FutureGen 2.0 –
CO_2 Pipeline and Storage Project

Quality Assurance and Surveillance Plan

Revision 0

FutureGen Industrial Alliance, Inc.
1101 Pennsylvania Ave., Sixth Floor
Washington, DC 20004

March 2014

A. Project Management

A.1 Title and Approval Sheet

FutureGen 2.0 –
CO_2 Pipeline and Storage Project

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1101 Pennsylvania Ave., Sixth Floor
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Approvals:

Project Manager Battelle	Tyler J Gilmore	Date
Monitoring, Verification, and Accounting Task Lead Battelle	Vince R. Vermeul	Date
Project Quality Engineer Battelle	William C. Dey	Date

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Acronyms and Abbreviations

3D	three-dimensional
4D	four-dimensional
ACP	annulus casing packer
ACZ	above confining zone
AMS	accelerator mass spectrometry
AoR	Area of Review
API	American Petroleum Institute
APS	Annulus Pressurization System
ASTM	ASTM International (formerly the American Society for Testing and Materials)
bgs	below ground surface
CCS	carbon capture and storage
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
CMP	Configuration Management Plan
CO_2	carbon dioxide
CVAA	cold vapor atomic absorption
DGPS	Differential Global Positioning System
DIC	dissolved inorganic carbon
DInSAR	Differential Interferometric Synthetic Aperture Radar
DOC	dissolved organic carbon
ECD	electron capture detector
EPA	U.S. Environmental Protection Agency
GC	gas chromatography
GC/FID	gas chromatography with flame ionization detector
GC/HID	gas chromatography with helium ionization detector
GC/MS	gas chromatography-mass spectrometry
GC/SCD	gas chromatograph with sulfur chemiluminescence detector
GPS	Global Positioning System
GS	Geologic Sequestration
HDI	How Do I…? (Pacific Northwest National Laboratory's web-based system for deploying requirements and procedures to staff)
IARF	infinite-acting radial flow
ICP	inductively coupled plasma
ICP-AES	inductively coupled plasma atomic emission mass spectrometry
ICP-MS	inductively coupled plasma mass spectrometry
IRMS	isotope ratio mass spectrometry
ISBT	International Society of Beverage Technologists
LC-MS	liquid chromatography-mass spectrometry
LCS	laboratory control sample

MIT	mechanical integrity testing
MMT	million metric tons
MS	mass spectrometry
MVA	Monitoring, Verification, and Accounting
NA	not applicable
OD	outside diameter
OES	optical emission spectrometry
P	pressure
P/T	pressure-and-temperature
P/T/SpC	pressure, temperature, and specific conductance
PDMP	Project Data Management Plan
PFT	perfluorocarbon tracer
PLC	programmable logic controller
PM	Project Manager
PNC	pulsed-neutron capture
PNWD	Battelle Pacific Northwest Division
QA	quality assurance
QASP	Quality Assurance and Surveillance Plan
QC	quality control
QE	Quality Engineer
RAT	reservoir access tube
RTD	resistance temperature detector
RTK	Real-Time Kinematic
RTU	remote terminal unit
SAR	Synthetic Aperture Radar
SCADA	Supervisory Control and Data Acquisition
scCO_2	supercritical carbon dioxide
SLR	single-level in-reservoir
SME	subject matter expert
SNR	signal-to-noise ratio
SpC	specific conductance
T	temperature
TC	thermocouple
TCD	thermal conductivity detector
TDMP	Technical Data Management Plan
TIC	total inorganic carbon
TOC	total organic carbon
UIC	Underground Injection Control
USDW	underground source of drinking water
VOA	Volatile Organic Analysis
WS-CRDS	wavelength scanned cavity ring-down spectroscopy

Definitions

Injection interval: The open (e.g., perforated) section of the injection well, through which the carbon dioxide (CO_2) is injected.

Injection zone: A geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic sequestration project.

Prover: A device that verifies the accuracy of a gas meter.

Reservoir: A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids (Schlumberger Oilfield Glossary). Used interchangeably with injection zone.

Sigma: A measure of the decay rate of thermal neutrons as they are captured.

A.3 Distribution List

Table A.1 lists the individuals that should receive a copy of the approved Quality Assurance and Surveillance Plan (QASP) and any subsequent revisions.

