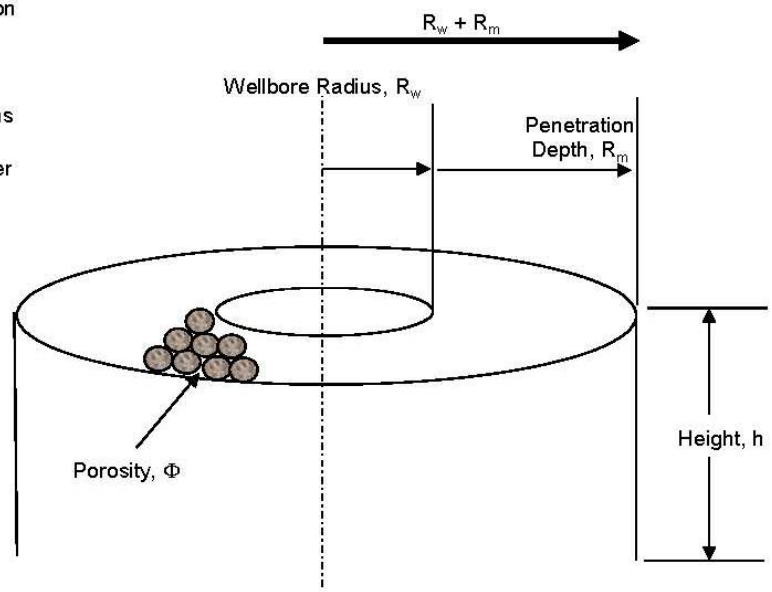
FLUID SELECTION:

The treatment fluid needs to be reactive enough to dissolve the damage, but mild enough not to cause damage to wellbore tubulars or aggravate sensitive minerals in the reservoir. Carbonate and polymer damage will be easily dissolved by a **15% hydrochloric acid** system. The reservoir is not known to contain any HCL-sensitive minerals (zeolites) and the bottomhole static temperature of 140 °F is well within limits of corrosion inhibition for the 13Cr wellbore tubulars. Prior to injecting the HCL, it is a good practice to use a breakdown or pre-flush of brine such as 4% Ammonium Chloride (NH_4Cl) to ensure injectivity into the reservoir before introducing acid into the wellbore and to provide a spacer between the reactive fliud and the initial wellbore fluids. The resulting fluid schedule would be:

- Preflush of 4% NH_4Cl
- Main Fluid of 15% HCl
- Displace to perforations with 4% NH_4Cl (over-displacing is acceptable)

The fluid volume must be sufficient to treat the depth of damage around the wellbore. Because drilling-related damage is considered the primary type, the damage is assumed to be concentrated near-wellbore, or approximately within the first half-foot of radial depth around the well. The treatment volume to penetrate 6-inches radially is easily calculated given the porosity, and open-hole diameter as illustrated below;

Interval Height	1	ft
Porosity	0.23	fraction
Penetration Depth	0.5	ft
Wellbore Radius	0.5104	ft
Pore Volume	**8.28**	gallons
	0.20	bbls
	from OH diameter	



$$\text{Volume} = \pi * [\,(R_m + R_w)^2 - R_w^2\,] * h * \Phi \quad \times 7.4805\ \text{gal/ft}^3$$

This is the volume required to treat a desired distance, Rm, around the wellbore given the zone height, h; the porosity, Φ; and wellbore radius, Rw.

A treatment volume of 8.3 gallons/foot will result in a 6-inch penetration and should dissolve the near-wellbore drilling damage. For 100-feet of perforated interval, the minimum treatment volume will be 100 x 8.3 or 830 gallons. This is the *minimum* recommended value and larger volumes will be advantageous in the event that damage exists deeper than 0.5 feet, or that the treatment is not distributed evenly throughout the interval. Using the above schematic, radial depths of treatment are calculated for different gallons/foot. To treat 1-foot deep instead of 0.5 feet will call for 20 gallons/foot, or 2000 gallons of acid.

gal/foot	radial depth
10	0.60
15	0.86
20	1.10
25	1.31

2000 gallons of 15% HCl is recommended to allow for treating 2x deeper than the assumed damage for contingency. Additionally, placement simulations show that once acid contacts the formation, there is a chance that more acid will preferentially enter one section of the interval, and won't uniformly contact all 100-feet of perforations. This can be mitigated by pumping either more volume of acid, pumping high injection rates, or by using diversion which will be discussed in the next section.

In addition to fluid type and volume, the fluid must contain an additive package that promotes good fluid penetration and prevents undesireable effects such

as tubing corrosion, iron precipitation, or emulsions. Additives commonly used are:

Additive Type	Description	Schlumberger Product to Be Used
Corrosion Inhibitor	Used to protect the tubulars against acid.	A264
Surfactant/wetting agents	Used to lower capilary forces and interfacial tension between treating fluids and reservoir fluids to improve penetration	F103 F100 if foam diversion is used
Mutual Solvent	Is a multi-functional additive that acts as a solvent for both water-soluble and hydrocarbon-soluble materials, it also reduces surface tension, leaves materials water-wet for better reaction with the acid	蕱•蓢•蔆Iron control agents
Iron control agents	To prevent iron compounds from precipitating in the wellbore, or pore space. There are two types: 1) Reducing agents that convert a highly reactive Ferric (Fe^{3+}) ion to the less-reactive Fe^{2+} ion and 2) iron chelanting agents that bind the iron and prevent it from contacting ions with which it can precipitate. Treatment acids should contain both reducing agents, and chelating agents	L58 – Iron reducing agent U42 – Iron chelating agent

INTERVAL COVERAGE/PLACEMENT TECHNIQUE

As fluids enter the reservoir, they will tend to take the path of least resistance. They will enter the most-permeable streak first, and there is always a chance that one particular section of the reservoir will be treated more than another. This is frequently prevented by using placement methods such as coiled-tubing to reciprocate back-and-forth as fluids are injected; mechanical methods such as a dual-packer to bracket reservoir sections one at a time; chemical methods such as foams or bridging agents that temporarly reduce permeability to allow balanced injection profiles; or mechanical sealing of the perofrations with ball-sealers that seat in the perforation hole where the most fluid is entering. For simplicity of operation and logistics, coiled-tubing, or the dual-packer placement techniques are not considered. Instead, interval coverage can be accomplished with either 1) increased fluid volume 2) foam diversion, 3) particulate bridiging agents (benzoate salt flakes) 4) ball-sealers. This proposal focuses on **fluid volume** and **foam** as diversion options. Particulate salts are not considered because the need for prolonged exposure to injected water to dissolve them after placement. Ball sealers are an option but require ball-injector equipment and a brief flow back period after acid placement to ensure they un-seat from perforations, and fall to the bottom of the well; this added step introduces complexity when compared with simplicity of foam as a diverter.

A reservoir model was input into StimCADE with the average mineralogy, as well as the expected treatment fluids to predict which sections of the interval will receive the most treatment fluid. To simulate variation of permeability in the reservoir, the 100-foot zone was divided into five 20-foot sections, with permeability alternateing between 120 mD, and 80 mD.

Each of these techniques (volume and foam diversion) is simulated in the fluid placement simulator StimCADE* (Stimulation Computer Aided Design and Evaluation) to show that each method will achieve desired performance.

Placement Results Without Diversion

StimCADE output showing radial penetration of the treatment fluid by layer in the reservoir model. The yellow is the NH4CL preflush, and the blue is the 15% HCl. The fluids take the path of least-resistance, so the top of the reservoir is treated more than the bottom; however the radial penetration of the acid is ~0.4 feet in the lowest zone. The damage was assumed to be
0.5 feet deep around the wellbore.

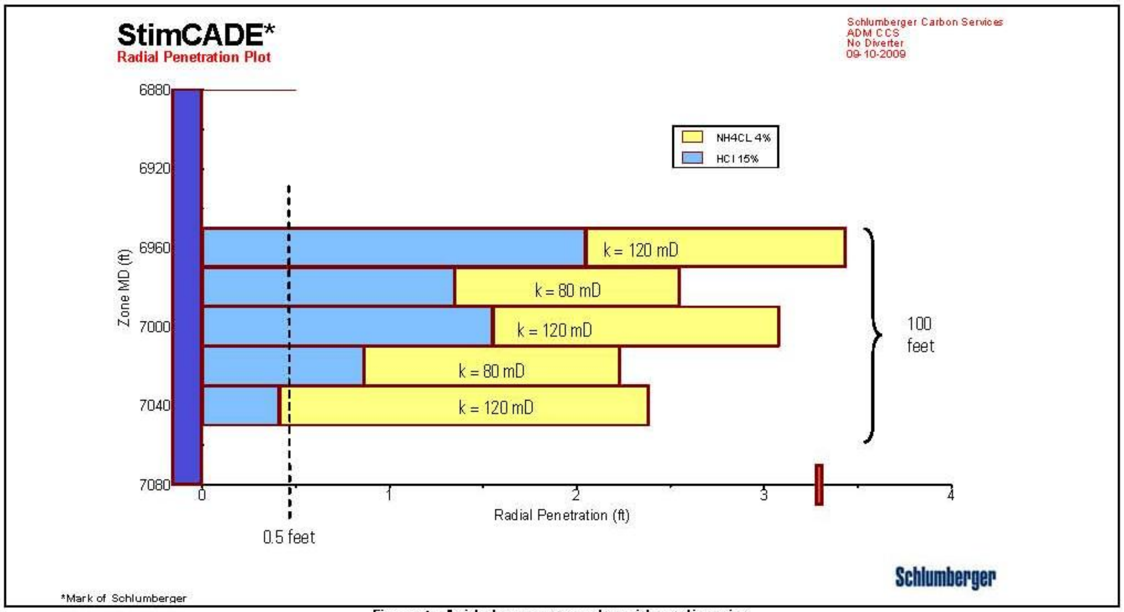


Figure 1: Acid placement results without diversion

In addition to zonal coverage, it is important that the frac-pressure is not exceeded during acid injection. The goal of the acid stimulation is to radially penetrate the rock matrix, if a fracture is created, it will likley 'steal' the treatment fluid and result in poor radial coverage. The

placement model also predicts the bottomhole injection pressures during placement. The placement model shows that for an initial injection rate of 0.7 BPM the bottomhole pressure is just below the frac pressure. As the HCL arrives at the perforations, the rates is increased to 2 BPM, which temporarily exceeds frac pressure, but decreases as the acid removes damage and increases injectivity. Procedurally, in the field it will be wise to start injection at approximately 0.5 BPM while closely monitoring the pressure response, and incrementally increase the rates to 2.0 BPM or more as the pressure allows. The surface treating pressure that corresonds to frac pressure is approximately 1800 psi. This should be set as the maximum allowable surface treating pressure.

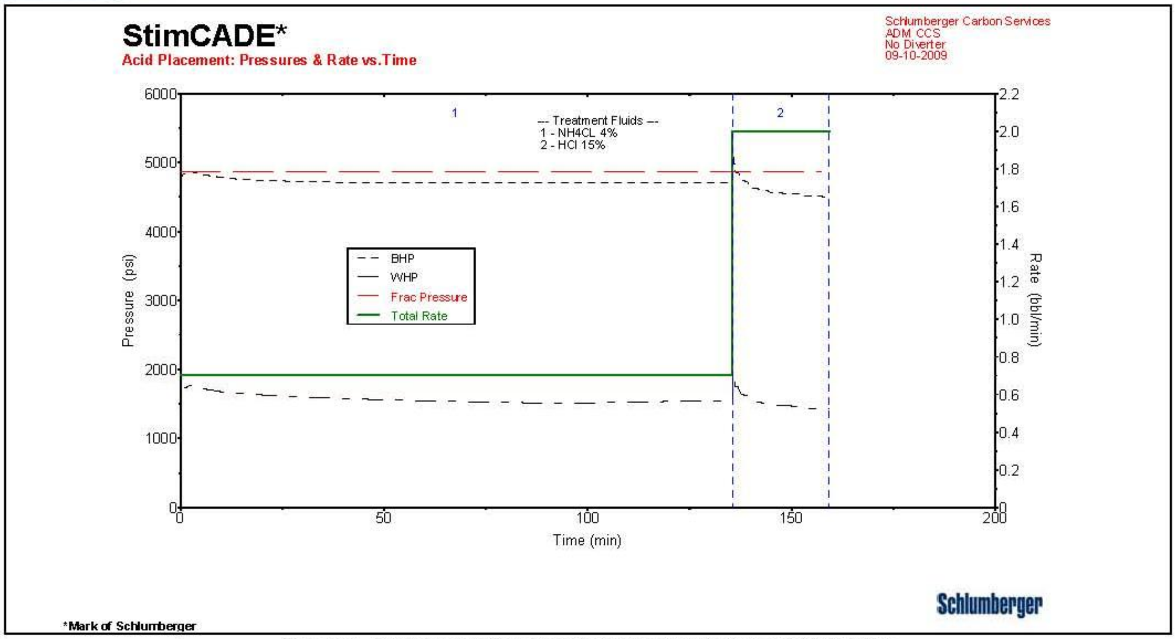


Figure 2: Surface and Bottomhole pressures during acid injection

Placement Results With Foam Diversion

Foam can be used as a diverting agent. As foam enters the most-permeable layer, its two-phases and increased viscosity temprorarily reduces the relative permeability to the acid, which serves to balance the injection profile and force acid to begin entering the next most-permeable layer. To use foam diversion, the entire 2000 gallon treatment volume is divided into stages, each is separated by a slug of foam. Generally one diverter stage per 20-feet of perforations is used, so for this treatment there are 5 foam stages, and 6 HCL stages. In this case the schedule will be:

- 500 gallons NH4CL preflush
- 333 gallons HCL
- 280 gallons (downhole volume) of 70 quality foam (70% gas, 30% liquid)
- 333 gallons HCL
- 280 gallons (downhole volume) of 70 quality foam (70% gas, 30% liquid)
- 333 gallons HCL
- 280 gallons (downhole volume) of 70 quality foam (70% gas, 30% liquid)
- 333 gallons HCL
- 280 gallons (downhole volume) of 70 quality foam (70% gas, 30% liquid)
- 333 gallons HCL
- 280 gallons (downhole volume) of 70 quality foam (70% gas, 30% liquid)
- 333 gallons HCL
- Displace with ~85 bbls of brine

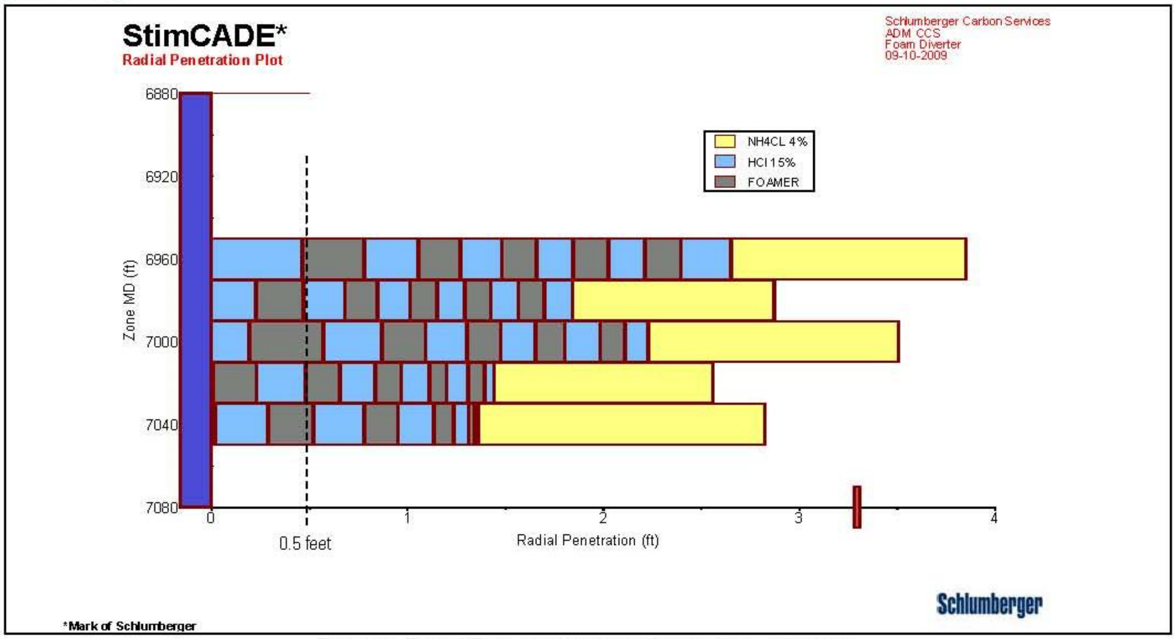


Figure 3: Radial fluid penetration using foam as a diverter.

The placement of acid extends beyond 1-foot from the wellbore when using foam diverter stages. The the surface pressures will be affected by the reduced hydrostatic of foam in the wellbore, but the rates shuold be managed similarly to the non-diverter case. Begin injection at a low rate ~0.5 BPM, and ramp up the rate as the pressure allows. The maximum allowable surface pressure with foam stages in the wellbore will be ~2500 psi. Total rates (liquid + N2) of around 2 BPM should remain below frac pressure.

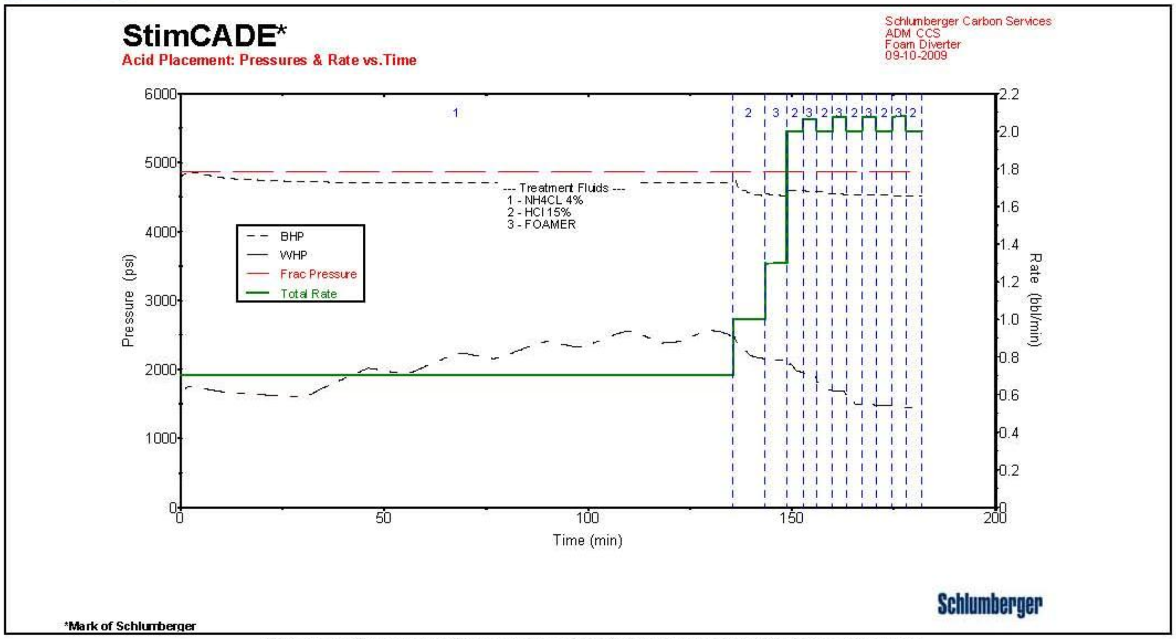


Figure 4: Rates and Pressures while injecting acid with foam diverter.

FLOWBACK AND RECOVERY OF TREATMENT FLUIDS

In producer wells it is good practice to flow-back the treatment fluids as soon as possible to minimize risks of precipitation, corrosion, and sensitive minerals. Because this is an injection well, no flow-back after the acid injection will be necessary. Once the treatmetnt is finished, injection can commence as soon as practical. Quick injection following the treatment will serve to over-displace spend acid out into the reservoir and away from the near-well region where prolonged contact can promote additional damage.

SUMMARY

Until the well is drilled, and an injection is attempted, it is not known whehter there will be damage present, however if damage is encountered it will most-likely be a combination of carbonate and polymer material from the drilling fluids. These solids should be easily dissolved by a 15% hydrochloric acid system. A total of 2,000 gallons of acid with brine preflush is recommended to ensure adequeate radial depth of treatment and interval coverage. Without diversion, placement models show a preferential treatment of the top of the reservoir, and most permeable layers. Interval coverage can be improved with foam diversion; this increases the radial depth of treatment in the lower part fo the zone from 0.4 feet, to more than 1-foot deep around the wellbore. After injecting the acid, it can be over-flushed with brine, and injection can commence as soon as practical.

Following is the well information and material requirements for the treatment without diversion, and the treatment with foam diversion.

PROCEDURES

1. MI (Move in) Schlumberger equipment.
2. Conduct Rig-up, Prime-up and pressure test safety meeting.
3. RU (Rig up) Schlumberger equipment and pressure test to customer master valve.
4. Conduct pre-job safety meeting.
5. Perform treatment per design pumping schedule and instructions of client representative.
6. Conduct post job rig down meeting.
7. Rig down Schlumberger equipment.
8. Conduct convoy meeting and move out Schlumberger equipment.

Option 1: PUMPING SCHEDULE-No Diversion

Stage	Fluid Name	Liquid Volume gal	Liquid Rate bbl/min	N2 Volume Fraction scf/bbl
Breakdown	NH4Cl 4.0	500	0.7	
Main Fluid	HCl 15.0	2000	2.0	
Displacement	NH4Cl 4.0	3482	2.0	

Total Liquid Volume:	5982	gal
Total Water Volume:	4442	gal
Total Nitrogen Volume:	0.0	Mscf
Total Pump Time:	82.3	min
Expected Treating Pressure:	2000	psi

Option 1: MATERIALS SUMMARY-No Diversion

Treating Fluids

Fluid Description	Additives		Quantity
NH4Cl 4.0	U066 F103	100.0 gal/mgal 2.0 gal/mgal	3982 gal
HCl 15.0	A264 U066 F103 L058 U042	3.0 gal/mgal 100.0 gal/mgal 2.0 gal/mgal 10.0 lb/mgal 25.0 gal/mgal	2000 gal

Some of the chemicals specified in this program have toxic properties. All personnel should be familiar with the inherent dangers and appropriate safeguards to prevent accidental injury. Use of the chemicals may be governed by certain laws and regulations and should only be used in accordance with such. Please refer to the MSDS sheets for the recommended safety precautions and required minimum personal protective equipment.

Option 2: PUMPING SCHEDULE – Foam Diverters

Stage	Fluid Name	Liquid Volume	Liquid Rate	N2 Volume Fraction
		gal	bbl/min	scf/bbl
Breakdown	NH4Cl 4.0	500	0.7	
Main Fluid	HCl 15.0	333	2.0	
Diverter	Foamer	84	2.0	3200
Main Fluid	HCl 15.0	333	2.0	
Diverter	Foamer	84	2.0	3200
Main Fluid	HCl 15.0	333	2.0	
Diverter	Foamer	84	2.0	3200
Main Fluid	HCl 15.0	333	2.0	
Diverter	Foamer	84	2.0	3200
Main Fluid	HCl 15.0	333	2.0	
Diverter	Foamer	84	2.0	3200
Main Fluid	HCl 15.0	333	2.0	
Displacement	NH4Cl 4.0	3482	0.0	

Total Liquid Volume:	6400	gal
Total Water Volume:	4872	gal
Total Nitrogen Volume:	32.0	Mscf
Total Pump Time:	45.8	min
Expected Treating Pressure:	2000	psi

Option 2: MATERIALS SUMMARY – Foam Diverters

Treating Fluids

Fluid Description	Additives		Quantity
NH4Cl 4.0	U066 F100	100.0 gal/mgal 0.0 gal/mgal	3982 gal
HCl 15.0	A264 U066 F100 L058 U042	3.0 gal/mgal 100.0 gal/mgal 0.0 gal/mgal 10.0 lb/mgal 25.0 gal/mgal	1998 gal
Foamer	F100 J285	2.0 gal/mgal 333.3 lb/mgal	420 gal
Nitrogen			32.0 Mscf

Some of the chemicals specified in this program have toxic properties. All personnel should be familiar with the inherent dangers and appropriate safeguards to prevent accidental injury. Use of the chemicals may be governed by certain laws and regulations and should only be used in accordance with such. Please refer to the MSDS sheets for the recommended safety precautions and required minimum personal protective equipment.

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4

UPPER COMPLETION INSTALLATION

THE SECTION BELOW IS TO BE INCORPORATED INTO THE MASTER COMPLETION PROGRAM FOR SCHLUMBERGER CARBON SERVICES.

Ensure all completion equipment for running production tubing is on location.

Prepare equipment for downhole permanent gauge installation:

1. Position Workstation as far as possible from the V-door, keeping a reasonable distance to spot the 2 spoolers between the workstation and the V-door. If possible rig visit should be mandatory considering this being the the first time that we are working on a land rig in Illinois, a rig site visit can determine the appropriate layout for Schlumberger equipment.
2. Spot spoolers next to the Workstation having the Neon line spooler as close as possible to the workstation.
3. Prepare the collector for the Neon line spooler and run the electric surface cable from the Neon spooler to the workstation, passing the cable through areas were equipment or people will not damage the surface cable and using caution tape to prevent anybody from stepping or damaging this cable.
4. Note: need a grounding bar for the spooler (typical on land installations) for the spooler which is typically common on land installations.
5. All the monitoring equipment for the NDPG gauge will be set up in the workstation, and a proper electricity connector should be found in the pipe deck area, but consult the rig electrician before connecting any power to the workstation.

   Note: Properly ground the workstation using a ground bar or similar
6. Use the proper explosion proof connector for the electricity of the workstation and also use caution tape to bring the awareness to the people working in the area.

Caution

Be aware of crane operating and any other operation while rigging up, proper JSA should be review before starting with any rig up operation

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7. The following layout is suggested:

- Gauge Cable (next to the workstation)

Rig visit(RV) is mandatory and pictures from the RV should be use as a reference

Refer to the step below for insulation and continuity check.

Warning

Be sure that no gauge is connected to the cable or any electronic device is attached to it when using MEGGER

Insulation Check

Location:	Between conductor & sheath.
Test voltage:	500 VDC
Acceptance Criteria:	>999 M-Ohms @20DegC

Continuity Check-Conductor

Location:	Between the conductor at cable drum end and conductor at point of connection for cable head.
Acceptance Criteria:	6.91 Ohms/1000ft maximum @20DegC

Continuity Check-Sheath (tube)

Location:	Between tubing at cable drum end and tubing at point of connection for cablehead.
Acceptance Criteria:	21 Ohms/1000 ft nominal @20DegC

Fiber Optic Line Check

Use OTDR to check DB loss.

8. Prepare Neon line for termination to the NDPG gauge (Part # P500897) following the NDPG procedure, ITT 4304515 and Diamould Sealtite Cablehead for NDPG using Neon Gems Document # 100458221 (to be updated with Phase 2 document provided by SRC) and test insulation and continuity prior to makeup to gauge.
9. Bench test the gauge and record results.
10. After a successful bench test, proceed to pressure test gauge to 10,000 psi following the NDPG procedures (to be witnessed by the client or rep).
11. Bench test the gauge and record results.
12. Prior to running the completion, rig up the Schlumberger Multi-line sheave wheel to the rig floor. Hang it using the slings and the air hoist, keep it in the rig floor to pass all the control lines, considering the position of the lines set in the Cannon clamps (and rig it up at the derrick making sure to include 2 slings with the proper shackles.

   Note: We need to have clamps sent to the location so that we can perform a clamp fit test.

13. Attach sheave wheel slings by wire rope to a suitable point on the derrick such as the top of the 'A' frame or the cross bar. Tie off the sheave with soft line to ensure it does not spin in high winds. This operation requires careful coordination to avoid damaging the Neon line and NDPG gauge that is fed through the sheave wheel prior to lifting (if possible).

1. Example of the common position of the sheave wheel hanging in the derrick

14. Note – Break up the multiline sheave wheel shown below into individual sheaves. Verify the safety pins are inserted. Each sheave must be secured with a backup sling.

2. Example of Multi-line spooling sheave wheel

15. After all the running in hole equipment is properly rigged up, pick up the production seal assembly, 4-1/2" 12.6 # JFE Bear 13 Cr Tubing and jewelry according to the schematic.

Note: Some of the following operations may seem tedious and time consuming as rig activities are suspended (such as during the installation and testing of cable at the tubing hanger on the rig floor). However, it is critical to the long-term reliability of the permanent downhole gauge system that these operations are carried out carefully and correctly. Do not unduly rush these operations.

16. Make up solid gauge mandrel (SGM) sub-assembly to the tubing string using proper torque values. Make up one joint above this gauge mandrel assembly to ensure a good torque chart before securing the gauge to the mandrel. Pull back one joint and orient mandrel so that the gauge, once installed, will face the spooler unit. If possible set the slips below the SGM around the pup joint to prevent axial movement. The SGM accommodates a single NDPG gauge.
17. Cover the well protecting the rotary table from any tools that could fall down into the well bore. Remove all protective caps and bolts to make up the NDPG gauge to the gauge mandrel, following the operating manual.
18. Proceed to install the permanent gauge in SGM / Tubing string following the procedure outlined in ITT # 3012817.

Warning

Be sure that the gauge is switched off via the ASU and no current or voltage is supply before the gauge is made up to the mandrel

19. Make up the appropriate NDPG connection at the lower tip to the mandrel and the gauge. Ensure the proper torque is applied. See copied and pasted info from ITT # 3012817 procedure below:

Axial Connection – NDPG and NLQG

Prior to installing the gauge on the mandrel, make sure the toolbox is ready and the spooler free to move, as stated in section .

1. Inspect the lower connection and particularly the sealing O'ring (B013339) (see Figure 3-12 NLQG/NDPG Lower Tip with Sealing O-Ring).

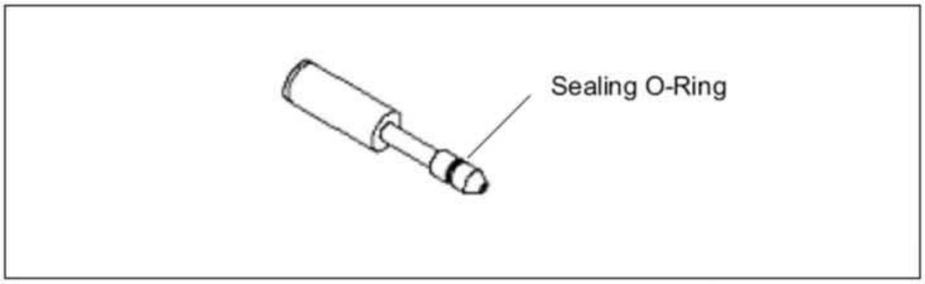


Figure 3-12: NLQG/NDPG Lower Tip with Sealing O-Ring

2. Grease O-ring with Lubriplate®.
3. Put a small amount of Lubriplate® on split nut threads.
4. Install the split nut P/N 100258316 onto the gauge lower tip as shown in Figure 3-13 Split Nut and Gauge Lower Tip.

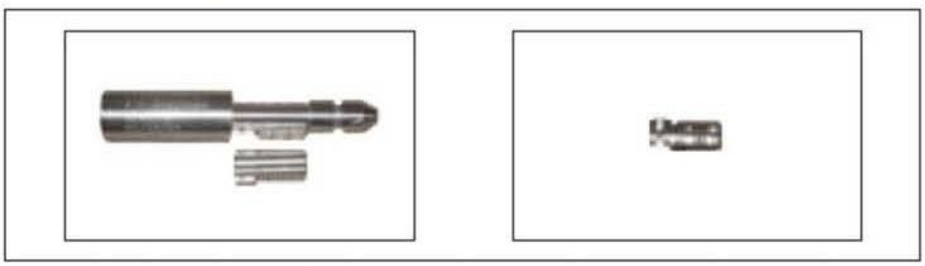


Figure 3-13: Split Nut and Gauge Lower Tip

5. Insert the gauge into the gauge pocket.

6. Screw the split nut on the lower connector into the flange block.
7. Torque down the split nut at 25 ft.lb +/- 1 ft.lb (34.5 +/- 1.5 mN).
8. The final connection as shown in Figure 3-14 NLQG/NDPG Final Connection for Pressure Test is ready for pressure test.

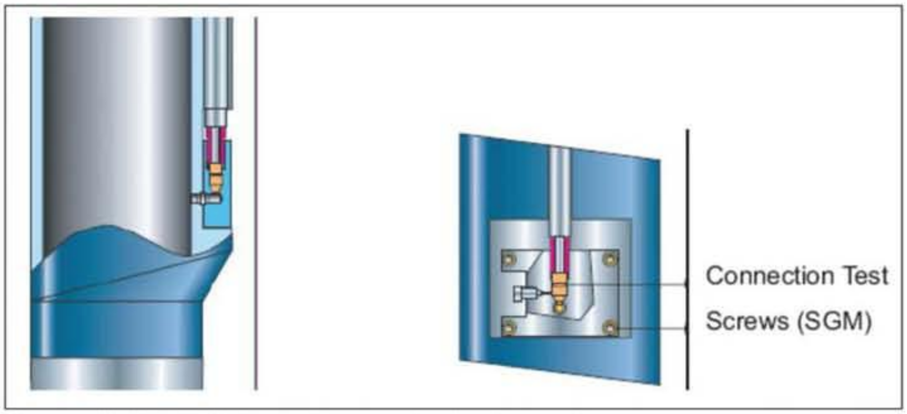


Figure 3-14: NLQG/NDPG Final Connection for Pressure Test

20. Insert the cable in guide at the top of the mandrel and make up all the screws.
21. Make-up all the screws and perform pressure test following the SLB recommendation at 7,640 psi for 15 min (this pressure will have to be chart recorded and witnessed by the client or rep).
22. While the pressure test is performed, switch on the gauge using the Soloconn in the workstation and check data readings, gauge voltage / current and log into the installation report.

Pressure & Temperature
Acceptance criteria: Data readings for Pressure and Temperature should equal to atmospheric pressure and temperature. Make sure that the gauge is reading real values, ambient pressure and temperature.

Note: Due to the mode of signal transmission (digital simplex FSK), the line voltage fluctuates by ± 2 vdc.XXXX criteria for (I, V) i.e. do not expect to measure a steady voltage.

23. Install a centralizer clamp (100615564) on the first connection made on top of the gauge mandrel sub-assembly (between the pup joint on top of the mandrel and the 1st full tubing

made up to the gauge mandrel assembly or the next joint above). Do not put a clamp right between the upper pup joint and the solid gauge mandrel.

24. Continue RIH with minimal tension applied in the Neon line spooler for 3 to 4 full joints, installing the centralizers (Qty 2, 100615564) and eccentralizer (Qty 1, 100578013) per PS3 requirements/ RIH procedure.
25. Run production tubing and test the completion assemblies.

Note: The utmost care should be taken by the driller and his crew to ensure that the downhole instrument cable is not damaged.

A Schlumberger operator will be on the rig floor at all times during the running of the tubing, and His/Her responsibilities are to supervise Clamp installation and cable tension.

A Schlumberger operator will control the spooler unit on the pipe deck and monitor gauge signal output.

REFER TO PS3 INSTALLATION PROCEDURES.

26. After every joint is properly torqued, continue installing the clamps on every coupling. Make sure that the slips are fully open before any line is pushed against the tubing, and cover the well hole with a proper tarp or special protection before the Clamp is installed.
27. The following list describes the P/N of the clamps to be used at each tool that will be installed on the completion string – Refer to Uwe's Tubing Tally attached in the Appendix and check with Uwe for the latest Tubing Tally. Also, refer to PS3 installation procedures.

Item	Location	P/N	Quantity
A	Refer to Uwe's Tubing Tally – Above Last Centralizer	4500-A-06	90 out of 100
B	Refer to Uwe's Tubing Tally	4500-A-63	31 out of 40
C	Centralizer – Refer to Uwe's Tubing Tally	100615564	22
D	Eccentralizer 47# & 40# - Refer to Uwe's Tubing Tally	100578013	17

Caution

Ensure that the lines are run straight and there is no slack cable between the clamps/ protectors. Proper tension should be kept in the spooler at all times.

28. Cable clamps should be installed at each connection using the proper installation kit and tools.

Note: SLB engineer should inform the driller and company representative of the numbers and type of cable clamps installed at the end of the job.

29. Check the signal from the gauge every 10 joints or every hour until gauge mandrel is at well kick off point and every 4 joints or every 30 minutes thereafter. This check takes a few minutes to perform. The pipe should be stationary during the test. Furthermore, the integrity of the fiber optic line can be checked with the OTDR every 1000'.
30. Record and report this test.
31. If the gauge signal is lost or the OTDR shows any discrepancy (include criteria), stop running in hole, troubleshoot the surface system and pull back to find problem and splice cable if necessary.
32. Always discuss with company man and FSM when the RIH operations are stopped for more than one hour regarding a problem with the downhole gauge.
33. Following the completion diagram, assist the PS3 personnel to make up the PS3 equipment to the completion string.
34. Reference PS3 running procedures. The PS3 Personnel are responsible for running their equipment. They may be aided by SLB RMC.
35. Refer to PS3 procedures for any pressure tests related to the PS3 control lines since this will be done using the spoolers.
36. Continue running in the hole installing one cross coupling Clamp on every joint.

Terminating the Control Lines & Neon cable to the Tubing Hanger

37. See attached in Appendix what Paul has sent regarding the tubing hanger.
38. Shoot an OTDR and TDR trace for both the conductor & the fiber.
39. Cut cable at least 15 feet above tubing hanger, remove encapsulation (Check any HSE issues with round encapsulation) and aid T3 to pass the control line through the tubing hanger. T3 will supply the necessary fittings for the tubing hanger.
40. After passing the neon cable, check voltage/current and frequency reading from the gauge at the cable on topside of tubing hanger.
41. Shoot an OTDR and TDR trace for both the conductor & the fiber.
42. Aid T3 to make up fittings to the tubing hanger following their appropriate procedures.
43. Splice the downhole cable back to the spooler unit so that you can monitor the gauge (electrical only) signal during landing out the tubing hanger. Do not use EDMC-R for this purpose.check that the splice is not put too low (check in procedure that you have at least 30" XX check this number)
44. RIH with Tubing Hanger as per client wellwork procedures however make sure that no damage can occur to the downhole splice during this critical operation. Continue to monitor the gauge during this period.
45. After landing the tubing hanger, proceed to remove BOP stack ensuring no damage to the neon cable. Ensure that at least two persons are available to carry out this operation.
46. Run through termination procedures so that each person is clear on appropriate actions during the process.
47. Collect necessary tools for the termination of the Neon cable at the wellhead.

48. Clean neon line exit port in the tubing spool.
49. Remove the splice using a file to cut the neon line just below the splice tube.

ROUTE NEON LINE IN TUBING HANGER

50. Slowly make a 45° bend in the cable just above the top of the tubing hanger in the needed direction around the spool (see diagram 4). This can be done by hand or with the cable-bending tool, but in both cases it must be done slowly, to ensure that the cable is not damaged.

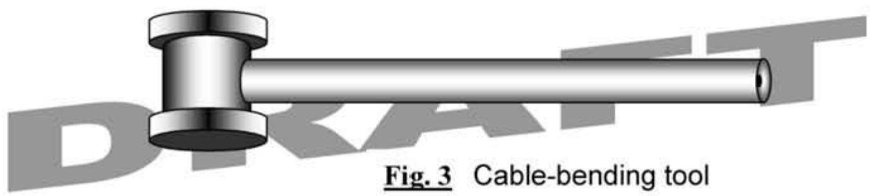


Fig. 3 Cable-bending tool

51. While one person continues to hold onto the special cable clamp, make a slight bend (20° to 30°) about 6 inches from the dressed end of the cable (see Fig. 4). This bend should be made by the second person, and once again it should be done slowly in order to avoid damaging the cable.
52. Slowly bend cable over so that it forms a high loop and pass the end through the neon line exit port in the tubing spool. One person should keep holding the control line at the fitting while the second performs this operation.

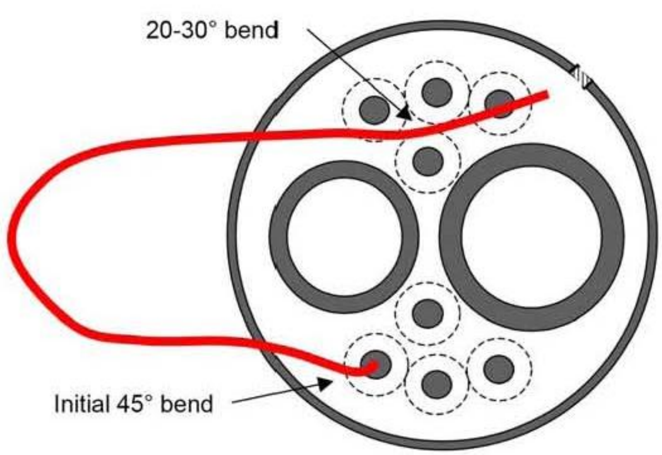
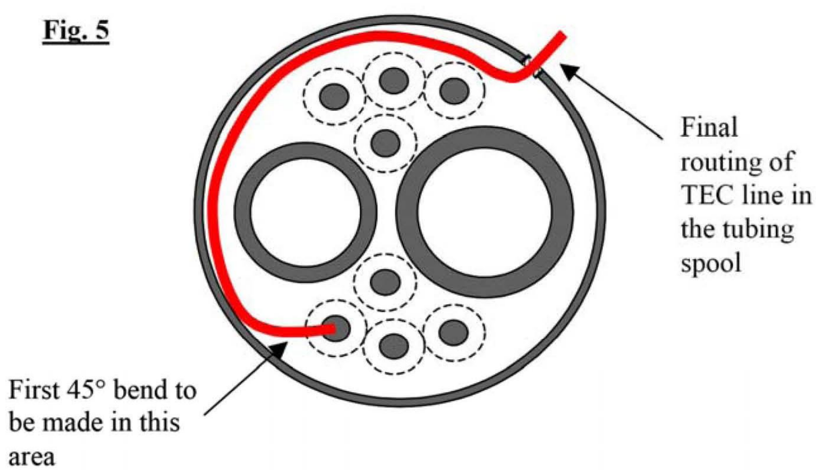


Figure 4

53. Once the cable is inside the exit port, one person must go around to the other side of the tubing spool to guide the cable as it comes out of the exit port.
54. The person on top of the tubing spool must now continue holding the control line at the fitting while pushing slowly on the loop of cable above the tubing hanger to allow it to feed through the exit port.
55. The second person should try to look through the port from the outer side to make sure that the end of the cable is not sticking on the walls or in the threads at the end of the exit port channel (ensure that safety glasses are used). If the cable does stick, use the pointed end of a file or pick to move it. Good communication between both persons carrying out this procedure is necessary to ensure that the cable is not pushed while it is stuck since this may cause kinks.
56. Continue this procedure until the cable end is about 2 or 3 inches out of the port exit.
57. Set vise grip pliers on the end of the cable and pull slowly while the cable is being pushed down by the person above the spool. The cable will have to be bent gently and continuously at the point where it enters the exit port to prevent any kinks from occurring on the edge of the port. The large end of the cable- bending tool can be used to help in this task.

Fig. 5



58. Continue with this procedure until the cable and all bends in the spool are below the tubing neck seals.

Terminating neon line to H-WHO, Part # 100387741

59. SLB RMC is responsible for terminating the Neon line to H-WHO following the H-WHO termination procedure, Doc # 100430796.
60. PS3 is responsible for terminating their lines.
61. T3 Energy is responsible to make up the Tubing hanger.

Landing in the Packer – Provided by Sand Control

62. Prior to tagging the Quantum X packer, obtain pick up and slack off weights and record in the log. PU Wt________________; Slackoff Wt _____________
63. Upon tagging the Quantum X packer, check the pipe tally to ensure proper depth and set down +/- 15 klbs (snapping in with the Snap Latch)
64. Test annulus to 1,000 psi for 5 minutes.
65. Pick up and snap out with +/- 15 klbs of overpull. This will indicate that the Snap Latch has engaged the packer and we are at the correct depth.
66. Pick up assembly in order to space out, install the hanger and circulate inhibited fluid.
67. XXXX
68. Rig down the SLB sheave wheels and spool all the lines into the spoolers. Place plugs and caps to the control line and secure all the reels before the equipment is sent back to the shop.
69. Slack off and land hanger.
70. Test annulus to 1,000 psi for 30 minutes on chart.

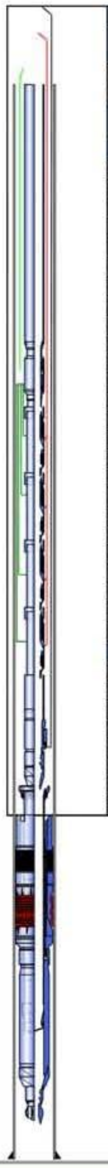
Appendix

1) Schematic

Schlumberger

Carbon Sequestration - Quantum Packer

Prepared For	Phone	Deviation	Deviation KOD	Formation Fluid	Density	Zone MD	Mid Perfs TVD
		0.00 deg					
Prepared By	**Final MD**	**Max Dogleg**	**Completion Fluid**	**Rig Name**	**Revision / Date**	**RKB**	**Water Depth**
Arin Basmajian		0.0 deg/100ft				30.00 ft	
BHP	**BHT**	**Field**	**Well Name**	**Completion Type**			
3,245.34 psia	176.00 °F			Injector			



Casing								Tubing						
Type	OD	Weight	Grade	ID	Drift ID	Connection	Depth	OD	Weight	Material	Yield Stress	ID	Drift ID	Connection
Casing	9.625	47	N80	8.681	8.525	MTC	7500	4.5	12.6	L80	80	3.958	3.833	MTC

Item	Description	Material		OD	ID	Length	Top Depth	Bottom Depth
Upper Completion								
E1	4-1/2 12.60 L80 MTC	L80		4.5	3.958	3347.31	0	3347.31
E2	JUNCTION BOX	13 CR		4.5	3.958	1	3347.31	3348.31
E3	4-1/2 12.60 L80 MTC	L80		4.5	3.958	400	3348.31	3748.31
E4	Geophone 4	13 CR		4.5	3.958	2	3748.31	3750.31
E5	4-1/2 12.60 L80 MTC	L80		4.5	3.958	1800	3750.31	5550.31
E6	Geophone 3	13 CR		4.5	3.958	2	5550.31	5552.31
E7	4-1/2 12.60 L80 MTC	L80		4.5	3.958	400	5552.31	5952.31
E8	Geophone 2	13 CR		4.5	3.958	2	5952.31	5954.31
E9	4-1/2 12.60 L80 MTC	L80		4.5	3.958	200	5954.31	6154.31
E10	Geophone 1	13 CR		4.5	3.958	2	6154.31	6156.31
E11	4-1/2 12.60 L80 MTC	L80		4.5	3.958	30	6156.31	6186.31
E12	4-1/2 12.60 L80 MTC	L80		4.5	3.958	150	6186.31	6336.31
E13	4-1/2, 12.60, SGM-FS, NDPG/NLQG, SINGLE, TUBING,	13CR[80]		5.712	3.879	5.17	6336.31	6341.48
E14	Pup Joint & Coupling, 10 ft (4-1/2, 12.6 PPF JFE BEAR	13 CR		4.5	3.958	10	6341.48	6351.48
E15	Nipple, X-STANDARD SELECTIVE (4-1/2" 12.6 PPF JFE	13 CR		4.5	3.813	1	6351.48	6352.48
E16	Pup Joint & Coupling, 10 ft (4-1/2, 12.6 PPF JFE BEAR	13 CR		4.5	3.958	10	6352.48	6362.48
E17	4.750 X 3.500, SNAP LATCH LOCATOR, 13 CR (80)	13 CR		7	3.5	2	6362.48	6364.48
E18	4.750 X 3.500 PRODUCTION SEAL SUB, 13CR (85), 4.124	13CR[85]		4.7	3.5	1.5	6364.48	6365.98
E19	4.750 X 3.500 PRODUCTION SEAL SUB, 13CR (85), 4.124	13CR[85]		4.7	3.5	1.5	6365.98	6367.48
E20	4.750 X 3.500 PRODUCTION SEAL SUB, 13CR (85), 4.124	13CR[85]		4.7	3.5	1.5	6367.48	6368.98
E21	4.750 X 3.500 PRODUCTION SEAL SUB, 13CR (85), 4.124	13CR[85]		4.7	3.5	1.5	6368.98	6370.48
E22	4.750 X 3.500 PRODUCTION SEAL SUB, 13CR (85), 4.124	13CR[85]		4.7	3.5	1.5	6370.48	6371.98
E23	4.750 X 3.500 PRODUCTION SEAL SUB, 13CR (85), 4.124	13CR[85]		4.7	3.5	1.5	6371.98	6373.48
E24	CROSSOVER, 4.124" SLHT BOX x 4.063-8 SA PIN, 13 CR					1	6373.48	6374.48
E25	4.750 X 3.645 SELF ALIGNING GUIDE SHOE WITH	13CR[80], 17-7 PH		4.73	3.65	2	6374.48	6376.48
Lower Completion								
F1	9-5/8 X 4.750 QUANTUM X (47-53.5), 410-13CR (80),	410-13CR[80]		8.34	4.752	5.67	6365	6370.67
F2	6.375-6 STUB ACME BOX X 6.250-8 STUB ACME BOX,	13CR, 85 KSI		7.01	5.24	0.83	6370.67	6371.5
F3	6.375-6 STUB ACME PIN X PIN, PBR, 4.750 IN ID, 13CR	13CR, 85KSI		7	4.75	19.4	6371.5	6390.9
F4	6.940 X 3.428 X 16 CROSSOVER, 13CR (85), 6.375-6	13CR[85]		6.94	3.428	1.17	6390.9	6392.07
F5	Pup Joint & Coupling, 10 ft (4", 11.60 PPF NUE 8 RND	13 CR		4	3.428	10	6392.07	6402.07
F6	Nipple, X-STANDARD SELECTIVE (4" 11.60 PPF NUE 8	13 CR		4	3.313	1	6402.07	6403.07
F7	Pup Joint & Coupling, 10 ft (4", 11.60 PPF NUE 8 RND	13 CR		4	3.428	10	6403.07	6413.07
F8	4.000 X 3.672, WIRELINE RE-RENTRY GUIDE/ HALF			4	3.672	0.71	6413.07	6413.78

Uwe's Tubing Tally

distance	PS3	pipe number			element length "ft"	description	# of component	
			-17.5					
		156			40			
			22.5			cross coupling protector	4500-A-06	
		155			40			
			62.5			cross coupling protector	4500-A-06	
		154			40			
			102.5			cross coupling protector	4500-A-06	
		153			40			
			142.5			cross coupling protector	4500-A-06	
		152			40			
			182.5			cross coupling protector	4500-A-06	
		151			40			
			222.5			cross coupling protector	4500-A-06	
		150			40			
			262.5			cross coupling protector	4500-A-06	
		149			40			
			302.5			cross coupling protector	4500-A-06	
		148			40			
			342.5			cross coupling protector	4500-A-06	
		147			40			
			382.5			cross coupling protector	4500-A-06	
		146			40			
			422.5			cross coupling protector	4500-A-06	
		145			40			
			462.5			cross coupling protector	4500-A-06	
		144			40			
			502.5			cross coupling protector	4500-A-06	
		143			40			
			542.5			cross coupling protector	4500-A-06	
		142			40			
			582.5			cross coupling protector	4500-A-06	
		141			40			
			622.5			cross coupling protector	4500-A-06	
		140			40			
			662.5			cross coupling protector	4500-A-06	
		139			40			
			702.5			cross coupling protector	4500-A-06	
		138			40			
			742.5			cross coupling protector	4500-A-06	
		137			40			
			782.5			cross coupling protector	4500-A-06	
		136			40			
			822.5			cross coupling protector	4500-A-06	
		135			40			
			862.5			cross coupling protector	4500-A-06	
		134			40			
			902.5			cross coupling protector	4500-A-06	
		133			40			
			942.5			cross coupling protector	4500-A-06	
		132			40			
			982.5			cross coupling protector	4500-A-06	
		131			40			
			1022.5			cross coupling protector	4500-A-06	
		130			40			
			1062.5			cross coupling protector	4500-A-06	
		129			40			
			1102.5			cross coupling protector	4500-A-06	
		128			40			

			1142.5			cross coupling protector	4500-A-06
		127			40		
			1182.5			cross coupling protector	4500-A-06
		126			40		
			1222.5			cross coupling protector	4500-A-06
		125			40		
			1262.5			cross coupling protector	4500-A-06
		124			40		
			1302.5			cross coupling protector	4500-A-06
		123			40		
			1342.5			cross coupling protector	4500-A-06
		122			40		
			1382.5			cross coupling protector	4500-A-06
		121			40		
			1422.5			cross coupling protector	4500-A-06
		120			40		
			1462.5			cross coupling protector	4500-A-06
		119			40		
			1502.5			cross coupling protector	4500-A-06
		118			40		
			1542.5			cross coupling protector	4500-A-06
		117			40		
			1582.5			cross coupling protector	4500-A-06
		116			40		
			1622.5			cross coupling protector	4500-A-06
		115			40		
			1662.5			cross coupling protector	4500-A-06
		114			40		
			1702.5			cross coupling protector	4500-A-06
		113			40		
			1742.5			cross coupling protector	4500-A-06
		112			40		
			1782.5			cross coupling protector	4500-A-06
		111			40		
			1822.5			cross coupling protector	4500-A-06
		110			40		
			1862.5			cross coupling protector	4500-A-06
		109			40		
			1902.5			cross coupling protector	4500-A-06
		108			40		
			1942.5			cross coupling protector	4500-A-06
		107			40		
			1982.5			cross coupling protector	4500-A-06
		106			40		
			2022.5			cross coupling protector	4500-A-06
		105			40		
			2062.5			cross coupling protector	4500-A-06
		104			40		
			2102.5			cross coupling protector	4500-A-06
		103			40		
			2142.5			cross coupling protector	4500-A-06
		102			40		
			2182.5			cross coupling protector	4500-A-06
		101			40		
			2222.5			cross coupling protector	4500-A-06
		100			40		
			2262.5			cross coupling protector	4500-A-06

		99			40		
			2302.5			cross coupling protector	4500-A-06
		98			40		
			2342.5			cross coupling protector	4500-A-06
		97			40		
			2382.5			cross coupling protector	4500-A-06
		96			40		
			2422.5			cross coupling protector	4500-A-06
		95			40		
			2462.5			cross coupling protector	4500-A-06
		94			40		
			2502.5			cross coupling protector	4500-A-06
		93			40		
			2542.5			cross coupling protector	4500-A-06
		92			40		
			2582.5			cross coupling protector	4500-A-06
		91			40		
			2622.5			cross coupling protector	4500-A-06
		90			40		
			2662.5			cross coupling protector	4500-A-06
		89			40		
			2702.5			cross coupling protector	4500-A-06
		88			40		
			2742.5			cross coupling protector	4500-A-06
		87			40		
			2782.5			cross coupling protector	4500-A-06
		86			40		
			2822.5			cross coupling protector	4500-A-06
		85			40		
			2862.5			cross coupling protector	4500-A-06
		84			40		
			2902.5			cross coupling protector	4500-A-06
		83			40		
			2942.5			cross coupling protector	4500-A-06
		82			40		
			2982.5			cross coupling protector	4500-A-06
		81			40		
			3022.5			cross coupling protector	4500-A-06
		80			40		
			3062.5			cross coupling protector	4500-A-06
		79			40		
			3102.5			cross coupling protector	4500-A-06
		78			40		
			3142.5			cross coupling protector	4500-A-06
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			3182.5			cross coupling protector	4500-A-06
		76			40		
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		75			40		
			3262.5			cross coupling protector	4500-A-06
		74			40		
			3302.5			cross coupling protector	4500-A-06
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			3342.5			cross coupling protector	4500-A-06
		72			40		
			3382.5			cross coupling protector	4500-A-06

		71			40		
			3422.5			cross coupling protector	4500-A-06
		70			40		
			3462.5			cross coupling protector	4500-A-06
		69			40		
			3502.5			cross coupling protector	4500-A-06
		68			40		
			3542.5			cross coupling protector	4500-A-06
		67			40		
			3582.5			cross coupling protector	4500-A-06
		66			40		
			3622.5			Centralizer	100615564
		65			40		
			3662.5			Centralizer	100615564
		64			40		
			3702.5			Centralizer	100615564
		63			39.5		
			3742			Centralizer	100615564
		62			38.6		
			3780.6			Eccentralizer 40#	100578013
		61			39.6		
			3820.2			Eccentralizer 40#	100578013
	DJB	60	3824.8		39.6	DJB	100263070
			3859.8			Eccentralizer 40#	100578013
					10	pup joint	
			3869.8				
-2296.8	PS3 - level 4		3874.3	2296.8	9	PS3 Mandrel	100603537
			3878.8				
				2287.8	10	pup joint	
			3888.8			Eccentralizer 40#	100578013
	42	59		2277.8	39.5		
			3928.3			Eccentralizer 40#	100578013
	41	58		2238.3	39.2		
			3967.5			Centralizer	100615564
	40	57		2199.1	39.2		
			4006.7			Centralizer	100615564
	39	56		2159.9	39.1		
			4045.8			Centralizer	100615564
	38	55		2120.8	39.6		
			4085.4			Centralizer	100615564
	37	54		2081.2	39.6		
			4125			cross coupling protector	4500-A-63
	36	53		2041.6	39.5		
			4164.5			cross coupling protector	4500-A-63
	35	52		2002.1	39.6		
			4204.1			cross coupling protector	4500-A-63
	34	51		1962.5	39.5		
			4243.6			cross coupling protector	4500-A-63
	33	50		1923	39.5		
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	32	49		1883.5	39.6		
			4322.7			cross coupling protector	4500-A-63
	31	48		1843.9	39.6		
			4362.3			cross coupling protector	4500-A-63

	30	47		1804.3	39.5		
			4401.8			cross coupling protector	4500-A-63
	29	46		1764.8	39.6		
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	28	45		1725.2	39.5		
			4480.9			cross coupling protector	4500-A-63
	27	44		1685.7	39.5		
			4520.4			cross coupling protector	4500-A-63
	26	43		1646.2	39.6		
			4560			cross coupling protector	4500-A-63
	25	42		1606.6	39.6		
			4599.6			cross coupling protector	4500-A-63
	24	41		1567	39.5		
			4639.1			cross coupling protector	4500-A-63
	23	40		1527.5	39.5		
			4678.6			cross coupling protector	4500-A-63
	22	39		1488	39.6		
			4718.2			cross coupling protector	4500-A-63
	21	38		1448.4	39.5		
			4757.7			cross coupling protector	4500-A-63
	20	37		1408.9	39.5		
			4797.2			cross coupling protector	4500-A-63
	19	36		1369.4	39.6		
			4836.8			cross coupling protector	4500-A-63
	18	35		1329.8	39.5		
			4876.3			cross coupling protector	4500-A-63
	17	34		1290.3	39.6		
			4915.9			cross coupling protector	4500-A-63
	16	33		1250.7	39.5		
			4955.4			cross coupling protector	4500-A-63
	15	32		1211.2	39.6		
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	14	31		1171.6	39.6		
			5034.6			cross coupling protector	4500-A-63
	13	30		1132	39.5		
			5074.1			cross coupling protector	4500-A-63
	12	29		1092.5	39.5		
			5113.6			cross coupling protector	4500-A-63
	11	28		1053	39.6		
			5153.2			cross coupling protector	4500-A-63
	10	27	5275	1013.4	39.6		Casing change 40# / 47#
			5192.8			cross coupling protector	4500-A-63
	9	26	5339	973.8	39.6		13-3/8" casing shoe
			5232.4			cross coupling protector	4500-A-63
	8	25		934.2	39.5		
			5271.9			cross coupling protector	4500-A-63
	7	24		894.7	39.5		
			5311.4			cross coupling protector	4500-A-63
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	5	22		815.6	39.5		
			5390.5			Centralizer	100615564
	4	21		776.1	39.6		
			5430.1			Centralizer	100615564

	3	20		736.5	39.5		
			5469.6			Centralizer	100615564
	2	19		697	39.6		
			5509.2			Eccentralizer 47#	100578013
	1	18		657.4	38.1		
			5547.3			Eccentralizer 47#	100578013
				619.3	10	pup joint	
			5557.3				
-609.3	PS3 - level 3		5561.8	609.3	9	PS3 Mandrel	100603537
			5566.3				
				600.3	10	pup joint	
			5576.3			Eccentralizer 47#	100578013
	9	17		590.3	39.1		
			5615.4			Eccentralizer 47#	100578013
	8	16		551.2	39.6		
			5655			Centralizer	100615564
	7	15		511.6	39.4		
			5694.4			Centralizer	100615564
	6	14		472.2	39.6		
			5734			Centralizer	100615564
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			5772.9			Centralizer	100615564
	4	12		393.7	39.6		
			5812.5			Centralizer	100615564
	3	11		354.1	39.5		
			5852			Centralizer	100615564
	2	10		314.6	39.5		
			5891.5			Eccentralizer 47#	100578013
	1	9		275.1	39.5		
			5931			Eccentralizer 47#	100578013
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			5941				
-225.6	PS3 - level 2		5945.5	225.6	9	PS3 Mandrel	100603537
			5950				
				216.6	10	pup joint	
			5960			Eccentralizer 47#	100578013
	5	8		206.6	39.5		
			5999.5			Eccentralizer 47#	100578013
	4	7		167.1	39.5		
			6039			Centralizer	100615564
	3	6		127.6	39.5		
			6078.5			Centralizer	100615564
	2	5		88.1	39.5		
			6118			Eccentralizer 47#	100578013
	1	4		48.6	38.6		
			6156.6			Eccentralizer 47#	100578013
				10	10	pup joint	
			6166.6				
0	PS3 - level 1		6171.1	0	9	PS3 Mandrel	100623044
			6175.6				
					10	pup joint	
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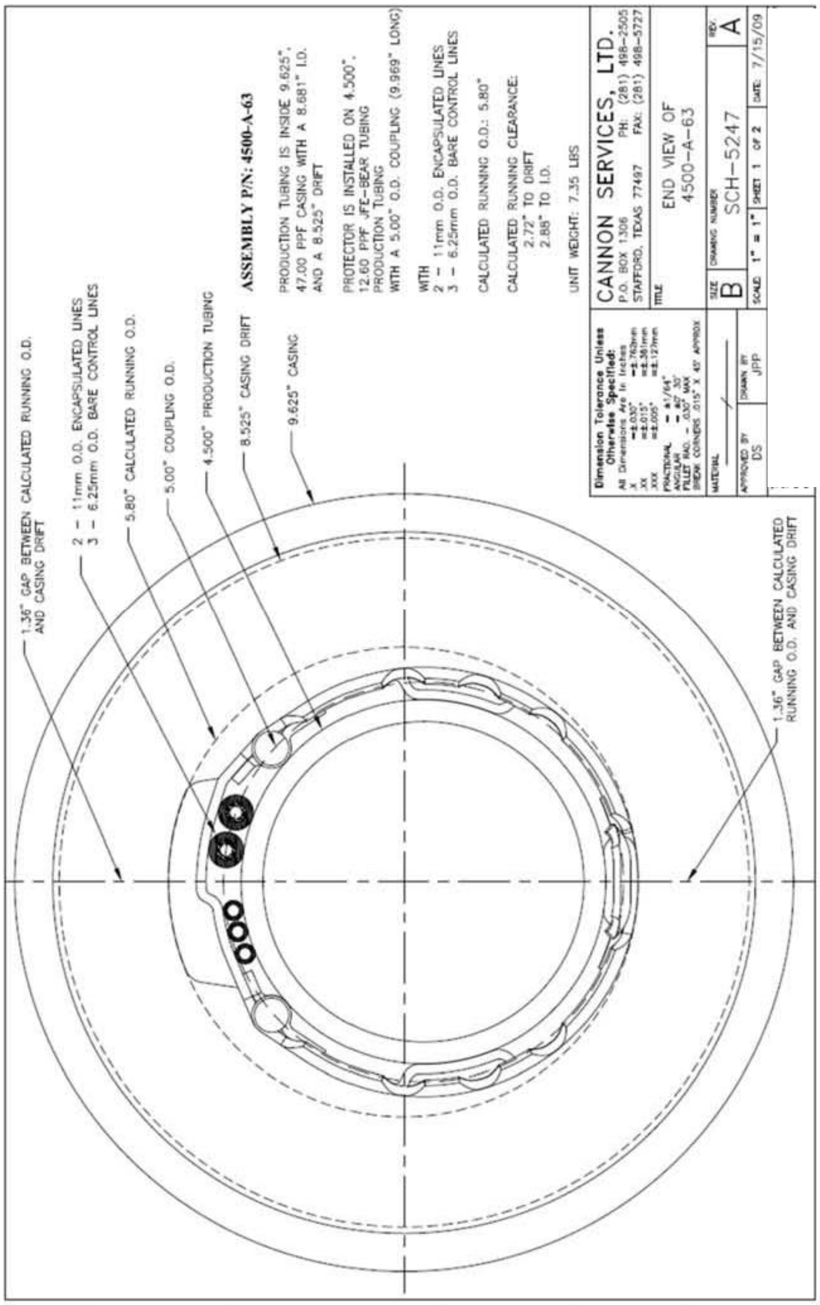
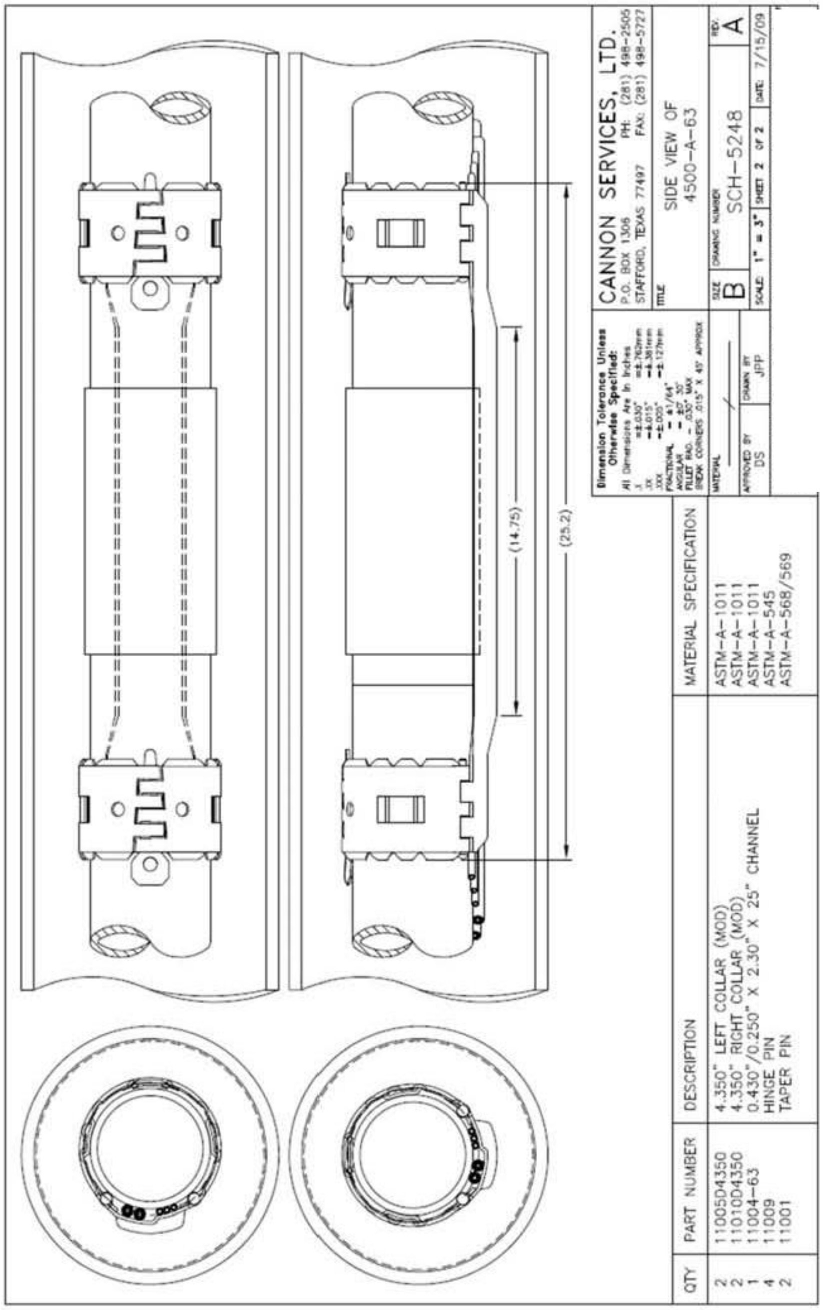
	3	3			39.6		
			6225.2			Eccentralizer 47#	100578013
	2	2			39.3		
			6264.5			Centralizer	100615564
	1	1			39.5		
			6304			Centralizer	100615564

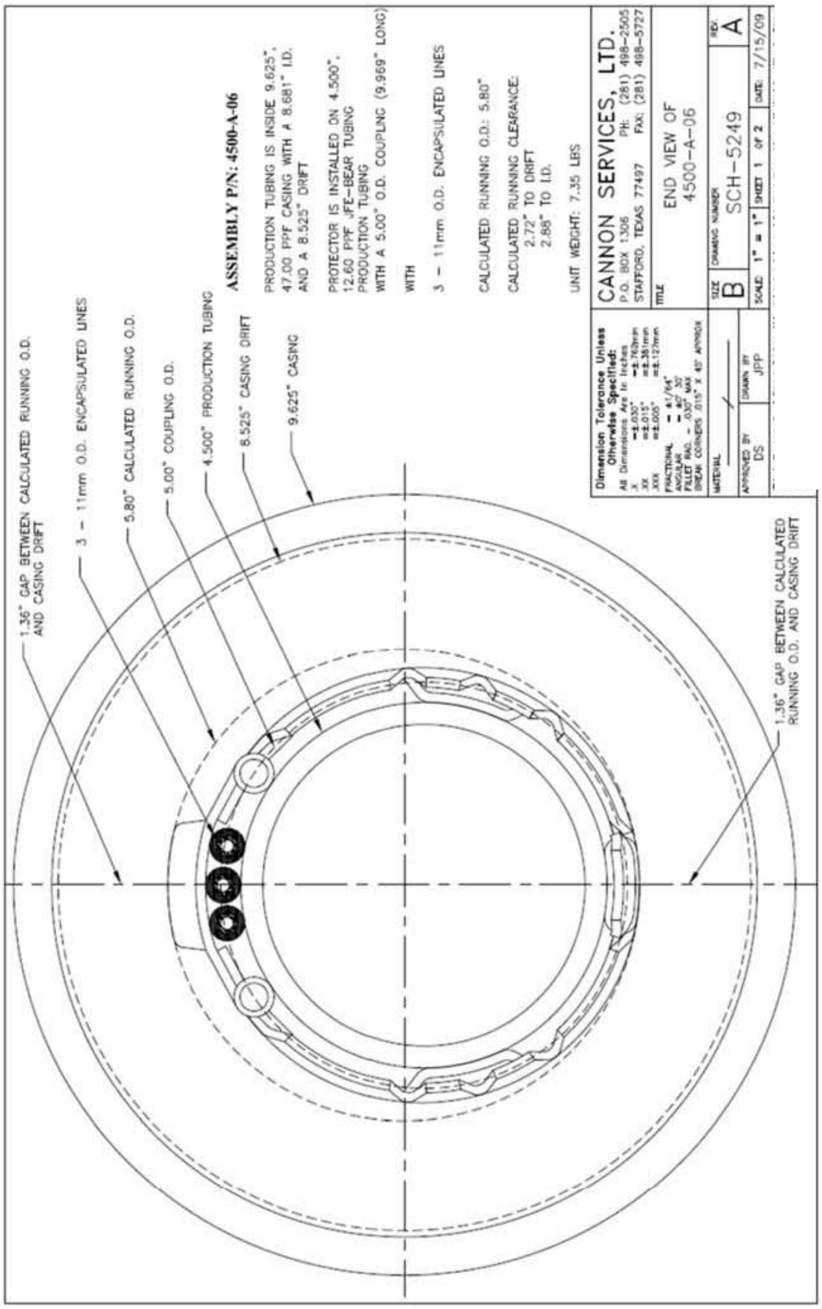
					10	pup joint	
			6314				
					8	PT gauge mandrel	
			6322				
					10	pup joint	
			6332				
					10	pup joint	
			6342				
					1	nipple	
			6343				
					10	pup joint	
		6365	6353			snap-latch	
						packer	
				count	spare	cplt	
		Centralizer		22	2	24	
		Eccentralizer 47#		12	2	14	
		Eccentralizer 40#		5	2	7	
		Cross Coupling Protector		121	17	138	

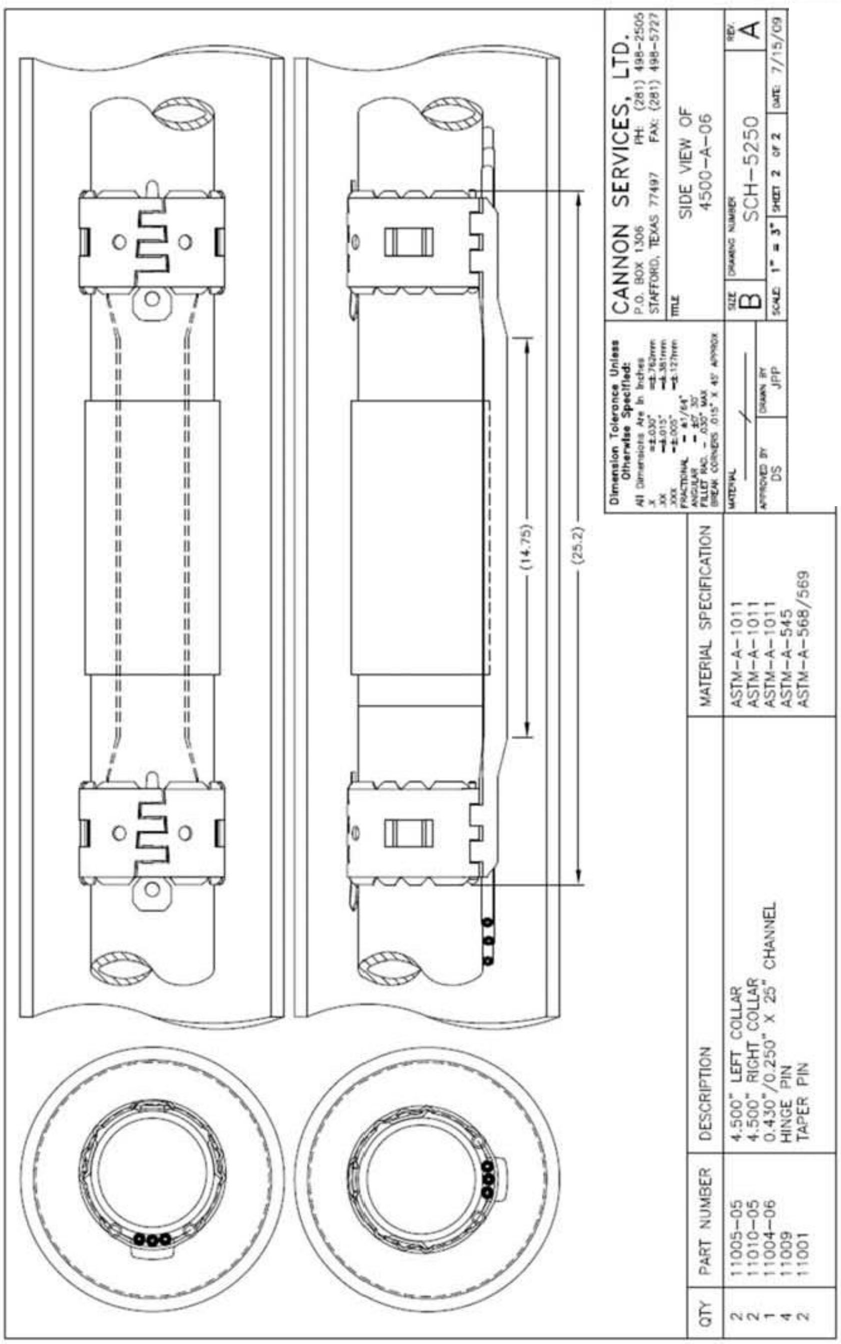
Clamp Drawings
4500-A-63



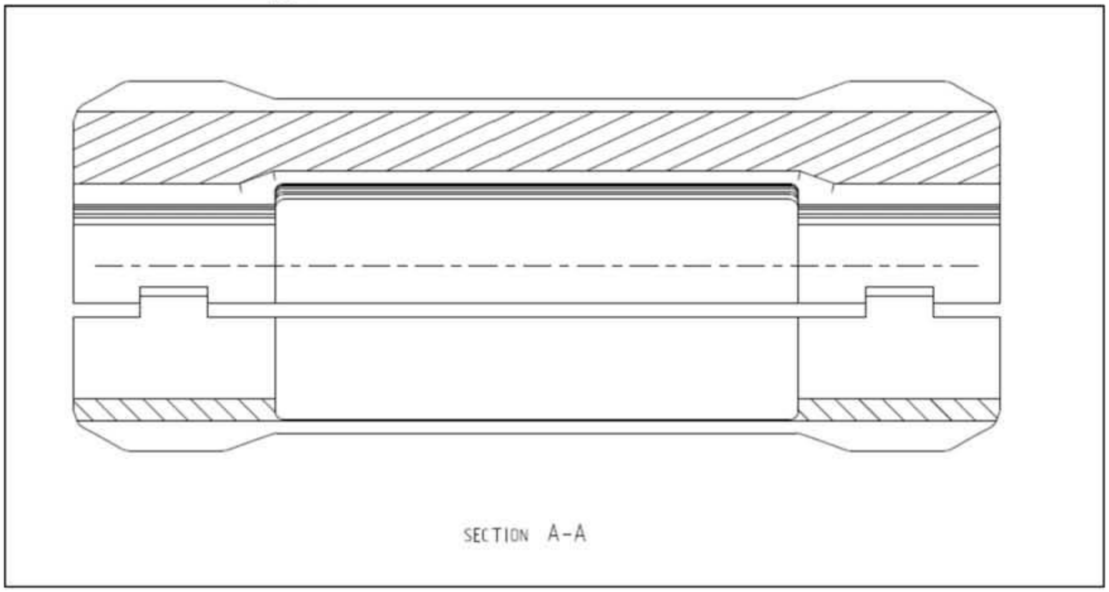

CANNON SERVICES, LTD.
P.O. BOX 1306 PH: (281) 498-2505
STAFFORD, TEXAS 77497 FAX: (281) 498-5727
TITLE
SIDE VIEW OF
4500-A-63
SIZE B
DRAWING NUMBER SCH-5248
REV. A
SCALE: 1" = 3"
SHEET 2 OF 2
DATE: 7/15/09
Dimension Tolerance Unless Otherwise Specified:
MATERIAL
APPROVED BY DS
DRAWN BY JPP
(14.75)
(25.2)
QTY
PART NUMBER
DESCRIPTION
MATERIAL SPECIFICATION
2 11005O4350 4.350" LEFT COLLAR (MOD) ASTM-A-1011
2 11010D4350 4.350" RIGHT COLLAR (MOD) ASTM-A-1011
1 11004-63 0.430"/0.250" X 2.30" X 25" CHANNEL ASTM-A-1011
4 11009 HINGE PIN ASTM-A-545
2 11001 TAPER PIN ASTM-A-568/569

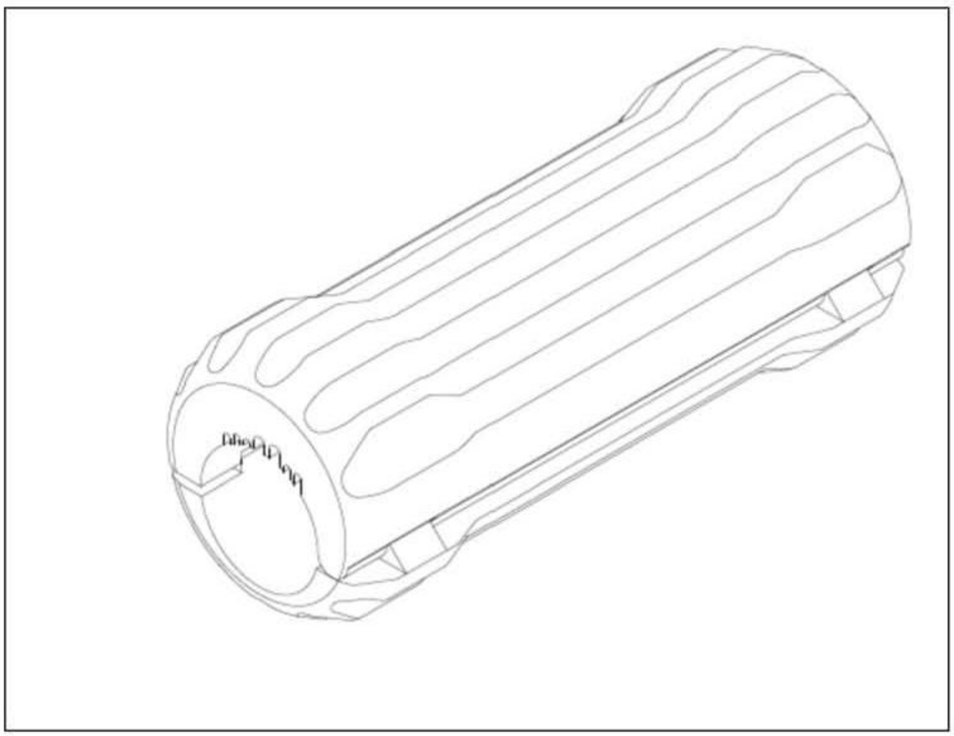
4500-A-06

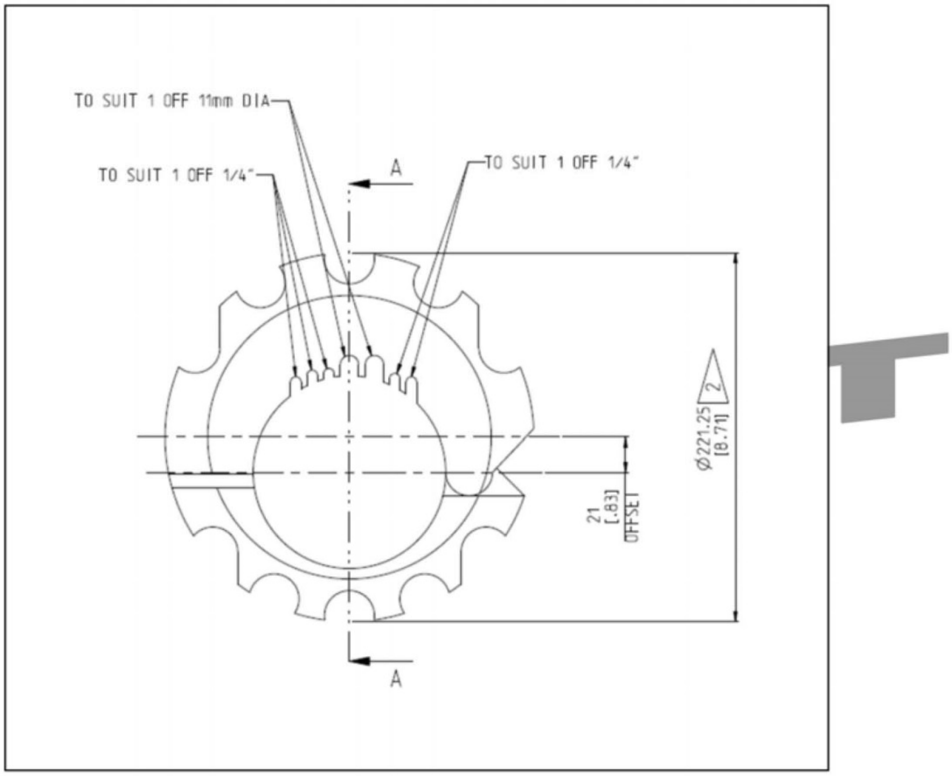

1.36" GAP BETWEEN CALCULATED RUNNING O.D. AND CASING DRIFT
3 – 11mm O.D. ENCAPSULATED LINES
5.80" CALCULATED RUNNING O.D.
5.00" COUPLING O.D.
4.500" PRODUCTION TUBING
8.525" CASING DRIFT
9.625" CASING
ASSEMBLY P/N: 4500-A-06
PRODUCTION TUBING IS INSIDE 9.625", 47.00 PPF CASING WITH A 8.681" I.D. AND A 8.525" DRIFT
PROTECTOR IS INSTALLED ON 4.500", 12.60 PPF JFE-BEAR TUBING PRODUCTION TUBING WITH A 5.00" O.D. COUPLING (9.969" LONG)
WITH
3 – 11mm O.D. ENCAPSULATED LINES
CALCULATED RUNNING O.D.: 5.80"
CALCULATED RUNNING CLEARANCE: 2.72" TO DRIFT 2.88" TO I.D.
UNIT WEIGHT: 7.35 LBS
CANNON SERVICES, LTD.
P.O. BOX 1306
STAFFORD, TEXAS 77497
PH: (281) 498-2505
FAX: (281) 498-5727
END VIEW OF 4500-A-06
SCH-5249
B
A
7/15/09
APPROVED BY DS
DRAWN BY JPP
1.36" GAP BETWEEN CALCULATED RUNNING O.D. AND CASING DRIFT


CANNON SERVICES, LTD.
P.O. BOX 1306 PH: (281) 498-2505
STAFFORD, TEXAS 77497 FAX: (281) 498-5727
TITLE
SIDE VIEW OF
4500-A-06
SIZE
B
DRAWING NUMBER
SCH-5250
REV.
A
SCALE: 1" = 3"
SHEET 2 OF 2
DATE: 7/15/09
Dimension Tolerance Unless Otherwise Specified:
MATERIAL
APPROVED BY
DS
DRAWN BY
JFP
(14.75)
(25.2)
QTY
PART NUMBER
DESCRIPTION
MATERIAL SPECIFICATION
2 11005-05 4.500" LEFT COLLAR ASTM-A-1011
2 11010-05 4.500" RIGHT COLLAR ASTM-A-1011
1 11004-06 0.430"/0.250" X 25" CHANNEL ASTM-A-1011
4 11009 HINGE PIN ASTM-A-545
2 11001 TAPER PIN ASTM-A-568/569