Table A.1. Distribution List

Name	Organization	Project Role(s)	Contact Information (telephone / email)
K. Humphreys	FutureGen Industrial Alliance, Inc.	Chief Executive Officer	202-756-2492 Khumphreys@futgen.org
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A. Bonneville	Battelle PNWD	Task Lead – Indirect Geophysical Monitoring	509-371-7263 Alain.Bonneville@pnnl.gov
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F. A. Spane	Battelle PNWD	Task Lead – Hydrologic Testing; Pressure Fall-Off Testing	509-371-7087 Frank.Spane@pnnl.gov

A.4 Project/Task Organization

The high-level project organizational structure for the FutureGen 2.0 CO_2 Pipeline and Storage Project is shown in Figure A.1 (Alliance 2013a).

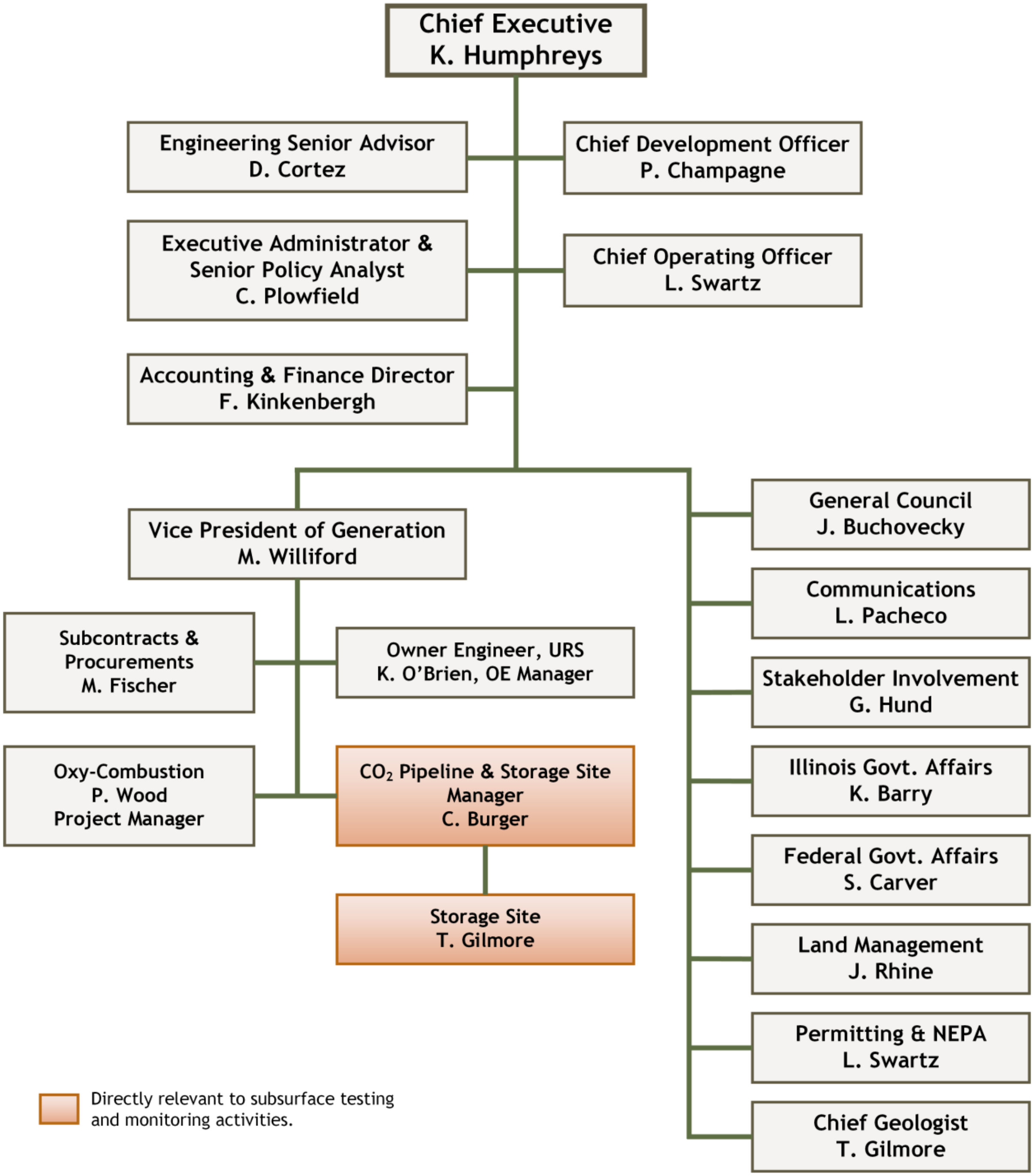

Figure A.1. CO_2 Pipeline and Storage Project Structure (after Alliance 2013a)

The organizational structure specific to well testing and monitoring is shown in Figure A.2.

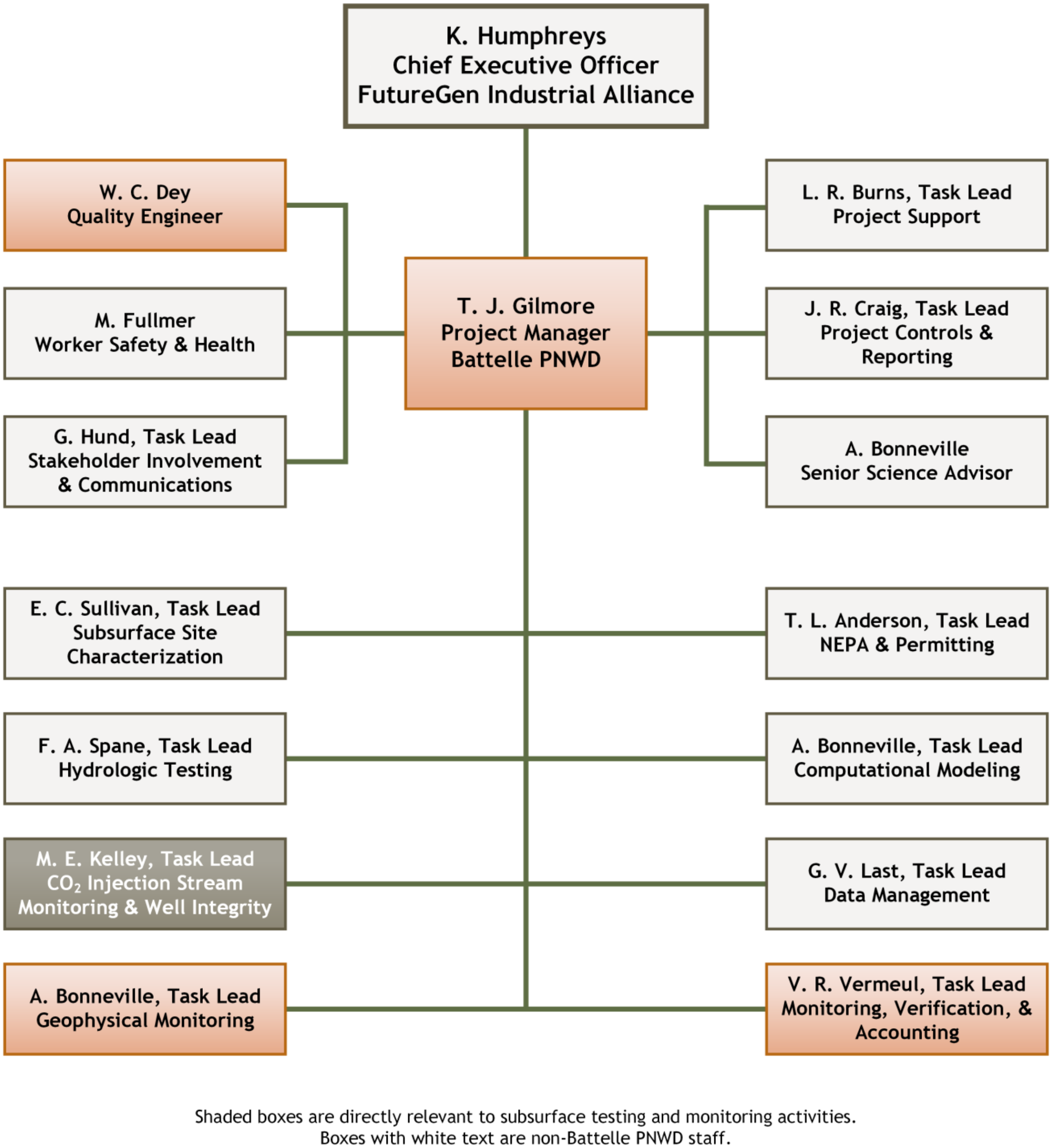

Figure A.2. Task Level Project Organization Relevant to Well Testing and Monitoring

A.4.1 Alliance Chief Executive Officer

The FutureGen 2.0 CO_2 Pipeline and Storage Project is led by the Chief Executive Officer (CEO) of the FutureGen Industrial Alliance, Inc. (Alliance), who is responsible on a day-to-day basis for the project. The Alliance CEO reports to a board of directors composed of industry executives (one executive for each company contributing funds on an equal basis to the Alliance).