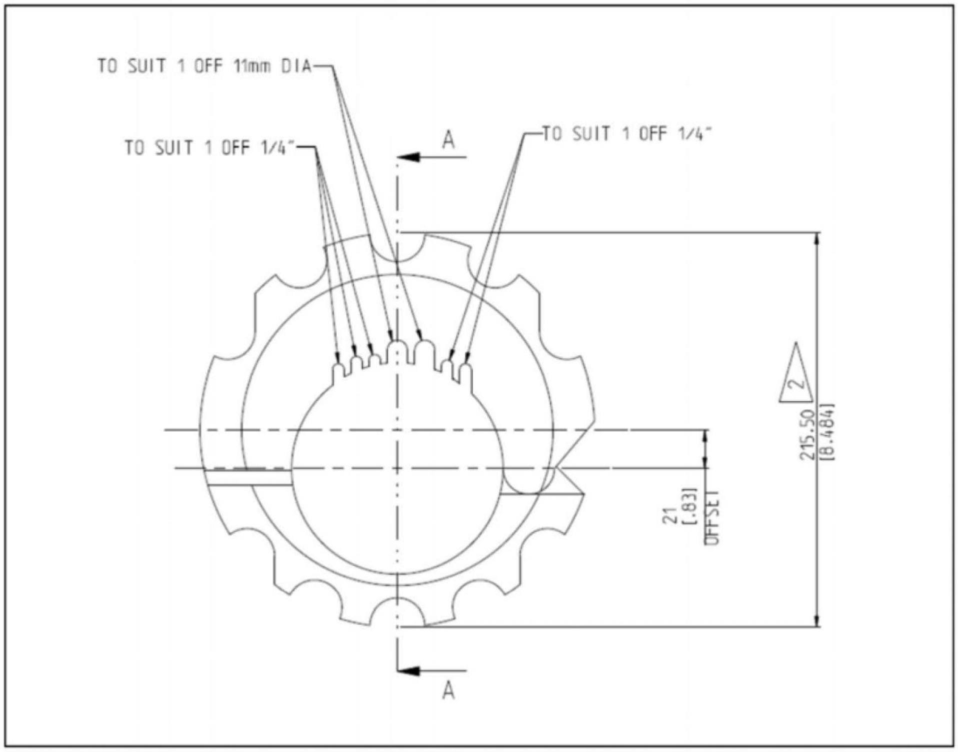
Eccentralizer 9-7/8" 40 ppf



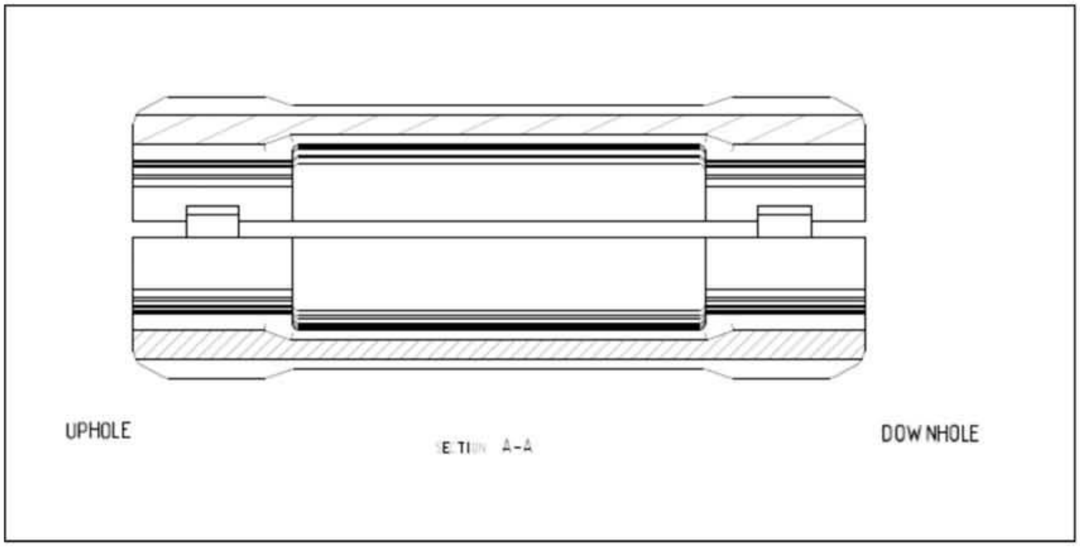


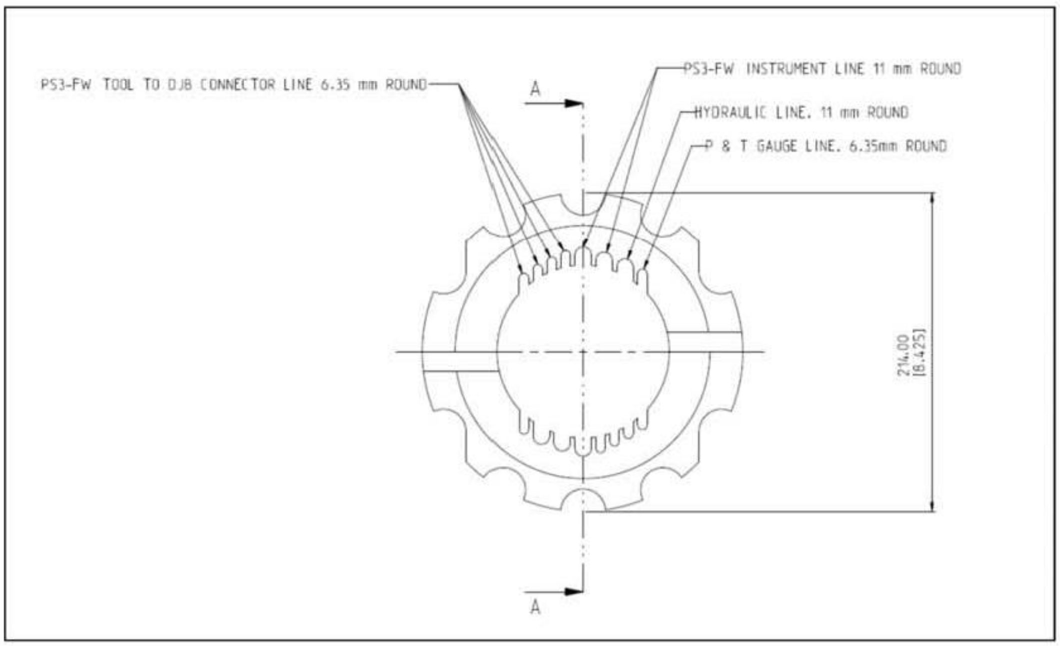

TO SUIT 1 OFF 11mm DIA
TO SUIT 1 OFF 1/4"
TO SUIT 1 OFF 1/4"
A
A
Ø221.25
[8.71]
2
21
[.83]
OFFSET

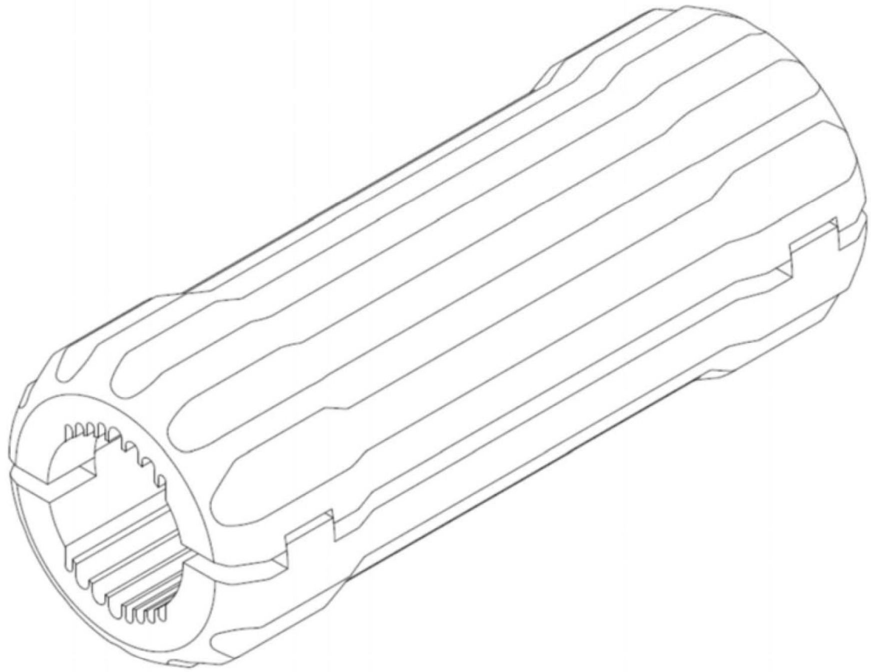
Eccentralizer 9-7/8" 47 ppf



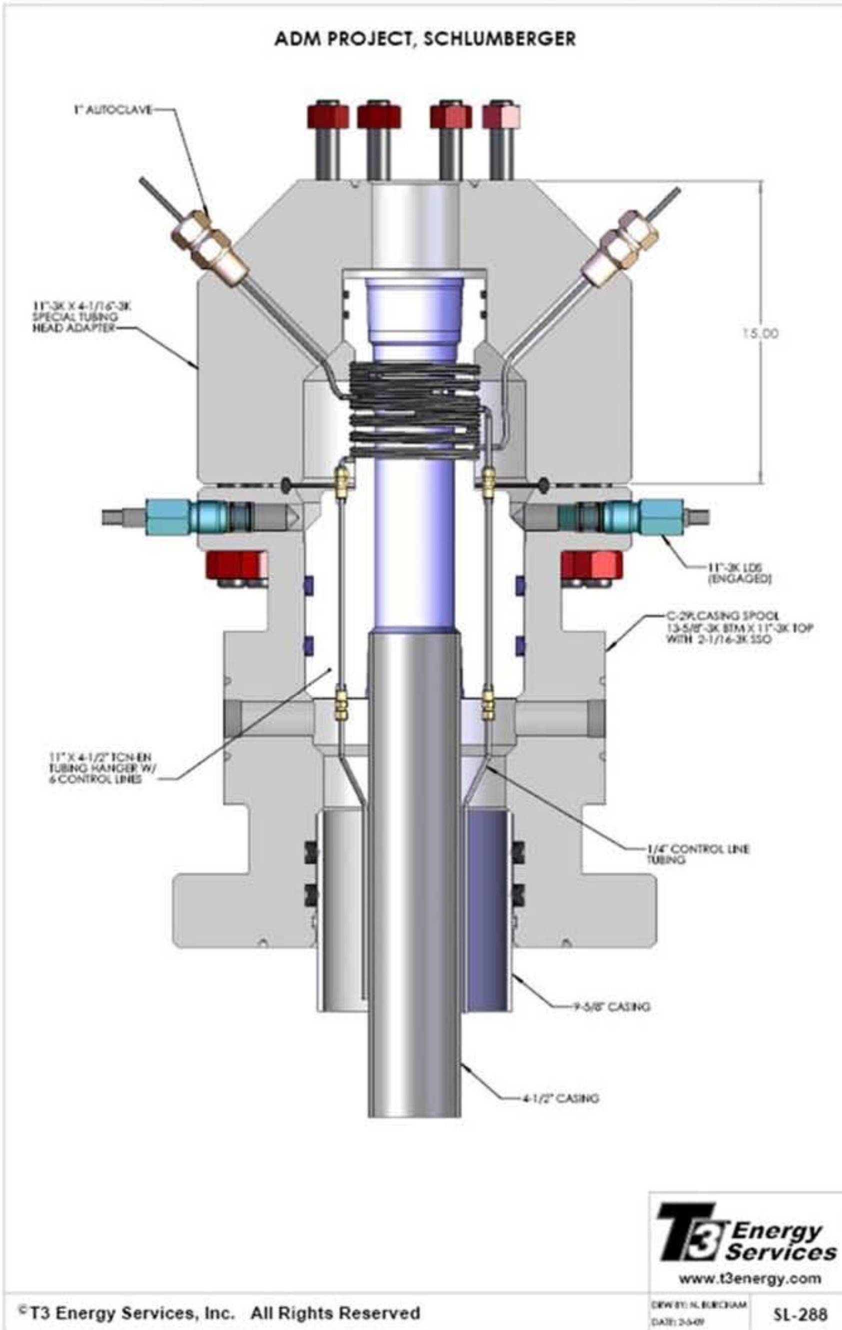
Centralizer 9-7/8" 40/47 ppf



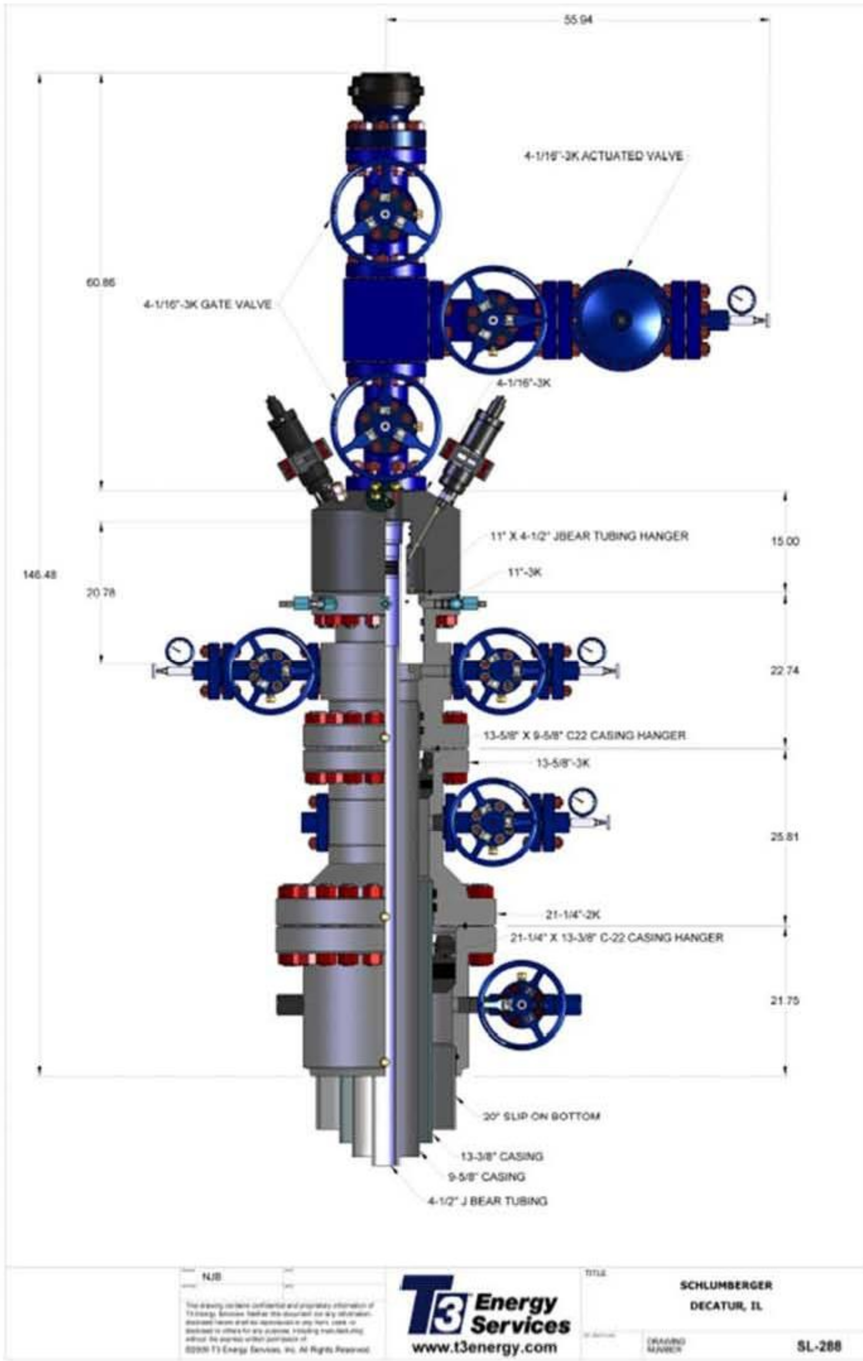




Tubing Head with Outlets

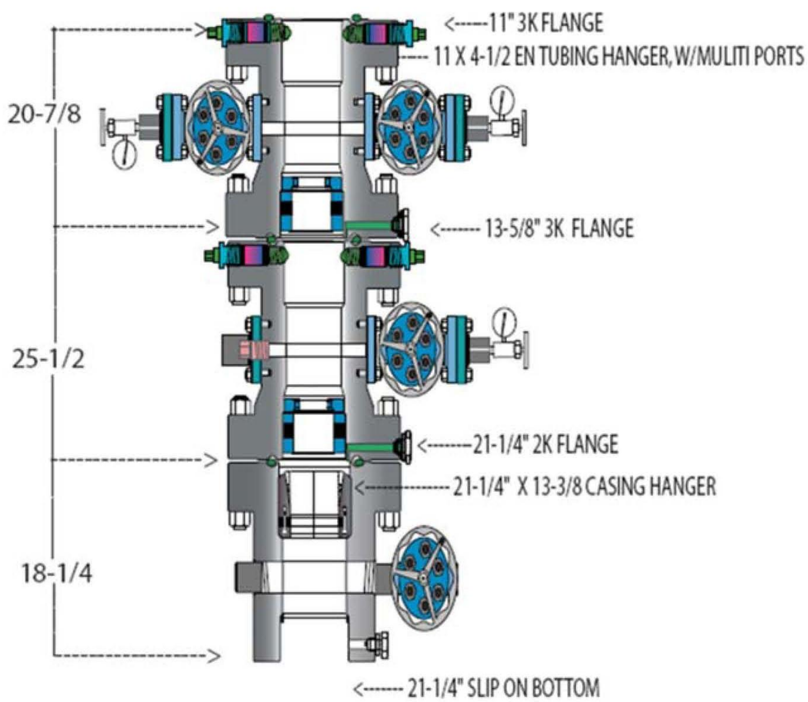


Final Tree Dimensions



T3 Energy Services
Wellhead & Production Systems

SCHLUMBERGER DECATUR, IL



NOT TO SCALE

Appendix F -- Completions Plan for VW1

Completion Procedure

ADM

Veiification Well # 1

Last Revision 4/18/2011

ADM VERIFICATION WELL #1 WELL PLAN OUTLINE

Surf Location: Section 5, Township 16N, Range 3E, Macon County, Illinois

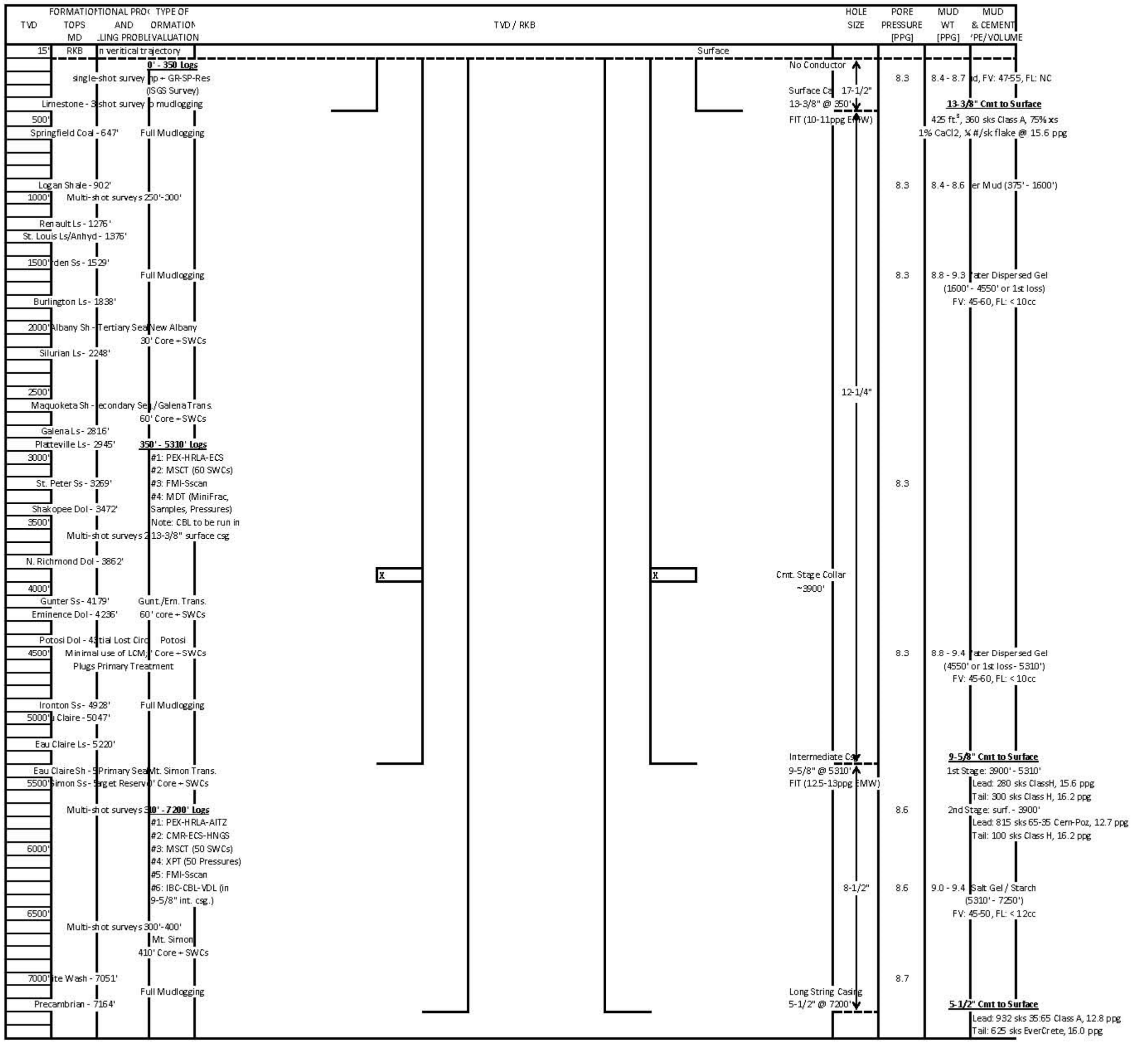
Spud Date: 15-Sep-10

Total Deptl 7200'

RKB-GL: 15.0'

Well

Objectives: St. Peter, Knox, Eau Claire, Mt. Simon, Precambrian



Step	Activity	Time	Cum
1	Run cased hole logs to confrim cement and wellbore integrity. This will be done two to three weeks before moving rig in. At the same time perform confirmation testing on Westbay control cabin	2day	1 day
2	Move in rig and support equipment.	1/2 day	
3	Conduct safety and orientation meeting for everyone involved in project.	1/2 day	2 days
4	Rig up completion unit and all support equipment	1/2 day	
5	Nipple up BOP stack and test casing and blind rams to 750 psi max	1/2 day	
6	Offload and talley 2 7/8 6.5# N-80 tubing		3days
7	Pick up 4 3/4 bit and casing scraper and trip in hole		
8	Tag PBTD and confirm with logs		
9	Circulate hole until clean with 9.2 ppg brine. Procedure still incomplete but possibly circulate with fresh water for underbalance.		
10	Test casing and pipe rams to max 750 psi	1 day	4 days
11	Trip out of hole with bit and scraper		
12	Rig up perforators and perforate Mt. Simon interval xxxx-xxxx with xxx JSPF and three zones above the Eau Claire at xxxxx	1 day	5 days
13	Trip in Hole with bit and scrapper and circulate hole . Trip out of hole	1 day	6 days
14	Pick up packer and RBP on 2 7/8 tubing and trip in hole. Install SN above packer. Run tandem memory gauges below RBP, on pup joint below packer, and above packer		
15	Set packer at xxxx and RBP at xxxx isolating lowermost set of perforations		
16	Swab test lower Mt Simon perfs. Recover fluid samples for testing. Have ability onsite to measure resistivity or TDS. Swab until samples stablize in salinity. ISGS to direct sampling and provide procedures	1 day	7 days
17	After fluid recovery has stabilized move packer and bridge plug to isolate the next set of perforations	1day	8 days
18	Swab test the next set of perfs as in Step 15. NOTE: If any perforations will not give up fluid the a small 250 gal 7.5% acid clean up job will be performed. This will require swabbing until acid load is cleaned up	1 day	9 days

Last rev 4/18/2011

19	Repeat Steps 16 and 17 for each set of perfs until all 10 zones have been tested	7 days	16 days
20	After all zones are swab tested trip out of hole and lay down packer and RBP. Prior to coming out of hole circulate well with permanent packer fluid. Swab well to match fluid level with BHP	1 day	17 days
21	Pick up bit and trip back in hole confirming PBTD, trip out of hole laying down bit	1day	18 days
22	Lay out West Bay completion on racks. This will be done while swabbing		
23	Run WestBay system in well testing each connection. When all of Westbay is in hole rig up Westbay wireline and check each port	5 days	23 days
24	Change over to 2 7/8 tubing and continue to run into well slowly		
25	Install gas lift valve and control line in in at approximately 1000ft in tubing string with control line back to surface		
26	Finish running completion into well very slowly	2 day	25 days
27	After spacing out completion but before landing tubing into well head rig up wireline and run GR/CCL to confirm depth		
28	After confirming depth land tubing into well head. Carefully connect control line to tubing hanger prior to landing tubing	1 day	26 days
28	Nipple down BOPs. Nipple up well head		
29	Rig down completion unit and move off well. Put rig on standby until WestBay packers are inflated. May leave rig on location. Will call at time.	1 day	27 days
30	Run one day pre-injection profile	1 day	28 days
31	Run West Bay tools into well and begin to inflate the West Bay packers from bottom to top	7 days	35 days
32	Open sliding sleeve below uppermost Westbay packer and circulate packer fluid in annulus.		
33	Set upper Westbay packer and then perform MIT test as per permit		
34	Purge and sample all ten zones	17 days	52 days
35	Position West Bay for monitoring. Rig up all permanent equipment including annulus system	2 days	54 days

Perforated Zone No.	Well Section	Perforation Interval Depths (MD ft.)		Net Interval (ft.)	Gun/Charge Type	Shot Density	Shot Phasing	# of Shots
		Top	Bottom			(spf)	(deg)	
10	Intermediate	4917	4920	3	3.5" HSD PJO3106	6	60	18
9	Intermediate	4967.5	4970.5	3	3.5" HSD PJO3106	6	60	18
8	Final	5653.8	5656.8	3	3.5" HSD PJO3106	4	120	12
7	Final	5840.4	5843.4	3	3.5" HSD PJO3106	4	120	12
6	Final	6416	6419	3	3.5" HSD PJO3106	4	120	12
5	Final	6632.3	6635.3	3	3.5" HSD PJO3106	4	120	12
4	Final	6718	6721	3	3.5" HSD PJO3106	4	120	12
3	Final	6840	6843	3	3.5" HSD PJO3106	4	120	12
2	Final	6945.6	6948.6	3	3.5" HSD PJO3106	4	120	12
1	Final	6983	6986	3	3.5" HSD PJO3106	4	120	12
GW/G*	Final	7060	7063	3	3.5" HSD PJO3106	6	60	18
								150

GW/G = Granite Wash-Granite Transition

Correlation Log Name: Reservoir Saturation Tool Sigma / Gamma Ray
Date: 15-Mar-2011
Logged By: Jason Baker / Sean Cross

Spare guns to be available onsite =

Qty.	Net Interval (ft.)	Gun/Charge Type	Shot Density	Shot Phasing	# of Shots
			(spf)	(deg)	
2	3	3.5" HSD PJO3106	6	60	36
1	3	3.5" HSD PJO3106	4	120	12
					48

DRAFT for discussion only

Decatur CO2 Verification Well

Abbreviated Work Flow for Westbay Installation

Walter Salden

Last rev: 22 Feb 2011

1.0 Prior to installation of monitoring components

QHSE
Safety plan in place and understood by all site workers
Safety communications and processes in place
Environmental monitors in place
Relevant Safety training completed
PPE specified and adhered to
ADM safety training completed and adhered to
Visitor Exclusion Zone

Work Area
Drill pad completed and ready for use
SWS winch / maintenance building located on site and wired for electricity (mains or generator)
Additional (rented?) container on-site of secure storage (packers, tools, hose reels etc) if needed,

Well Head
WHA and BOPs in place and ready for use
Check of gas (regularly)
Determine standing fluid level in cased monitoring well

Well Preparation
Casing grouted and bond log tested,
Casing perforated at selected locations ~ 10 locations
A pig (scraper) has been run to clean perforated zones
Video of perforated zones to verify quality of packer target locations
Verification of tail pipe (free of debris)
Deviation log – deviation from vertical
Temperature log – verify maximum temperature
Other logs as requested by others

Kill fluid water tank on site
Waste water tank on site
Fluid collection dam in place around wellhead

Other weather specific equipment in place

Summer:
- Shade tent
- Adequate fluids
- Insect protection
- Cold fluids

Winter:
- Heaters
- Warming stations
- Warm fluids

2.0 MP Casing Design

Design Approval
Westbay tubing design completed and approved (written):

Westbay:	Project Manager
	Site Project Engineer
SCS:	Project Manager

Engineering and Design
Expected load vs depth calculations completed
Expected depths to add kill fluid calculations completed
Thermal and stretch calculations completed

Magnetic location collars distance with respect to ports and packers
Tubing centralizers

Well Design layout checked for accuracy and exported to Excel for verification

3.0 Layout

Unpacking
Crates with casing to be delivered to the pad area by others (fork lift, Hiab),
Crates opened; need snips to remove banding and cordless electric drill with Robertson screw driver to open crates
Two men to place casing onto casing racks, pin end closest to well,

Layout
Casing racks supplied by others, appropriate for the weights and lengths.
Racks should be clean (not grease covered),
The estimated length of racking required is 50 feet,
Will need adjustable supports for short lengths (pubs, 5 footers etc)
Packers and port couplings to be stored in secured building until required (do not place on the racks – keep away from freezing, direct sunlight, dust, etc),
If taken outside, keep packers under cover from sun

Inspection
Visual Inspection inside of each pipe
Go – NoGo each end of casing
Spare orings and Teflon rings to be available
Install bottom plug and torque to specifications
Crossover, from API tubing to Westbay Tubing

Strapping
Each length to be measured (strapped) using steel tape to nearest 1/8"
Length to be written on each casing item using Sharpie felt pen,
Lengths to be entered into computer and verified; export to Excel
Record serial numbers of packers and ports,

Accessory Components
Move casing pieces requiring centralizer of magnetic location collar to a local work area. (This area to have stable pipe stands at each end and a surface to hammer clamping.)
Install centralizers as per approved well design
Install magnetic location collars as per approved well design

Packer De-airing
De-air every packer to verify valve operation and record valve opening pressure

Function Testing
Open and Close each pumping port to verify operation

Manpower Requirement:

Minimum of two experienced crew

4.0 Lowering and Joint Testing

Safety Preamble
During the lowering there will be significant activity by on-site personnel who will be handling tools, equipment and well tubulars. There will be potential slipping and tripping hazards, pinch hazards, lifting hazards and possibly working at heights hazards. Appropriate safety precautions will be taken at all times.

Engineer in Charge
The Engineer in charge has responsibility for the following:

Components are stored and handled safely,
Components are placed in the correct order,
Components are placed in the correct orientation,
Safe working loads are not exceeded,
Progress of the installation is documented (check list).

Wellhead
Work-over rig with operator and helpers
Balcony work area built to suit WHA and BOP
At the end of each work period (if not 24hrs/day) a sealing plug with pressure vent line and pressure gauge will be placed on the top of the tubing to prevent accidental flow while the site is not occupied. The driller will close off the annulus between the tubing and casing to prevent any chance of flow.

Lifting equipment
Estimated maximum load 11,000 lbs
Estimated maximum load hold points identified and followed
Lifting elevators with suitable rating and recently inspected
May require special elevator for packers
Lifting straps and Crosby clamps with suitable rating
Slip plates with suitable rating
Load indicator (recording type) will these be used and readings compared to predicted by installation spreadsheet. Any deviations from expected will be investigated. Westbay to provide device rated to 50,000 lbs.

Fluid Management
Kill fluid displaced from the well will be collected and pumped to a holding tank.

Estimated total displaced volume: 1000 US gal

Pump to transfer kill fluid from tank into well
Kill fluid for filling Westbay tubing

Fill Westbay tubing with fluid every 200 feet (estimated) to manage differential pressures
Total quantity (Westbay only) 820 US gallons

Joint Make up
Each joint will be tightened to a torque of ?? ft-lbs.

Joint Testing
Joint testing with N2 gas or water (N2 preferred for speed and non-freezing)
All joints to be 100% tested and verified before lowering into the well.
Observe for 3 to 5 minutes each joint.

Lowering Speed
Estimated lowering speed: ____ pieces / day
Total lowering time estimated 3 days
Lowering by Drill rig – likely need coaching in being 'gentle' (no shock loads, and slow speed)

Software – Westbay Well Designer – to be used to keep track of installation

Work crew
Workover rig:
Two SWS (?) handling the tubing
SWS Engineer in Charge

5.0 First Pre Inflation pressure profile

Objectives
The main objectives of the pre-inflation pressure profile are:
Verification of proper component placement (magnets, etc),
Verification of proper location and functioning of Measurement ports,
Sounding of depth,
Inside pressure vs depth gives deviation info,
Inside vs outside pressures gives insights into fluid density in annular column

Open Well Safety
The entire Westbay tubing string will be installed
The 2 7/8" cross over will installed, but not 2 7/8" tubing
A 2 7/8" cable cutter will be installed for use in the event of an uncontrolled flow. The tubing can be shut in by cutting the cable and allowing the tool to drop to the bottom. This would be used only in an emergency.

Equipment
The InterOcean wireline winch will be used
The sheave and counter will be attached to the workover rig sand line
Two MOSDAX Pressure probes will be used separated by 20' of wireline. This will provide redundancy in case of a broken location arm or backing shoe.

This activity will be continued until completed then the tools will be removed and the well tubing closed in at the surface. Note: it is assumed that an open, unattended well is not permitted)

Quality Assurance
The collected data will be reviewed and plotted to verify that all components are functioning properly.

Depending on the results of testing the MOSDAX repeater may be placed on top of the uppermost probe.

6.0 Lowering 2 7/8" and final positioning

Approximately 4000' of 2 7/8 tubing will be lowered using rig
Loads will be monitored and recorded
Lowering speed will be no more than ____ ft / min to minimize risk of damage to Westbay tubing items
Do not apply sudden shock loads or excessive lowering speed
Do they joint test?

Final positioning will be undertaken using Schlumberger
Use geophysics tools and short pups to final position the Westbay

Clamp off and install final WHA

7.0 Second Pre-Inflation Pressure Profile

The main objectives of the pre-inflation pressure profile are:

Verification of proper component placement (magnets, etc),
Verification of proper functioning of Measurement ports,
Sounding of depth,
Inside pressure vs depth gives deviation info,
Inside vs outside pressures gives insights into fluid density in annular column

A 2 7/8" cable cutter will be installed for use in the event of an uncontrolled flow. The tubing can be shut in by cutting the cable and allowing the tool to drop to the bottom. This will be done only in an emergency.

The InterOcean wireline winch will be used
The sheave and counter will be attached to the workover rig sand line
Two MOSDAX Pressure probes will be used separated by 20' of wireline. This will provide redundancy in case of a broken location arm or backing shoe.

This activity will be continued until completed then the tools will be removed and the well tubing closed in at the surface. Note: it is assumed that an open, unattended well is not permitted)

The collected data will be reviewed and plotted to verify that all components are functioning properly.

Depending on the results of testing the MOSDAX repeater may be placed on top of the uppermost probe.

When this activity is completed the work over rig may leave and alternative support (pump truck?) could be brought in to reduce costs.

8.0 Packer inflation

Each MP Packer will be inflated sequentially and independently, beginning with the lowermost, using the inflation tool.

The inflation fluid (water) will be provided by a 12VDC electric pump located at the surface and conveyed down-hole using 3/16 diameter hose.

Extra filters will be used to minimize the risk of plugging the downhole filters.

Electrically operated valves in the down-hole packer inflation tool will be operated from the surface PC.

The inflation pressure and volume of each packer will be recorded using the Multitester software.

The present best-practice is to use PVC tape (electricians tape) to fasten the water filled hose and the electrical wireline together at distances not greater than 50 feet.
Although slow and labor intensive, the taping method will be used for at least the first demonstration wells.

Water displaced out of the Westbay tubing will be captured and disposed of.

On the way in, stop the winch every 1000 feet and verify tool operation and the ability of the winch to lift the tools.

A repeater may be used

A total of three 1000m inflation hose reels will be required. These will all be connected in series during operation.

The hose will be run over a separate sheave that will take very little weight. Will an exemption be needed for this?

Walkie talkie radios and hand signals will be used between the winch operator (inside the building) and the crew.

Differential pressures: water inside inflation tubing is fresh water, fluid outside is kill fluid (greater than formation pressure).

This activity will take longer than one day. Since it is not possible to close off the top of the tubing with a wireline and hose deployed, either work 24 hrs (two shifts) or have a night guard ready to close the cable cutter in the event of an unexpected flow.

To minimize tripping in and out of the well with this assembly keep the Measurement port to packer spacing constant for all zones.

The PVC tape is removed as the packer inflation tool is removed from the well (within several days). It is expected that this technique will be suitable for expected the downhole temperature conditions.

Comment:
During inflation, the pressure in the perforated zone is expected to fall off to the zone pressure (super pressurized by the kill fluid). The QA zones will drop to the inside tubing pressure (less than formation pressure since it is fresh water). This is expected to lock-in a differential pressure across the packers that is proportional to the pressure caused by the different fluid densities at the corresponding depths.

9.0 Commissioning Post Inflation Pressure Profile

This is the first measurement of natural formation pressure. It is likely not necessary to remain at any one zone for a long time since equilibration could take time. Recommend 5 to 10 minutes observation time at each zone.

Measure the QA zones as well.

A 2 7/8" cable cutter will be installed for use in the event of an uncontrolled flow. The tubing can be shut in by cutting the cable and allowing the tool to drop to the bottom. This is an emergency operation only but may be required.

The InterOcean wireline winch will be used.
The sheave and counter will be attached to the surface structure (?)

Two MOSDAX Pressure probes will be used separated by 20' 1/8" diameter wireline. The lower tool will be a sampler so flow into the casing can be created for testing purposes. This will provide some level of redundancy in case of a broken location arm or backing shoe.

This activity will be continued until completed then the tools will be removed and the well tubing closed in at the surface. Note: it is assumed that an open, unattended well is not permitted overnight)

The pressure response during activation will be recorded.

The collected data will be reviewed and plotted to verify that all components are functioning properly.

Depending on the results of testing the MOSDAX repeater may be placed on top of the uppermost probe.

10.0 Pumping Port Operation Verification

As part of the system verification proper operation of all pumping ports will be demonstrated. The response of each pumping port as it opens and the resulting equilibration of pressures will be monitored to provide information about formation hydraulic conductivity.

The pumping ports are hydraulically operated (differential pressure driven) sliding sleeve valves. They are operated using a downhole tool to apply a pressure differential across two access ports. This differential pressure drives the sliding port valve to either the open or closed position.

The differential pressure can be applied using several tools;

OCI (open/close/inflation) tool with sample bottle
modified Sampling tool with sample bottle
OCI with downhole pump

Tools used to operate these valves are designed for a maximum differential pressure of 2000 psi. At depths where the inside Westbay tubing hydrostatic pressure exceeds 2000 psi pre-charging of the sample bottle will be required. At the deepest pumping port this hydrostatic pressure (with no influence from the injection well or CO_2 reactions) is expected to be approximately 3500 psi. This would require a pre charge of 1500 psi. A drop tube and a water buffer should be used inside the bottle to keep gas from contacting the pumping port.

These tools are wireline deployed. During this time there would be a direct connection between the formation and the surface through the fluid column. A wire cutter would be required to control unexpected flow in the case of an emergency.

OCI Tool with sample bottle
The OCI tool can be used to open or close one or more pumping ports in a single trip. This is a tremendous advantage considering the long travel times required for tripping in and out of the verification well.
A potential drawback is the large diameter of this tool relative to the inside diameter of the Westbay tubing. There is potential for significant flow restriction. Furthermore, the inflow of formation fluid containing sediments could impact the operation of the tool.

Sampling Tool with sample bottle
This tool can be used to open or close a pumping port, but only one event per trip. For example, the tool would be tripped in to open a port and then tripped out, reconfigured, and then tripped back in to close the port.

OCI tool with downhole pump
This combination relies on a downhole pump. This configuration has the clear safety advantage that handling of pressures at the surface to pre-charge is not required. Also,

this configuration allows virtually unlimited operation (opening and closing) operation at a multitude of pumping ports during a single deployment. This will save considerable file time. At this present time development has ceased.

How to apply a pre-charge at the surface:

If we consider the deepest pumping port we will have to apply a pressure pre-charge of approximately 1500 psi.

Pre-charge and formation temperature

Worst likely case:
Surface temperature 0C
Downhole temperature 55C

If obeys the simple gas law: P(55C) ~ 1800 psi

The sampling tool is rated to operate to 5000 psi only at the electric valve and below. The 2000 psi rating applies above the electric valve.

Once the first Pumping Port is opened (most likely the lowest) there will be a sudden inflow of formation fluid and wellbore skin material into the Westbay tubing as a result of the differential pressures. This inflow may displace kill fluid out the top of the Westbay tubing at the surface. It is expected that this flow will slow and finally equilibrate when the two pressures are in equilibrium. The rate of inflow will be determined by the formation hydraulic conductivity and pressure difference.

Show quick calculation of recovery time of slug test under these conditions.

10.0 Fluid Sampling

What sample volume required?
Sample handling
Sample shipping
Certification required since this is a pressure vessel

To be resolved:
Who will be doing the sampling and what specifically are they looking for. This has implications with regard to the quantity of fluid required. The Westbay system will have lengthy travel times at extreme depths.

The existing sample technique is not a zero-pressure change sampling method. This has been mentioned as a desirable approach and has been promoted as such by proponents of the U-tube system.

DOT requirements for transportation of pressure vessels
Safety tags
Certificates of traceability

11.0 Pressure profiling

Plan to use water sampling tool or a single MOSDAX probe.
Winch
Wireline, type, diameter,
Sheaves
Depth counter
Cable clamps
Long travel times to get up and down the well

The monitored zones are likely not low permeability thus equilibration times at each zone will be reasonably quick.

Will we recommend using a water level tape to verify pressure head?

12.0 MOSDAX Pressure and Temperature Datalogging

The total number of MOSDAX pressure probes connected to any one datalogger can not exceed 31. This is an existing limitation of the datalogger. This number could not be increased without a significant redesign of software and firmware and is not being contemplated at this time. Recent discussions suggest that the number of MOSDAX pressure probes at any one monitoring well will typically be eleven or twelve.

Magnetic collars will be used to provide an independent indication of depth. Repositioning and possibly adding more collars is being considered.

Sam unit to record inside water levels. This is good to check on the probe sealing. A slow leak anywhere will likely show up here.

Installation – with no 'feel'
At the installation depths anticipated it will no longer be possible to locate probes by 'feel'. A very structured program of lifting, lowering a precise distance and speed to locate the probe at the port will be required. At present there a preliminary R&D project underway to determine if a tiny accelerometer could be used to detect the sudden stop as the probe lands in the port. As anticipated at this early stage, the accelerometer would be placed in each MOSDAX probe and indicate a 'bump' on the surface computer monitor. It is not known if this will be ultimately successful or not.

Work over rig or monopod
Winch requirements
Slip plates
Pulley, rollers
Power requirements, 117VAC, 60 Hz or solar, etc

Westbay long-term contract to download and review data periodically to check on system performance.

13.0 Surface Completion

Security fencing
Ceiling height suitable to monopod / tripod or access hatch or removable building.
Grounding, especially important for corrosion control
Lightening protection
Monopod bracket designed for expected loads
Telemetry – cell phone, radio, hardwire, WIFI, other
Power, AC, solar and battery other
Likely need 220VAC 3 Phase power for the winch.

Instrument set-backs from well head (ie explosive perimeter)

Other instrumentation in the house that might interfere with reliable communications to be identified.

Appendix G – Completions Plan for GM1

Procedure for Permanent Installation of Borehole Seismic Array

1. Review drill site for all possible hazards in immediate work area.
2. Review drill rig for hazards.
3. Discuss deployment for sheave with tool pusher and or driller.
    a. Topics should include who will hang the sheave, how it will be secured in place safely, and whether or not it is best to use the tugger line or a cross-beam in the derrick.
4. Discuss reel placement.
    a. Angle of approach to rig may be limited due to tubing racks on east side of cat walk and berm on the west side.
5. Review location of surface acquisition system for surface op-check during installation.
    a. The GeoRes system may be best located in a truck or van next to the reel (ISGS may be able to provide a van, if necessary).
    b. Extension cords running to wellsite trailer can provide power.
6. Discuss tubing insertion with driller
    a. Topics should include the following: safe running speed, who will be giving hand signals, where the completion hardware will be staged during the operation, tubing rotation while running in hole, etc.
7. Discuss with driller best method of cable dress through Kelly bushing and tubing slips.
    a. Rig hands should be present so that they are aware of the delicate cable.
8. Check on tubing tally and space-out of geophone array.
    a. Pup joint selection is limited but some will be available on site.
9. Review placement of re-bar targets for oriented perforating.
    a. 1" re-bar (or similar) will be tack-welded onto the tubing at one or two strategic depths to provide an electromagnetic target for potential oriented perforating operations in the St. Peters sandstone.
    b. Exact depth will be decided based on tubing tally and geophone well space out, so as to avoid placement next to a geophone pod.
10. Check seis cable for operation.
11. Assemble clamping tools and check for operation.
12. Locate cable and reel to deployment area.
13. Hold safety meeting with all personnel involved with operation and review JSA's.
14. Dress cable through sheave wheel.
15. Secure bottom end of cable for sheave placement.
16. Raise cable and sheave towards rig crown.
17. Monitor reel deployment of cable.
    a. Depending on ease with which the cable spools off the reel, we may consider using a spotter to control the rotation of the spool.
18. Start deployment of tubing.
    a. Adhere to agreed running speeds.
    b. Obey commands of person in charge of installation.
19. Attach first seis cable point to tubing with clamps.
20. Monitor cable deployment through drill floor.
    a. *Should we have someone stage below the rig floor to see if there is any interference with the cable that may not be obvious?*
21. Monitor cable tension during deployment.
    a. *How will this actually be achieved: by person on rig floor or on the ground by the reel?*
22. Attach cable at tubing joint with clamp/centralizer.
23. Lower tubing attaching seis cable as required.
24. Check seis cable operation after deploying 5 number of pods.
25. Tack-weld re-bar targets at appropriate depths.
    a. Ensure cable is safely out of the way.
    b. Install cable immediately adjacent to the re-bar after welds have cooled.

26. Continue deploying tubing and cable, placing remaining seis pods between tubing joints as required and attaching with clamping hardware.
27. Continue to attach seismic cable to tubing and perform operational check every 10 joints.
28. Continue until approximately 400 foot from top of well.
29. Clamp last two geophone pods at 380' and 160'.
30. Lower sheave wheel and slowly redress cable unto spool.
    a. *To what height above the rig floor should the sheave be lowered?*
31. Continue with tubing insertion clamping as required.
32. Add seis cable from spool and attach as necessary.
    a. *How will this be accomplished? Will we need to lift/hoist the remaining cable up to the rig floor?*
33. When completely inserted check cable operation.
34. Cementing operations will commence after successful check-out of downhole array.
    a. *Procedure for safe cementing operations will be detailed in another document (i.e., to ensure bottom-hole pressure and temperature that is below safe working limits of seismic cable).*
    b. *Do we want to continue acquisition during the entire cementing operation?*

Items of concern to be addressed with risk assessment

1. Pinch points.	11. JSA's.
2. Over head ops.	12. Site access.
3. Trip hazards.	13. Punctures from use of special tools.
4. Slip hazards.	14. Type of hand protection.
5. Possible splinters from cable reel.	15. Types of eye protection.
6. PPE.	16. Hearing protection required?
7. Communications.	17. High pressure air
8. Stop the job.	18. Hydraulics.
9. 5 X 5 assessments.	19. Use of tools.
10. Unnecessary personnel	

What about potential failure before cementing ? how to fix if you can ?
Re test after cementing
After completion of operation secure cable before the rig moves

Appendix H -- HSE Bridging Document for IBDP

HSE BRIDGING DOCUMENT

Issue/Revision:	1.1
Operating Co:	Archer Daniel Midland (ADM)
Integrated Services	Schlumberger Carbon Services
Well Name:	ADM Well #1 - CCS
Rig:	Les Wilson Rig 25
Field:	ADM Plant site

Prepared by: PT Hughes, Jr., P.E. SCHLUMBERGER CARBON SERVICES ____________________ (signature) Date:	Agreed by: Mark Carroll ADM HSE Manager ____________________ (signature) Date:
Agreed by: Scott Marsteller SCHLUMBERGER CARBON SERVICES/Project Manager ____________________ (signature) Date:	Agreed by: Ron Peterson ADM ____________________ (signature) Date:
Agreed by: Scott Pugsley Les Wilson Drilling, Contracts Manager ____________________ (signature) Date:	Agreed by: Tom Stone ADM ____________________ (signature) Date:

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1.1 INTRODUCTION

ISGS, ADM, Schlumberger and Les Wilson Drilling are jointly involved in the drilling of a CCS injection well on ADM Plant site property, Decatur, Illinois. Each of these parties operates it's own HSE management system. For drilling operations to proceed efficiently and safely, it is necessary to integrate these systems. This is particularly critical for the management of activities. Many of the activities present significant risk to one or more of the parties. The imposition of one party's HSE-MS does not provide adequate risk control.

The purpose of this HSE Bridging Document is to integrate the HSE management systems of ADM, Schlumberger, and Les Wilson Drilling by clearly defining the interfaces and by assigning responsibilities to individuals in each of the three organizations. The document provides the reference point for all involved companies during the drilling and well operations phase of the CCS Contract between the ISGS, ADM, Schlumberger and Les Wilson Drilling as well as other core services that occasionally might offer services in the Project and gives evidence to the senior management of all parties that operations will be conducted within the envelope of the respective HSE management systems. This approach promotes open lines of communication among all parties.

HSE management systems bridging arrangements should ensure that HSE standards achieved by any one party through the application of it's HSE-MS are not compromised by another party while undertaking shared activities.

The company HSE management systems involved in the process are documented in detail in the respective HSE management system manuals:

- ADM – as described in their ADM Safety Rules for Contractors (see attached)
- SCHLUMBERGER CARBON SERVICES - as described in their QHSE Management System
- Les Wilson Drilling Co - as described in their *HSE Management System* (See attached)
- SCHLUMBERGER CARBON SERVICES contractors - as described in their individual HSE Management System documents.
- Management of contractors and third parties by ADM and Les Wilson Drilling Co. is managed in accordance with their respective HSE management systems (Ref. 1.10.1 and Ref. 1.10.4).

1.2 HSE OBJECTIVES

General HSE objectives are summarized within the HSE corporate statements and policies of the different members of the project team. This document defines which company's policies take precedence for HSE issues.

The overall objective of this document is to ensure the effective management of risks to the environment and the health and safety of people, assets and the reputation of all parties involved in the project to ALARP - "as low as reasonably practicable". By defining all interface issues, potential sources of conflict among the companies' HSE management systems can be removed. This HSE Bridging Document supports the companies' HSE policies. This helps to ensure that health, safety and environmental objectives can be treated in an equal manner to all other business objectives, and are not compromised in the pursuit of other goals, such as efficiency or financial targets.

1.3 MANAGEMENT STRUCTURE, RESPONSIBILITIES AND ACCOUNTABILITIES

1.3.1 Management Structure

A management organization chart summarizing the companies involved in the project, key positions for personnel in land offices and at the well site and the primary lines of reporting/communication is given in Figure 1.

1.3.2 Roles and Individual Responsibilities and Accountabilities

The roles of the principal companies involved in the drilling operations of the CCS, ADM drilling campaign are summarized as follows:

ADM	Overall control of and responsibility of the CCS, CO2 sequestration well construction campaign, i.e. drilling, well services, logistics, transportation, communications, HSE, Emergency Response Plan including Medevac, etc.
Schlumberger	Responsible for the day-to-day supervision of drilling operations, service providers, logistics, administration of services and execution of operations.
Les Wilson Drilling	Provision of the rig including crew, medical First Aid Kit for rig personnel and rig HSE management system.

1.3.2.1 On the Rig

The roles and responsibilities of the management team on the rig are summarized below.

- The ADM CCS Project Coordinator and the SCHLUMBERGER CARBON SERVICES Project Manager are responsible for giving overall direction to the project. They are the interface between other ISGS/Schlumberger and ADM departments and the drilling operations team.

- The ADM Contract Wellsite Supervisor has overall responsibility for all day to day drilling operations. He is accountable to the SCHLUMBERGER CARBON SERVICES Project Manager in Champaign, Illinois and receives direction/input from the ADM Project Coordinator to ensure that drilling operations are conducted in a safe, environmentally responsible, and cost effective manner. He is responsible for the direction of the Les Wilson Drilling Toolpusher. In the case of a well control emergency, the ADM Contract Wellsite Supervisor takes overall responsibility of all operations in close liaison with the SCHLUMBERGER CARBON SERVICES Project Manager and the SCHLUMBERGER CARBON SERVICES Well Architect , ADM Project Coordinator and the Les Wilson Drilling Co Toolpusher. The ADM Contract Wellsite Supervisor is also responsible for the direction of any Schlumberger Assistant Well

  Site Supervisor (if any), Well Site Engineer, and ADM contractors on the rig. His duties include ensuring compliance with the HSE policies and procedures of the Project, ADM, Schlumberger and their respective companies. He attends all Rig HSE meetings.

- The Les Wilson Drilling Toolpusher is responsible for the direction and supervision of the drill crew, for analyzing and overseeing all rig operations and for regular rig inspections. He also has a responsibility to ensure that all drill crewmembers are trained in, and comply with, HSE procedures.

The Toolpusher is accountable to the Les Wilson Drilling Rig Manager to ensure that rig operations are conducted in a safe and environmentally responsible manner. The Les Wilson Drilling Toolpusher takes directions for execution of operations from the ADM Contract Wellsite Supervisor assisted by Schlumberger Carbon Services Project Manager and the Well Architect. In the case of a well control emergency, the Toolpusher takes the responsibility of executing all operations, under the direct direction of the ADM Contract Wellsite Supervisor.

- The Les Wilson Drilling Night pusher (if this be the case) assumes responsibility for the Toolpusher's duties whenever the Toolpusher is off duty. He is also responsible for providing training in well control, fire prevention, firefighting and emergency response to work crews. He is also charged with the responsibility for organizing pre-operational safety meetings.

The Les Wilson Driller on tour is responsible for operating and maintaining drilling and safety related equipment. The Les Wilson Driller oversees rig floor operations to ensure compliance with HSE procedures.

1.3.2.2 Office

The roles and responsibilities of the office management team are summarized below:

- The Schlumberger Project Manager is accountable to the ADM Management and ISGS Management staff. He is responsible for overseeing the execution of the drilling program in the CCS Project drilling campaign in a safe and efficient manner. The Schlumberger project manager works closely with the Les Wilson Drilling management at all times. He is directly responsible for ensuring that the ADM Contract Wellsite Supervisor, the Senior Well Architect understand all the policies in place and carry out the work program, policies and procedures as required.

- The Schlumberger Well Architect reports to the Schlumberger Project Manager in the ADM, CCS Project. His main responsibilities are to ensure that the day to day operations are carried out as per the well plans. He is responsible for the appropriate technical integrity of the designs for the wells. He is responsible for the in depth analysis and implementation of new technology and lessons learnt. He is responsible for the implementation of new processes and procedures that will impact the performance of the drilling of the wells in the ADM, CCS Project, Illinois.

- The Les Wilson Drilling Rig Manager is the primary point of contact for ADM and Schlumberger for all matters related to the rig, and oversees all Les Wilson Drilling operations on the rig. The LES WILSON DRILLING Rig Manager reports directly to the ADM Operations Manager in Carmi. The LES WILSON DRILLING Rig Manager works closely with the SCHLUMBERGER CARBON SERVICES Well Architect and Project Manager to ensure the operations are carried out in an efficient manner.

- ADM Engineering is responsible for ensuring that the overall drilling program is carried out in an efficient and safe manner. The ADM Operations Managers ensures that SCHLUMBERGER CARBON

SERVICES and LES WILSON DRILLING have the information and resources available to carry out the operations as requested by ADM and the ISGS.

- The ADM HSE Manager, located in Decatur, Illinois, is responsible for supporting the project as needed and providing day-to-day HSE advice, especially concerning emergency response operations e.g. MEDEVAC, major environmental incidents and ADM plant-specific HSE compliance.

1.3.3 Management of Well Control Incidents

The parties have agreed that the SCHLUMBERGER CARBON SERVICES **Well Control** Procedures for the ADM, CCS drilling campaign with the LES WILSON DRILLING Rig 25 (Appendix A) will be followed for all well control incidents. In case of a kick, the parties have agreed to the use of a hard shut-in of the well using either the ram or annular preventers.

For any Well Control Incident it will be the responsibility of the LES WILSON Driller on tour/duty (or authorized delegate) to initiate communication with the LES WILSON DRILLING Toolpusher and the Contract Drilling Supervisor.

Responsibility for shutting-in the well lies with the LES WILSON Driller, or his authorized delegate. LES WILSON DRILLING will ensure that the Driller or his authorized delegate is aware that he is empowered to perform this task.

The ultimate responsibility for any well kill decision rests with the ADM Contract Wellsite Supervisor with consultation with the SCHLUMBERGER CARBON SERVICES Well Architect in consultation with LES WILSON DRILLING and ADM.

Regarding any decision to change the well kill procedure defined in appendix A

- If there is sufficient time, such change must be approved in writing by the SCHLUMBERGER CARBON SERVICES Project Manager and Well Architect and the LES WILSON DRILLING Rig Manager in Carmi, Illinois.

- If there is not sufficient time, such change must be approved by the ADM Contract Well Site Supervisor, the Well Architect and the LES WILSON DRILLING Rig Toolpusher.

At all times there will be a minimum of one LES WILSON DRILLING employee on the rig floor who is competent in well control, demonstrated by holding a current BOP certificate, which must be to the either the IADC Well Cap or International Well Control Forum (IWCF) standard. Additionally there must be at least 1 LES WILSON DRILLING Toolpusher or Tourpusher on site with a well control certificate to one of these two standards. Also the SCHLUMBERGER CARBON SERVICES Well Architect and the ADM Contract Well Site Supervisors must hold a well control certificate to one of these two standards. Training will be provided if any of the certifications have expired. All certificates will be filed at the rigsite in one of the Project Files

1.4 COMMUNICATION

1.4.1 Communication Interface

Good communication between ADM, SCHLUMBERGER CARBON SERVICES, SCHLUMBERGER CARBON SERVICES's contractors and LES WILSON DRILLING are vital to ensure safe, environmentally responsible and effective operations. It is important that communication links are re-defined following any organizational changes within or among the parties.

There are four main areas of communication among the parties:

- routine communications
- feedback
- management of change
- emergency communication

1.4.2 Routine Communications

A variety of communication tools will be utilized on a routine basis to establish and maintain effective lines of communication between the rig and office management teams and on the rig itself. The tools to be used include but are not limited to:

- Risk Identification Reports
- Weekly project progress reports
- Monthly performance reports
- Near miss and injury reporting
- Emergency response drills
- Weekly rig crew safety meetings
- Pre-tour safety meetings
- Log books
- Daily planning meetings

- Pre-operations safety meetings
- Tool box safety meetings prior to non-routine operations
- Office/rig site communications.

Where appropriate, regular meetings are held with employee representatives to communicate and encourage participation and involvement in HSE issues.

1.4.3 Feedback

Feedback in the form of suggestions for improvement is also encouraged from the LES WILSON DRILLING 25 rig crews and service personnel during daily pre-tour HSE meetings.

1.4.4 Management of Change

Significant changes to the Drilling Program must be approved in writing by ADM, SCHLUMBERGER CARBON SERVICES Well Architect and LES WILSON DRILLING management teams. Such changes will be issued by the ADM Contract Wellsite Supervisors in written communications between the SCHLUMBERGER CARBON SERVICES office management team and the ADM Contract Well Site

Supervisor. The changes must be distributed to the LES WILSON DRILLING rigsite management team and all parties in town. If such changes impact upon this HSE Bridging Document, then its custodian, the SCHLUMBERGER CARBON SERVICES Project Manager, will make any updates required.

Changes in the personnel roster at the rig will be notified as part of the normal reporting procedures from the rig to the office. All new personnel to the rig will receive an initial HSE briefing, which will be provided by designated LES WILSON DRILLING personnel and which is briefly outlined in the attached.

1.4.5 Emergency Communication

Details of the communication requirements for an emergency situation are contained in Section 1.5.6 of this bridging document, **Emergency Response Procedures**, and are summarized in the flowchart in Figure 2.0. Contact numbers for the SCHLUMBERGER CARBON SERVICES Alliance are listed in Figure 3.0

1.4.6 Regulatory Body Communication

Any communications required to be made with any local, state or Federal USA government agencies or regulatory bodies will be made by ADM and/or the ISGS or via the Schlumberger Carbon Services Project Manager and Team at the University of Illinois. This communication will have to be coordinated with assistance from the ADM Contract Wellsite Supervisor and the Schlumberger Well Architect

1.5 HAZARD IDENTIFICATION, ANALYSIS AND RISK MANAGEMENT

Prior to the onset of operations, the office and rig site management teams, assisted by the ADM HSE Manager, systematically identify and assess the HSE hazards that are present in the shared activities. Controls are specified for those hazards, which are considered to pose a significant risk to operations.

Hazard controls are primarily contained in the Work Program, Operational Procedures and the Permit to Work System, as detailed in Section 1.6. Additional controls relating to health, the environment, security and safety are detailed below.

1.5.1 Health Arrangements

To protect the health of everyone involved in the ADM, CCS drilling campaign, ADM, LES WILSON DRILLING and SCHLUMBERGER CARBON SERVICES have specified a number of medical requirements. All Les Wilson Drilling personnel are to adhere to the employment requirements of Les Wilson Drilling, including but not limited to Drug Testing Policy, routine medical physicals, if any, and other employment requirements. ADM, LES WILSON DRILLING and SCHLUMBERGER CARBON SERVICES are responsible for ensuring that all their own personnel and contractor staff meet these requirements. In the case of an emergency or a severe operational problem, these requirements may be waived for temporary visitors to the well site. This waiver requires the written approval of the ADM Operations Manager, SCHLUMBERGER CARBON SERVICES Project Manager and LES WILSON DRILLING Rig Manager. The provision of medical facilities and the upkeep of the medical records on the rig LES WILSON DRILLING 25 (if any) is the responsibility of Les Wilson Drilling.

The LES WILSON DRILLING Rig Toolpusher is responsible for regular hygiene and medical care for their personnel and areas such as any rig toilets, bathrooms, and crew change rooms (if any).

1.5.2 Waste Management

Arrangements and individual responsibilities for waste management conform to the recommendations specified in the ADM Environmental Impact Statement or Site Environmental Plan (Ref. 1.10.12) and comply with regulatory discharge requirements. ADM is the owner of all wastes, surface or sub-surface and such wastes will be managed by the rig team on behalf of ADM to ensure world class Environmental compliance and performance in the drilling campaign. In addition, solids control environmental monitoring with regards to discharged water from drilling fluids, sewage, cuttings disposal, gas emissions, and sample analyses are in compliance with all local, state, and federal government official hydrocarbon decrees or permit criteria. ADM Contract Wellsite Supervisor to have a copy of this in the WSS trailer at all times.

1.5.3 Security

ADM is responsible for informing the appropriate government authorities (if any are required) of the location of the rig and for providing copies of the certificate issued by the various local, state or Federal authorities to the rigsite (Wellsite Drilling Supervisor's trailer) SCHLUMBERGER CARBON SERVICES Project Manager.

1.5.4 Weapons, Alcohol & Drugs

ADM, SCHLUMBERGER CARBON SERVICES and LES WILSON DRILLING maintain a policy of no weapons, alcohol, and drugs in the ADM, CCS Drilling Campaign. All personnel working on the rig are subject to this policy. Each third party (Les Wilson and Schlumberger) will comply with their own policies and practices in regards to weapons, drugs & alcohol.

1.5.5 Use of STOP or Equivalent Program

All parties at the well site agree to the use of Dupont's Safety Training and Observation Program (STOP) or equivalent to reduce unsafe acts and conditions, identify and record near miss accidents and incidents, and reduce the risk of lost time injuries and environmental incidents to ALARP. It is known that Les Wilson Drilling does not utilize the Dupont STOP system of constructive, positive reinforcement HSE system, but rather their own, which will be utilized during the drilling campaign. All rigsite employees and SCHLUMBERGER CARBON SERVICES contractor employees will undergo some training in the proper use of this proactive, positive reinforcement system of Les Wilson Drilling.

1.5.6 Recovery Measures

The office and rig site management teams, assisted by the ADM HSE Manager, agree on the key recovery measures required in the event of loss of control/release of a significant hazard. Recovery measures are in place for:

- Well Control Incident
- Medical Evacuations
- Environmental Incident

1.5.6.1 Well Control Incident

Refer to Section 1.3.3: Management of Well Control Incidents.

1.5.6.2 Medevac

Medical evacuations (Medevac) from the well site are initiated by the ADM Contract Drilling Supervisor or LES WILSON DRILLING Toolpusher with prior approval and assistance from the ADM Security Manager for the Plant.. The ADM Contract Drilling Supervisor or LES WILSON DRILLING Toolpusher will contact the ADM radio operator at on duty to initiate ADM's evacuation procedures. ADM is responsible for the provision of transportation from the rig to the local airport. Arrangements for ambulance, hospital, notification of next of kin, etc. are the responsibility of ADM, SCHLUMBERGER CARBON SERVICES or LES WILSON DRILLING as appropriate.

1.5.6.3 Environmental Incident

Environmental incidents are controlled in the same manner as other emergency responses and are dealt with as specified in the ADM Environmental Impact Statement (Ref. 1.10.12) and the Operations Emergency Response Plan (Ref 1.10.14).

1.6 WORK PROGRAM AND PROCEDURES

1.6.1 Work Program

The contracted scope of work for each of the parties involved in the ADM, CCS Drilling campaign is primarily defined by the respective contracts and by the Drilling Program.

Prior to the commencement of drilling operations there will be a pre-spud meeting (and Drill Well on Paper Exercise-DWOP). Any disagreements or questions regarding program content, hazard identification, assessment and control or HSE management will be resolved, and amendments to the Drilling Program made as required.

Additionally, it is the responsibility of all key office and rig-site managers and supervisors from SCHLUMBERGER CARBON SERVICES, ADM and LES WILSON DRILLING CO to continually assess the suitability of this drilling program and recommend any alterations that may be required to maintain a risk level that is "as low as reasonably practicable."

1.6.2 Changes to Program

Any significant changes to the Drilling Program are covered in Section 1.4.4: **Management of Change**.

1.6.3 Operational Procedures

All work is carried out in accordance with the written Drilling Program. No work is performed which in any way conflicts with ADM, SCHLUMBERGER CARBON SERVICES or LES WILSON DRILLING HSE objectives, policies or procedures. In such cases where conflict occurs, work is to be stopped until conditions are once more safe to continue as determined by the relevant person in charge, i.e. the ADM Contract Drilling Supervisor or LES WILSON DRILLING Toolpusher. The Drilling Program will be re-assessed and amended as required.

1.6.4 Permit to Work (PTW) System

All rig operations are controlled by the LES WILSON DRILLING's Permit to Work (PTW) System covering:

- Confined space entry
- Welding & Cutting
- Electrical and Mechanical Isolation

The PTW system is supplemented by the LES WILSON DRILLING's Job Safety Analysis program. This program requires analysis of the hazards associated with a particular activity (or sub-activity) and hence identification of the required safe working practices. The LES WILSON DRILLING Job Safety Analysis (JSA) program is developed on the rig and is therefore rig specific. It is developed by rig based personnel, including the crews and supervisors and third party personnel when relevant. Development of the Job Safety Analysis program is a training exercise for these staff as well as a risk mitigation measure. The file containing previous LES WILSON DRILLING Job Safety Analysis program activities, remains with the rig at all times.

All personnel new to the rig will receive induction training in the PTW and LES WILSON DRILLING Job Safety Analysis program systems. Appropriate personnel receive formal training.

Personnel are issued with personal protective equipment (PPE) as required by the relevant SCHLUMBERGER CARBON SERVICES, ADM or LES WILSON DRILLING policy. Where such PPE is rig specific, it is provided by LES WILSON DRILLING. All other PPE is the responsibility of the individual companies. All personnel will have to wear proper PPE per ADM Policy (safety boots/shoes, safety gloves where /when needed, safety goggles/glasses and hard hat at a minimum).

1.6.5 Emergency Response Procedures

Emergency response arrangements for the well site are the responsibility of ADM, as defined in Figure 2.0 and the ADM Operations Emergency Response Plan. Emergency response arrangements are supported by the ADM Security Manager.

The initial declaration of an emergency is made by the ADM Contract Drilling Supervisor or LES WILSON DRILLING Toolpusher. Should escalation occur such that resources on the rig are unable to manage the incident, the rig site Radio Operator is notified to initiate call-outs of the duty personnel forming the initial Emergency Response Team. This team convenes at the location indicated in the ADM Operations Emergency Response Plan and co-ordinates responses from there. Additional support will be made available from ADM, SCHLUMBERGER CARBON SERVICES or LES WILSON DRILLING management support teams in Illinois when required.

Copies of the ADM Operations Emergency Response Plan are held at the well site, the location Supply Base and at the designated location for the response teams in Illinois and Schlumberger in Texas.

A schedule of emergency exercises and drills will be planned and implemented by the LES WILSON DRILLING Toolpusher. Emergency exercises will be monitored and supervised by ADM Contract Wellsite Supervisor. Results of the exercises will be reported to the ADM Manager, HSE and Security Manager, the SCHLUMBERGER CARBON SERVICES Project Manager as well as the LES WILSON DRILLING Rig Manager. They also will be reviewed in daily pre-tour meetings.

1.7 PERSONNEL MANAGEMENT, COMPETENCE & TRAINING

1.7.1 Crewing Levels

Crewing levels for the ADM, CCS drilling campaign should be held to a minimum. Additional personnel may be required at various stages throughout the campaign to provide maintenance skills, specialist assistance, training and to conduct audits. However, the use of such personnel is governed by rig operations and availability of site-only space. It is the responsibility of the LES WILSON DRILLING Toolpusher or ADM Contract Well Site Supervisor to assess the available space availability for the utilization of additional personnel.

Crewing levels are monitored by the ADM Contract Well Site Supervisor and are notified to the office management team via the daily reports. This is in the format of total numbers on the rig and total numbers by company. The LES WILSON DRILLING Toolpusher is responsible for maintaining a rig site personnel breakdown by name and company.

1.7.2 Competence, Selection and Training

SCHLUMBERGER CARBON SERVICES operates a Quality Management System (QMS). A major element of this QMS is the SCHLUMBERGER CARBON SERVICES Competence Assurance program which in turn assesses and utilizes the competence assurance programs of SCHLUMBERGER CARBON SERVICES contractors.

The required competencies of key LES WILSON DRILLING personnel are detailed in the ADM and LES WILSON DRILLING, Drilling Agreement. All LES WILSON DRILLING CO personnel are trained throughout the contract and are subject to performance competence checks by their supervisors. Any 'site specific' training requirements are provided by ADM/Drilling Contractor as required.

1.8 EQUIPMENT FITNESS FOR PURPOSE

1.8.1 Design and Construction Standards and Certification.

The LES WILSON DRILLING Rig 25 is constructed in accordance with the standards described in the LES WILSON DRILLING QA Procedures. The mast and superstructure are certified by a manufacturer's representative. All overhead string components are inspected as per API-RP8B. All BOP equipment is hydrostatically tested upon installation and at no more than 14 day intervals. Drill string components are inspected as per API-RP7G.

The SCHLUMBERGER CARBON SERVICES Quality Management System (Shield 2000 or IPMS) assures the fitness for purpose of all SCHLUMBERGER CARBON SERVICES contractor well service equipment. Only certified well services equipment will be used. Appropriate certifying documentation will be provided to enable this to be verified. If this documentation does not arrive with the equipment, the equipment is not to be put into service until such time as verification can be made, unless approval in writing is obtained from the ADM Contract Drilling Supervisor and the SCHLUMBERGER CARBON SERVICES Project Manager.

Individual Schlumberger product lines and third party contractors ensure fitness for purpose of their equipment through control of design and construction standards and certification.

Any additional HSE-critical equipment manufactured elsewhere outside the USA or on the rig requires appropriate certification prior to use, e.g. pressure vessels and lifting equipment/pad-eyes, etc.. It is the responsibility of the ADM Contract Wellsite Supervisor to ensure that any such additional equipment is fit for purpose and safe to use prior to entering service.

All lifting equipment (i.e. slings, harnesses, pad-eyes, etc.) will be inspected and certified prior to use by LES WILSON DRILLING or the respective service company providing the equipment and are/will be re-certified annually for continued use.

The parties recognize and agree that reliance on ISO 9000 certificates alone is not sufficient to reduce operational risk of equipment design and construction to ALARP, and that this requires the personal, active, and visible involvement of management at all levels.

1.8.2 Modification Procedures

Minor modifications to the LES WILSON DRILLING RIG 25 structure or layout will be subject to agreement by the LES WILSON DRILLING Toolpusher and the ADM Contract Wellsite Supervisor with consultation with the Schlumberger Well Architect. For any significant modifications, notification and approval from the office management team is also required. Major changes to the mast, sub-structure, or lifting equipment of the rig LES WILSON DRILLING 25 must be notified to LES WILSON DRILLING headquarters in Carmi, Illinois for prior approval. Depending upon the degree of modification requested, LES WILSON DRILLING headquarters and the manufacture's approval is also required.

In all cases it is the responsibility of the LES WILSON DRILLING Rig Manager to ensure that the LES WILSON DRILLING Headquarters office HSE or Engineering Department approves any such rig modifications.

Field technical equipment of Schlumberger Well Services and REW (Wireline & Testing) is modified in accordance with standard instructions (Modification Recaps) issued to the product center responsible for its design and manufacture. Modifications are only performed in accordance with such instructions and by suitably trained personnel. All such modifications are recorded in the tool/equipment history cards and are stamped on the tool identification plate.

1.9 MONITORING, AUDITING AND REVIEW

HSE performance is monitored by means of agreed performance indicators such as:

- STOP Cards or equivalent positive reinforcement card system
- HSE Training Hours per Employee per Year
- % of Action Items Complete (from STOP Audits or other safety audits)
- Lost Time Injury Frequency Rate

HSE statistics will be collated on the rig by the LES WILSON DRILLING Toolpusher and are forwarded to the LES WILSON DRILLING HSE Manager and the ADM Contract Wellsite Supervisor and then comiled for all personnel by the Contract Wellsite Supervisor and presented to both ADM Security/HSE Management as well as to the Schlumberger Project Manager every week. The ADM Contract Drilling Supervisor will prepare a monthly report and send it to the LES WILSON DRILLING Rig Manager, SCHLUMBERGER CARBON SERVICES Project Manager and ADM HSE/Security Manager.

Appropriate controls will be in place to ensure the implementation of corrective actions identified by the monitoring, auditing and review processes. It is the responsibility of the SCHLUMBERGER CARBON SERVICES Project Manager or LES WILSON DRILLING Rig Manager to ensure that all corrective actions

are implemented and closed out on a timely basis. All corrective items should be reported to the SCHLUMBERGER CARBON SERVICES Project Manager.

1.10 INCIDENT INVESTIGATION AND REPORTING

ADM's reporting system has primacy for the reporting of all accidents and incidents. Additionally, all accident/incident reporting is in accordance with LES WILSON DRILLING's incident & investigation reporting procedures. In parallel, the SCHLUMBERGER CARBON SERVICES QHSE Incident/Injury investigation system is also followed if the incident affects SCHLUMBERGER CARBON SERVICES or its contractor staff and will be entered into QUEST (after a project node is set up by the Project Manager).

All action items resulting from investigations by SCHLUMBERGER CARBON SERVICES, ADM and LES WILSON DRILLING are incorporated into a remedial work plan. Each action item is assigned an action party, verification party and a target close-out date. (Example can be furnished if desired)

1.11 CONCURRENCE STATEMENT

The HSE management systems detailed in this document is to remain in place for the duration of the ADM, CCS drilling campaign, or until such time as this bridging document is re-issued.

It is the responsibility of the SCHLUMBERGER CARBON SERVICES Project Manager to ensure that this bridging document is subject to detailed review and revision on a routine basis or upon significant changes in the work program. (or if/when additional work scope is planned or another well is planned)

This HSE Bridging Document is acceptable to the respective companies, as acknowledged by the signatures on page 1.

REFERENCES

1.10.1 ADM HSE Management System

1.10.2 Schlumberger SCHLUMBERGER CARBON SERVICES HSE Management System ***SHIELD 2000***, Version 1, June 2000 and or IPMS

1.10.3 Les Wilson Drilling Co HSE or Safety Management System

1.10.4 Well Control Bridging Document for the ADM, CCS Drilling campaign with the LES WILSON DRILLING 138

1.10.5 ADM Environmental Impact Assessment - ADM (if required)

1.10.6 ADM Operations Emergency Response Plan for the drilling campaign -

1.10.7 ADM Environmental Contingency Plan

1.10.8 SCHLUMBERGER CARBON SERVICES Quality Management System

1.10.9 Job Descriptions for Field Personnel

1.10.10 Operations Emergency Response Plan

1.10.14 ADM Spill Contingency Plan

Figure 1.0 HSE Management Organization Chart for ADM, CCS Drilling Campaign

(see below for organization names & call-out)

Figure 4.0

Flowchart of Emergency Communications and ERP Contacts to be made from the Rig to the SCHLUMBERGER CARBON SERVICES Team and ADM Plant:

Plant Call Coordinators and Assignments

Responsible Plant Employee	Department(s) to Call	Name	Work #	Home / Mobile
Safety Manager	Corn Division Safety Manager	Greg Gurski	451-2744	
	Corporate Compliance (Safety)	Dave Debrosky	451-4760	
	Corporate Insurance	Molly Smalley	451-2664	
	OCE Safety and Health	Gene Smith	451-4212	
Human Resources Manager	Corporate External Affairs	David Weintraub	424-5413	972-4150
	Corporate Worker's Compensation			
Quality Assurance Manager	Corporate Sales	Dick Light	451-4683	
		Pat Laegeler	424-5695	
Environmental Compliance Manager	Division Environmental	Dean Frommelt	451-6330	
	Corporate Compliance (Environmental.)	Mark Calmes	451-7456	

Corn Plant Contact Numbers

Title	Name	Work	Home	Other
V.P. Corn Division Operations	Randy Kampfe	451-5755	865-2838	**791-1488**
Corn Division General Manger	Ray Neff	451-2326	319-455-9822	319-551-7204
Plant Manager	Bill Manley	424-5750	864-3247	412-1334
Plant Superintendent	Steve Merritt	424-5751	864-2621	412-1337
Feedhouse Superintendent	Jerry Keezer	451-5114		217-413-7180
Alcohol Superintendent	Brian Berger	451-2747		
Mill Superintendent	Roger Edgecombe	424-5584	795-2148	
Refinery Superintendent	Brad Hunt	451-3330		217-412-0259
Maintenance Superintendent	Doug Oller	451-3414		
Maintenance Alternate	Rick Hadden	424-5732	763-6639	
Maintenance Alternate	Dan Rule	424-5762	864-5159	
Treatment Plant Superintendent	Brad Crookshank	424-5786	428-7341	
Treatment Plant Alternate	Steve Bugle	424-5786	874-2025	
Chief Engineer	Ron Peterson	424-5759	422-4864	
Engineering Alternate	Tom Stone	424-5897	875-0907	
Engineering Alternate	Jim Frieden	424-5757	692-2896	
Safety Manager	Greg Gurski	451-3277	672-8580	
Safety Alternate	Dennis Woodard	451-6740	877-2497	
Quality Assurance Manager	Deve Watson	451-4071		

Human Resources Manager	Jennifer Peck	424-5781		217-413-0232
Environmental Compliance Mgr.	Mark Carroll	451-2720	872-0945	217-412-9869
Environmental Alternate	Mike Reid	451-4630		201-1270
Environmental Alternate	Levi Lamothe	451-4724		
Corporate Traffic Coordinator				
Corporate Traffic Coordinator				
Corporate Traffic Coordinator	Tracy Causey		864-9279	413-9294

Outside Services

Bodine Environmental		800-637-2379
Electric Company	Ameren IP	424-7000
Gas Company	Ameren IP	424-7000
Decatur Water Department		424-2831
NS Railroad Company		425-2060
IC Railroad Company		424-2391
EPA National Response Cntr.		800-424-8802
EPA State Emergency Response Cntr.		800-782-7869

All other services to be requested through Corporate Security at 4444

Figure 5.0 Contact Numbers for SCHLUMBERGER CARBON SERVICES, ADM and All Core Services (to be completed prior to spud)

ADM-SCHLUMBERGER CARBON SERVICES ALLIANCE CONTACT LIST					
Name	**Company**	**Position**	**Ext.**	**Cell**	**Home**
			Fax:		
Ron Peterson	**ADM**				
Tom Stone	ADM				
Mark Carroll	ADM				
	ADM	SCHLUMBERGER CARBON SERVICES Comp. Man			
LES WILSON DRILLING RIG 25	ADM	SCHLUMBERGER CARBON SERVICES Comp. Man			
SCHLUMBERGER – Champaign, Illinois:			**Fax:**		
	Schlumberger	**General Manager**			
Dwight Peters	**SCHLUMBERGER CARBON SERVICES**	**SCHLUMBERGER CARBON SERVICES Mgr.**			
Scott Marsteller	SCHLUMBERGER CARBON SERVICES	Project Manager			
Jim Kirksey	SCHLUMBERGER CARBON SERVICES	Project Coordinator & SLB Service delivery Manager for Project			
	SCHLUMBERGER CARBON SERVICES				
	SCHLUMBERGER CARBON SERVICES				
	SCHLUMBERGER CARBON SERVICES				
Paul T Hughes, Jr., P.E.	SCHLUMBERGER CARBON SERVICES	Well Eng.			
	SCHLUMBERGER CARBON SERVICES	Well Eng.			
Ted Gilbert	SCHLUMBERGER CARBON SERVICES	Company Man			
Bob Herr III	SCHLUMBERGER CARBON SERVICES	Company Man			
	SCHLUMBERGER CARBON SERVICES				
	SCHLUMBERGER CARBON SERVICES				
	SCHLUMBERGER CARBON SERVICES				

	Dowell				
	Dowell				
	Dowell				
	Smith Bits				
MI/SWACO-Schwartz Drilling Fluids ???: 250-120 / 121 Fax: 261-701 PBX: 255-104					
Bo Kowskie	MI /SWACO	Mgr.			
Tristan Zimmerman	MI /SWACO	Drlg Fluids Specialist			
	MI /SWACO	Ops. Engineers			
	MI /SWACO	Ops. Manager			
ARMSTRONG PIPE & SUPPLY Fax:					
		Mgr.			
		Eng.			
Les Wilson Drilling ?????: 263-817 Ops. Fax: 435-964 Carmi:???? 263-823 444-715					
Scott Pugsley	LES WILSON DRILLING	Gen.Mgr.			
Verdayne Seals	LES WILSON DRILLING	Ops. Sup.			
Scott Pugsley	LES WILSON DRILLING	Ops. VP			
	LES WILSON DRILLING	Eng			
Marion White	LES WILSON DRILLING	Safety Mgr.			

Appendix A Interface Matrix

SECTION	Interface Issues to be Addressed	ADM	SCS	LWD	Notes on Interface Agreement/Comments/Document Reference (record the respective parties' systems, policies, procedures, codes of practice etc., which are agreed will apply to manage the health and safety risks at the interface)	Action Completed (Y/N) Date
1.1	**INTRODUCTION**		X			
1.1	Bridging Document Objectives		X			
	Contractor Qualification and Selection		X			
	Contractor Interfacing					
	Control of Contractor Activities					
1.1.1	Interface Matrix Issues	X	X	X		
1.2	**HSE OBJECTIVES**	X	X	X		
1.3	**MANAGEMENT STRUCTURE, RESPONSIBILITIES AND ACCOUNTABILITIES**					
1.3.1	HSE Management Organization Chart for Drilling Campaign, HSE Representatives, HSE Committee Structure	X	X	X		
1.3.2	Roles and Individual Responsibilities and Accountabilities	X	X	X		
1.3.3	Management of Well Control Incidents		X	X		
1.3.4	Operational Support and Interface Resources		X	X		
1.3.5	Reward and Recognition Schemes, Incentive Schemes		X	X		
1.4	**COMMUNICATION**		X			
1.4.1	Communication of Interface Arrangements	X	X	X		
1.4.2	Routine Communications	X	X			
1.4.3	Feedback Mechanisms, Workforce Involvement		X			
1.4.4	Change Management	X	X			
1.4.5	Emergency Communication	X	X	X		
1.4.6	Communication with Regulatory Bodies					
1.5	**HAZARD IDENTIFICATION, ANALYSIS AND RISK MANAGEMENT**					
	QRA/HAZOP/HAZID studies if applicable	X	X	X		
	Task/Activity/Specific Risk Assessments:		X	X		
	Identification and Analysis of Hazards, Assessment of Significant Risks, Hazard Controls, Plan and Set Standards for Identified Hazards:		X	X		
	Passenger and Freight Transportation	X				
	Adverse Weather Working Policy	X		X		

SECTION	Interface Issues to be Addressed	ADM	SCS	LWD	Notes on Interface Agreement/Comments/Document Reference (record the respective parties' systems, policies, procedures, codes of practice etc., which are agreed will apply to manage the health and safety risks at the interface)	Action Completed (Y/N) Date
	Scaffolding/Access/Working Environment			X		
	Tools and Equipment			X		
	Electrical		X	X		
	Ignition Sources			X		
	Housekeeping		X	X		
	Personal Protective Equipment		X	X		
	Equipment Procurement Standards		?	?		
	Equipment Certification			X		
	Equipment QC System		X	X		
	Manual Handling			X		
	Hazardous Substance/Materials		X	X		
	COSHH/OCNS					
	Dangerous goods Declaration - IATA Regulations	X		X		
	Noise and Vibration			X		
	Thermal Radiation			X		
	Ionising/Non-Ionising Radiation		X	X		
	Pressure		X	X		
1.5.1	Identification and Management of Occupational Health Hazards, Hazard Controls, Plan and Set Standards for Identified Hazards:		X	X		
	Drug and Alcohol Abuse Policy	X	X	X		
	Health and Fitness Screening and Monitoring		X	X		
	Smoking Hygiene and Welfare	X	X	X		
	Medical Treatment			X		
	Display Screen Equipment		X			
	Food Hygiene			X		
	Potable Water, Legionella Sampling	X		X		
1.5.2	Identification of Environmental Hazards and Waste Management Arrangements, Hazard Controls, Plan and Set Standards for Identified Hazards	X	X	X		
1.5.3	Identification and Management of Security Hazards, Hazard Controls, Plan and Set Standards for Identified Hazards	X	X	X		
1.5.4	Additional Policies, Weapons/Firearms, etc.	X	X	X		
1.5.5	Program for the Identification and Feedback of Unsafe	X	X	X		

SECTION	Interface Issues to be Addressed	ADM	SCS	LWD	Notes on Interface Agreement/Comments/Document Reference (record the respective parties' systems, policies, procedures, codes of practice etc., which are agreed will apply to manage the health and safety risks at the interface)	Action Completed (Y/N) Date
	Acts, e.g. STOP, Observation of Work/Behavior					
1.5.6	Recovery Measures for Well Control Incident, MEDEVAC, Environmental Incident, etc.	X	X	X		
1.6	**WORK PROGRAM AND PROCEDURES**					
1.6.1	Work Program, Work Instructions		X	X		
1.6.3	Operational Procedures		X	X		
1.6.4	Permit to Work System, Job Safety Analysis (JSA)		X	X		
	PTW System Formal Training		X	X		
	Job and Task Training		X	X		
1.6.5	Emergency Response Procedures, Exercises and Drill Schedules		X	X		
1.7	**PERSONNEL MANAGEMENT, COMPETENCE AND TRAINING**					
1.7.1	Crewing Levels		X	X		
1.7.2	Competence, Selection, Training, and Reviews		X	X		
	Well Control Training		X	X		
	Onshore Induction		X	X		
	Hazardous Substances Training		X	X		
	Occupation Health and Hygiene Training		X	X		
	Emergency Response Training		X	X		
	Defensive Driving / Commentary Drives		X			
1.8	**EQUIPMENT FITNESS FOR PURPOSE**					
1.8.1	Design and Construction Standards and Certification		X	X		
1.8.2	Modification Procedures, Engineering Hardware Modifications			X		
1.8.3	Materials and Spares Procurement			X		
1.8.4	Preventive Maintenance Procedures			X		
1.9	**MONITORING, AUDIT AND REVIEW**					
	Active Monitoring of HSE Performance	X	X	X		
	HSE Performance Measures		X	X		
	Structured HSE Monitoring Program (vs HSE Plan)		X	X		
	Worksite/Plant/Equipment Inspections			X		
	General Housekeeping Inspections		X	X		
	Joint Management Visits	X	X	X		
	Quality Improvement Process		X	X		
	Workforce Surveys		X	X		

SECTION	Interface Issues to be Addressed	ADM	SCS	LWD	Notes on Interface Agreement/Comments/Document Reference (record the respective parties' systems, policies, procedures, codes of practice etc., which are agreed will apply to manage the health and safety risks at the interface)	Action Completed (Y/N) Date
	HSE Performance Reports (Review of performance against plans)		X	X		
	Involvement of Staff in Performance Monitoring		X	X		
	Structured HSE Audit Program	X	X	X		
	Audits of Third Parties		X			
	HSE Management System Audits		X	X		
	Audits to Check Compliance with Standards	X	X	X		
	Audits to assist the Implementation of HSE Plans	X	X	X		
	Final review of the HSE Management System Interface Arrangements before Start of Operations		X			
	Pre-Execution Audits		X	X		
	Periodic Reviews for HSE Performance Reports, including reviews of Incident Reports and statistics		X	X		
	Joint Audits to Verify Compliance with HSE Management System Interfacing Arrangements	X	X	X		
	Demobilization and Close Out reviews	X	X	X		
	Schedule and Format of Joint Management HSE Performance Reviews		X			
	Joint Management Review of Effectiveness of HSE Management System Interfacing Arrangements	X	X	X		
	Communications/Tracking/Follow-up of Audit and Review Recommendations - Share Learning Lessons from Reviews		X	X		
1.10	**INCIDENT INVESTIGATION AND REPORTING**					
	Incident Notification (Internally and Externally to Authorities)	X	X	X		
	Incident Investigation, Reporting and Review	X	X	X		
	Communication/Tracking/Follow-Up of Incident Corrective Actions - Shared Learning		X	X		
1.11	**CONCURRENCE STATEMENT**					
Figure 1.0	Integration of HSE management systems		X	X		
Figure 2.0	Flow Chart of Outline Process for Establishing an HSE-MS Interface Document		X			
Figure 3.0	HSE Management Organization Chart for Drilling Campaign		X			

SECTION	Interface Issues to be Addressed	ADM	SCS	LWD	Notes on Interface Agreement/Comments/Document Reference (record the respective parties' systems, policies, procedures, codes of practice etc., which are agreed will apply to manage the health and safety risks at the interface)	Action Completed (Y/N) Date
Figure 4.0	Emergency Communication	X	X	X		
Figure 5.0	Emergency Contact Numbers, Radio Communications	X	X	X		

Appendix B Briefing Record

To be completed by the party receiving the briefing.

SECTION No.	SECTION	COMMENTS (See Below)
1.1	Introduction	Yes / No
1.2	HSE Objectives	Yes / No
1.3	Management Structure, Responsibilities and Accountabilities	Yes / No
1.4	Communication	Yes / No
1.5	Hazard Identification, Analysis and Risk Management	Yes / No
1.6	Work Program and Procedures	Yes / No
1.7	Personnel Management, Competence and Training	Yes / No
1.8	Equipment Fitness for Purpose	Yes / No
1.9	Monitoring, Audit and Review	Yes / No
1.10	Incident Investigation and Reporting	Yes / No
1.11	Concurrence Statement	Yes / No
Appendix A	Interface Matrix	Yes / No
Appendix C	Well Control Bridging document	Yes / No

ITEM	COMMENTS	SIGNED

I have read the detailed arrangements defined in the Interface Document and I understand and accept my accountabilities for the above mentioned Contract/Project.

NAME	FUNCTION	COMPANY	SIGNATURE	DATE

Appendix C - Well Control Bridging Document

- **GENERAL**
  - API System of units to be used.

- **WELL CONTROL**
  - All supervisory personnel for the rig contractor (Drillers, Tourpusher & Toolpusher), SCHLUMBERGER CARBON SERVICES Well Architect and the ADM WSS will hold a current Well control certification to Wellcap or IWCF standards.
  - Well control drills will be held at a minimum of weekly with all crews. LES WILSON DRILLING Tourpusher is responsible for carrying out the drills.
  - BOP's with a minimum of Annular, pipe rams, and blind rams will be installed below the 20" /13-3/8". They will be tested upon rigup and at no more then 14 day intervals thereafter.
  - The choke manifold will be installed and tested prior to drilling out the 20"/13-3/8" casing.
  - Casing pressure tests will be carried out prior to drilling out any string as per the well plans.
  - Should there be excessive metal shavings, a casing wear log should be run and a repeat of casing pressure test should be carried out.
  - Formation integrity test will be carried out immediately after drilling out the shoe of each casing string.
  - A minimum of 0.5 ppg Kick tolerance will be maintained at all times while drilling.
  - Drilling will be suspended after all drilling breaks exceeding 5 feet and investigated.
  - Flow check shall be done any time an unusual situation occurs.
  - A minimum of 50 psi overbalance will be maintained during static conditions.
  - The flow show and PVT will be working at all times when drilling in the 17 1/2" hole section and below.
  - An inventory of barite sufficient to raise the MW 1 ppg will be maintained at the well site at all times.

    When drilling below the 20"/13-3/8" shoe, slow pump rates will be carried out at the beginning of each tour and whenever there is a change of MW, BHA.
  - The well will be shut in using the hard shut in method using the annular preventer.
  - Responsibilities in the event of a kick.

    - The ADM WSS will be responsible for preparing the well control plan. The ADM WSS will make the plan in conjunction with LES WILSON DRILLING Toolpusher, SCHLUMBERGER CARBON SERVICES Well Architect.
    - LES WILSON DRILLING's Toolpusher will execute the plan.
    - LES WILSON DRILLING's driller has the authority to shut in the well anytime he fills that there is a well kick in progress. The driller will immediately inform the tourpusher/toolpusher.

  - For vertical wells, surveys will be carried out at no more than 300' intervals.

● **DIRECTIONAL DRILLING**

- An anti collision program will be continually run any time two wells are closer then 2 times the radius of uncertainty. Two separate operators will run the program independently on two different computers. Whenever the ellipse of uncertainty overlaps, for two wells, drilling will be suspended until it is decided to sidetrack or shut in the other well.

Distribution: The final Well Control Bridging Document shall be:

- Distributed to key office and well site personnel by the ADM, SCHLUMBERGER CARBON SERVICES, SCHLUMBERGER CARBON SERVICES contractors, and LES WILSON DRILLING as appropriate.
- Reviewed in detail during the pre-spud meeting.

ADM CONTRACT Well Site Supervisor

REPORTING:

- Directly reports to SCHLUMBERGER CARBON SERVICES Project Manager or the SCHLUMBERGER CARBON SERVICES Well Architect on a daily basis.
- Accepts advice from ADM and Les Wilson Drilling Co personnel.

RESPONSIBILITIES:

General:

- The SCHLUMBERGER CARBON SERVICES WSS is responsible for all OPERATIONS and QHSE of all persons at the wellsite.
- The SCHLUMBERGER CARBON SERVICES WSS is the representative of ADM and Schlumberger on the rig. He is the local manager of all ADM and Schlumberger assets and personnel on-site.
- The SCHLUMBERGER CARBON SERVICES WSS is responsible for planning, co-ordination, supervision, execution, and evaluation of all work performed by LES WILSON DRILLING, Schlumberger and other third parties on the rig.

HSE:

- Shows leadership in all HSE matters by actively participating in all safety meetings and actively promotes the use of the STOP (or equivalent) program through his participation on a daily basis.
- Authority for all HSE related activities for all personnel on rigsite.
- Ensures a permit to work system is in place and working according to SCHLUMBERGER CARBON SERVICES policies AND/OR Les Wilson Drilling's, depending on the higher standard.
- Ensures the rig operations are conducted in accordance with ADM and SCHLUMBERGER CARBON SERVICES policies and procedures.
- Ensures that all personnel follow the HSE policies and procedures of ADM, SCHLUMBERGER CARBON SERVICES and LES WILSON DRILLING.
- Ensures that all Schlumberger, Schlumberger sub contractor's personnel have received and are up to date in the relevant HSE training for their position.
- Ensures that all Schlumberger and Schlumberger sub contracted personnel attend the relevant safety meetings for their position and furthermore play an active part in these meetings.
- Ensures that **all** accidents and incidents are reported to the project office in Champaign , Illinois and Decatur, Illinois in a timely manner (immediately for serious accidents or incidents, next report for minor accidents or incidents.
- Leads accident/incident investigation and reporting.
- Monitors compliance with applicable rules, regulations and other program constraints.
- Ensures that all programs are in compliance with policies and procedures.
- Ensures that all personnel attend STOP training or equivalent, rig-based, positive reinforcement system and actively participate in the program.