A.4.2 Project Manager

The Project Manager (PM) plays a central role in the implementation of all data gathering and analysis for the CO_2 Pipeline and Storage Project and provides overall coordination and responsibility for all organizational and administrative aspects. The PM is responsible for the planning, funding, schedules, and controls needed to implement project plans and ensure that project participants adhere to the plan.

A.4.3 Quality Engineer

The role of the Quality Engineer (QE) is to identify quality-affecting processes and to monitor compliance with project requirements. The QE is responsible for establishing and maintaining the project quality assurance plans and monitoring project staff compliance with them. The QE is responsible for ensuring that this Quality Assurance and Surveillance Plan (QASP) meets the project's quality assurance requirements.

A.4.4 Monitoring, Verification, and Accounting Task Lead

Well testing and monitoring activities are the responsibility of the Monitoring, Verification, and Accounting (MVA) Task Lead. The MVA Task Lead is responsible for developing, maintaining, and updating all well testing and monitoring plans, including this QASP.

A.4.5 Subject Matter Experts/Subtask Task Leads

Well Testing and Monitoring Subject Matter Experts (SMEs) and Task Leads comprise both internal (Battelle Pacific Northwest Division [PNWD]) and external (Battelle Columbus and other subcontractors) geologists, hydrologists, chemists, atmospheric scientists, ecologists, etc. The role of these SMEs is to develop testing and monitoring plans, to collect environmental data specified in those plans using best practices, and to maintain and update those plans as needed.

The SMEs, assisted by the MVA Task Lead, are responsible for planning, collecting, and ensuring the quality of testing and monitoring data and managing all necessary metadata and provenance for these data. The SMEs are also often responsible for data analysis and data products (e.g., publications), and acquisition of independent data quality/peer reviews.

A.5 Problem Definition/Background

A.5.1 Purpose and Objectives

The FutureGen CO_2 Pipeline and Storage Project is part of the larger FutureGen 2.0 Project aimed at demonstrating the technical feasibility of oxy-combustion technology as an approach to implementing carbon capture and storage (CCS) from new and existing coal-fueled energy facilities. The advancement of CCS technology is critically important to addressing CO_2 emissions and global climate change concerns associated with coal-fueled energy. The objective of this project is to design, build, and operate a commercial-scale CCS system capable of capturing, treating, and storing the CO_2 off-gas from a oxy-combustion coal-fueled power plant located in Meredosia, Morgan County, Illinois. Using safe and proven pipeline technology, the CO_2 will be transported to a nearby storage site, located near Jacksonville, Illinois, where it will be injected into the Mount Simon Sandstone at a rate of 1.1 million metric tons (MMT) of CO_2 each year, for a planned duration of at least 20 years.

The objective of the CO_2 Pipeline and Storage project is to demonstrate utility-scale integration of transport and permanent storage of captured CO_2 in a deep geologic formation (a.k.a. geologic sequestration) and to demonstrate that this can be done safely and ensure that the injected CO_2 is retained within the intended storage reservoir.

A.5.2 Background

The U.S. Environmental Protection Agency (EPA) established requirements for CO_2 geologic sequestration under the Underground Injection Control (UIC) Program for Geologic Sequestration (GS) Class VI Wells. These federal requirements (codified in the U.S. Code of Federal Regulations [40 CFR 146.81 et seq.], known as the Class VI Rule) set minimum technical criteria for CO_2 injection wells for the purposes of protecting underground sources of drinking water (USDWs). Testing and Monitoring Requirements (40 CFR 146.90) under the Class VI Rule require owners or operators of Class VI wells to develop and implement a comprehensive testing and monitoring plan that includes injectate monitoring; corrosion monitoring of the well's tubular, mechanical, and cement components; pressure fall-off testing; groundwater quality monitoring; and CO_2 plume and pressure-front tracking. These requirements (40 CFR 146.90[k]) also require owners and operators to submit a QASP for all testing and monitoring requirements.

This QASP details all aspects of the testing and monitoring activities that will be conducted, and ensures that they are verifiable, including the technologies, methodologies, frequencies, and procedures involved. As the project evolves, this QASP will be updated in concert with the Testing and Monitoring Plan.