- Ensures that all personnel are aware and in compliance with ISO 14000 certification standards and follow these requirements.

Planning and Control:

- Co-ordinates and supervises rig site activities with LES WILSON DRILLING, third party contractors to ensure compliance with work program and optimum efficiency in job execution.
- Prepares daily the 72 hour forecasts and sends to town each afternoon by 1800 hours.
- Prepares equipment checklists for each hole section and sends to town prior to starting each hole section.
- Provides feedback to SCHLUMBERGER CARBON SERVICES Well Architect regarding changes to well plan.

Operations:

- Summarises and researches offset data for well optimisation.
- Responsible for monitoring well parameters and drilling trends.
- Assists in evaluation of potential improvements to well design and execution of operations.
- Ensure suitable operational procedures are followed.
- Leads recommendations and decisions regarding Stuck Pipe and Fishing Operations.
- Final authorisation of downhole and equipment installation (Tallies, space-outs, etc.)
- Overall responsibility for quality control of construction of the well.
- Responsible for witnessing wireline logging when no ADM or SCS representative is onsite.

Emergency Duties:

- Directs well control operations and Supervises the application of appropriate well control measures.
- Makes decisions to evacuate the rig.
- Focal point for implementation of Emergency Response procedures.

Management:

- Overall management of rig site team.
- Onsite management and interpretation of contracts and terms.
- Cost control and monitoring for the wellsite operations.
- Responsible for compliance with Environmental Management Plan requirements.

Communication:

- Holds daily co-ordination meeting with companies and service contractors.
- Prepares daily morning report and cost report, sends reports to town by 06:30 each morning.
- Communicates daily with SCHLUMBERGER CARBON SERVICES Project Management, ADM Operations Manager, and SCHLUMBERGER CARBON SERVICES Well Architect.

- Prepares weekly report and sends to SCHLUMBERGER CARBON SERVICES Project Management office by 08:00 each Monday morning.

- Prepares monthly report and sends to SCHLUMBERGER CARBON SERVICES Project Management office by 08:00 hrs. on the first of each month or as agreed to by Project Manager/ADM & ISGS.

Administration:

- Final authorisation of the rig contractors morning report (IADC) Report.
- Final responsibility for the daily drilling report.
- Approval of job tickets.
- Chairs daily meetings with service contractors and ensures that actions are followed up.
- Contributes comments for End of Well reports (EOWR).

LES WILSON DRILLING Toolpusher

REPORTING:
- Reports functionally to the Rig Superintendent.
- Reports operationally and with regard to QHSE matters to the ADM wellsite supervisor.
- Reports contractually to the ADM Operations Manager.

RESPONSIBILITIES:

General:
- The TOOLPUSHER is the representative of LES WILSON DRILLING on the rig. He is the local manger of LES WILSON DRILLING´s assets and personnel.
- The TOOLPUSHER manages LES WILSON DRILLING´s interest at the rig site in respect to ADM, the well program and all personnel on the rig.

HSE:
- Shows leadership in all HSE matters by actively participating in all safety meetings and actively promotes the use of the STOP or equivalent program thru his participation on a daily basis.
- Ensures the rig operations are conducted in accordance with LES WILSON DRILLING´s policies and procedures and the HSE case.
- Ensures that all personnel follow the LES WILSON DRILLING´s and ADM HSE policies and in particular that LES WILSON DRILLING and all other services´ personnel follow these policies.
- Ensures that all LES WILSON DRILLING´s and LES WILSON DRILLING´s subcontracted personnel have received and are up to date in the relevant HSE training for their position.
- Participates in accident/incident investigation and reporting.
- Co-ordinates the Permit to work system
- Enforces the use of the STOP programme covering all operations on site.
- Trains crew in emergency response procedures (fires, evacuation, spills, etc.)
- Ensures that all personnel are trained in well control procedures.

Operations:

- Supervises drilling equipment and operation of same.
- Supervises the use and operation of the BOP and other associated equipment, and ensures subordinates know, understand and follow the guidelines of applicable well control policies and other general operating policies and procedures.
- Supervises and plans LES WILSON DRILLING´s aspects of rig moves.

Equipment:

- Directs the application of the LES WILSON DRILLING´s preventive and planned maintenance programs.
- Ensures drillstring and lifting equipment inspections are performed as per schedule.
- Keeps equipment and systems operational by setting priorities on equipment repairs and ensuring that PMR (or equivalent) system is being followed.
- Monitors rig equipment and systems´ usage by ensuring operational parameters and limits are observed.
- Ensures diesel tanks are appropriately monitored and if/when needed, advise ADM of additional fuel required (ADM to furnish the diesel)

Emergency Duties:

- Secures the well in emergency situations and handles primary controls during well control emergency operations.
- Makes decisions to evacuate or abandon the rig in conjunction with ADM & SCHLUMBERGER CARBON SERVICES.
- Directs the crew in other emergencies such as fires, spills etc.

Management:

- Plans work for crews.
- Ensures rig personnel are being trained to meet LES WILSON DRILLING´s, SCHLUMBERGER CARBON SERVICES and ADM training requirements.
- Supervises adherence to safety policies and procedures.
- Controls the budget and warehouse inventory at the rig site.
- Safeguard the physical presence of fixed assets and inventories.

Administration:

- Maintains appropriate logs and records.
- Administers and approves the IADC Drilling Report and assists preparation of the Daily Drilling Report.
- Receives visitors and keeps track of personnel onsite.

Technical/Diagnostic Skills:

- Researches information on parts, equipment, data and/or operations procedures as required.
- Interprets and responds to downhole conditions and provides his particular expertise to the ADM WSS.

Appendix I -- Open-Hole and Cased-Hole Logging Plans

ADM Injection Well Logging Program

On October 2, 2008 a meeting was held to discuss the logging program for the ADM injection well. Representatives of ISGS and Schlumberger were present to discuss the data that was needed and the logging tools required to provide that data. The decision was made to look at the logging run for the intermediate casing separately from the logging run over the injection zone.

The table below identifies the logging tools needed and the primary reason for running that logging tool. The table also identifies logging tools that would provide additional information about this interval that may be useful, but the data is not required to achieve the objectives of the project. These logs should be considered if it does not place undue financial strain on the project. The overall results are that the standard "Triple Combo" of Resistivity, Density, and Neutron should be run for basic petrophysical properties. The Sonic Scanner should be run for Mechanical Rock Properties and the FMI should be included to identify structure and depositional environment. Sidewall cores are also included to help resolve permeability and lithology in any reservoirs in this interval. If possible it would be nice to have the ECS and HNGS for lithology and clay type, as well as the CMR for porosity and permeability. This table is specific for the first logging run over the interval where intermediate casing will be set.

Run 1 – Intermediate Casing

Data Required	**Logging tools needed**	**Logging tools if possible**
Depth/Correlation	GR, Resistivity	
Porosity	Dens, Neut, Sonic (SS)	CMR
Saturations	Resistivity (porosity)	
Permeability	Sidewall cores (30)	
Pressure		
Fluid Samples		
Lithology – Clay Minerals		ECS, HGNS
Structure/Env. Deposition	FMI	
Fractures		
Mechanical Rock Prop.	Sonic (SS)	
Hydraulic Isolation	Isolation Scanner	
Monitor changes		

Below is the table that was generated by the group for the second logging run that will include the injection zone. The overall results are that the standard "Triple Combo" of Resistivity, Density, and Neutron should be run for basic petrophysical properties. The Sonic Scanner should be run for Mechanical Rock Properties and the FMI should be included to identify structure and depositional environment as well as any indications of fractures. The ECS and HNGS were considered essential over this interval for lithology and clay type, as well as the CMR for porosity and permeability. Additional openhole data that was included over this interval is the MDT for several reasons. The MDT will enable the measurement of reservoir pressure and gathering fluid samples. With this tool we can also perform minifracs and vertical interference tests to better understand the fracture pressure and gradient within the well. Sidewall cores are also included and there was quite a bit of discussion about increasing the number of sidewall cores and not running whole core in this well. The whole core in that case would be run in the verification well.

Since this interval will contain the injection zone the Isolation Scanner has been included as a log that needs to be run after casing has been run. This tool will evaluate the cement integrity and hydraulic isolation to ensure there are no channels in the cement annulus. The base RST log has also been included as this will be the primary monitor log to combine with the other monitoring techniques.

Run 2 – Injection Zone

Data Required	**Logging tools needed**	**Logging tools if possible**
Depth/Correlation	GR, Resistivity	
Porosity	Dens, Neut, Sonic (SS) CMR	
Saturations	Resistivity (porosity)	
Permeability	CMR, Sidewall cores (40)	
Pressure	MDT (20), Minifrac (2), VIT (3)	
Fluid Samples	MDT (6)	MDT (12)
Lithology – Clay Minerals	ECS, HGNS	
Structure/Env. Deposition	FMI	
Fractures	FMI	
Mechanical Rock Prop.	Sonic (SS)	
Hydraulic Isolation	Isolation Scanner	
Monitor changes	RST	

Appendix J -- CCS1 Completion Report

ADM

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

May 5, 2010

Mr. Steve Nightingale
Illinois Environmental Protection Agency
Bureau of Land, Permit Section #33
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, Illinois 62794-9276

Via Courier Service

Re: Permit No. UIC-012-ADM
CCS Well #1 Completion Report

Dear Mr. Nightingale:

In accordance with Condition A.8.b of the above referenced permit, ADM is submitting the Well Completion Report for the CCS #1 well. This well will be used for the injection of carbon dioxide for the geologic sequestration project for the Illinois Basin – Decatur project.

The enclosed report addresses the items required by the permit. If you have any questions regarding this please contact Sallie Greenberg at 217-244-4068 or myself at 217-451-6330.

Sincerely,

Dean Frommelt

Dean Frommelt
Division Environmental Manager
Corn Processing & BioProducts

Cc: Mark Burau - ADM
Mark Carroll – ADM
Rob Finley – ISGS
Sallie Greenberg – ISGS

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

Mark Burau
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

ADM

ISGS
Illinois State Geological Survey

MGSC

Location in Application

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% $CaCl_2$, 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 K -- VW1 Completion Report

Archer Daniels Midland Company
P.O. Box 1470, Decatur IL 62525

August 1, 2011

Mr. Steve Nightingale
Illinois Environmental Protection Agency
Bureau of Land, Permit Section #33
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, IL 62794-9276

Via Certified Mail

Re: Permit No. UIC-012-ADM
Verification Well Completion Report

Dear Mr. Nightingale:

In accordance with Condition B.4.g of the above referenced permit, ADM is submitting this Completion Report for the verification well. This non-injection well will be used for injection zone monitoring for the geologic sequestration project for the Illinois Basin – Decatur Project.

If you have any questions regarding this please contact Sallie Greenberg at 217-244-4068 or myself at 217-451-6330.

Sincerely,

Dean Frommelt
Division Environmental Manager
Corn Processing & BioProducts

Cc: Kevin Lesko - IEPA
Mark Burau - ADM
Rob Finley – ISGS
Sallie Greenberg – ISG

Illinois
Environmental
Protection Agency

Bureau of Land
1021 North Grand Avenue East
Box 19276
Springfield, IL 62794-9276

GENERAL APPLICATION FOR PERMIT (LPC-PA1)

This form must be used for any application for permit, except for landscape waste composting or hazardous waste management facilities regulated in accordance with RCRA, Subtitle C from the Bureau of Land. One original and two (2) photocopies, or three (3) if applicable, of all permit application forms must be submitted. Attach the original and appropriate number of copies of any necessary plans, specifications, reports, etc. to fully support and describe the activities or modifications being proposed. Attach sufficient information to demonstrate compliance with all applicable regulatory requirements. Incomplete applications will be rejected. Please refer to the instructions for further guidance.

Note: Permit applications which are hand-delivered to the Bureau of Land, Permit Section must be delivered to 1021 North Grand Avenue East between the hours of 8:30 a.m. to 5:00 p.m., Monday through Friday (excluding State holidays).

Please type or print legibly.

I. SITE IDENTIFICATION

Name: Archer Daniels Midland Company - Corn Processing Site # (Illinois EPA): 1150155136

Physical Site Location (street, road, etc.): 4666 Faries Parkway

City, Zip Code: Decatur, 62526 County: Macon

Existing DE/OP Permit Nos. (if applicable): N/A

II. OWNER/OPERATOR IDENTIFICATION

	OWNER	OPERATOR
Name:	Archer Daniels Midland Company - Corn Processing	Same
Address:	4666 Faries Parkway	
	Decatur, IL 62526	
Contact Name:	Dean Frommelt	
Phone #:	(217) 451-6330	( )

III. PERMIT APPLICATION IDENTIFICATION

TYPE SUBMISSION/REVIEW PERIOD:
- ☐ New Landfill/180 days (35 IAC Part 813)
- ☐ Landfill Expansion/180 days (35 IAC Part 813)
- ☐ Sign. Mod to Operate/90 days (35 IAC Part 813)
- ☐ Other Sign. Mod/90 days (35 IAC Part 813)
- ☐ Renewal of Landfill 90 days (35 IAC Part 813)
- ☐ Developmental/90 days (35 IAC Part 807)
- ☐ Operating/45 days (35 IAC Part 807)
- ☐ Supplemental/90 days (35 IAC Part 807)
- ☐ Permit Transfer/90 days (35 IAC Part 807)
- ☐ Renewal of Experimental Permit (35 IAC Part 807)

TYPE FACILITY:
- ☐ Landfill
- ☐ Land Treatment
- ☐ Transfer Station
- ☐ Treatment
- ☐ Storage
- ☐ Incinerator
- ☐ Composting
- ☐ Recycling/Reclamation
- ☒ Other (Specify)

Carbon Sequestration

TYPE WASTE:
- ☐ General Municipal Refuse
- ☐ Hazardous
- ☐ Special (Non-hazardous)
- ☐ Chemical Only (exc. putrescible)
- ☐ Inert Only (exc. chemical and putrescible)
- ☐ Used Oil
- ☐ Potentially Infectious Medical Waste
- ☐ Landscape Waste
- ☒ Other (Specify)

Carbon Dioxide

DESCRIPTION OF THIS PERMIT REQUEST: (Include a brief narrative description here.)

Verification well completion report.

IL 532-1857
LPC 350 Rev. 2/03

This Agency is authorized to require this information under Illinois Revised Statutes, 1979, Chapter 111 1/2, Section 1039. Disclosure of this information is required under that Section. Failure to do so may prevent this form from being processed and could result in your application being denied. This form has been approved by the Forms Management Center.

IV. COMPLETENESS REQUIREMENTS

The following items must be checked Yes, No or N/A. Each item will be reviewed by the log clerk. Blank items will result in rejection of the application. Please refer to the instructions for further guidance.

			Yes	No	N/A
1.		Have all required public notice letters been mailed in accordance with the LPC-PA16 instructions? (If so, provide a list of those recipients of the required public notice letters for Illinois EPA retention.) Such retention shall not imply any Illinois EPA review and/or confirmation of the list.)	☐	☐	☒
2.	a.	Is the Siting Certification Form (LPC-PA8) completed and enclosed?	☐	☐	☒
	b.	Is siting approval currently under litigation?	☐	☐	☒
3.	a.	Is a closure, and if necessary a post closure, plan covering these activities being submitted, or	☐	☐	☒
	b.	has one already been approved? (Provide permit number ________________.)	☐	☐	☒
4.	a.	For waste disposal sites only: Has any employee, owner, operator, officer or director of the owner or operator had a prior conduct certification denied, canceled or revoked?	☐	☒	☐
	b.	Have you included a demonstration of how you comply or intend to comply with 35 Ill. Adm. Code Part 745?	☐	☐	☒
5.	a.	Is land ownership held in beneficial trust?	☐	☒	☐
	b.	If yes, is a beneficial trust certification form (LPC-PA9) completed and enclosed?	☐	☐	☒
6.	a.	Does the application contain information or proposals regarding the hydrogeology; groundwater monitoring, modeling or classification; a groundwater impact assessment; or vadose zone monitoring for which you are requesting approval?	☐	☐	☒
	b.	If yes, have you submitted a third (3rd) copy of the application (4 total) and supporting documents?			

V. SIGNATURES (Original signatures required. Signature stamps or applications transmitted electronically or by facsimile are not acceptable.)

All applications shall be signed by the person designated below as a duly authorized representative of the owner and/or operator.
Corporation - By a principal executive officer of at least the level of vice-president.
Partnership or Sole Proprietorship - By a general partner or the proprietor, respectively.
Government - By either a principal executive officer or a ranking elected official.

A person is a duly authorized representative of the owner and operator only if:
1. They meet the criteria above or the authorization has been granted in writing by a person described above; and
2. is submitted with this application (a copy of a previously submitted authorization can be used).

I hereby affirm that all information contained in this Application is true and accurate to the best of my knowledge and belief.

I do herein swear that I am a duly authorized representative of owner/operator and I am authorized to sign this permit application form.

Owner Signature: Mark Braun Title: Decatur Corn Plant Manager Date: 8/1/11
Owner FEIN or S.S. Number: 41-0129150

Operator Signature: ________________ Title: Same as Owner Date: Same as Owner
Operator FEIN or S.S. Number: Same as Owner

Notary: Subscribe and sworn before me this 1 day of Aug. 2011.
Notary Signature: Dale A. King Notary Seal:
My commission expires on: 6/19/2015

"OFFICIAL SEAL"
DALE A KING
NOTARY PUBLIC, STATE OF ILLINOIS
MY COMMISSION EXPIRES 06-19-2015

Engineer Signature: Robert C. Herr III Title: ________________ Date: 7/29/11
Engineer Address: PO BOX 885 Engineer Seal:
MT. VERNON, IL 62864

LICENSED PROFESSIONAL ENGINEER
ROBERT C. HERR III
062-039059
STATE OF ILLINOIS

Engineer Phone No. 618-237-7101

All information submitted as part of the Application is available to the public except when specifically designated by the Applicant to be treated confidentially as a trade secret or secret process in accordance with Section 7(a) of the Environmental Protection Act, applicable Rules and Regulations of the Illinois Pollution Control Board and applicable Illinois EPA rules and guidelines.

jab/98781p.doc

Messenger Log Sheet

Messenger__________ Date____________

Shipper	Recipient	Tracking # / Item	Signature	Time
Corporate	Neal Tire - MTZ	Chad's Truck		
Beth Osowoski	Aviation	Wssage (5)	[illegible]	
Sandy Pagan	Jan Rinion	env.	J. Rinion	
Sample Room	Jay Mayberry	Box	Tom West	
Covered Ron's	Break From	12:00 - 12:30		
Dean Frommelt	IEPA - Springfield, Il Steve Nightingale	2 Boxes 2 Tubes	Jeff Baker	
Company Store	Gift Shop	4 Boxes	M. Edmonson	

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, ADM Verification Well #1 Completion Report
Revised July 19, 2011

Geological Sequestration in the Illinois Basin

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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
CBL, cement bond log
CCS, carbon capture and sequestration
Cf, cubic feet
Cf/sk, cubic feet per sack
CFR, Code of Federal Regulations
Cm, centimeter(s)
CMR, combinable magnetic resonance
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
F, farenheit
FEED, front end engineering design
FMI, formation micro imager
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
VDL, variable density log
WFL, water flow log
WOC, wait on cement
XPT, pressure express tool

UIC Form 4h, Verification 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: ADM Verification Well #1

I. *Type of Permit*

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

Location in Application

II. *Location, see instructions*

A. *Township-Range-Section:*

Verification Well #1 is located 605 feet North and 1175 feet East in the Southwest quadrant of Section 32 of Township 17 North and Range 3 East, Macon County, IL.

B. *Latitude/Longitude:*

The latitude and longitude coordinates of the well in degrees-minutes-seconds are 39° 52' 47.2620" N and 88° 53' 36.0924" W.

C. *Closest Municipality*

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

III. *Surface Elevation*

Surface elevation of the well is 669 feet (203.9 meters) above Mean Sea Level.

IV. Well Depth

The well was drilled to a total measured depth of 7272 feet (2216.5 meters) below the drilling rig kelly bushing (RKB). NOTE: the RKB is 15 feet (4.6 meters) above the surface elevation, or 684 feet (208.5 meters) above Mean Sea Level.

V. Static Water Level

The static water level in the well is 194 feet (59.1 meters) above Mean Sea Level.

VI. Demonstrated Fracturing Pressure, if applicable

Since this well will not be used for injection, no tests were performed to demonstrate the fracture pressure.

VII. Verification Well Completion

The Verification Well #1 is fully-cased and perforated at the intervals indicated in Table 1.

Table 1: Perforation Details

Port No.	Perf Top (MD feet)	Perf Bottom (MD feet)	Formation Name	Shot Phasing (deg)	Total Shots
Z11 MP	4917.5	4920.5	Ironton-Galesville	60	18
Z 10 MP	5000.7	5003.7	Ironton-Galesville	60	18
Z 9 MP	5653.8	5657.3	Mt. Simon	120	11
Z 8 MP	5840.4	5843.9	Mt. Simon	120	11
Z 7 MP	6416.2	6419.7	Mt. Simon	120	11
Z 6 MP	6632.3	6635.8	Mt. Simon	120	11
Z 5 MP	6720.3	6723.8	Mt. Simon	120	11
Z 4 MP	6837.1	6840.6	Mt. Simon	120	11
Z 3 MP	6945.6	6949.1	Mt. Simon	120	11
Z 2 MP	6983.0	6986.5	Mt. Simon	120	11
Z 1 MP	7061.2	7064.2	Granite Wash	60	18

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

Please see the Verification Well #1 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 the Contractor Morning Reports, Drilling Mechanics Log, and Daily Completion as-built Reports which summarize the rig performance and operations throughout the drilling and completion 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 – 377 feet, 17.5-inch diameter

<u>Intermediate Hole:</u> 377 – 5322 feet, 12.25-inch diameter

<u>Final Hole:</u> 5322 – 7272 feet, 8.5-inch diameter

B. *Annulus Protection System*

Verification Well #1 will not be used for injection, however, the well has been constructed in a way that meets the requirements of Part 704 UIC Permit Program Subpart E, Permit Conditions Section h to establish and maintain mechanical integrity and part 730 Underground Injection Control Requirements, Section 730.108 Mechanical Integrity.

The surface, intermediate, and long casing strings are cemented to surface so there are no open annuli between these strings.

Due to the unique completion design of the Verification Well #1, the annulus of the well is defined as the volume above the uppermost Westbay packer (#28) and the surface. More specifically, this space will be the annulus between the 2-7/8-inch OD tubing and the 5 ½ inch, 17 lb/ft casing (4.892 inch ID).

Throughout the operation of the well, the annulus between the 2-7/8-inch tubing and the 5 ½ inch long string casing will be continuously monitored at the wellhead to verify that pressure is within the limits prescribed in the permit language (14 – 100 psia). Annulus pressure within the prescribed limits can be construed as evidence of mechanical integrity in the annular space, which will also be confirmed annually via the test described in section X.C. of this report.

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 (0 – 377 feet): 13.375 inches / 17.5 inches

Intermediate (0 – 5322 feet): 9.625 inches / 12.615 inches

Long (0 – 7272 feet): 5.5 inches / 8.835 inches

Production Tubing (0 – 4745 feet): 2.875 inches / 4.892 inches

Westbay Tubing (4745 – 7128 feet): 2.5 inches /4.892 inches

2. *Type of annular fluid(s)*

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

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

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

Long string: fully cemented (see cement details in section XI.C)

Westbay Tubing: The Westbay monitoring intervals, which are perforated and open to the formation, contain native formation brines, whose density varies slightly depending on the composition of the fluid. The Westbay quality assurance zones (QA), which are not perforated and are isolated against the inner diameter of the long-string casing, contain 9.4 lb/gal NaCl with adomite ASP 539D brine which was used during the installation of the completion system.

Production Tubing: the annular space between the production tubing and the long string casing – above the shallowest Westbay packer – contains 9.4 ppg NaCl brine with Nalco Adomite ASP 539D corrosion inhibitor at a concentration of 2 gallons per 1000 gallons brine.

3. *Specific gravity of annular fluid*

The brine occupying the annulus space between the final casing string and the 2-7/8-inch production tubing has a specific gravity of approximately 1.127. The fluid occupying the annular spaces of the perforated Westbay monitoring intervals varies; therefore, the specific gravity is dependent on the composition of the native reservoir fluid. The fluid occupying the annular spaces of the non-perforated Westbay QA zones has a specific gravity of 1.127.

4. *Coefficient of annular fluid*

The fluid occupying the annulus space between the final casing string and the production tubing has a hydrostatic coefficient of approximately 0.488 psi/ft. The fluid occupying the annular spaces of the perforated Westbay monitoring intervals varies; therefore, the hydrostatic coefficient is dependent on the composition of the native reservoir fluid. The fluid occupying the annular spaces of the non-perforated Westbay QA zones has a specific gravity of 0.488 psi/ft.

5. *Packer(s)*

a. *Setting depth*

There are a total of 28 Westbay MP55 packers in Verification Well #1. Table 2 displays the setting depth of each individual packer.

Table 2: Packer Depths

Packer No.	Top Depth (MD feet)	Packer No.	Top Depth (MD feet)
P28	4823.8	P14	5860.7
P27	4890.7	P13	6389.3
P26	4937.9	P12	6436.5
P25	4973.8	P11	6605.4
P24	5021.0	P10	6652.6
P23	5283.5	P9	6693.4
P22	5329.3	P8	6740.6
P21	5365.2	P7	6811.0
P20	5410.9	P6	6858.2
P19	5456.6	P5	6918.7
P18	5502.4	P4	6956.1
P17	5627.0	P3	7003.3
P16	5674.2	P2	7034.2
P15	5813.5	P1	7081.4

The packers were inflated with tap water in sequence beginning with the deepest. All of the packers were inflated normally with the exception of packers P24 and P26. Packer P24 is positioned below Zone 10 and packer P26 is positioned below Zone 11. During the operation, inflation diagnostics indicated that these two particular packers were not able to maintain the appropriate inflation pressure. These two packers are judged to be uninflated. In each case, the subject packer provided redundancy as part of a 2-packer set designed to seal inside the casing between two perforated intervals. The second packer of each set (packer P23 and packer P25, respectively) inflated normally and all standard monitoring operations of the well are un-affected.

b. *Type*

The Westbay packers can be described as steel-reinforced, rubber gland inflatable packers.

c. *Name and model*

The packers in the completion assembly are Westbay Steel MP55 System MP55 Packer – 90mm Element Part No. 0414100C4. Detailed specifications of these packers were provided with the revisions to the permit modification log UIC-143-M2 received by the IEPA on 15-Nov-2010.

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

After the 5 ½-inch long string casing was cemented in place, it was filled with a 9.2 lb/gal (0.477 psi/ft equivalent hydrostatic gradient) NaCl completion brine, which was of sufficient density to control fluid movement into the wellbore from open perforations and throughout the installation of the Westbay monitoring system. The maximum reservoir pressure gradient calculated from surface is approximately 0.45 psi/ft, as determined from reservoir pressure measurements acquired during open-hole logging. Prior to installing the Westbay system in the well, 65 barrels of 9.4 ppg sodium chloride brine, with Nalco Adomite ASP 539D corrosion inhibitor at a concentration of 2 gallons per 1000 gallons of brine, were spotted from TD back to 4500 feet. See daily Completion as-built reports in Appendix IX for the detailed chronology of the completion operations.

After the Westbay system was installed and all but the shallowest Westbay packer (P28) was inflated, the pumping port sliding sleeve of QA Zone 16 was opened and the annulus was flushed with approximately 20 bbls of 9.2 lb/gal brine which was circulated through the tubing. This mixture was then replaced with 27.8 bbls of 9.4 lb/gal sodium chloride brine with Nalco Adomite ASP 539D corrosion inhibitor at a concentration of 2 gallons per 1000 gallons of brine. Afterwards, the sliding sleeve in QA Zone 16 was closed and the shallowest packer (P28) was inflated properly, thereby isolating the annular space to surface. The 9.4 lb/gal NaCl brine (with above-mentioned additives) is currently the fluid that resides in the tubing-casing annular space above the shallowest packer.

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.

Pioneer Oil field Services, LLC
1290 N State Road 67
Vincennes, IN 47591
(812) 882-0999
Contact Person: Mike Robinson

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 boxes labeled as Appendices X.A-B.

A. *During Drilling*

Surface Hole:

- Wireline Logs: (Logs included in File Box Appendix X.A-B)
  - Laterolog-GR-SP

Intermediate Hole:

- Wireline Logs: (Logs included in File Box Appendix X.A-B)
  - Neutron-Density-GR Combo
  - Laterolog Resistivity
  - Micro-Resistivity Imaging (FMI)
  - Elemental Capture Spectroscopy
  - Natural Gamma Ray Spectroscopy
  - Formation Pressures (MDT)
  - Rotary Sidewall Cores (routine analysis results included in File Box Appendix X.A-B)
  - SP

Final Hole:

- Wireline Logs: (Logs included in File Box Appendix X.A-B)
  - Neutron-Density-GR Combo Laterolog Resistivity
  - Induction Resistivity
  - Microlog
  - Micro-Resistivity Imaging (FMI)
  - Sonic (MSIP – Sonic Scanner)
  - Elemental Capture Spectroscopy
  - Natural Gamma Ray Spectroscopy

- Magnetic Resonance (CMR)
- Rotary Sidewall Cores (routine analysis results included in File Box Appendix X.A-B)
- Formation Pressures (XPT; summary report included in File Box Appendix X.A-B)

- Conventional Whole Core:

Table 3 Whole Core Intervals (uncorrected driller's depths).

Hole Section (in)	Formation Name	Length (ft)	Est. Top of Formation (ft)	Core Top (ft)	Core Bottom (ft)
12-1/4	New Albany	27	2071	2132	2159
12-1/4	Knox (Gunter-Eminence transition)	46	4238	4218	4264
12-1/4	Knox (Potosi)	46	4344	4513	4559
8-1/2	Eau Claire-Mt Simon transition	139	5017	5425	5564
8-1/2	Mt. Simon	60	5515	5930	5990
8-1/2	Lower Mt. Simon	389	5515	6680	7069

Results of routine analysis on full-diameter whole core samples is included in File Box Appendix X.A-B.

B. *During and after casing installation*

Surface Hole: (Logs included in File Box Appendix X.A-B)

- Wireline Logs:
  - Cement Bond Log with Variable Density Log (CBL-VDL)

Intermediate Hole: (Logs included in File Box Appendix X.A-B)

- Wireline Logs:
  - Ultrasonic Cement Imaging
  - Cement Bond Log with Variable Density Log (CBL-VDL)

Final Hole:

- Wireline Logs: (Logs included in File Box Appendix X.A-B)
  - Isolation Scanner Image Log
  - Cement Bond Log with Variable Density Log (CBL-VDL)
  - Pressure/Temperature Log
  - Thermal Neutron Decay (Formation Sigma) Log (RST)
  - Multi-finger Casing Caliper Log
  - Casing Collar and Perforating Record Logs
  - Pressure/Temperature Log (Run 2)

C. *Demonstrate mechanical integrity prior to operation*

Once the appropriate completion fluid was spotted in this annular space (see description in section IX.B.6), the mechanical integrity was verified via a positive pressure test conducted on June 10, 2011 and witnessed by IEPA Regional Geologist, Jeff Turner, P.G. During the test, the annulus was pressurized to approximately 317 psig and, once stabilized, demonstrated less than 1 psig leak-off during the hour-long observation period, which is less than the prescribed maximum leak-off criteria of 3%. Please refer to File Box Appendix X.A-B for a plot of the results of the Mechanical Integrity Pressure Test. During the life of the well this same annulus will be pressure tested to at least 200 psig on an annual basis with a maximum of 3% leakoff allowed, as per the permit requirements.

In addition to demonstrating the mechanical integrity of the tubing-casing annulus, the integrity of the entire Westbay system was confirmed through a negative-pressure test. As per the permit requirements, the sealed Westbay completion assembly was to be tested to at least a 100 psi differential pressure and demonstrate no more than 3% leak-off over a one hour period. Such a test was conducted over approximately 20 hours from June 13 to June 14, 2011. In order to conduct the under balance test, the hydrostatic column in the well was reduced via nitrogen gas-lift through the gas-lift mandrel installed in the completion tubing at a depth of 1208 feet KB. The fluid column was successfully lowered to a depth of 1097 feet KB. A Westbay measurement probe was positioned at a depth of approximately 1550 feet KB in order to monitor the pressure throughout the duration of the test. The effective pressure under balance across the Westbay tubing at the position of the measurement probe was estimated to be 535 psi and of a comparable magnitude throughout the rest of the completion. The pressure was then monitored for approximately 20 hours, during which period the pressure was observed to change from 222.2 to 223.3 (1.1 psi), or less than 0.5% of the measured value. A plot of the results of the interior tubing test is included with the File Box Appendix X.A-B.

Finally, zonal isolation between the Westbay packers was verified in both the monitoring and QA zones by means of pre- and post-inflation pressure profile. A plot of the pre- and post-inflation pressure profiles is included in the File Box Appendix X.A-B. The pre-inflation profile reflects the mixed hydraulic head between the monitoring and QA zones when there is no zonal isolation; therefore, the pressure at each measurement point can be observed to lie along a common pressure gradient line. As each subsequent packer is inflated and as each zone is isolated (from deepest to shallowest), the hydrostatic influence of the underlying zone(s) is removed. Therefore, differences between the pre- and post-inflation pressure profiles provide confidence that, in fact, the packers are effectively isolating hydrostatic communication between each zone.

D. *Copies of logs and tests listed above*

Please see file boxes labeled Appendix X.A-B accompanying completion report for copies of geophysical logs and the results of the various test described above.

E. *Description of well stimulation*

No stimulation was required for the purpose of this well.

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): 367
O.D. (inch): 13.375
I.D. (inch): 12.615
Weight (lbs/ft): 54.50
Grade: J55
Coupling Type: STC
Coupling O.D. (inch): 14.375
Thermal Conductivity (BTU/ft-hr-°F): 29.02

3. *Intermediate casing(s)*

Top Depth (feet): 0
Bottom Depth (feet): 5306
O.D. (inch): 9.625
I.D. (inch): 8.835
Weight (lbs/ft): 40
Grade: N-80
Coupling Type: LTC
Coupling O.D. (inch): 10.625
Thermal Conductivity (BTU/ft-hr-°F): 29.02

4. *Long string casing*

<u>Top Section:</u>
Top Depth (feet): 0
Bottom Depth (feet): 5056
O.D. (inch): 5.5
I.D. (inch): 4.892
Weight (lbs/ft): 17
Grade: J55
Coupling Type: LTC
Coupling O.D. (inch): 6.050
Thermal Conductivity (BTU/ft-hr-°F): 31

<u>Bottom Section:</u>
Top Depth (feet): 5056
Bottom Depth (feet): 7272
O.D. (inch): 5.5
I.D. (inch): 4.892
Weight (lbs/ft): 17.00
Grade: 13Cr85
Coupling Type: BEAR
Coupling O.D. (inch): 6.050
Thermal Conductivity (BTU/ft-hr-°F): 16

5. *Other casing*

N/A

B. *Tubing, see instructions*

<u>Production Tubing</u>
Top Depth (feet): 0
Bottom Depth (feet): 4745
O.D. (inch): 2.875
I.D. (inch): 2.44
Weight (lbs/ft): 6.5
Grade: J-55
Coupling Type: EUE (min)
Coupling O.D. (inch): 3.668
Thermal Conductivity (BTU/ft-hr-°F): 29.02

<u>Westbay Tubing</u>
Top Depth (feet): 4745
Bottom Depth (feet): 7128
O.D. (inch): 2.5
I.D. (inch): 2.26
Weight (lbs/ft): 3.12
Grade: 316L SS

Coupling Type: pin-up/box (captive nut) down, with proprietary
Westbay/ACME thread
Coupling O.D. (inch): 3.45
Thermal Conductivity (BTU/ft-hr-°F): 9.246

1. *Maximum allowable suspended weight based on joint strength*

   Production Tubing: 99660 lbs (45205 kgs)

   Westbay Tubing: 22000 lbs (9979 kgs)

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

   Production Tubing: 30843 lbs (13990 kgs)

   Westbay Tubing: 7466 lbs (3387 kgs)

C. *Cement, see instructions*

Details about the various cement blends used in each stage of the construction of ADM Verification 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 – 377
   Type/Grade (Lead): Class A
   Additives (Lead): Accelerator, LSCM
   Quantity (Lead) (sk): 366

   Type/Grade (Tail): Class A
   Additives (Tail): Accelerator, LSCM
   Quantity (Tail) (cubic yards): 365
   Circulated: Yes
   Thermal Conductivity (BTU/ft-hr-°F): 0.73

3. *Intermediate casing*

   Stage 1:

Depth Interval (feet): 3692 – 5322
Type/Grade (Lead): Class H
Additives (Lead):

Additives Code	Conc.	Function
D047	0.020 gal/sk blend	Antifoam

Quantity (Lead) (sk): 353.4
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.54

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

Additives Code	Conc.	Function
D047	0.020 gal/sk blend	Antifoam

Quantity (Slurry) (sk): 348.13
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.74

Stage 2:

Depth Interval (feet): 0 – 3692
Type/Grade (Lead): 35:65 Poz:H
Additives (Lead):

Additives Code	Conc.	Function
D020	4.000 %BWOB	Extender
D079	0.400 %BWOB	Extender
D046	0.200 %BWOB	Antifoam
D167	0.400 %BWOB	Fluid loss
D042	5.000 lb/sk blend	LCM/extender
D044	10.000 %BWOW	Salt
D065	0.350 %BWOB	Dispersant

Quantity (Lead) (sk): 979.2
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.54

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

Additives Code	Conc.	Function
D047	0.020 gal/sk blend	Antifoam

Quantity (Tail) (sk): 99.57
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.74

4. *Long string casing*

Depth Interval (feet): 0 – 4950
Type/Grade (Lead): 35:65 Poz:H
Additives (Lead):

Additives Code	Conc.	Function
D020	6.000 %BWOB	Extender
D046	0.200 %BWOB	Antifoam
D167	0.400 %BWOB	Fluid loss
D153	0.300 %BWOB	Antisettling
D079	0.175 %BWOB	Extender

Quantity (Lead) (sk): 725.18
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.75

Depth Interval (feet): 4950- 7272
Type/Grade (Tail): EverCRETE
Additives (Tail):

Additives Code	Conc.	Function
D174	10.000 %BWOC	Expanding ce
D206	0.050 gal/sk blend	Antifoam
D145A	0.100 gal/sk blend	Dispersant
D500	0.400 gal/sk blend	GASBLOK LT
D177	0.020 gal/sk blend	Retarder

Quantity (Tail) (sk): 800.71
Circulated: Yes
Thermal Conductivity (BTU/ft-hr-°F): 0.75

5. *Other casing*

N/A

XII. *Surface Facilities, see instructions*

Verification Well #1 will not be used for injection and therefore there are no surface facilities or injection-related equipment affiliated with this well.

A. *Filters(s)*

N/A

B. *Injection pump(s)*

N/A

XIII. *Hydrogeologic Information*

A. *Revised UIC Form 4a*

Revised UIC Form 4a can be referenced in the Completion Report filed for the injection well CCS #1 (Frommelt, 2010).

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

Revised UIC Form 4d can be referenced in the Completion Report filed for the injection well CCS #1 (Frommelt, 2010).

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, see instructions*

The verification well will not inject CO_2 however it is anticipated that it will come in contact with CO_2 from the nearby injection well.

A. *Compatibility with injection zones fluid*

Please refer to the discussion included in the Completion Report for the injection well CCS #1 (Frommelt, 2010).

B. *Compatibility with minerals in the injection zone*

Please refer to the discussion included in the Completion Report for the injection well CCS #1 (Frommelt, 2010).

C. *Compatibility with minerals in confining zone*

Please refer to the discussion included in the Completion Report for the injection well CCS #1 (Frommelt, 2010).

D. *Compatibility with injection well components*

1. *Injection tubing*

The Verification Well #1 is not intended for either injection or production; however, it has been designed with stainless steel components that are resistant to corrosion from exposure to CO_2-brine mixtures. The only place the Westbay tubing may come in contact with the CO_2 is at the perforated intervals and there are no compatibility issues expected.

2. *Long string casing*

As per the design specifications approved under the UIC Permit No. UIC-012-ADM, a portion of the long string casing installed from total depth of the well past the base of the confining layer (to a depth of 5056') is composed of chrome steel (13CR85) and is specifically engineered to function in environments with high concentrations of CO_2. The long string casing in the remainder of the well (5056' to surface) is carbon steel. 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 4950 feet (or approximately 370 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 above the shallowest Westbay packer is a 9.4 lb/gal sodium chloride brine with Nalco Adomite ASP 539D corrosion inhibitor. Reactivity between the injected CO_2 and the annular fluid is expected to be negligible.

5. *Packer(s)*

The packers installed are a Westbay MP55 are manufactured from 316/316L stainless steel and incorporate a reinforced rubber gland made of Hydrogenated Nitrile Butadiene Rubber (HNBR) and a pressure balanced inflation/deflation valve mounted on a stainless steel mandrel. The Westbay MP55 packers are CO_2 resistant and as a result will not be impacted by the injected CO_2.

6. *Well head equipment*

Due to the isolation provided by the Westbay completion, components of the wellhead equipment will not be in contact with the injected CO_2; therefore, no adverse reactions are expected between the injected CO_2 and any of the wellhead components.

7. *Holding tank(s) and flow lines*

Verification Well #1 is not used for injection and therefore will not possess holding tanks and flow lines for CO_2 injection.

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

In summary, Verification Well #1 is not used for injection or production and 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. In addition, the materials from which the Westbay completion system is constructed are fit-for-purpose and designed to be resistant to adverse reactions with CO_2 and CO_2-brine mixtures.

XV. *Monitoring Program, see instructions*

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. *Pressure Monitoring gauge(s)*

Surface Pressure Gauge: Monitoring tag name to be determined (PIT-XX)
Location: Installed directly into the Verification Well #1 wellhead tree cap port.
Make / Model: ABB Model 266GSH-U
Type: Electrical; Continuous Recording
Operating Range (psig): 0 – 435; this exceeds maximum operating range

of system by more than 20%

Downhole Pressure Gauges: Westbay MOSDAX System Pressure/Temperature Probe Model 2580
Location: There are a total of 11 measuring ports and 1 QA/QC port in the well as displayed below in Table 4.

Table 4: Measurement Port Depths

Measurement Port	Depth	Measurement Port	Depth
1	7060.6	7	6415.6
2	6982.4	8	5839.8
3	6945.0	9	5653.3
4	6837.3	QA/QC	5482.0
5	6719.7	10	5001.1
6	6631.7	11	4917.0

Make / Model: Westbay MOSDAX System Pressure/Temperature Probe Model 2580
Type: Electrical; Continuous Recording
Operating Range (psig): 0 – 5,000; this exceeds maximum operating range of the 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.

Surface Pressure Gauge: Monitoring tag name to be determined (PIT-XX)
Location: Mounted on the Verification Well #1 wellhead port open to the casing-tubing annulus.
Make / Model: ABB Model 266GSH-U
Type: Electrical; Continuous Recording
Operating Range (psig): 0 – 435; this exceeds maximum operating range of system by more than 20%

C. *Flow meter(s)*

N/A

D. *pH recording device(s)*

N/A

E. *Temperature*

Downhole Temperature Gauges: Westbay MOSDAX System Pressure/Temperature Probe Model 2580

Location: There are a total of 11 measuring ports and 1 QA/QC port in the well as displayed above inTable 4.
Make / Model: Westbay MOSDAX System Pressure/Temperature Probe Model 2580
Type: Electrical; Continuous Recording
Operating Range (degF): 32 to 158; this exceeds maximum operating range of system by more than 20%

Sources:

Frommelt, D. (2010). Letter to the Illinois Environmental Protection Agency, Subject: CCS Well #1 Completion Report, – UIC Permit UIC-012-ADM. Archer Daniels Midland Company

Appendix L -- GM1 Completion Report

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

April 5, 2010

Illinois Department of Natural Resources
Office of Mines and Minerals
Division of Oil and Gas
One Natural Resources Way
Springfield, Illinois 62702-1271

Re: Archer Daniels Midland Company – Decatur, IL
Geophone Well Completion Report
IEPA UIC Permit No. UIC-012-ADM
IDNR Forms OG-9 & OG-5

To Whom It May Concern:

Archer Daniels Midland (ADM) submitted the Well Completion Report to IEPA for the geophysical monitoring well drilled at the ADM CCS #1 site. This well will be used for seismic monitoring on the Illinois Basin – Decatur project. This monitoring well will facilitate the gathering of micro-seismic and VSP data over the life of the project. It is for monitoring only and does not serve as an injection well.

One of the items requested for the IEPA's completion report is a copy of the completion forms submitted to IDNR. Based on a recent telephone conversation between Sallie Greenberg, ISGS and Doug Schutt, IDNR, ADM understands that these forms are not required by IDNR since these wells are not regulated by IDNR. However, ADM is submitting the enclosed forms for informational purposes.

If you have any questions regarding this please contact Sallie Greenberg at 217-244-4068 or myself at 217-451-6330.

Sincerely,

Dean Frommelt
Division Environmental Manager
Corn Processing & BioProducts

Cc: Mark Burau - ADM
Mark Carroll – ADM
Rob Finley – ISGS
Sallie Greenberg – ISGS

Print Form

ILLINOIS DEPARTMENT OF NATURAL RESOURCES

Office of Mines and Minerals

Division of Oil and Gas
(217) 557-6379

One Natural Resources Way
Springfield, Illinois 62702-1271

OG-9 WELL COMPLETION REPORT

TYPE OF REPORT:

☒ NEW WELL ☐ CONVERSION ☐ DOPH ☐ DEEPENING ☐ WORKOVER

TYPE OF WELL:

☐ OIL PRODUCER ☐ GAS PRODUCER ☐ CLASS II INJECTION WELL ☐ WATER SUPPLY
☐ OBSERVATION ☐ GAS STORAGE ☐ D&A ☒ SERVICE

PERMITTEE: Archer Daniels Midland Company PERMITTEE #:

WELL NAME: Geophysical Monitoring Well # 1 PERMIT #:

LOCATION: 390 ft S,185 ft W of NE NW NW REFERENCE #:

COUNTY: Macon SECTION: 5 TOWNSHIP: 16N RANGE: 3E

DRILLING DATA:

☐ WELL NOT DRILLED, PERMIT EXPIRED ☐ WELL NOT CONVERTED, PERMIT EXPIRED

DATE DRILLING BEGAN: FINISHED:

ELEVATION: KB 690 DF 15 GR 675

ROTARY: FROM 0 TO 3,500 CABLE: FROM TO

T.D.: 3,500 P.B.T.D. 3,496

TEST DATA:

WERE ELECTRIC OR OTHER WIRELINE LOGS RUN: ☒ YES ☐ NO

TYPE OF LOG: Compensated Neutron/Litho Density Gamma Ray Caliper DATE: 11/4/2009

TYPE OF LOG: Laterlog SP Micro Resistivity Gamma Ray DATE: 11/4/2009

TYPE OF LOG: Cement Bond Log VDL Cement Map Temp Pressure DATE: 2/3/2010

WAS WELL CORED: ☐ YES ☒ NO INTERVAL CORED:

DRILL STEM TEST RUN: ☐ YES ☒ NO ZONE TESTED:

CONSTRUCTION DATA:

CASING	SIZE	SETTING DEPTH	SACKS CEMENT	HOLE SIZE	TOP OF CEMENT	TOP DETERMINED BY
SURFACE	9.625	350	200	12.25	0	
INTERMED./MINE STRING / OR LINER						
PRODUCTION	3.5	3,496	920	8.5	0	

TUBING: TYPE: None SIZE: ______

PACKER: 1. BRAND AND TYPE: None SETTING DEPTH: ______

2. BRAND AND TYPE: ______ SETTING DEPTH: ______

WELL COMPLETION DATA FOR PRODUCTION / INJECTION FORMATIONS:

FORMATION NAME	LITHOLOGY	PERF. INTERVAL	OPEN HOLE INTERVAL	ACIDIZED / FRACTURED / OTHER (LIST AMOUNTS USED AND OTHER DETAILS)
St Peter	sand	None	3276 Top	
New Albany	shale	None	2085 Top	
Tops given for information purpose				

PRODUCTION INFORMATION:

PRODUCING FORMATIONS: None

DATE OF FIRST PRODUCTION (OIL TO TANK) ______

DATE OF TEST: (STARTED TESTING TO TANK) ______

LENGTH OF TEST: ______

INITIAL PRODUCTION RATE:

OIL ______ BBLS PER DAY WATER ______ BBLS PER DAY GAS ______ MCF

INJECTION INFORMATION:

INJECTION / DISPOSAL FORMATION(s): None

TYPE OF INJECTED FLUID: ☐ FRESHWATER ☐ SALTWATER ☐ OTHER (SPECIFY) ______

SOURCE OF INJECTED FLUID: ______

DATE OF FIRST INJECTION: ______

RATE PER DAY: ______ BBLS WATER AT ______ PSI.

______ MCF GAS AT ______ PSI.

UNDER PENALTIES OF PERJURY, I DECLARE THAT I HAVE EXAMINED THIS REPORT, INCLUDING ACCOMPANYING STATEMENTS AND DOCUMENTS, AND TO THE BEST OF MY KNOWELDGE, IT IS TRU, CORRECT, AND COMPLETE.

[signature]
SIGNATURE OF PERMITTEE OR DESIGNEE

Decatur Corn Plant Manager
TITLE

4666 Faries Parkway
ADDRESS

4/5/2010
DATE

Decatur, IL
CITY, STATE

This state agency is requesting desclosure of information that is necessary toaccomplish the statuory purpose as outlined in the Ill. Complied Stat. Ch. 225 pars. 725 et. seq. Failure to disclose this information will result in this form not being processed. This form has been approved byt eh Forms Management Center.

L 472-0242 (Rev 7/02)

Print Form

ILLINOIS DEPARTMENT OF NATURAL RESOURCES
Office of Mines and Minerals

Division of Oil and Gas
(217) 557-6379

One Natural Resources Way
Springfield, Illinois 62702-1271

OG-5 WELL DRILLING REPORT

Type of Well: ☐ Oil Producer ☐ Gas Producer ☐ Class II Injection ☐ Water Supply ☒ Other Geophysical m☐ ☐ Observation ☐ Gas Storage ☐ D&A

Type of Report: ☐ New Well ☐ Conversion ☐ DOPH ☐ Deepening ☐ Workover

Permittee: Archer Daniels Midland Company Permittee #
Well Name: Geophysical Monitoring Well # 1 Permit # Reference #
Location: 390 ft S,185 ft W of NE NW NW API No.
County: Macon Section: 5 Township: 16N Range: 3E

Drilling Data:

Date Drilling Began: 10/29/2009 Finished: 11/06/2009 T.D. 3,500
Elevation: KB: 690 DF: 15 GR 675 Rotary: From: 0 To: 3,500
Air Rotary: From: ____ To: ____ Cable: From: ____ To: ____

Test Data:

Were Electric or other wireline logs run? ☒ YES ☐ NO Type of Logs:
Compensated Neutron/Litho Density Gamma Ray Caliper, Laterlog SP Micro Resistivity Gamma Ray
Was well cored? ☐ YES ☒ NO Interval(s) cored:
Drill Stem test run? ☐ YES ☒ NO Zone(s) Tested:
Attach a copy of drill stem test results

Geological Data: (Fill out or attach copy of geologists report)

FORMATION	DEPTH Top	DEPTH Bottom
West Franklin	460	482
Renault	1,279	1,293
Aux Vases	1,293	1,312
St Louis	1,374	1,530
New Albany	2,084	2,215
Maquoketa	2,610	2,722
Trenton	2,814	2,942
St Peter	3,276	3,470
Shakopee	3,470	

FORMATION DETERMINED BY
☐ Samples
☐ Geophysical Log
☒ Other: Offset 160 ft away
List any oil and gas shows:
(Give depth):
None

Signature of Permittee or Designee

4666 Faries Parkway
Address

Decatur, IL 62526
City, State, Zip

This state agency is requesting disclosure of information that is necessary to accomplish the statutory purpose as outlined in the Ill. Compiled Stat. Ch. 225, pars. 725 et. seq. Failure to disclose this information will result in this form not being processed. This form has been approved by the Forms Management Center.

IL472-0279

April 5, 2010

Mr. Steve Nightingale
Illinois Environmental Protection Agency
Bureau of Land, Permit Section #33
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, Illinois 62794-9276

Via Next Day Service

Re: Permit No. UIC-012-ADM
Geophone Well Completion Report

Dear Mr. Nightingale:

In accordance with Condition A.8.b of the above referenced permit, ADM is submitting the Well Completion Report for the geophysical monitoring well drilled at the ADM CCS #1 site. This well will be used for seismic monitoring on the Illinois Basin – Decatur project. This monitoring well will facilitate the gathering of micro-seismic and VSP data over the life of the project.

This well is for monitoring only and does not serve as an injection well. The enclosed report addresses the items required by the permit. If you have any questions regarding this please contact Sallie Greenberg at 217-244-4068 or myself at 217-451-6330.

Sincerely,

Dean Frommelt
Division Environmental Manager
Corn Processing & BioProducts

Cc: Mark Burau - ADM
Mark Carroll – ADM
Rob Finley – ISGS
Sallie Greenberg – ISGS

Geophone Monitoring Well Completion Report

Archer Daniels Midland Company
1150155136 – Macon County
ILD984791459
Permit No. UIC-012-ADM
Log No. UIC-143-M-1

Table of Contents

Attachments

Attachment 1: Well Schematic
Attachment 2: Well Tally Data Sheets
Attachment 3: Cement Reports
Attachment 4: Drilling Logs
Attachment 5: Drilling Log, Laterlog/SP/Micro Resistivity/Gamma Ray, Compensated Neutron/Litho Density/Gamma Ray/ Caliper/ Directional Survey
Attachment 6: CBL VDL/ Cement Map /Pressure Temperature/Gamma Ray/ CCL
Attachment 7: IDNR Forms

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

April 5, 2009
Date Signed

Well Location

A photo of the well head showing the 9 5/8 x 3.5 2000 psi SO casing head with 3 ½ tubing is provided as Figure 1. A map showing well pad with respect to the facility boundaries is provided as Figure 2. Also, a map identifying the location of the geophone monitoring well, the injection well, and other appropriate structures is provided as Figure 3.

Additional location information follows:

Township-Range-Section:	390 feet(118.87m) south and 185 feet (56.39m) west of the NE corner of the NW corner of the NW corner of Sec 5, T16N,R3E; Macon County, Illinois
Local Latitude:	39.87704081
Local Longitude:	-88.89395539
Surface Elevation:	675ft (205.74m) KB 15 (4.57m) ft above GL
Well Depth:	3500ft (1066.8m)

Figure 1: ADM Geophysical Well Head #1

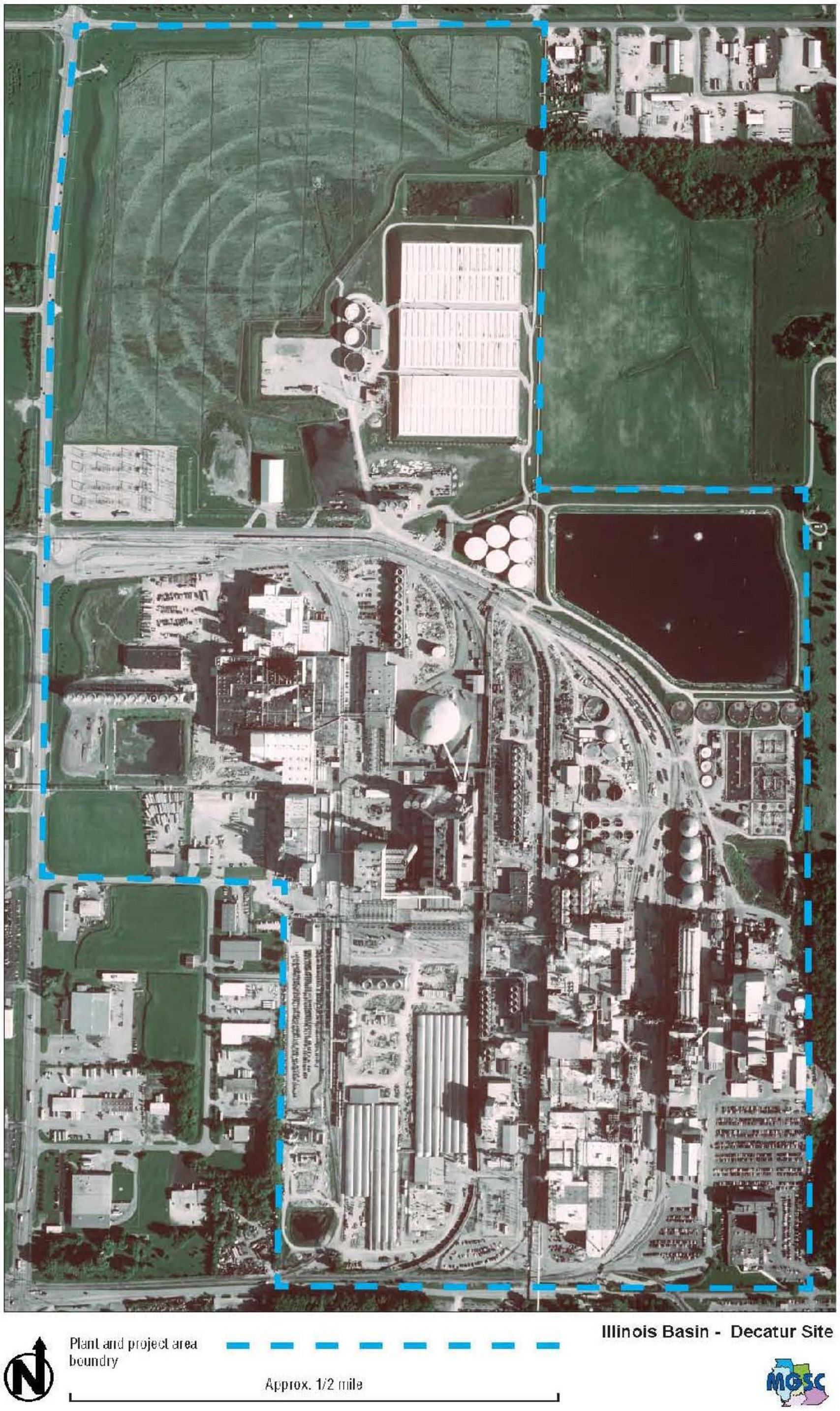


Figure 2: Map depicting facility boundaries

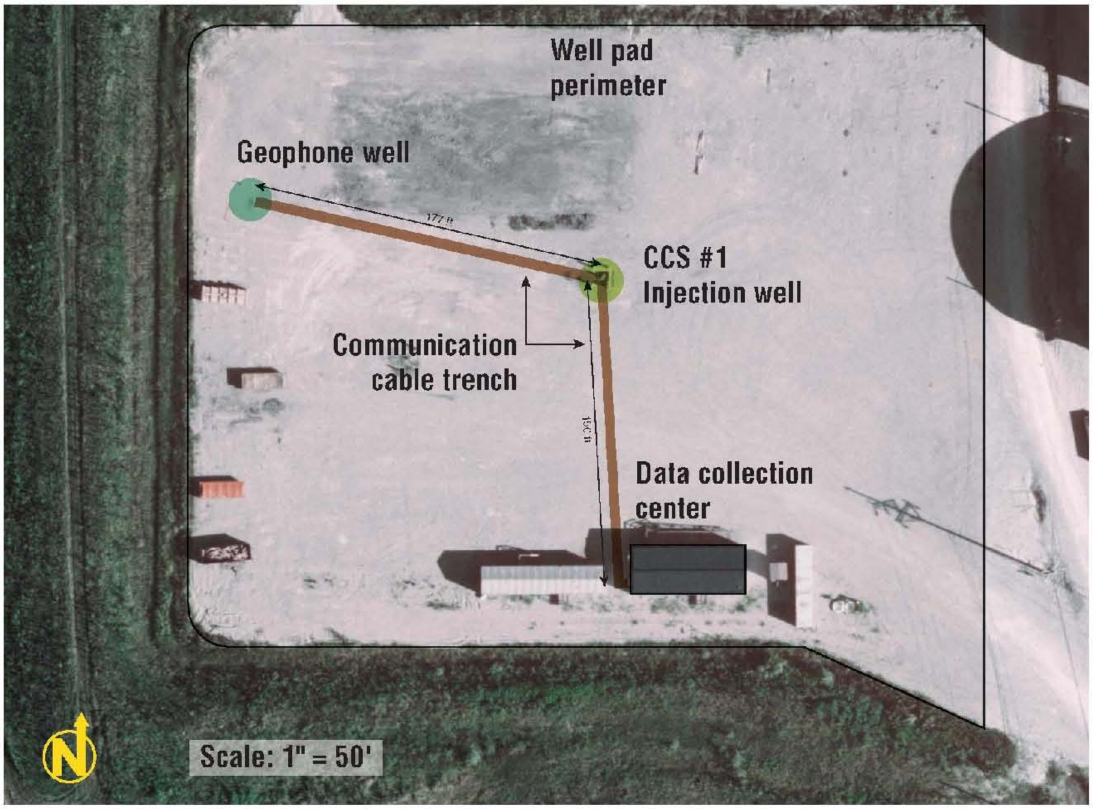


Figure 3: Map showing well pad detail

Description of Construction

Summary

Drilling operations on this well were started on Oct. 29, 2009 and finished on November 11, 2009. The well was drilled using Pioneer Drilling Rig # 15 and was rotary mud drilled.
The well driller used for construction of this well is:

Pioneer Drilling Rig 15
Rt 4, Box 142 B
Lawrenceville, Il 62439

Surface casing was set to 350 ft and cemented back to surface. An 8.5 inch hole was drilled to 3500 ft into the top of the Shakopee shale. No cores or DSTs were taken but a suite of open hole logs were run. A 31 level geophone array was installed in the well via a string of 3 ½ inch tubing. The geophone array attached to the outside of the 3 ½ inch pipe was then cemented in place with cement returned to surface. Operations were suspended until all necessary trenching and cabling could be installed and connected to a data acquisition system on site. In early February a cement bond log was run showing excellent cement to surface. The array was tested and found to be working well. Testing continued until mid February and system was permanently connected to data acquisition system. The array was then used in obtaining VSP data at the well site. The system is continuously recording seismic events at the present.

Well Design and Construction Details

A detailed well drawing of surface and subsurface construction is included in Attachment 1.

- Well hole diameters and corresponding depth intervals:
  - 12 ¼''(311mm) hole to 351 (106.98m)ft
  - 8.5'' (216mm) hole to 3500ft (1066.8m)
- Casings
  - Conductive casing: None
  - Surface casing: 9 5/8" (244mm) 40#/ft (59.53 kg/m)N-80 LT&C to 349 ft (106.37m) Thermal conductivity 29.02 BTU ft-hr degrees F
  - Intermediate casing: None
  - Long string casing: 3 ½ inch OD (89mm) 2.992inch ID (76mm) 9.3 #/ft (13.83 kg/m)EUE 8 rd L-80 tubing run as casing to 3496 ft (1065.6m) to support the geophone array Thermal conductivity : 29.02 BTU ft-hr degrees F
  - Other casing: None
- Cement
  - Conductive casing: None
  - Surface casing: Cemented with 150 sack Class A cement with 2% Cacl2 and ¼#/sk flake. Mix wt 15.8 ppg, Yield 1.19 ft3/sk. Thermal Conductivity .73BTU,ft-hr F Lost circulation with two bbls displacement left. Picked up 1" grout string and found cement 13 feet below surface. Mixed and pumped 50 more sacks of same cement and got cement to surface. Total 200 sacks cement used. Displaced with fresh water. Floats held.
  - Intermediate casing: None
  - Long string casing: Ran 920 sacks Franklin 10/10 FSS cement with .2% C-13 retarder and 1/8#/sk flake. Mixed at 14.2 ppg and yield of 1.63 ft3/sk. Thermal Conductivity .6 BTU ft-hr F. Displaced with fresh water. Circulated 30 bbls cement to pit. Floats held
  - Other casing: None

The following attachment provides additional details regarding the construction and design of the well:

Attachment 1: Well Schematic
Attachment 2: Well Tally Data Sheets
Attachment 3: Cement Reports

Tests and Logs

The following tests and logs were completed for this well.

- During Drilling: Drilling Log, Laterlog/SP/Micro Resistivity/Gamma Ray, Compensated Neutron/Litho Density/Gamma Ray/ Caliper/ Directional Survey
- During and after casing installation: CBL VDL/ Cement Map /Pressure Temperature/Gamma Ray/ CCL

The following attachments provide additional details regarding the testing and logging completed:

Attachment 4: Drilling Logs
Attachment 5: Drilling Log, Laterlog/SP/Micro Resistivity/Gamma Ray, Compensated Neutron/Litho Density/Gamma Ray/ Caliper/ Directional Survey
Attachment 6: CBL VDL/ Cement Map /Pressure Temperature/Gamma Ray/ CCL

DNR Well Forms

Forms OG-5 Well Drilling Report and OG-9 Well Completion Report have been submitted to the Illinois Department of Natural Resources – Office of Mines and Minerals. Copies of these forms are contained in Attachment 7.

Attachment 1: Well Schematic

Attachment 2: Well Data Sheets

Jt #	Jt. Tally	Depth	Pod #	Pod Depth	Clamp	Date/Time	Notes
						11/5/09 1:00 PM	
Shoe	1.25	3496.00					
Collar	1.17						
		3493.58					
1	31.37						
		3462.21			MC/CC	11/05/2009 14:00	Modified 1st Clamp
2	33.02		31	3443.21	GC		
		3429.19		FALSE			
3	30.47				MC		
		3398.72					
4	31.33		30	3393.21	GC/MC		
		3367.39		FALSE	CC/MC		
5	29.50		29	3343.21	GC		
		3337.89		FALSE	CC		
6	31.53			10' Re-Bar	MC	11/05/2009 15:00	3.5" above tubing collar
		3306.36		10' Re-Bar		11/05/2009 16:00	12" below tubing collar
7	30.69		28	3293.21	GC/MC		
		3275.67		FALSE			
8	30.15				MC		
		3245.52					
9	32.40		27	3243.21	GC/MC(2)		Backup tongs released
		3213.12		FALSE	CC		(KB turned 1/4 rot.)
10	31.21		26	3193.21	GC		
		3181.91		FALSE	CC	11/05/2009 17:15	Fill Tubing
11	33.05				MC		
		3148.86			CC		
12	31.52		25	3143.21	GC/MC		
		3117.34		FALSE			
13	32.84		24	3093.21	MC/GC		
		3084.50		FALSE			
14	32.81				MC		
		3051.69					
15	30.42		23	3043.21	GC		
		3021.27		FALSE	CC		
16	31.39		22	2993.21	GC		
		2989.88		FALSE			
17	32.95				MC		
		2956.93					
18	31.44		21	2943.21	GC		
		2925.49		FALSE	CC		
19	4.25						
		2921.24					
20	30.51		20	2893.21	MC/GC		
		2890.73		FALSE			
21	32.91				MC		
		2857.82					
22	32.98		19	2843.21	GC		
		2824.84		FALSE			
23	6.04						
		2818.80			CC		
24	31.38		18	2793.21	MC/GC		
		2787.42		FALSE			
25	31.40				MC		
		2756.02			CC		
26	33.00		17	2743.21	GC		
		2723.02		FALSE	CC		
27	32.99		16	2693.21	MC/GC		
		2690.03		FALSE		11/05/2009 19:36	

Jt #	Jt. Tally	Depth	Pod #	Pod Depth	Clamp	Date/Time	Notes
		2690.03					
28	31.52				MC		
		2658.51			CC		
29	31.47		15	2643.21	GC		
		2627.04		FALSE			
30	31.37				MC		
		2595.67			CC		
31	31.52		14	2593.21	GC/MC		Tight Connection
		2564.15		FALSE	CC		
32	33.03		13	2543.21	GC/MC		
		2531.12		FALSE			
33	31.37				MC		
		2499.75					
34	30.99		12	2493.21	GC		
		2468.76		FALSE	CC		
35	33.01		11	2443.21	MC/GC		
		2435.75		FALSE			
36	30.46				MC		
		2405.29					
37	31.42		10	2393.21	GC		
		2373.87		FALSE		11/05/2009 20:30	Break to fill tubing
38	30.48		9	2345.21	GC	11/05/2009 21:00	Start-up again
		2343.39		FALSE			Jt. #38: cable wound
39	29.65				GC		around tubing to put
		2313.74			CC		Geo. #9 below collar
40	30.5		8	2295.21	MC		(48' spacing)
		2283.24		FALSE			
41	32.89				MC		
		2250.35					
42	31.41		7	2245.21	GC/MC		
		2218.94		FALSE	CC		
43	32.8		6	2195.21	MC/GC		
		2186.14		FALSE			
44	31.33				MC		
		2154.81					
45	32.64		5	2145.21	GC/MC		
		2122.17		FALSE	CC		
46	30.26		4	2095.21	MC/GC		
		2091.91		FALSE	CC		
47	31.35				MC		
		2060.56			CC		
48	31.55		3	2045.21	GC	11/05/2009 22:05	Attach Geo #3
		2029.01		FALSE			
49	33.06				MC		
		1995.95			CC		
50	31.39				MC	11/05/2009 22:16	Start cable pattern
		1964.56					
51	33				MC		
		1931.56			CC		
52	31.46				MC		
		1900.10					

Jt #	Jt. Tally	Depth	Pod #	Pod Depth	Clamp	Date/Time	Notes
		1900.10					
53	32.92				MC		
		1867.18			CC		
54	33.02				MC		
		1834.16					
55	30.48				MC		
		1803.68			CC		
56	31.18				MC		
		1772.50					
57	30.48				MC		
		1742.02			CC		
58	31.59				MC		
		1710.43					
59	33.04				MC		
		1677.39			CC		
60	32.75				MC		
		1644.64					
61	31.36				MC	11/05/2009 23:30	Break to fill tubing
		1613.28			CC		
62	31.35				MC	11/6/09 0:00	Start-up again
		1581.93					
63	32.87				MC		
		1549.06			CC		
64	32.83				MC		
		1516.23					
65	32.96				MC		
		1483.27			CC		
66	31.44				MC		
		1451.83					
67	31.32				MC		
		1420.51			CC		
68	31.4				MC		
		1389.11					
69	30.69				MC		
		1358.42			CC		
70	32.95				MC		
		1325.47					
71	32.91				MC		
		1292.56			CC		
72	33.1				MC		
		1259.46					
73	32.63				MC		
		1226.83			CC		
74	31.54				MC		
		1195.29					
75	32.56				MC		
		1162.73			CC		
76	32.84				MC		
		1129.89					
77	32.44				MC		
		1097.45			CC		

Jt #	Jt. Tally	Depth	Pod #	Pod Depth	Clamp	Date/Time	Notes
		1097.45			CC		
78	30.69				MC		
		1066.76					
79	31.5				MC		
		1035.26			CC		
80	30.47				MC		
		1004.79					
81	30.49				MC		
		974.30			CC		
82	32.92				MC		
		941.38					
83	32.96				MC		
		908.42			CC		
84	31.5				MC		
		876.92					
85	31.36				MC		
		845.56			CC		
86	32.86				MC		
		812.70					
87	31.48				MC		
		781.22			CC		
88	30.61				MC		
		750.61					
89	32.62				MC		
		717.99			CC		
90	33.05				MC		
		684.94					
91	31.51				MC		
		653.43			CC		
92	33.13				MC		
		620.30					
93	33.04				MC		
		587.26			CC		
94	31.48				MC		
		555.78					
95	31.44				MC		
		524.34			CC		
96	31.36				MC		
		492.98					
97	32.94				MC		
		460.04			CC		
98	30.52				MC		
		429.52					
99	32.68				MC		
		396.84			CC		
100	30.28				MC		
		366.56					
101	32.98		2	355.21	GC		
		333.58		FALSE	CC		
102	30.7				MC		
		302.88					

Jt #	Jt. Tally	Depth	Pod #	Pod Depth	Clamp	Date/Time	Notes
		302.88					
103	31.64				MC		
		271.24					
104	31.49				MC		
		239.75			CC		
105	33.05				MC		
		206.70					
106	32.9				MC		
		173.80					
107	31.14				MC		
		142.66			CC		
108	31.5		1	135.21	GC		
		111.16		FALSE			
109	33				MC		
		78.16			CC		
110	32.93				MC		
		45.23			CC		
111	31.44				MC		
		13.79			CC		
P2	4.13						
		9.66					
P3	6.08						
		3.58					

GC = Geophone Clamp
MC = Mid-joint Clamp
CC = Centralizing Clamp
Red = Pup Joint
Blue = Re-bar

Attachment 3: Cement Reports

CEMENTING SERVICE REPORT

Franklin Well Services, Inc.

TREATMENT NUMBER 81-7880 / DATE 10/29/08
STAGE | DISTRICT L-ville

WELL NAME AND NO.	LOCATION (LEGAL)
GeoPhone #CCS-1	
FIELD-POOL	FORMATION: SURFACE
COUNTY/PARISH: MACON	STATE: IL / API. NO.

NAME Pioneer Oilfield Services
AND ADM
ADDRESS
ZIP CODE

SPECIAL INSTRUCTIONS
Cement 9 5/8 Surface Pipe Per Customer Request

RIG NAME: POFS Rig #15

WELL DATA:			BOTTOM	TOP
BIT SIZE 12 1/4		CSG/Liner Size	9 5/8	
TOTAL DEPTH 3		WEIGHT	36#	
☐ ROT ☐ CABLE		FOOTAGE	35/50	
MUD TYPE		GRADE	N-80	
☐ BHST ☐ BHCT		THREAD	8 Rd	
MUD DENSITY		LESS FOOTAGE SHOE JOINT(S)	47.25	
MUD VISC.		Disp. Capacity	22.8	

NOTE: Include Footage From Ground Level To Head In Disp. Capacity

Float TYPE	Collar	Stage Tool TYPE	
Float DEPTH	301.71	DEPTH	
SHOE TYPE	Guide	TYPE	
SHOE DEPTH	350.71	DEPTH	

Head & Plugs	☐ TBG ☐ D.P.	SQUEEZE JOB
☐ Double	SIZE	TOOL TYPE
☑ Single	☐ WEIGHT	DEPTH
☐ Swage	☐ GRADE	TAIL PIPE: SIZE / DEPTH
☐ Knockoff	☐ THREAD	TUBING VOLUME Bbl
TOP ☐R ☐W	☐ NEW ☐ USED	CASING VOL. BELOW TOOL Bbl
BOT ☐R ☐W	DEPTH	TOTAL Bbl
		ANNUAL VOLUME Bbl

IS CASING/TUBING SECURED? ☐ YES ☐ NO
LIFT PRESSURE PSI | CASING WEIGHT ÷ SURFACE AREA (3.14 x R²)
PRESSURE LIMIT PSI | BUMP PLUG TO PSI
ROTATE RPM | RECIPROCATE FT | No. of Centralizers

JOB SCHEDULED FOR TIME: 1630 DATE: 10/29
ARRIVE ON LOCATION TIME: 1630 DATE: 10/29
LEFT LOCATION TIME: 0130 DATE: 10/30

TIME 0001 to 2400	PRESSURE TBG OR D.P.	PRESSURE CASING	VOLUME PUMPED BBL INCREMENT	VOLUME CUM	INJECT RATE	FLUID TYPE	FLUID DENSITY	SERVICE LOG DETAIL
								PRE-JOB SAFETY MEETING
2302								Break Circulation H2O Ahead
2307		75	13		2.5	H2O	8.3	ST. Flake
2310		100	10		3.0	H2O		ST. H2O Spacer
2316		100	23		3.5	H2O	8.3	ST. Cement
2324		300	30.5		4.0	Cem	15.6	ShutDown Drop Plug
2325	–	–	–		–	–	–	ST. Displacement
2333		100	22.8		3 1/2	H2O	8.3	Bump Plug
2334		500						~~Flo~~ Check Float
2335		100						ReBump Plug
2336		900				H2O	8.3	Bump Plug
2337								Float held Rig UP 1" tub For
								Backside
1212								ST. Cement
1223			10		1.0	Cem	15.6	ShtDwn

REMARKS ON LOC. @ 1630 CASING NOT ON LOC.

SYSTEM CODE	NO. OF SACKS	YIELD CU. FT/SK	COMPOSITION OF CEMENTING SYSTEMS	SLURRY MIXED BBLS	DENSITY
1.	145	1.18	Class 'A' + 2% C-1 + 1/8# C-30	30.5	15.6
2.					
3.	50	1.18	Class 'A' + 2% C-1 + 1/8# Flake (Backside	10	15.6
4.					
5.					
6.					

BREAKDOWN FLUID TYPE | VOLUME | DENSITY | PRESSURE MAX. | MIN:
☐ HESITATION SQ. ☐ RUNNING SQ. | CIRCULATION LOST ☐ YES ☑ NO | Cement Circulated To Surf. ☑ YES ☐ NO Yes Bbls.
BREAKDOWN PSI | FINAL PSI | DISPLACEMENT VOL. 22.8 Bbls | TYPE OF WELL ☐ OIL ☐ GAS ☐ STORAGE ☐ INJECTION ☐ BRINE WATER ☐ WILDCAT
Washed Thru Perfs ☐ YES ☐ NO TO FT. | MEASURED DISPLACEMENT ☑ Tanks ☐ WIRELINE
PERFORATIONS TO TO / TO TO
CUSTOMER REPRESENTATIVE Jim Kirksey
SUPERVISOR Pat Stoltz

CEMENTING SERVICE REPORT

Franklin Well Services, Inc.

TREATMENT NUMBER 11951 | DATE 11-6-09
STAGE | DISTRICT L. Ville

WELL NAME AND NO.: GEOPHONE #CCS-1
LOCATION (LEGAL):
FIELD-POOL: ADM
FORMATION: 3½" LONGSTRING
COUNTY/PARISH: MACON
STATE: Illinois
API. NO.:

NAME: PIONEER OILFIELD SERVICES
AND:
ADDRESS:
ZIP CODE:
SPECIAL INSTRUCTIONS: 3½" LONGSTRING

IS CASING/TUBING SECURED? ☒ YES ☐ NO
LIFT PRESSURE 3385 PSI — CASING WEIGHT + SURFACE AREA (3.14 × R²)
PRESSURE LIMIT PSI | BUMP PLUG TO 1800 PSI
ROTATE — RPM | RECIPROCATE — FT | No. of Centralizers —

RIG NAME: PIONEER RIG #15

WELL DATA:			BOTTOM			TOP	TOTAL
BIT SIZE 8½"	CSG/Liner Size	3½"					
TOTAL DEPTH 3500	WEIGHT	9.3					
☒ ROT ☐ CABLE	FOOTAGE	3496					
MUD TYPE Gel	GRADE	J55					
☐ BHST ☐ BHCT —	THREAD	8RD					
MUD DENSITY N/A	LESS FOOTAGE SHOE JOINT(S)	3462					
MUD VISC. N/A	Disp. Capacity	30.1					30.1

NOTE: Include Footage From Ground Level To Head In Disp. Capacity

Float	TYPE	FLOAT Collar	Stage Tool	TYPE	
	DEPTH	3462'		DEPTH	
SHOE	TYPE	FLOAT SHOE		TYPE	
	DEPTH	3496'		DEPTH	

Head & Plugs	☐ TBG ☐ D.P.	SQUEEZE JOB
☐ Double	SIZE	TOOL TYPE
☒ Single	☐ WEIGHT	TOOL DEPTH
☐ Swage	☐ GRADE	TAIL PIPE: SIZE DEPTH
☒ Knockoff	☐ THREAD	TUBING VOLUME Bbls
TOP ☒R ☐W	☐ NEW ☒ USED	CASING VOL. BELOW TOOL Bbls
BOT ☐R ☐W	DEPTH	TOTAL Bbls
		ANNUAL VOLUME Bbls

JOB SCHEDULED FOR TIME: 0300 DATE: 11-11 | ARRIVE ON LOCATION TIME: 0300 DATE: 11-11 | LEFT LOCATION TIME: 1430 DATE: 11-11

TIME 0001 to 2400	PRESSURE TBG OR D.P.	PRESSURE CASING	VOLUME PUMPED BBL INCREMENT	VOLUME PUMPED BBL CUM	INJECT RATE	FLUID TYPE	FLUID DENSITY	SERVICE LOG DETAIL
0805	–	2000	–	–	–			PRE-JOB SAFETY MEETING YES - PRESSURE TEST
0810	–	650	–	–	5	H2o	8.34	START Pumping WATER, BREAK Circ.
0821	–	700	50	50	5	H2o	8.34	START Pumping MUD FLUSH
0825	–	700	20	70	5	H2o	8.34	START Pumping WATER
0849	–	600	50	120	5	H2o	8.34	START 10/10 FSS CEMENT
0933	–	700	266	386	6	LEAD	14.2	CEMENT IN, WASH LINES, DROP PLUG
0934	–	950	–	386	6	H2o	8.34	START Pumping Displacement
0940	–	1350	30	416	2	H2o	8.34	BUMP Plug To 1800 PSI
								BLEED PRESSURE, CHECK SHOE
								SHOE HOLDING OK
								30 - BBL. CEMENT To PIT = 105-SKS.
								RIG DOWN LEAVE LOC.

REMARKS

SYSTEM CODE	NO. OF SACKS	YIELD CU. FT/SK	COMPOSITION OF CEMENTING SYSTEMS	SLURRY MIXED BBLS	SLURRY MIXED DENSITY
1.	920	1.63	10/10 FSS + 0.3% C-65 + 0.2% C-13 + 1/8" FLAKE	266	14.2
2.					
3.					
4.					
5.					
6.					

BREAKDOWN FLUID TYPE | VOLUME | DENSITY | PRESSURE MAX. 1350 MIN: 600
☐ HESITATION SQ. ☐ RUNNING SQ. | CIRCULATION LOST ☐ YES ☒ NO | Cement Circulated To Surf. ☒ YES ☐ NO 30 Bbls.
BREAKDOWN PSI | FINAL PSI | DISPLACEMENT VOL. 30 Bbls | TYPE OF WELL ☐ OIL ☐ GAS ☐ STORAGE ☒ INJECTION ☐ BRINE WATER ☐ WILDCAT
Washed Thru Perfs ☐ YES ☐ NO | TO FT. | MEASURED DISPLACEMENT ☐ | ☐ WIRELINE
PERFORATIONS TO TO TO TO
CUSTOMER REPRESENTATIVE: Jim Kirksey
SUPERVISOR: Jeff Moore

Attachment 4: Drilling Logs

PIONEER OIL FIELD SER…

DRILLING-TIME LOG OF WELL

No.______

Company: ADM Geophysical Well #1 Farm ______ Co. ______

Sec. ______ T. ______ N. S., R. ______ E. W.

Elev. ______ Contractor: PIONEER

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
50	5:00		
55	05	5	
60			
65			
70			
75	~~6:23~~ 33	10	
80	43	10	
85	53	10	
90	7:03	10	
95	13	10	
100	23	10	
05	33	10	
10	43	10	
15	53	10	
20	8:03	10	
25	13	10	
30	8:23	10	Circ to fix Weight
35	~~33~~ 49	16	Indicator
40	59	10	
45	9:04	5	
50	14	10	
55	29	15	
60	47	18	Lime
65	~~9:58~~ 10:08	10	Calibrate Pason
70	17	7	
75	23	6	
80	32	9	
85	49	17	Lime
90	53	4	
95	57	4	CONN 197
200	5/11:09	12	
05	15	6	
10	21	6	
15	26	5	
20	35	9	
25	44	9	CONN 228

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
30	11:59	15	
35	12:02	3	
40	07	5	
45	12	5	
50	15	3	
55	22	7	
60	26	4	CONN
65	~~36~~ 45	9	
70	54	9	
75	1:01	7	
80	18	17	
85	35	17	
90	52	17	CONN 291
95	2:12	20	
300	20	8	
05	27	7	
10	35	8	
15	43	8	
20	2:53	10	CONN 322
25	~~3:01~~ 3:12	11	
30	3:19	7	
35	3:25	6	
40	3:35	10	
45	3:46	11	
50	4:00	14	T.D
55	~~7:10~~ 7:24	14	
60	7:36	12	
65	7:41	5	
70	7:47	6	
375	7:57	10	
80	8:07	10	CONN 382
85	~~8:27~~ 8:29	2	
90	8:31	2	
95	8:33	2	
400	8:39	6	
405	8:43	4	

…d weight ______ Viscosity ______ Speed of Rotary Table ______ Points weight ______

TABCO/Kramac Division-Vincennes Fort…

PIONEER OIL FIELD SERVICES, LLC

DRILLING-TIME LOG OF WELL

Company A D M   Farm MONITOR   No. #1

Elev.   Contractor   Sec   T.   N. S.,   R.   E. W.   Co.

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
410	8:43 / 8:48	5	CONN 413
15	9:00 / 9:04	4	
20	9:08	4	
25	9:12	4	
30	9:17	5	
35	9:22	5	
40	9:27	5	
45	9:31	4	CONN 445
450	10:00 / 10:08	8	TIGHTEN KOLLY HOSE
55	10:13	5	
60	10:19	6	
65	10:24	5	
70	10:34	10	Lime
75	10:43	9	CONN 475
80	10:50 / 56	6	
85	11:00	4	
90	05	5	
95	10	5	
500	15	5	
05	20	5	CONN 507
10	11:24 / 46	5	PUT OIL I ROTARY TABLE
15	51	5	
20	55	4	
25	12:00	5	
30	05	5	
35	11	6	CONN 540
40	12:16 / 27	5	
45	31	4	
550	36	5	
55	41	5	
60	46	5	
65	51	5	CONN 571
70	12:56 / 1:07	5	
75	1:12	5	
80	15	3	
85	20	5	

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
90	24	4	
95	29	5	
600	33	4	CONN 603
05	1:38 / 1:47	5	
10	52	5	
15	57	5	
20	2:03	6	
25	07	4	
30	12	5	CONN 634
35	2:15 / 2:25	4	
40	26	6	
45	32	5	
650	36	4	
55	40	4	
60	46	6	CONN 665
65	2:51 / 3:03		
70	08	5	
75	14	6	
80	21	7	
85	28	7	
90	35	7	CONN 696
95	3:42 / 3:49	7	
700	54	5	
05	58	4	
10	4:03	5	
15	10	7	
20	16	6	CONN 726
25	4:23 / 4:31	6	
30	37	4	
35	40	3	
40	44	4	
45	50	6	
750	56	6	CONN 758
55	5:02 / 5:10	8	
60	13	3	
65	17	4	

Mud weight   Viscosity   Speed of Rotary Table   Points weight

PIONEER OIL FIELD SERVICES, LLC

DRILLING-TIME LOG OF WELL

Company ADM Farm MONITOR No 1

Elev. Contractor Sec T. N. S., R. E. W. Co.

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
770	22	5	
75	28	6	
80	34	6	
85	40	6	
90	6:43 / 52	6	CONN 789
95	58	6	
800	6:02	6	
05	08	6	
10	13	5	
15	18	5	
20	6:23 / 7:15	5	Straight Hole 1/4
25	7:21	6	
30	28	7	
35	35	7	
40	42	7	
45	49	7	
50	7:56	7	CONN 852
55	8:07	7	
60	13	6	
65	19	6	
70	25	6	
75	31	6	
80	38	7	CONN 884
85	51	7	
90	57	6	
95	9:03	6	
900	09	6	
05	15	6	
10	22	7	
15	28 / 10:05	7	Conn Work on MP
20	10	5	
25	15	5	
30	21	6	
35	26	5	
40	31	5	
45	37	6	CONN 946

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
50	48 / 50	2	
55	55	5	
60	11:00	5	
65	06	6	
70	12	6	
75	17	5	CONN 977
80	31	6	
85	36	5	
90	42	6	
95	47	5	
1000	53	6	
05	59	6	Conn 1009
10	12:12	6	
15	15	3	
20	18	3	
25	21	3	
30	25	4	
35	28	3	Conn 1039
40	38	4	
45	41	3	
50	44	3	
55	47	3	
60	50	3	
65	53	3	
70	56	3	Conn 1071
75	1:08	6	
80	23	15	Auto Driller
85	27	4	
90	32	5	
95	37	5	
1100	42	5	Start Mud up
05	53	5	Conn 1103
10	57	4	
15	2:01	4	
20	06	5	
25	11	5	

Viscosity Speed of Rotary Table Points weight

TABCO/Kramac Division-Vincennes Form

PIONEER OIL FIELD SERVICES, LLC

DRILLING-TIME LOG OF WELL

Company ADM Farm MONitor No. 1

Elev. Contractor Sec T. N. S., R. E. W. Co.

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP	DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
1130	16	5		10	8:48	6	
35	35	19	CONN 1135	15	8:53	5	
40	~~41~~ 48	7		20	8:58	5	CONN 1322 [illegible] HOLE [illegible]
45	2:52	4		25	9:40 / 9:43	3	
50	2:56	4		30	10:00	17	
55	3:01	5		35	10:22	22	
60	3:06	5		40	50	28	
65	3:10	4	CONN 1165	45	11:02	12	
70	3:22 / 3:26	4		50	14	12	CONN 1352
75	3:29	3		55	11:31 / 11:35	14	
80	3:33	4		60	43	8	
85	3:38	5		65	47	4	
90	3:43	5		70	54	7	
95	3:48	5	CONN 1196	75	12:02	8	
1200	3:52 / 4:00	4		80	12	10	CONN 1384
05	4:04	4		85	12:21 / 12:31	10	
10	4:08	4		90	43	12	
15	4:12	4		95	54	11	
20	4:17	5		1400	1:08	14	
25	4:22	5	CONN 1228	05	16	8	
30	4:30 / 4:34	4		10	25	9	CONN 1415
35	4:39	5		15	1:33 / 2:24		WORK ON KELLY SPINNER
40	4:43	4		20	2:29	5	
45	4:49	6		25	37	8	
50	4:54	5		30	45	8	
55	4:59	5		35	53	8	
60	5:05	6	CONN 1260	40	3:01	8	CONN 1445
65	5:12 / 5:17	5		45	3:10 / 3:22	9	
70	5:24	7		50	30	8	
75	5:28	4		55	37	7	
80	5:42	14	Lime	60	43	6	
85	6:25	43		65	51	8	
90	7:03	38	CONN 1291 Pull out miss Run	70	58	7	CONN 1475
95	8:30 / 8:32	2	STRAIGHT HOLE Down	75	4:10 / 4:21	7	
1300	8:37	5		80	29	8	
05	8:42	5		85	34	5	

Mud weight Viscosity Speed of Rotary Table Points weight

PIONEER OIL FIELD SERVICES, LLC
DRILLING-TIME LOG OF WELL

Company ADM Farm MONITOR No 1

Elev. Contractor Sec T. N. S., R. E. W. Co.

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP	DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
1490	5:40	6		70	46	5	
95	46	6		75	52	6	
1500	52	6		80	58	6	
05	8:01 / 13	6		85	12:04	6	
10	20	7		90	11	7	CONN 1692
15	34	14		95	26	7	
20	51	17		1700	31	5	
25	7:03	12		05	35	4	
30	10	7		10	40	5	
35	17	7	CONN 1538	15	45	5	
40	8:30 / 33	3		20	51	6	CONN 1724
45	38	5		25	1:17	6	FIX Kelly Spinners
50	43	5		30	21	4	
55	48	5		35	26	5	
60	54	6	Plugged Jet	40	32	6	
65	9:00	6	CONN 1568	45	37	5	
70	16	6		50	42	5	
75	24	8		55	49	7	CONN 1760
80	30	6		60	54 / 2:00	6	
85	35	5		65	05	5	
1590	41	6		70	09	4	
95	46	5		75	14	5	
1600	52	6	CONN	80	19	5	CONN 1787
05	10:00 / 06	6		85	24	5	
10	11	5		90	30	6	
15	17	6		95	37	7	
20	23	6		1800	42	5	
25	29	6		05	2:47	5	
30	35	6	CONN	10	2:52	5	
35	48 / 54	6		15	2:56	4	CONN 1818
40	11:00	6		20	3:08 / 3:10	2	
45	07	7		25	3:13	3	
50	13	6		30	3:18	5	
55	18	5		35	3:23	5	
60	24	6	CONN 1661	40	3:30	7	
65	41	7		45	3:38	8	CONN 1848

Mud weight Viscosity Speed of Rotary Table Points weight

TABCO/Kramac Division-Vincennes Form

PIONEER OIL FIELD SERVICES, LLC
DRILLING-TIME LOG OF WELL

Company ADM Farm MONITOR No 1

Elev. Contractor Sec T. N. S., R. E. W. Co.

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP	DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
1850	~~4:22~~ 24	2	STRAIGHT HOLE ½ °	30	09	8	CONN 2035
55	4:30	6	VIS 55 WT 9,3	35	~~11:17~~ 31	8	
60	4:40	10		40	11:36	5	53 VIS 9.4 WT
65	4:49	9		45	12:11		WORK ON LIGHT PLANT
70	5:02	13		2050	15	4	
75	5:13	11	CONN 1879	55	21	6	
80	~~5:27~~ 5:29	2		60	26	5	CONN 2067
85	5:36	7		65	~~12:39~~ 42	5	
90	5:43	7		70	48	6	
95	5:49	6		75	1:02	14	WORK ON LIGHT PLANT
1900	5:56	7		80	1:41	39	
05	6:03	7		85	52	11	
10	6:18	12	CONN 1910	90	58	6	CONN 2099
15	~~6:29~~ 6:40	11		95	~~2:02~~ 20	6	
20	6:53	13		2100	26	6	59 VIS 9.4
25	7:02	9		05	35	9	
30	7:14	12	VIS 60 WT 9,4	10	42	7	
35	7:25	11	CONN 1939	15	52	10	
40	~~7:42~~ 7:48	6		20	3:01	9	
45	7:59	11		25	10	9	CONN 2130
1950	8:11	12		30	~~3:31~~ 31	9	
55	8:25	14		35	38	7	
60	8:40	15		40	42	4	
65	8:53	13		45	46	4	
70	9:09	16	CONN 1970	2150	51	5	56 VIS 9.4+
75	~~9:16~~ 9:27	11		55	56	5	CONN 2162
80	9:41	14		60	~~4:01~~ 14	7	
85	9:50	9		65	21	7	
90	10:04	14	58 VIS WT 9,4	70	26	5	
95	10:16	12		75	31	5	
2000	10:25	9	CONN 2002	80	36	5	
05	~~10:37~~ 43	6		85	42	6	
10	43	6		90	48	5	
15	49	6	54 VIS WT 9.4	95	~~4:53~~ 5:02	5	
20	55	6		2200	5:07	10	
25	01	6		05	5:14	7	

Mud weight Viscosity Speed of Rotary Table Points weight

TABCO/Kramac Division-Vincennes Form

PIONEER OIL FIELD SERVICES, LLC

DRILLING-TIME LOG OF WELL

Company ADM Farm GEOTHERMAL MONITOR No. 1

Elev. Contractor PIONEER Sec T. N. S., R. E. W. Co.

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP	DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
2210	28	10		90	28	6	
2215	36	8	CONN 2223	95	34	6	
20	5:45 / 6:00	8		2400	40	6	
25	05	5		05	10:47	7	Conn 2409
30	13	8		10	11:00	7	
35	23	10		15	06	6	
40	34	11		20	15	9	
45	44	10		25	24	9	
50	54	10	Conn 2254	30	33	9	
55	7:04	10		35	43	10	
60	7:11	7		40	53	10	Conn 2441
65	17	6		45	12:10	10	
70	25	8		50	12:21	11	
75	35	10		55	31	10	
80	41	6		60	42	11	
85	49	8	CONN Serv Rig	65	54	12	
90	7:56 / 8:02	6		70	1:05	11	Conn 2472
95	07	5		75	22	17	
2300	12	5		80	34	12	
05	16	4		85	45	11	
10	21	5		90	56	11	
15	26	5	CONN 2316 Straight	95	2:06	10	
20	9:01	5	3/4 Hole	2500	18	12	Conn 2504
25	05	4		05	2:35 / 2:38	3	
30	10	5		10	2:47	9	
35	15	5		15	2:58	11	
40	19	4		20	3:10	12	
45	24	5	Conn 2346	25	3:24	14	
50	36	5		30	3:38	14	CONN 2534
55	43	7		35	5:29 / 5:33	3	
60	50	7		40	5:47	12	
65	9:55	5		45	5:58	14	
70	10:01	6		50	6:12	14	
75	06	5	Conn 2377	55	6:28	16	
80	17	6		60	6:43	15	
85	22	5		65			CONN 2565

Mud weight Viscosity Speed of Rotary Table Points weight

TABCO/Kramac Division

PIONEER OIL FIELD SERVICES, LLC
DRILLING-TIME LOG OF WELL

Company ADM   Farm MONITOR   No. 1

Elev.   Contractor   Sec   T.   N. S.,   R.   E. W.   Co.

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP	DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
2570	7:06 / 7:15	9		2750	3:44 / 54	14	CONN 2718
75	7:24	9		55	24	20	54 VIS 9.6 WT
80	7:32	8		60	40	16	
85	7:50 / 8:00	10		65	56	16	
90	8:12	12		70	14	18	
95	8:28	16	CONN 2595	75	23	9	SHT
2600	8:40 / 8:48	8		80	5:30 / 6:15	45	5:40 CONN 2779
05	8:59	11		85	29	14	56 VIS 9.6 WT
10	9:11	12		90	45	16	
15	9:24	13		95	54	9	
20	9:32	8		2800	7:02	8	Pumpup Wt Ind
25	9:41	9	CONN 2626	05	15	13	CONN 2808
30	10:18 / 10:24	6		10	37	13	51 VIS 9.6
35	10:32	8		15	45	8	
40	48	16		20	55	10	
45	59	11		25	8:05	10	
2650	10	11	9.6 WT 55 VIS	30	15	10	
55	19	9	CONN 2656	35	23	8	CONN 2839
60	11:22 / 36	8	✓ RIG	40	38	8	
65	45	9		45	47	9	
70	53	8		2850	56	9	
75	12:02	9		55	9:03	7	
80	12	10		60	12	9	Serv Rig Cal Pason
85	22	10		65	24	12	CONN 2869
90	12:31 / 46	15	CONN 2687	70	46	12	
95	56	10		75	55	9	
2700	1:06	10	54 VIS 9.6	80	10:05	10	
05	18	12		85	15	10	
10	29	11		90	23	8	
15	42	20	LIME	95	31	8	
20	2:00 / 2:20	18	CONN 2718	2900	39	8	CONN 2901
25	40	22	54 VIS 9.6.	05	53	8	
30	51	11		10	11:01	8	
35	09	18		15	08	7	
40	32	23		20	16	8	
45	40	8		25	24	8	

Mud weight   Viscosity   Speed of Rotary Table   Points weight

TABCO/Kramac Division-Vincennes Form

PIONEER OIL FIELD SERVICES, LLC

DRILLING-TIME LOG OF WELL

Company ADM Farm Monitor No. 1

Elev. Contractor Sec T. N. S., R. E. W. Co.

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP	DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
30	24 / 32	8	CONN 2932	10	7:01	12	
35	49	9		15	7:12	11	CONN 3115
40	59	10		20	7:22 / 7:29	7	
45	12:08	9		25	7:40	11	
50	18	10		30	7:51	11	
55	28	10		35	8:03	12	
60	39	11	CONN 2962	40	8:15	12	
65	57	11		45	8:27	12	CONN 3145
70	1:05	8		50	8:35 / 8:43	8	
75	15	10		55	8:54	11	
80	25	10		60	9:04	10	
85	36	11		65	9:13	9	
90	46	10	CONN 2993	70	9:22	9	
95	2:03	10		75	9:32	16	CONN 3177
3000	13	10		80	9:40 / 9:48	8	
05	23	10		85	9:57	9	
10	34	11		90	10:07	10	
15	2:42	8		95	10:16	9	
20	2:53	11		3200	10:25	9	
25	3:04	11	CONN 3025	05	10:32	7	CONN 3208
30	3:20 / 3:30	10	ODOR	10	10:42 / 48	6	
35	3:41	11		15	50	2	
40	3:50	9		20	55	5	
45	4:02	12		25	11:01	6	57 rbs 96 wt
50	4:18	16	CONN 3054	30	08	7	
55	4:34 / 44	10		35	14	6	CONN 3240
60	4:55	11		40	11:20 / 26	6	
65	5:09	14		45	30	4	
70	5:20	11		50	35	5	
75	5:31	11		55	40	5	
80	5:43	12	CONN 3084	60	45	5	
85	6:00 / 6:08	8		65	50	5	CONN 3271
90	6:18	10		70	10:57 / 11:05	5	
95	6:26	8		75	11:30	5	
3100	6:38	12		80	1:44	5	
05	6:49	11		85	1:49	5	

Mud weight Viscosity Speed of Rotary Table Points weight

TABCO/Kramac Division-Vincennes Form

PIONEER OIL FIELD SERVICES, LLC
DRILLING-TIME LOG OF WELL

Company ADM Farm MONTEROR No 1

Elev. Contractor Sec T. N./S., R. E./W. Co.

DEPTH	TIME	MINUTES	LOG, REMARKS, STOP	DEPTH	TIME	MINUTES	LOG, REMARKS, STOP
3290	1:55	5		70	9:06	39	
95	2:00	5		75	28	22	
3300	2:05	5	CONN 3302	80	49	21	
3305	2:11 / 2:55	44	SHT 3/4	85	10:10	21	Conn 3489
10	3:05	10		90	32	19	
15	19	9		95	51	19	
20	28	9		3500	11:05	14	Circ ½ Short Trip
25	38	10					
30	48	10	CONN 3334				
35	3:58 / 4:04	6					
40	09	5					
45	18	9	VIS 55 9.6 WT				
50	27	9					
55	34	7					
60	42	8	CONN 3365				
65	4:51 / 58	7					
70	56	8					
75	14	8					
80	22	8					
85	30	8					
90	38	8	CONN 3397				
95	5:53 / 58	7					
3400	01	3					
05	07	6	64 VIS 9.7 WT				
10	14	7					
15	24	10					
20	29	5					
25	39	10	CONN 3427				
30	7:03	12					
35	13	10					
40	21	8					
45	37	16					
50	45	18					
55	53	8	CONN 3458				
60	8:18	10	Serv Rig				
65	27	9					

Mud weight Viscosity Speed of Rotary Table Points weight

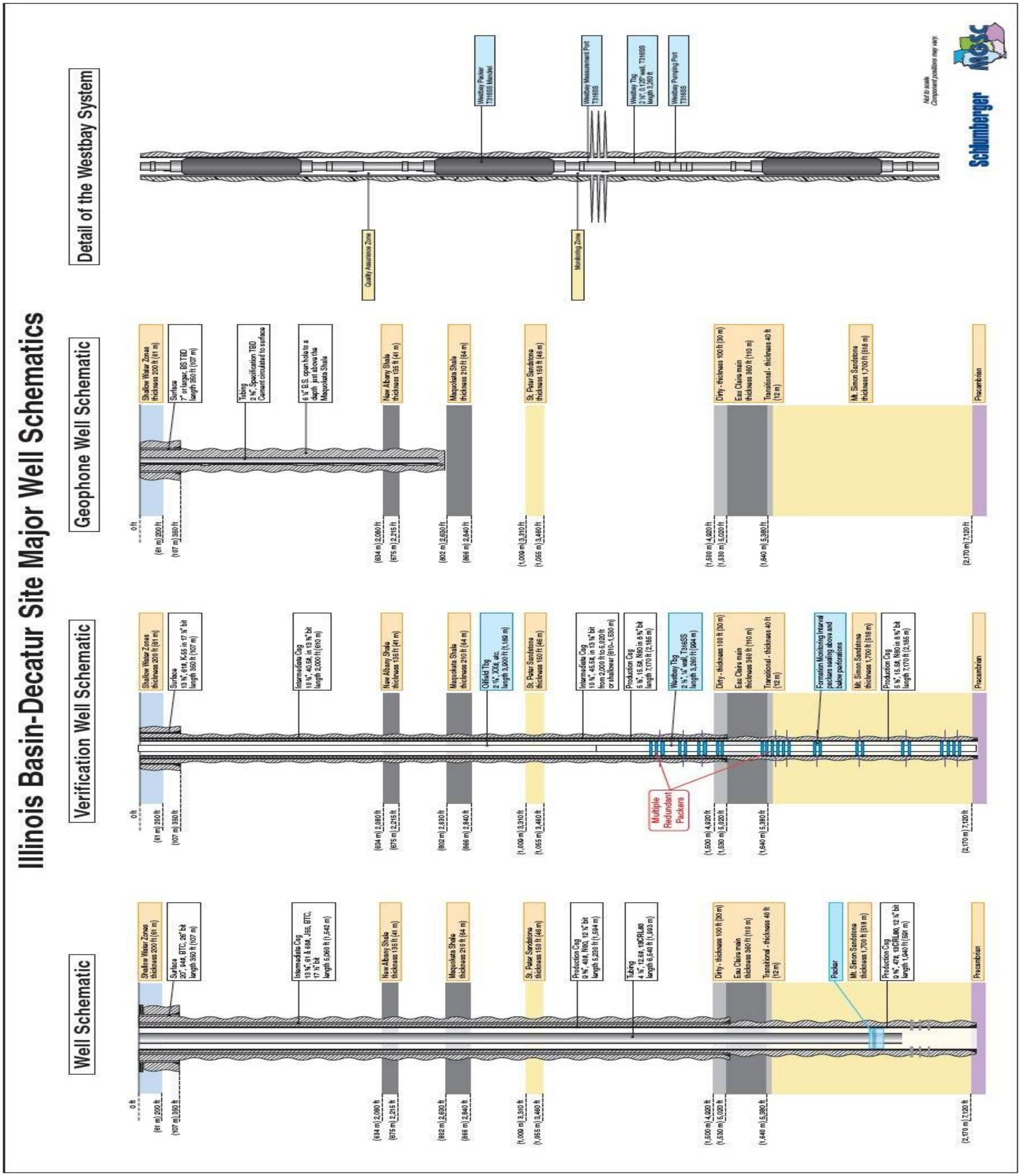
TABCO/Kramac Division

Attachment 5: Drilling Log, Laterlog/SP/Micro Resistivity/Gamma Ray, Compensated Neutron/Litho Density/Gamma Ray/ Caliper/ Directional Survey

Attachment 6: CBL VDL/ Cement Map /Pressure Temperature/Gamma Ray/ CCL

Attachment 7: IDNR Forms

Appendix M -- IBDP Wells As-Built Schematics



Appendix N -- Injectivity Testing Results

Description of Step-rate Test (Exerpt from Revised UIC Form 4a):

C.3. Fracture pressure at top of injection zone, include source

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**.

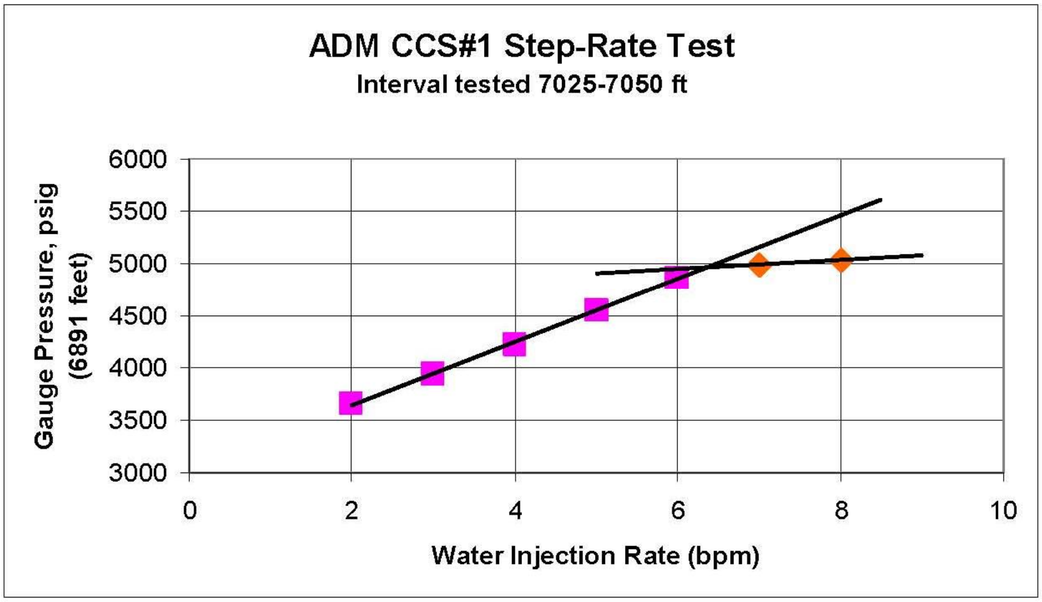


Figure 4a3: ADM CCS#1 step-rate test with fracture propagation pressure of 4966 psig estimated from the intersection of the two lines. The first line (2-6 bpm) represents radial flow of the Mt. Simon; the second line 7-8 bpm represents flow into the Mt. Simon after a fracture has propagated. The perforated interval was 7,025 to 7,050 feet during this step-rate test. (see Frailey_completionreport_0310.xls for original plot)

Appendix O -- HSE Results

ADM Project QHSE SafetyNet - Report
All Rig, SCS/SLB-related Project Personnel-PH II Tasks
FINAL REPORT

Drilling and Completions CCS#1 and GM#1	YTD-2009
Life Loss (for above period)	
Life Loss - Total	0
Automotive - Employee (SCS/SLB)	0
Automotive - Other	0
Total Accidents (for above period)	
Catastrophic	0
Major	0
Serious	0
Light	0
Risk Reports/STOP Cards or comparable	161
Regulatory Recordable Incidents	0
Lost Time Injuries - CMS (for above period)	
Lost Time Injury Accidents	0
LWC - Lost Work Cases	0
RWC - Restricted Work Cases	0
LTI - Lost Time Injuries	0
LD - Lost Days	0
RD - Restricted Days	0
TDL - Total Days Lost	0
MC - Medical Treatment Cases	0
FAC - First Aid Cases	0
TRI - Total Recordable Injuries (LWC + RWC + MC)	0
LTIR - Lost Time Injury Rate (LTI/1000 emp/yr)	0
Automotive - CMS (for above period)	
Total AA's - Automotive Accidents	0
Environmental - CMS ((for above period)	
Total Environmental Accidents	0
Supporting Data (for above period)	
Vehicles (Light and Heavy Vehicles-SCS/SLB)	32
Vehicles with Working Monitors	32
Total Headcount (SCS HR + Contractors + Consultants)	45
Drivers (inc. SLB/SCS, Contractors & Consultants)	13
Additional Data (for above period)	
Man Hours for period above (hours)	35,901
Man Hours cum. for month shown (hours)	35,901
Injury - Light - First Aid	1
No of safety meetings for period above (and cum.)	410
HSE Training Hours	115.5

ADM VERIFICATION WELL #1 QHSE SafetyNet - Report
All Verification Well, SCS/SLB-related Project Personnel

VW#1 Drilling	YTD-2010
Life Loss (for above period)	
Life Loss - Total	0
Automotive - Employee (SCS/SLB)	0
Automotive - Other	0
Total Accidents (for above period)	
Catastrophic	0
Major	0
Serious	0
Light	0
Risk Reports/STOP Cards or comparable	0
Regulatory Recordable Incidents	0
Lost Time Injuries - CMS (for above period)	
Lost Time Injury Accidents	0
LWC - Lost Work Cases	0
RWC - Restricted Work Cases	0
LTI - Lost Time Injuries	0
LD - Lost Days	0
RD - Restricted Days	0
TDL - Total Days Lost	0
MC - Medical Treatment Cases	0
FAC - First Aid Cases	0
TRI - Total Recordable Injuries (LWC + RWC + MC)	0
LTIR - Lost Time Injury Rate (LTI/1000 emp/yr)	0
Automotive - CMS (for above period)	
Total AA's - Automotive Accidents	0
Environmental - CMS ((for above period)	
Total Environmental Accidents	0
Supporting Data (for above period)	
Vehicles (Light and Heavy Vehicles-SCS/SLB)	18
Vehicles with Working Monitors	0
Total Headcount (SCS HR + Contractors + Consultants)	21
Drivers (inc. SLB/SCS, Contractors & Consultants)	11
Additional Data (for above period)	
Man Hours for period above (hours)	14,251
Man Hours cum. for month shown (hours)	14,251
Injury - Light - First Aid	0
No of safety meetings for period above (and cum.)	38.25
HSE Training Hours (Cum 2010)	14.3

Appendix P -- Open-Hole Log Data Collection Results CCS1

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.

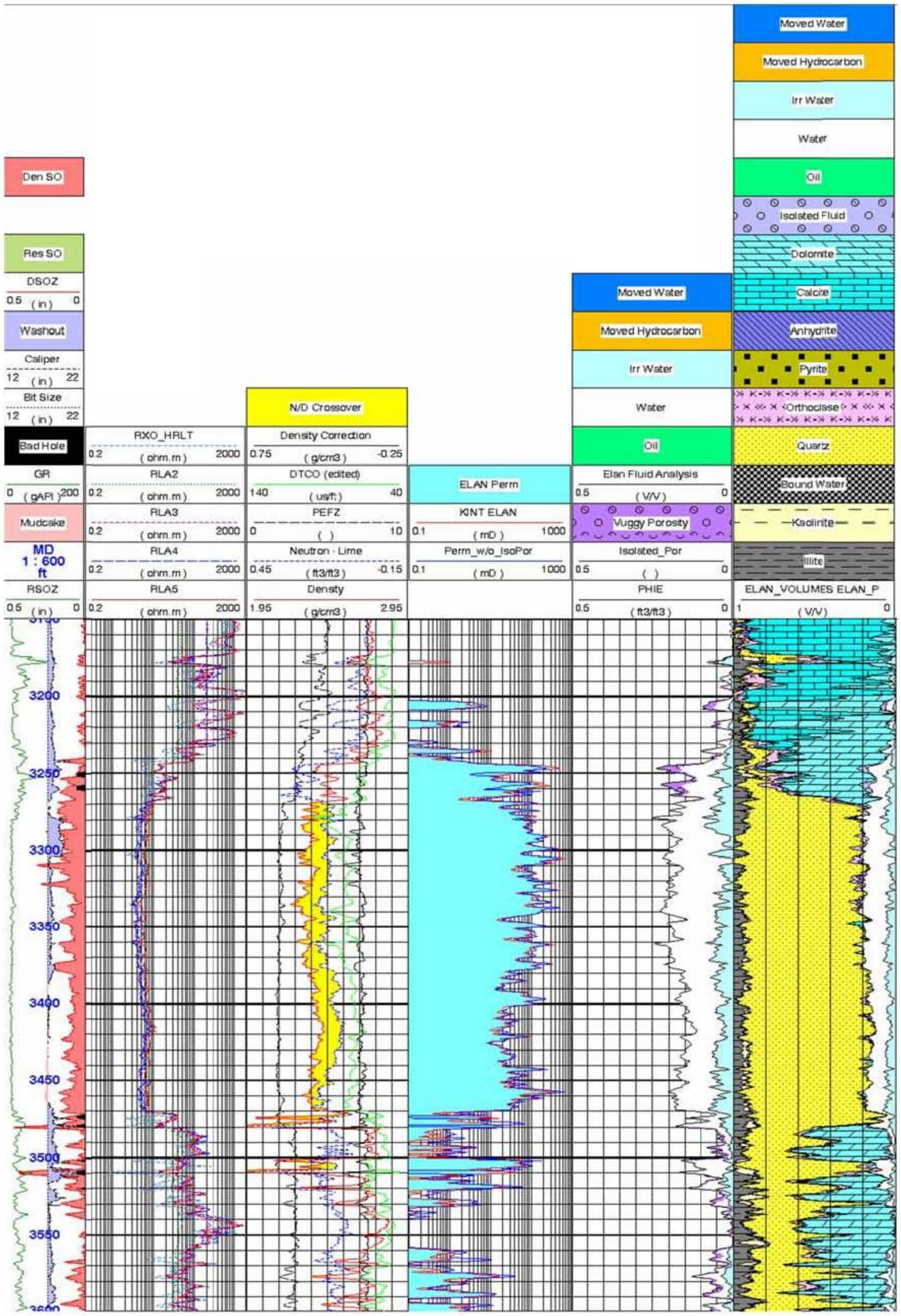
The middle interval of the Mount Simon has an average porosity of 9% and an average permeability of only 2.5 md. Based on the CMR pore size distribution and measurement of bound fluids, most of the fluids in this interval appear to be bound fluids, hence the greatly reduced permeability. While this interval 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.

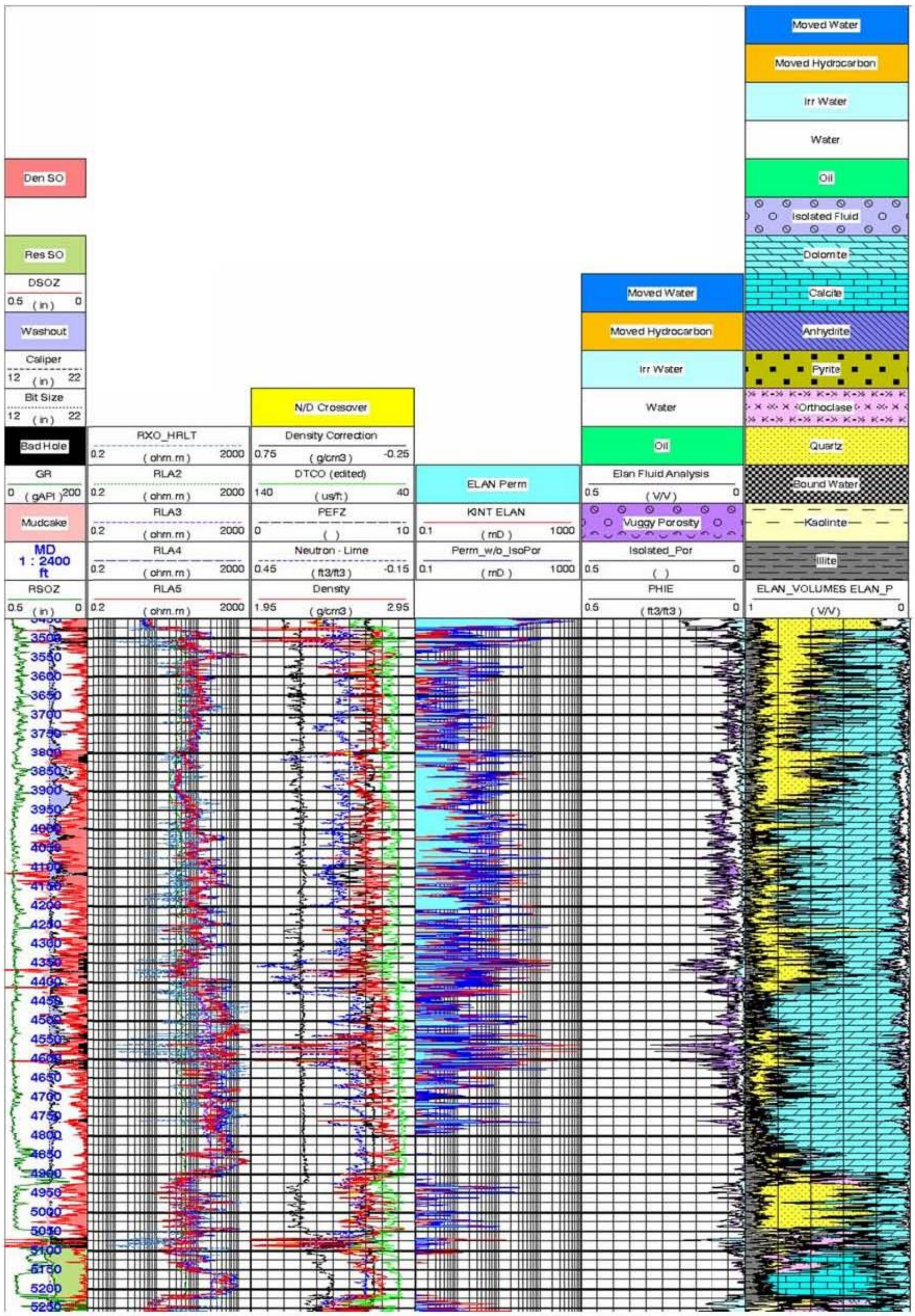
Detailed Interpretation of the Primary Seal (Eau Claire Shale)

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.

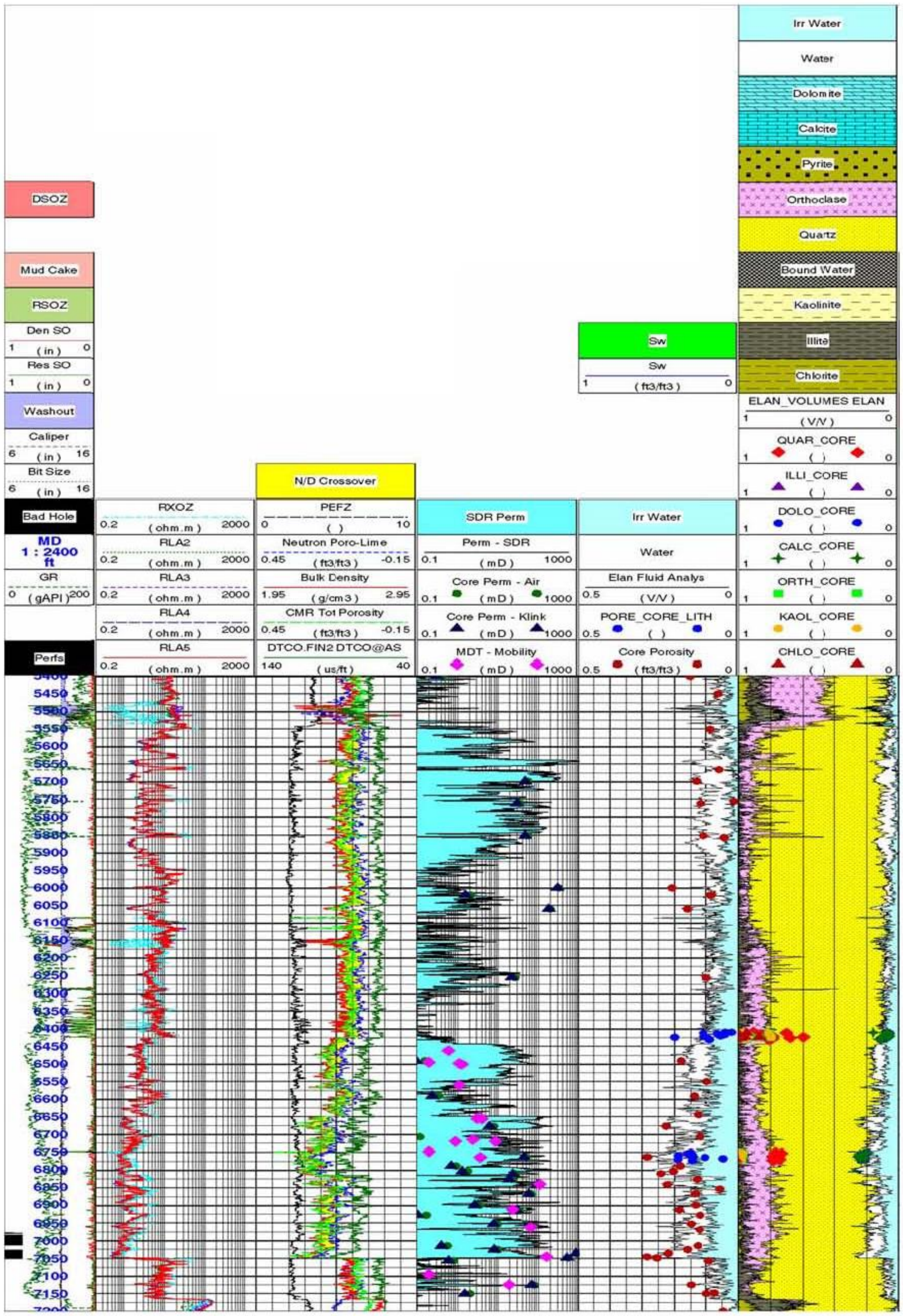
ELAN of St. Peter – CCS #1



ELAN of Knox – CCS #1



ELAN of Mt. Simon – CCS #1



Appendix Q -- Open-Hole Log Data Collection Results VW1

ADM Verification Well #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:
Oct 23, 2010 367 – 5320 ft	**PEX-HRLA (Platform Express)**	GR, Caliper, SP, Resistivity (Laterolog), Density, Neutron	Correlation, Porosity, Saturations, Hole Size
	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
	MDT	Modular Dynamic Tester	Formation Pressure, Mobility
	MSCT	Sidewall Coring Tool	Porosity, Permeability
Nov 15, 2010 5306 – 7264 ft	**PEX-HRLA-ZAIT (Platform Express)**	GR, Caliper, SP, Resistivity (Laterolog & Induction), Density, Neutron	Correlation, Porosity, Saturations, Hole Size, Resistive Anisotropy
	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
	XPT	PressureXpress Tool	Formation Pressure, Mobility

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.

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 Monitor Zone (Mount Simon)

The monitor zone in the ADM Verification Well #1 well is the Mount Simon Formation which extends from the base of the Eau Claire Shale at 5520 ft to the top of the Granite Wash zone at 6999 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 6380 ft. The section of the Mount Simon from 6380 ft to approximately 5890 ft is relatively low porosity with significantly reduced permeability. The third interval of the Mount Simon is from approximately 5890 ft to the top of the Mount Simon at 5520 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 monitor zone and has an average porosity of 16.0%, but there are intervals where the porosity approaches 30%. Average permeability in this interval is 29.5 md; however, permeability in the zone equivalent to the perforated interval in the CCS #1 well ranges from 60 md to several hundred md. There are a few thin shale intervals with in the bottom section of the mount Simon however, correlating this interval in the Verification Well #1 well with the CCS #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.

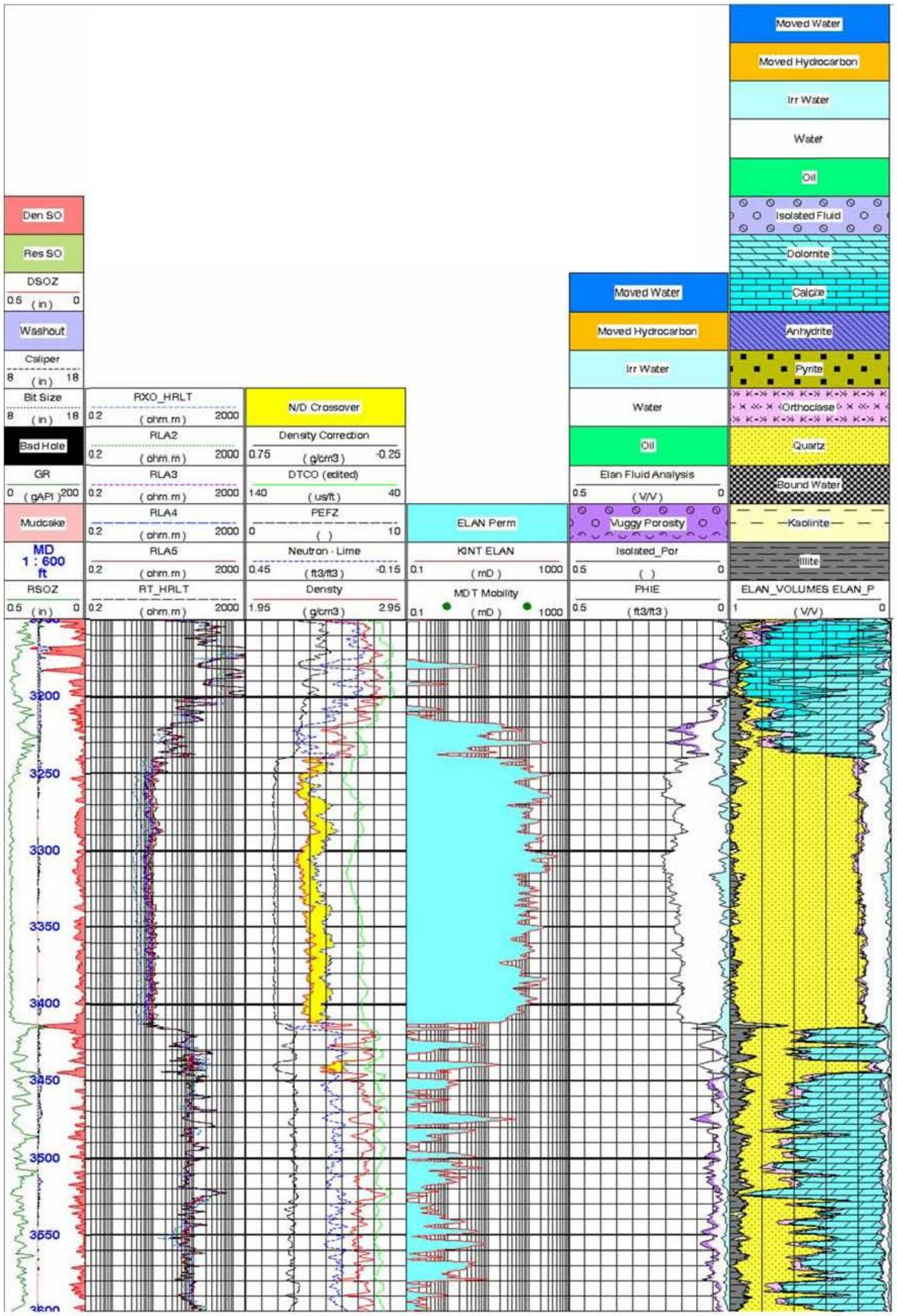
The middle interval of the Mount Simon has an average porosity of 8.5% and an average permeability of only 1.5 md. Based on the CMR pore size distribution and measurement of bound fluids, most of the fluids in this interval appear to be bound fluids, hence the greatly reduced permeability. While this 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 10.3% and an average permeability of 77 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.

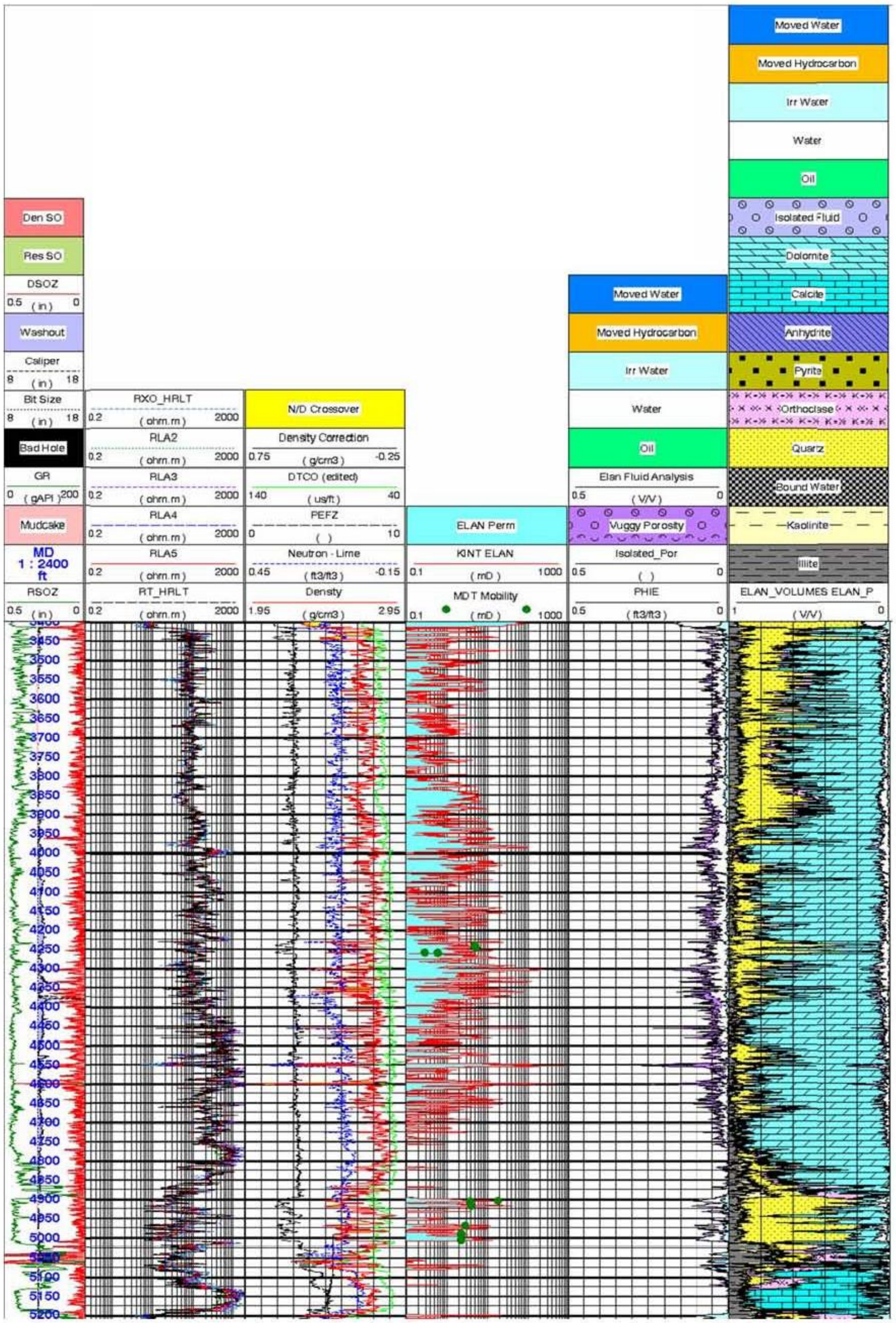
Detailed Interpretation of the Primary Seal (Eau Claire Shale)

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 5195 ft to 5520 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.

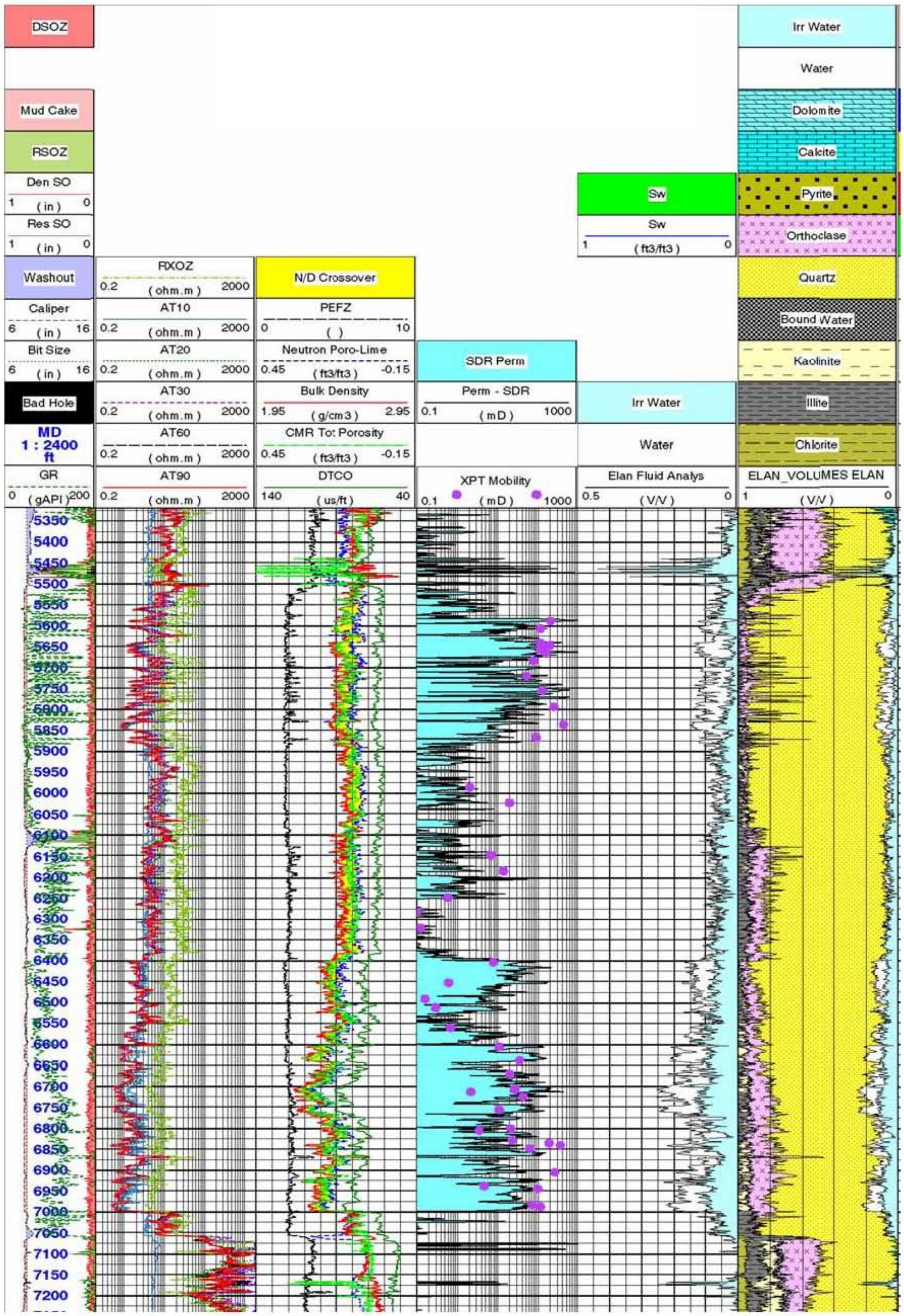
ELAN of St. Peter – Verification Well #1



ELAN of Knox – Verification Well #1



ELAN of Mt. Simon – Verification Well #1



Appendix R -- Cased-Hole Log Data Collection Results CCS1

ADM CCS #1

Mechanical Integrity Log and Testing Descriptive Report

Bob Butsch – Schlumberger Carbon ServicesJim Kirksey – Schlumberger Carbon Services

This document will describe the logging and testing programs related to the mechanical integrity of this well. It will also contain the analysis of the data collected, with the goal of demonstrating that the well is mechanically sound, and that no fluids will flow into the USDW at this site.

The Casing and Logging Program

Three casing strings were run in the ADM CCS #1 well. Logging runs investigating and verifying the baseline mechanical integrity of each casing string were made, and will be discussed in this document. Many other types of logs were run during installation of the borehole for the purpose of characterizing site geologic conditions. A discussion of those logs is available in the well completions report.

The surface casing string was run from surface to 353 ft and consisted of 20.0 inch, 94 lb/ft casing. The intermediate casing string was run from surface to 5339 ft and consisted of 13 3/8 inch, 59.5 and 66.2 lb/ft casing. The production casing string was run from surface to 7219 ft and consisted of 9 5/8 inch 40 lb/ft casing down to 5273 ft, and 9 5/8 inch 47 lb/ft CR13 chrome casing from 5273 ft to TD at 7219. All three casing strings were cemented to surface. Figure 1 is a wellbore diagram showing the casing configuration.

A Cement Bond Log (CBL) was run in each of the casing strings to help evaluate the cement of each casing string. The CBL transmits a sonic signal from a transmitter, and then measures the amplitude of that sonic signal after traveling through a section of the casing. If there is cement in the casing annulus the amplitude of the sonic signal will be attenuated and the amplitude of the sonic signal measured will be small. How small the amplitude actually becomes is dependent on many factors, including the percent of the casing bonded, the type of cement, and many of the casing properties to name a few.

To evaluate the casing and cement of the intermediate casing string an Ultrasonic Imager Tool (USIT) was used. The USIT uses a single transducer mounted on an ultrasonic rotating sub on the bottom of the tool. The transmitter emits ultrasonic pulses between 200 and 700 kHz and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface, by computing an acoustic impedance of the material outside the casing. The time for the signal to be transmitted and reflected back to the transducer is used to measure the internal radius, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. Because the transducer is mounted on the rotated sub, the entire circumference of the casing is scanned. This 360° data coverage enables the evaluation of the quality of the cement bond as well as the determination of the internal and external casing condition.

To evaluate the mechanical integrity of the production string of casing the Isolation Scanner tool was used in combination with the CBL and a Multi-finger Caliper Log (PMIT). The Isolation Scanner combines the same ultrasonic measurement as the USIT with a measurement of Flexural Wave Attenuation. The Flexural Attenuation measurement incorporates one ultrasonic transducer acting as the transmitter and two ultrasonic transducers acting as receivers to determine how much a flexural wave is attenuated after traveling through the casing. This measurement is more sensitive to cements that have low acoustic impedances than the USIT and can help identify when these cements are present. The measurements of acoustic impedance and flexural wave attenuation are combined into an interpretation breaking down the interpretation into solid (cement), liquid (water, mud, oil), and gas to make the visualization of the interpretation easy. The Multi-finger Caliper provides a baseline measurement of the internal radius as well as providing another measurement of the internal radius that can be compared to the measurement coming from the USIT.

Another log run that will be used to monitor changes in the mechanical integrity of the well is the Reservoir Saturation Tool (RST). This tool will primarily be used to monitor the CO_2 in the reservoir but also has several measurements that can be used to identify CO_2 that might be migrating up in any of the casing annuli. As expected, the base pass of the RST showed no indications of CO_2 present in any of the annuli. The portion of the log data that was related to the reservoir was consistent with the petrophysical analysis of the reservoir as described in the Geophysical Log Descriptive Report. The RST is most effective when used as a monitor log with subsequent monitoring passes. This is the base pass of the RST and these measurements will be compared to the same measurements on subsequent runs of the tool.

Analysis of the Well Integrity Logs

The CBL on the surface string of casing shows that at 352 ft. the amplitude measures just under 2 mv. This translates into an attenuation of 9 dB/ft. Using this value to compute the compressive strength of the cement at this interval, a value of approximately 3000 psi is computed. To demonstrate zone isolation it is desirable to have a continuous interval with the attenuation greater than 6 dB/ft. The attenuation is greater than 6 dB/ft from 354 to 347.5 ft. Ideally an interval longer than this would be preferred to indicate hydraulic isolation. However, there are several additional considerations. The CBL tool is designed for use in smaller casing, yet there are no better tools to evaluate the cement in this large casing. In addition to the zone mentioned above, several other intervals in the well have attenuations in the 4 to 6 dB/ft range where cement is certainly present. Also, it is known that cement was circulated to surface and that the cementing job was executed according to plan. Given this information it is believed the CBL is showing good hydraulic isolation at the base of the casing and a sufficient amount of cement behind the entire interval to prevent any fluids from flowing up from below into any USDW behind the casing in this interval as is the objective of this casing string.

The USIT shows that the intermediate string of casing has good hydraulic isolation over most of the length of the casing, with only short intervals where there are isolated pockets of fluid and not cement behind the casing. Figure 2 shows the results of the USIT and a brief description of the log is as follows:

Track1 – Gamma Ray and other QC type data.

Track 2 - Amplitude of the received ultrasonic signal (light colors are high amplitude)

Track 3 and 4 – Casing cross section showing minimum, maximum and average internal radius and average external radius.

Track 5 – Internal radius image

Track 6 – Minimum, maximum and average casing thickness.

Track 7 – Casing thickness image

Track 8 – Acoustic impedance image

Track 9 – Bond index presentation (yellow = cement, blue = liquid, red = gas, green = solid)

Track 10 – Interpreted acoustic impedance image (any shade of brown = cement, blue = liquid, red = gas, green = solid)

The USIT log also shows that the casing has no internal or external defects at this time based on the internal radius and thickness measurements.

The production string of casing was also determined to have good hydraulic isolation over most of the length of the casing, with only short intervals where there are isolated pockets of fluid and not cement behind the casing. The top of the injection zone is 5544 ft. and the first of these intervals below this point that has any potential to flow fluids is from 5660 to 5664 ft. It is actually more likely that this zone has a thin cement sheath rather than a channel. The next interval below this that is not completely isolated is from 6760 to 6750 ft. Above the base of the confining layer the first potential channel would be just above 4900 ft. Therefore, there is no potential for any fluids to migrate from the injection zone to zones above the confining layer by way of the casing-formation annulus. Figure 3 shows the Isolation Scanner log on this casing string and a brief description is as follows:

Track1 – Gamma Ray and other QC type data.

Track 2 – Diagnostic track – the processing of the tool is model based and this track indicates any deviations of the model.

Track 3 - Amplitude of the received ultrasonic signal (light colors are high amplitude)

Track 4 and 5 – Casing cross section showing minimum, maximum and average internal radius and average external radius.

Track 6 – Internal radius image

Track 7 – Minimum, maximum and average casing thickness.

Track 8 – Casing thickness image

Track 9 – Acoustic impedance image

Track 10 – Bond Flexural Wave Attenuation image

Track 11 – Interpreted Solid/Liquid/Gas image (brown = cement, blue = liquid, red = gas)

It was also determined that a microannulus does exist in a few places between the casing and cement. This is a condition where the acoustic coupling between the casing and cement has been reduced. The CBL log is the tool most affected by this condition and a CBL log with 500 psi pressure applied to the wellbore fluids was enough to eliminate this condition. Based on the API data on casing expansion this would mean that the microannulus is less than one thousandth of an inch, which is prohibitive to fluid flow. The USIT measurement is the better measurement to use for the analysis in these intervals and it shows very good hydraulic isolation. The USIT part of the Isolation Scanner and the PMIT also show that the casing has no internal or external defects at this time based on the internal radius and thickness measurements.

Mechanical Integrity Tests

Part 730 Underground Injection Control Operating Requirements

Subpart A 730.108 Mechanical Integrity

a) The owner or operator must demonstrate mechanical integrity when required by other Sections.

And Condition H.26 (b) of the permit (Log# UIC-143-M-2)

Mechanical integrity was established several times during the injection well completion. Prior to perforating, the casing was tested by both a low and high pressure test. The low pressure test was to 330 psig and the high pressure test was to 1750 psi. Both tests were recorded for 30 minutes with no bled off for the low pressure test and nine psi bleed off for the high pressure test. This was done on Sept 2, 2009. Upon installation of the lower completion the packer elements were successfully tested to 1040 psig for 30 minutes with no leakoff. This was performed on October 7, 2009 . After the completion brine was spotted and the blanking plug was set in the lower completion the casing above the packer and lower completion was tested overnight to 750 psi with no leak off. This overnight test was performed October 8-9, 2009. During the installation of the upper completion each joint of the injection tubing was hydro-tested to 3500 psi while being run in the hole. This occurred from Nov 13-26, 2009. After installation of the upper completion and packer seal assembly and tubing landed in the well head the annulus was tested to 1000 psi with no leak off however the pressure chart from this test cannot be located and therefore did not meet the requirement of Attachment A, Item I.A. Details of all these tests can be found in the daily as built completion reports.

After installation of the upper well head T3 Energy Services performed a pressure and function tested the tree to 3000 psig on December 2, 2009. To establish mechanical as required H.26 (b) on February 27, 2010 annulus was re-pressured to 1000 psi and was tested for one hour. The casing tubing annulus was full of fluid prior to the test and approximately 50 gallons of annular treated brine was used to bring the pressure to 1000 psig. Test was witnessed and recorded Jim McCain of by McNDT using NIST certified dead weight tester. Details of equipment and test results are in the file box of documents submitted with the completion report. Test was successful with pressure fall off of 5 psig in one hour. The tubing pressure was zero at the surface and downhole tubing pressure was monitored via downhole sensor with no change in downhole tubing pressure. The annulus was tested to 1000 psi as this would be 2.5 times the required annular pressure of 400 psi during injection and down hole annular pressure exceeds the expected downhole injection pressure. A primary focus of the completion and all pressure tests has been provide adequate testing of the wellbore without exposing the casing to unnecessary or excessive pressure and to avoid rapid pressuring and de-pressuring of the casing so as not to cause inadvertent damage to wellbore integrity. Research continues in this area and for CO2 injection wells the current technical leaning is to avoid excessive pressure tests.

Pursuant to Condition H-26, Attachment A, Item I.B. Subsequent test

On Sept 9, 2011 the 4 ½ inch by 9 5/8 inch annulus on the CCS# 1 was pressure tested. The annulus had remained with positive pressure of 8 psig from the test conducted April 27, 2010. The well was initially pressured at 1100 am using a 9.5 ppg NaCl brine with corrosion inhibitor and allowed to stabilize. The tubing pressure was zero and downhole tubing pressure was monitored with the downhole pressure gauge. No change in downhole tubing pressure was noted during the test. Jeff Turner with the IEPA Champaign office arrived at the site at 1330 pm. Jeff Turner was then briefed as to the method of pressurization and inspected the pressure recording equipment. Mr. Turner had previously been provided the certification certificate for the Omega pressure data logger used. The official test was started at 1400 pm with the pressure at 1047.6 psia. The test was monitored and recorded for one hour. The final test pressure at 1500 pm was 1046.6 psia indicating a successful test. Approximately 53.5 gallons of the NaCl brine was used to pressure the annulus and then slowly bled from the well. While at the site Mr. Turner also inspected the annular maintenance system and the instrumentation in place at the CCS#1. Mr. Turner was given a copy of the pressure chart and was subsequently electronically mailed the data from the test.

Conclusion

Based on the analysis of the log data and well test information, this well meets the requirements for mechanical integrity and is protective of groundwater.

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All interpretations are opinions based on inferences from electrical or other measurements and we cannot, and do not, guarantee the accuracy or correctness of any interpretations, and we shall not, except in the case of gross of willful negligence on our part, be liable or responsible for any loss or damages or expenses incurred or sustained by anyone resulting from any interpretation made by any of our officers, agents or employees.

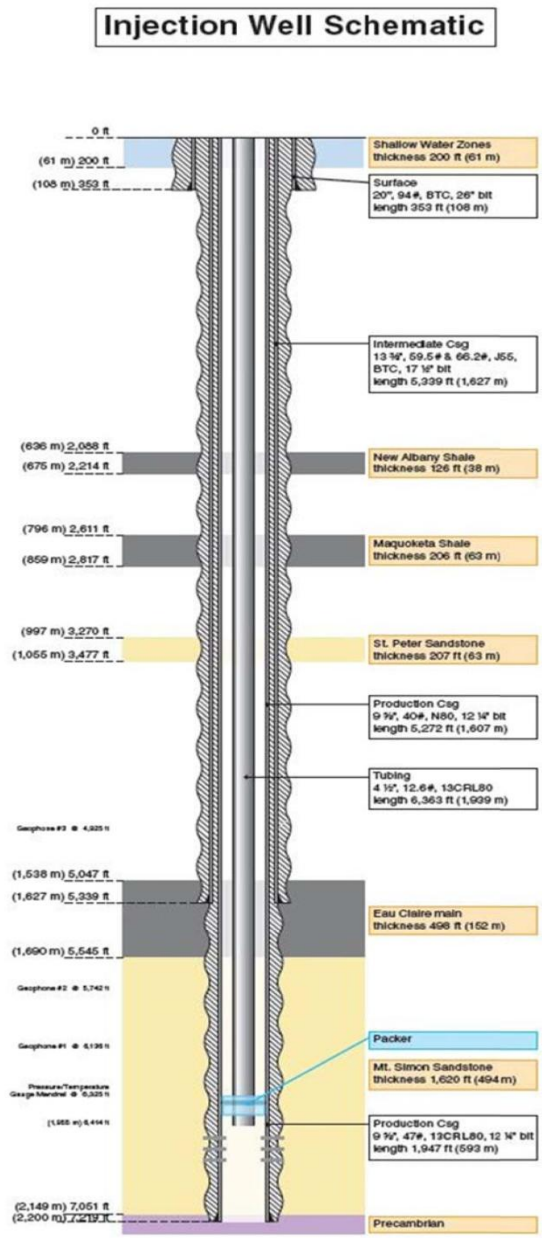


Figure 1 – Wellbore Diagram

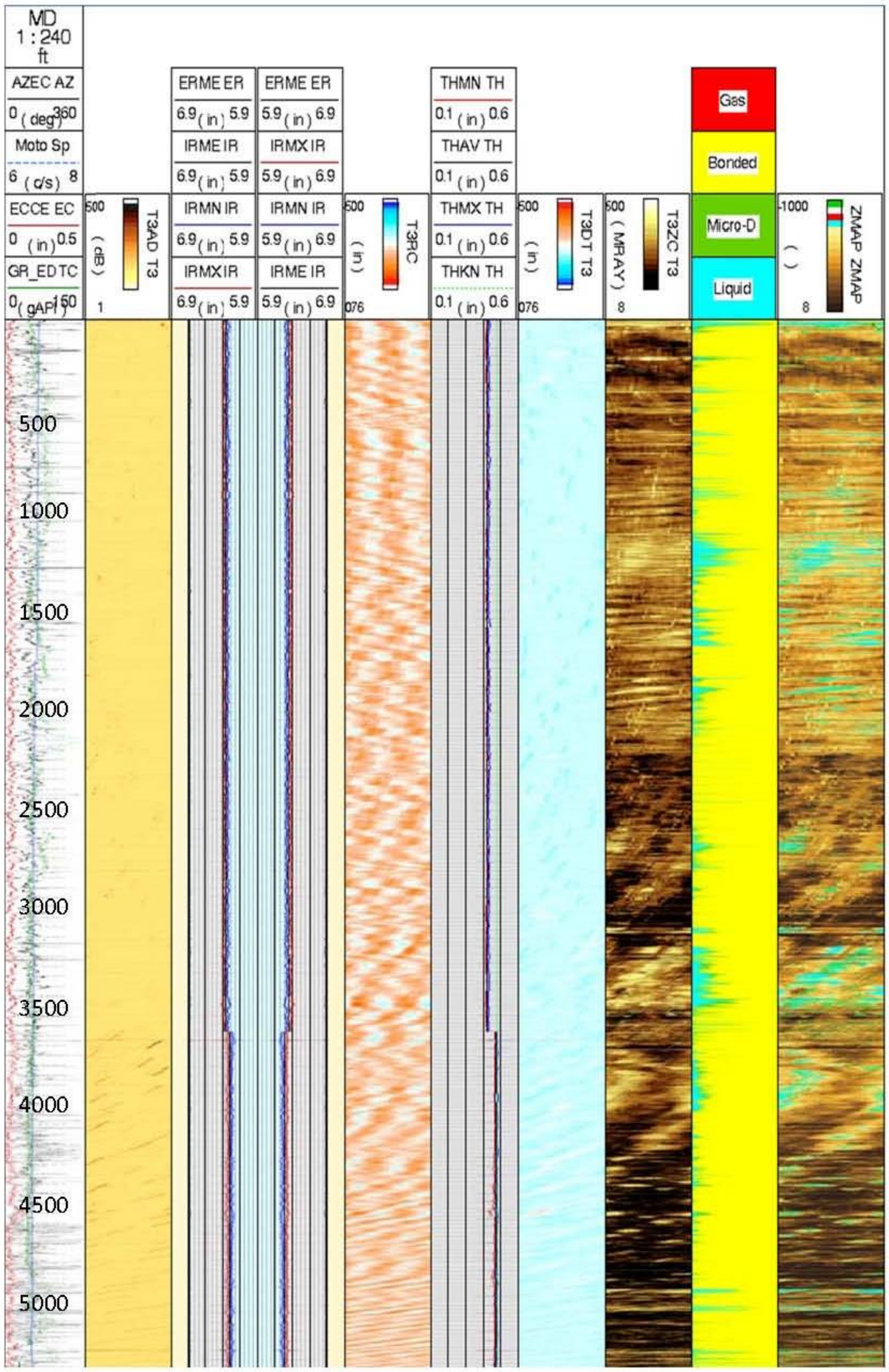


Figure 2 – USIT Intermediate Casing String

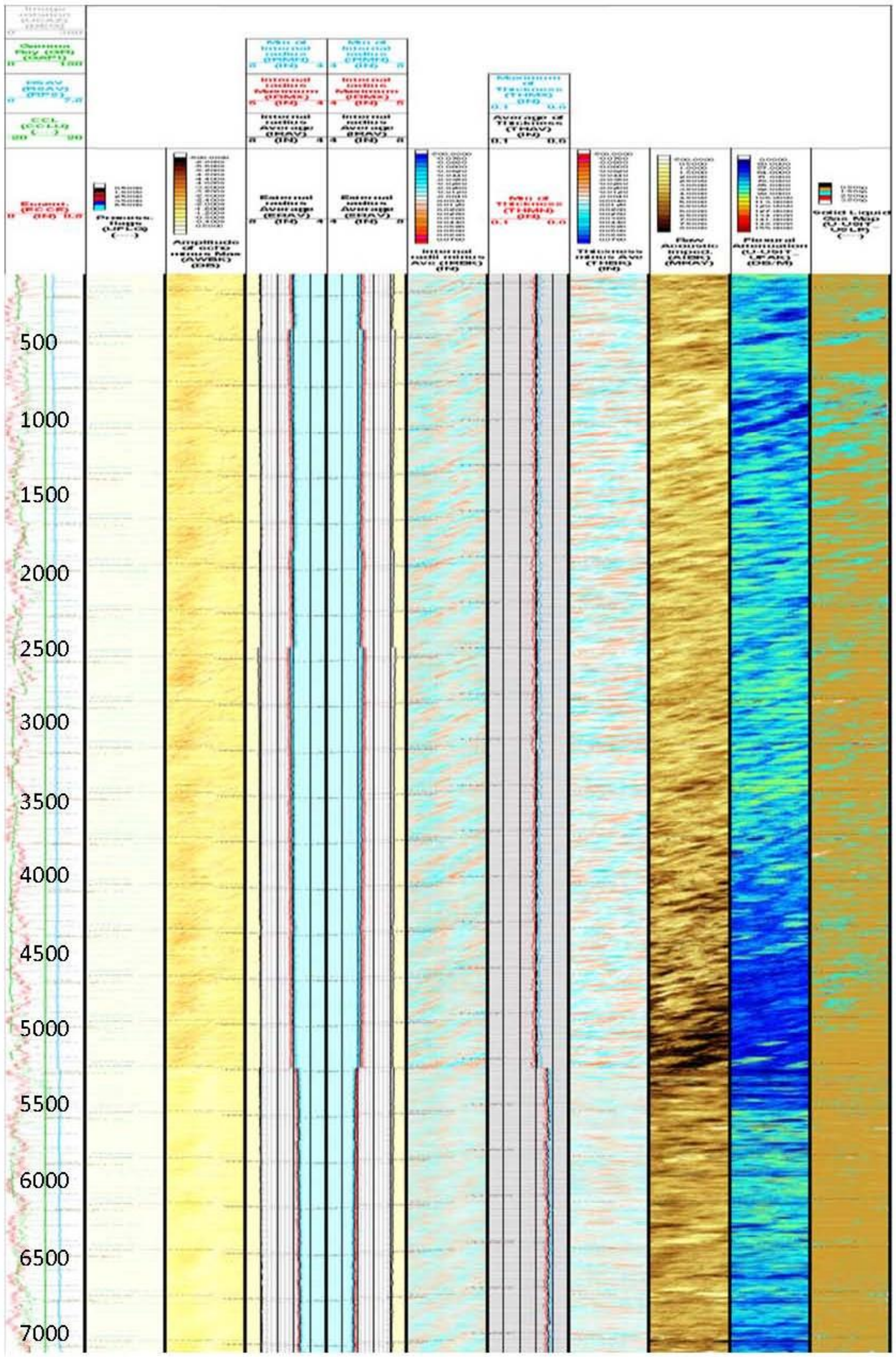


Figure 3 – Isolation Scanner Production Casing String

Appendix S -- Cased-Hole Log Data Collection Results VW1

ADM Verification Well #1

Mechanical Integrity Log and Testing Descriptive Report

Bob Butsch – Schlumberger Carbon Services

Jim Kirksey – Schlumberger Carbon Services

This document will describe the logging and testing programs related to the mechanical integrity of this well. It will also contain the analysis of the data collected, with the goal of demonstrating that the well is mechanically sound, and that no fluids will flow into the USDW at this site.

The Casing and Logging Program

Three casing strings were run in the ADM Verification Well #1 well. Logging runs investigating and verifying the baseline mechanical integrity of each casing string were made, and will be discussed in this document. Many other types of logs were run during installation of the borehole for the purpose of characterizing site geologic conditions. A discussion of those logs is available in the well completions report.

The surface casing string was run from surface to 367 ft and consisted of 13 3/8 inch, 54.5 lb/ft casing. The intermediate casing string was run from surface to 5305 ft and consisted of 9 5/8 inch, 40.0 lb/ft casing. The production casing string was run from surface to 7260 ft and consisted of 5 1/2 inch 17.0 lb/ft casing. The lower 2163 ft was CR-13 chrome and from 5047 back to surface was N-80. All three casing strings were cemented to surface. Figure 1 is a wellbore diagram showing the casing configuration.

A Cement Bond Log (CBL) was run in each of the casing strings to help evaluate the cement of each casing string. The CBL transmits a sonic signal from a transmitter, and then measures the amplitude of that sonic signal after traveling through a section of the casing. If there is cement in the casing annulus the amplitude of the sonic signal will be attenuated and the amplitude of the sonic signal measured will be small. How small the amplitude actually becomes is dependent on many factors, including the percent of the casing bonded, the type of cement, and many of the casing properties to name a few.

To evaluate the casing and cement of the intermediate casing string an Ultrasonic Imager Tool (USIT) was used in combination with a CBL. The USIT uses a single transducer mounted on an ultrasonic rotating sub on the bottom of the tool. The transmitter emits ultrasonic pulses between 200 and 700 kHz and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface, by computing an acoustic impedance of the material outside the casing. The time for the signal to be transmitted and reflected back to the transducer is used to measure the internal radius, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. Because the transducer is mounted on the rotated sub, the entire circumference of the casing is scanned. This 360° data coverage enables the evaluation of the quality of the cement bond as well as the determination of the internal and external casing condition.

To evaluate the mechanical integrity of the production string of casing the Isolation Scanner tool was used in combination with the CBL and a Multi-finger Caliper Log (PMIT). The Isolation Scanner combines the same ultrasonic measurement as the USIT with a measurement of Flexural Wave Attenuation. The Flexural Attenuation measurement incorporates one ultrasonic transducer acting as the transmitter and two ultrasonic transducers acting as receivers to determine how much a flexural wave is attenuated after traveling through the casing. This measurement is more sensitive to cements that have low acoustic impedances than the USIT and can help identify when these cements are present. The measurements of acoustic impedance and flexural wave attenuation are combined into an interpretation breaking down the interpretation into solid (cement), liquid (water, mud, oil), and gas to make the visualization of the interpretation easy. The Multi-finger Caliper provides a baseline measurement of the internal radius as well as providing another measurement of the internal radius that can be compared to the measurement coming from the USIT.

Another log run that will be used to monitor changes in the mechanical integrity of the well is the Reservoir Saturation Tool (RST). This tool will primarily be used to monitor the CO_2 in the reservoir but also has several measurements that can be used to identify CO_2 that might be migrating up in any of the casing annuli. As expected, the base pass of the RST showed no indications of CO_2 present in any of the annuli. The portion of the log data that was related to the reservoir was consistent with the petrophysical analysis of the reservoir as described in the Geophysical Log Descriptive Report. The RST is most effective when used as a monitor log with subsequent monitoring passes. This is the base pass of the RST and these measurements will be compared to the same measurements on subsequent runs of the tool.

Analysis of the Well Integrity Logs

The CBL on the surface string of casing shows that from 253 to 262 ft. and at 189 ft. the amplitude measures just under 2 mv. This translates into an attenuation of 9.2 dB/ft. Using this value to compute the compressive strength of the cement at this interval, a value of approximately 2000 psi is obtained and the interval is believed to be a 100% bonded interval. To demonstrate zone isolation it is desirable to have a continuous interval with the attenuation greater than 6 dB/ft. The attenuation is greater than 6 dB/ft from 253 to 262 ft., from 232 to 226 ft., and a total of 15 ft. between 212 ft. and 184 ft. Ideally it would be preferred that the cement were more continuous. However, there are several additional considerations. There are also several other intervals in the well have attenuations in the 4 to 6 dB/ft range where cement is certainly present. Also, it is known that cement was circulated to surface and that the cementing job was executed according to plan with no observed fallback even though the CBL does not indicate the presence of cement above 148 ft. Given this information it is believed that the CBL is showing good hydraulic isolation in the zones mentioned and a sufficient amount of cement behind the casing up to 148 ft. This volume is sufficient to prevent any fluids from flowing from below in to any USDW behind the casing in this interval as is the objective of this casing string.

The USIT and CBL show that the intermediate string of casing has good hydraulic isolation over most of the length of the casing. There is an interval from 4120 ft to 3696 which is not cemented. This occurred during the cementing job when circulation was lost for a short time during the cementing of the first stage of the two stage cement job of the well. This likely was caused by a known lost circulation zone that was encountered at about 4550 ft during the drilling process. The potential problem for the cement job was anticipated and circulation was regained in time to cover this lost circulation zone with cement thereby providing for hydraulic isolation around this interval. The formation behind the pipe in this interval is the Potosi dolomite with almost no porosity or permeability. With good cement both above and below this interval there is little chance of fluid movement through the uncemented potion of the casing. The cementing of the upper portion of the well had no problems and the cement is in good condition above the stage collar, with only a few isolated pockets of fluid that will not provide a channel. Figure 2 shows the results of the USIT and a brief description of the log is as follows:

Track1 – Gamma Ray and other QC type data.

Track 2 - Amplitude of the received ultrasonic signal (light colors are high amplitude)

Track 3 and 4 – Casing cross section showing minimum, maximum and average internal radius and average external radius.

Track 5 – Internal radius image

Track 6 – Minimum, maximum and average casing thickness.

Track 7 – Casing thickness image

Track 8 – Acoustic impedance image

Track 9 – Bond index presentation (yellow = cement, blue = liquid, red = gas, green = solid)

Track 10 – Interpreted acoustic impedance image (any shade of brown = cement, blue = liquid, red = gas, green = solid)

The USIT log also shows that the casing has no internal or external defects at this time based on the internal radius and thickness measurements.

The production string of casing was also determined to have good hydraulic isolation over most of the length of the casing, with only short intervals where there are isolated pockets of fluid and not cement behind the casing. The top of the injection zone is 5520 ft. and the first of these intervals below this point that has any potential to flow fluids is a very short interval from 5564 to 5570 ft. It is actually more likely that this zone has a thin cement sheath rather than a channel. The casing below this point is all considered to be 100% bonded with good hydraulic isolation. Above the base of the confining layer the first potential channel would be from 4314 to 4306 ft. Therefore, there is no potential for any fluids to migrate from the injection zone to zones above the confining layer by way of the casing-formation annulus. The acoustic impedance image of the USIT clearly shows the change in acoustic impedance for the two different cement types used while cementing this string of casing. This change occurs at about 4900 ft, indicating that the CO_2 resistant cement was brought up into the annulus of the long string and the intermediate string of casing. Figure 3 shows the Isolation Scanner log on this casing string and a brief description is as follows:

Track1 – Gamma Ray and other QC type data.

Track 2 – Diagnostic track – the processing of the tool is model based and this track indicates any deviations of the model.

Track 3 - Amplitude of the received ultrasonic signal (light colors are high amplitude)

Track 4 and 5 – Casing cross section showing minimum, maximum and average internal radius and average external radius.

Track 6 – Internal radius image

Track 7 – Minimum, maximum and average casing thickness.

Track 8 – Casing thickness image

Track 9 – Acoustic impedance image

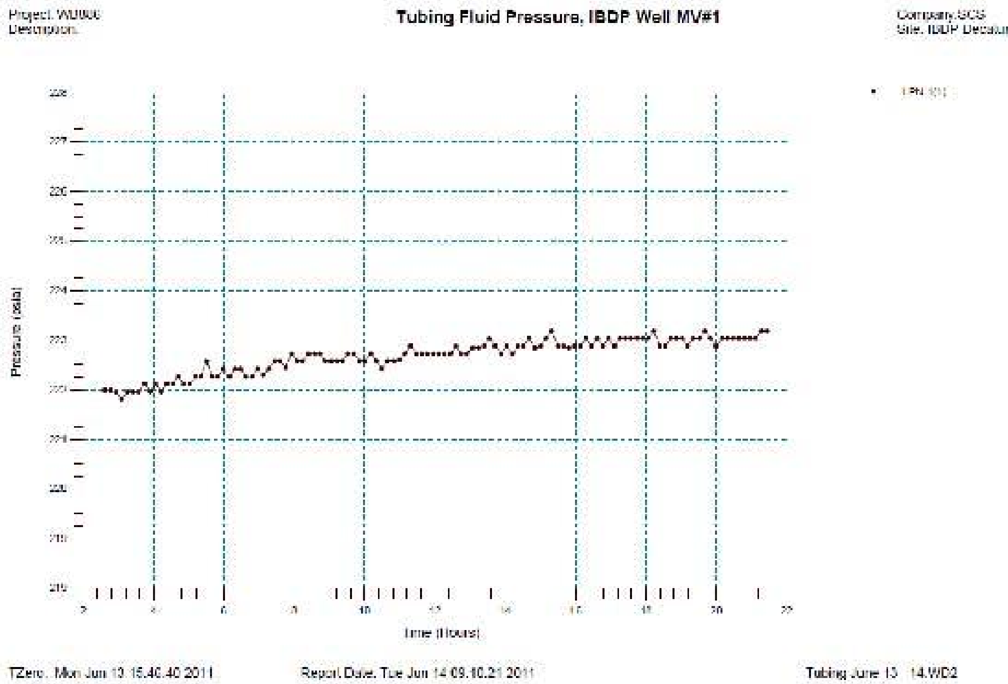
Track 10 – Bond Flexural Wave Attenuation image

Track 11 – Interpreted Solid/Liquid/Gas image (brown = cement, blue = liquid, red = gas)

The USIT part of the Isolation Scanner and the PMIT also show that the casing has no internal or external defects at this time based on the internal radius and thickness measurements. The PMIT was run after the casing was perforated in the zones to be monitored by the Westbay system, and these perforations can be seen on the log. The perforations were not considered as defects as the holes were intentional and part of the completion.

Mechanical Integrity Tests

During installation the Westbay tubing was tested using negative differential tests which monitored the fluid level inside the tubing daily while running the system into the well. The Westbay system is a sealed tube so fluid was added to the tubing string while running in to keep the fluid level approximately 250 feet lower than the fluid level in the annulus which had been established to stand at approximately 250 feet below surface with a 9.2 ppg completion fluid in the well. The maximum differential was reached on May 25 when the fluid level inside the tubing was at 1965 feet and the annulus at 250 feet below surface with no change in fluid level. After packer inflation the gas lift valve was used to lower the fluid level in the well to approximately 1122 feet below surface. The pressure probe was at a counter depth of 1530 feet. The well was data logged overnight June 13-14 with less than 1 psia change in pressure and was absolutely stable for the last six hours of the test. This chart is included below. This established the integrity of the Westbay tubing with a negative differential much greater than 100 psig. Additionally, each joint of the Westbay tubing and each component connection was hydro- tested to 150 psia while running in the hole.



On June 7, 2011 after inflating Packer 27 the pumping port between packers 27 and 28 located at 4785 was opened and the well was circulated down through the tubing and out the annulus. First 20 bbls of 9.2 ppg NaCL brine completion fluid was pumped to clean the hole ahead of final completion brine. Then 78 bbls of 9.4 bbl NaCl with Nalco ASP 539D corrosion inhibitor was pumped. The treated fluid was then followed by a tubing volume (27.8 bbls) of 9.4 NaCl brine with no corrosion inhibitor to displace the tubing. Treated brine was returned to surface. The pumping port was closed and the annulus was tested to 200 psi with no increase in tubing pressure as measured by a Westbay gauge inside tubing. The uppermost packer number 28 at approximately 4826 was inflated. After recovering the packer inflation tools the annulus was tested using the Westbay inflation pump to 300 psi on June 9, 2011. The tubing was full and no fluid movement was noted during the test. On June 10, 2011 the annulus was re-pressured to 317 psia with Jeff Turner of the IEPA on site to witness the test. Again the tubing was full of fluid and no fluid movement was seen from the tubing. The pressure held for one hour with no leak off. Jeff Turner was provided with a chart and the data from test. This test established the mechanical integrity of the uppermost Westbay packer and the tubing above it to surface. Previous to this annular test the casing had been successfully tested on three other occasions during the completion of the well.

After packer inflation the QA/QC zone was monitored and continuously logged from July 17 to the beginning of the second round of fluid testing on September 8, 2011. The QA/QC zone behaved as expected with such a small volume of fluid between the QA/QC straddle packers. When the well warms up, as happens when flowing warmer fluids from the bottom zones, the pressure increases and likewise decreases when the well cools off. The QA/QC zone can also experience pressure changes as a result of the mechanical process of engaging and dis-engaging the pressure transducer probe at the measurement port. The adjacent zones showed a normal buildup after purging while the QA/QC zone responded to temperature. An example of the data is as follows from the post purging pressure profile run on July 8, 2011:

Zone 9	5653.8 ft KB	pressure 2533.6 psia, gradient = .4481 psi/ft
QA/QC Zone	5482 ft KB	pressure 2243.1 psia, gradient = .4091 psi/ft
Zone 10	5000.6 ft KB	pressure 2111.1 psia, gradient = .422 psi/ftd the QA/QC zone

This establishes the mechanical integrity of the QA/QC zone.

Conclusion

Based on the analysis of the log data and well test information, this well meets the requirements for mechanical integrity and is protective of groundwater.

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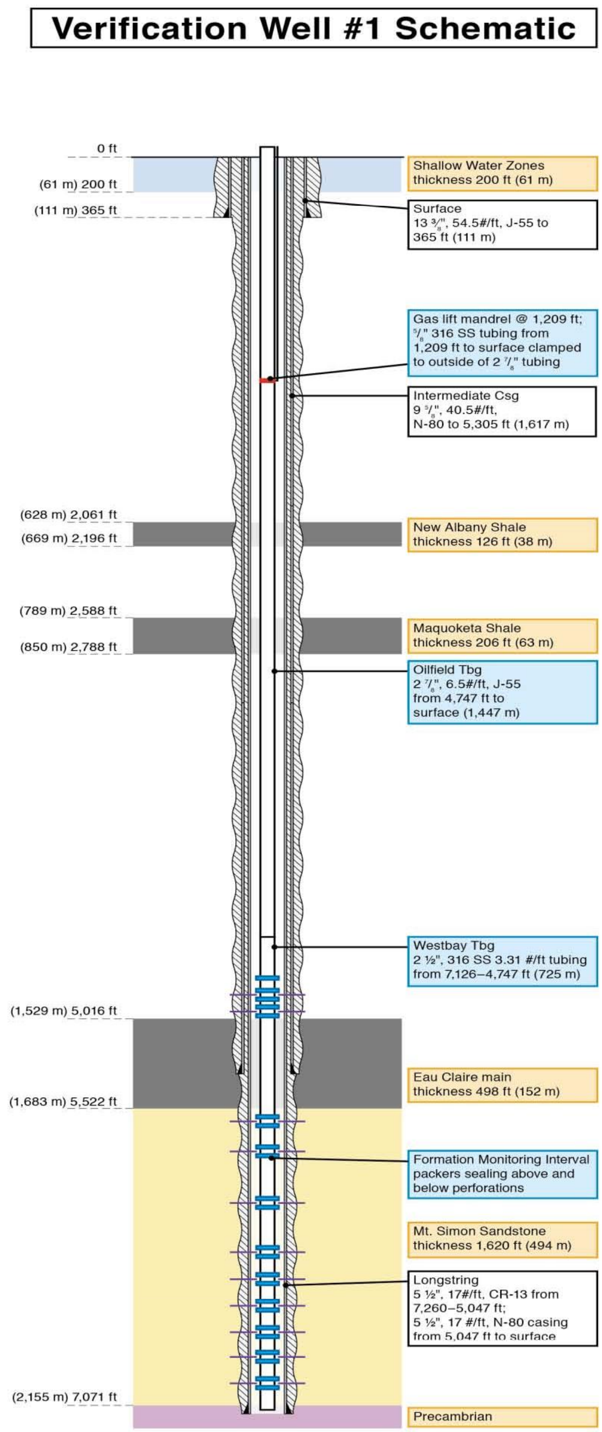

Figure 1 – Wellbore Diagram

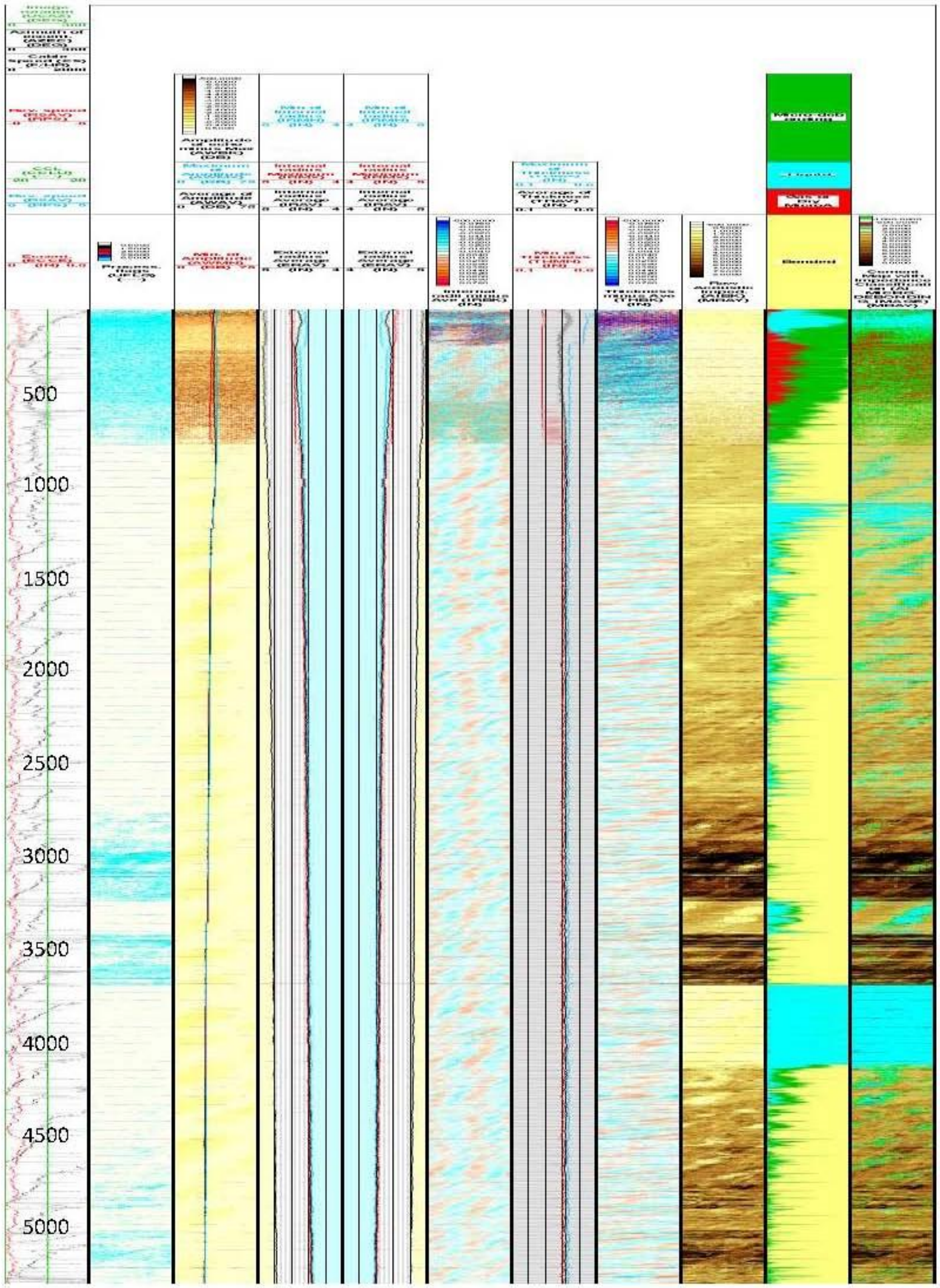

Figure 2 – USIT Intermediate Casing String

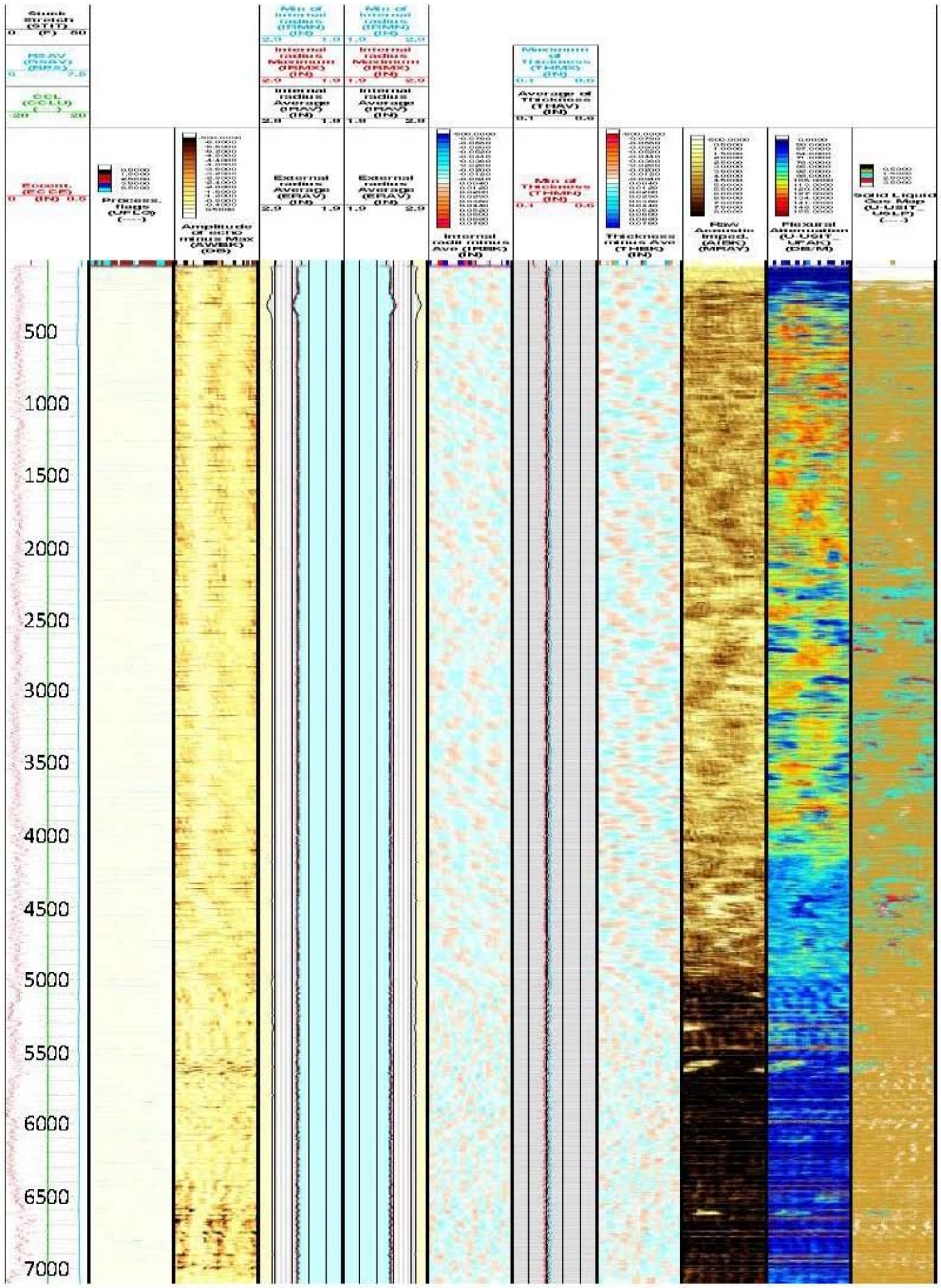

Figure 3 – Isolation Scanner Production Casing String