A.6 Project/Task Description

The FutureGen CO_2 Pipeline and Storage Project will undertake testing and monitoring as part of its MVA program to verify that the Morgan County CO_2 storage site is operating as permitted and is not endangering any USDWs. The MVA program includes operational CO_2 injection stream monitoring, well corrosion and mechanical integrity testing, geochemical and indicator parameter monitoring of both the reservoir and shallow USDWs, and indirect geophysical monitoring, for characterizing the complex fate and transport processes associated with CO_2 injection. Table A.2 describes the general Testing and Monitoring tasks, methods, and frequencies.

Table A.2. Monitoring Tasks, Methods, and Frequencies by Project Phase

Monitoring Category	Monitoring Method	Baseline 3 yr	Injection (startup) ~3 yr	Injection ~2 yr	Injection ~15 yr	Post-Injection 50 yr
CO_2 Stream Analysis	Grab sampling and analysis	3 events, during commissioning	Quarterly	Quarterly	Quarterly	NA
Continuous Recording of Injection Pressure, Rate, and Annulus Pressure	Continuous monitoring of injection process (injection rate, pressure, and temperature; annulus pressure and volume)	NA	Continuous	Continuous	Continuous	NA
Corrosion Monitoring	Corrosion coupon monitoring of Injection Well Materials	NA	Quarterly	Quarterly	Quarterly	NA
Groundwater Quality Monitoring	Fluid sample collection and analysis in all ACZ and USDW monitoring wells	3 events	Quarterly	Semi-Annual	Annual	Every 5 yr
	Electronic P/T/SpC probes installed in ACZ and USDW wells	1 yr min	Continuous	Continuous	Continuous	Continuous
External Well Mechanical Integrity Testing	PNC and Temperature logging	Once after well completion	Annual	Annual	Annual	Annual until wells plugged
	Cement-evaluation and casing inspection logging	Once after well completion	During well workovers	During well workovers	During well workovers	NA
Pressure Fall-Off Testing	Injection well pressure fall-off testing	NA	Every 5 yr	Every 5 yr	Every 5 yr	NA
Direct CO_2 Plume and Pressure-Front Monitoring	Fluid sample collection and analysis in SLR monitoring wells	3 events	Quarterly	Semi-Annual	Annual	Every 5 yr
	Electronic P/T/SpC probes installed in SLR wells	1 yr min	Continuous	Continuous	Continuous	Continuous
Indirect CO_2 Plume and Pressure-Front Monitoring	Passive seismic monitoring (microseismicity)	1 yr min	Continuous	Continuous	Continuous	Continuous
	Integrated deformation monitoring	1 yr min	Continuous	Continuous	Continuous	Continuous
	Time-lapse gravity	3 events	Annual	Annual	Annual	NA
	PNC logging of RAT wells	3 events	Quarterly	Quarterly	Annual	Annual

ACZ = above confining zone; NA = not applicable; PNC = pulsed-neutron capture; P/T/SpC = pressure, temperature, and specific conductance; RAT = reservoir access tube; SLR = single-level in-reservoir; USDW = underground source of drinking water.

A.6.1 CO_2 Injection Stream and Corrosion/Well Integrity Monitoring

The CO_2 injection stream will be continuously monitored at the surface for pressure, temperature, and flow, as part of the instrumentation and control systems for the FutureGen 2.0 CO_2 Pipeline and Storage Project. Periodic grab samples will also be collected and analyzed to track CO_2 composition and purity.

The pressure and temperature will be monitoring within each injection well at a position located immediately above the injection zone at the end of the injection tubing. The downhole sensor will be the point of compliance for maintaining injection pressure below 90 percent of formation fracture pressure. If the downhole probe fails between scheduled maintenance events, then the surface pressure measurement coupled with the analytical code, CO2Flow, will be used to determine permit compliance downhole at the injection elevation. The CO2Flow program estimates pressure and fluid state evolution as CO_2 moves through pipelines and injection tubing and will be used to determine an equivalent downhole pressure.

CO_2 Stream Analysis

The composition and purity of the CO_2 injection stream will monitored through the periodic collection and analysis of grab samples.

Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure

Pressure monitoring of the CO_2 stream at elevated pressure will be done using local analog gauges, pressure transmitters, or pressure transmitters with local digital readouts. Flow monitoring will be conducted using Coriolis mass type meters. Normal temperature measurements will be made using thermocouples (TCs) or resistance temperature detectors (RTDs). A Supervisory Control and Data Acquisition (SCADA) system will be used to transmit operational power plant, pipeline, and injection well data long distances (~30 mi) for the pipeline and storage project.

Corrosion Monitoring

Samples of injection well materials (coupons) will be periodically monitored for signs of corrosion to verify that the well components meet the minimum standards for material strength and performance and to identify well maintenance needs.

External Well Mechanical Integrity Testing

Wireline logging, including pulsed-neutron capture (PNC) logs (both in the gas-view and oxygen-activation modes) and temperature logs, and cement-evaluation and casing inspection logging, will be conducted to verify the absence of significant fluid movement through potential channels adjacent to the injection well bore and/or to determine the need for well repairs.

A.6.2 Storage Site Monitoring

The objective of the storage site monitoring program is to select and implement a suite of monitoring technologies that are both technically robust and cost-effective and provide an effective means of 1) evaluating CO_2 mass balance (i.e., verify that the site is operating as permitted) and 2) detecting any unforeseen containment loss (i.e., verify that the site is not endangering any USDWs). Both direct and indirect measurements will be used collaboratively with numerical models of the injection process to verify that the storage site is operating as predicted and that CO_2 is effectively sequestered within the targeted deep geologic formation and is fully accounted for. The approach is based in part on reservoir-monitoring wells, pressure fall-off testing, and indirect (e.g., geophysical) methods. Early-detection monitoring wells will target regions of increased leakage potential (e.g., proximal to wells that penetrate the caprock). During baseline monitoring, a comprehensive suite of geochemical and isotopic analyses will be performed on fluid samples collected from the reservoir and overlying monitoring intervals. These analytical results will be used to characterize baseline geochemistry and provide a metric for comparison during operational phases. Selection of this initial analyte list was based on relevance for detecting the presence of fugitive brine and CO_2. The results for this comprehensive set of analytes will be evaluated and a determination made regarding which analytes to carry forward through the operational phases of the project. This selection process will consider the uniqueness and signature strength of each potential analyte and whether its characteristics provide for a high-value leak-detection capability. Indicator parameters will be used to inform the monitoring program. Once baseline conditions and early CO_2 arrival responses have been established, observed relationships between analytical measurements and indicator parameters will be used to guide less-frequent aqueous sample collection and reduced analytical parameters in later years.

Monitoring Well Network (Geochemical and Indicator Parameter Monitoring)

The monitoring well network will address transport uncertainties by using an "adaptive" or "observational" approach to monitoring (i.e., the monitoring approach will be adjusted as needed based on observed monitoring results).

Two aquifers above the primary confining zone will be monitored for any unforeseen leakage of CO_2 and/or brine out of the injection zone. These include the aquifer immediately above the confining zone (Ironton Sandstone, monitored with above confining zone [ACZ] wells) and the St. Peter Sandstone, which is separated from the Ironton by several carbonate and sandstone formations and is considered to be the lowermost USDW. In addition to directly monitoring for CO_2, wells will initially be monitored for changes in geochemical and isotopic signatures that may provide indication of CO_2 leakage. Wells will also be instrumented to detect changes in the stress regime (via pressure in all wells and microseismicity in selected wells) to avoid over-pressurization within the injection or confining zones that could compromise sequestration performance (e.g., caprock fracturing). Table A.3 describes the planned monitoring well network for geochemical and indicator parameter monitoring. Figure A.3 illustrates the nominal monitoring well layout.

Table A.3. Planned Monitoring Wells in the Network

	Single-Level In-Reservoir (SLR)	Above Confining Zone (ACZ)	USDW
Number of Wells	2	2	1
Total Depth (ft)	4,150	3,470	2,000
Monitored Zone	Mount Simon SS	Ironton SS	St. Peter SS
Monitoring Instrumentation	P/T/SpC probe in monitored interval[(a)]	Fiber-optic (microseismic) cable cemented in annulus; P/T/SpC probe in monitored interval[(a)]	P/T/SpC probe in monitored interval[(a)]

(a) The P/T/SpC probe is an electronic downhole multi-parameter probe incorporating sensors for measuring fluid pressure (P), temperature (T), and specific conductance (SpC) within the monitored interval. The probe will be installed inside a tubing string, which is perforated (slotted) over the monitoring interval. Measurements will be recorded with a data logger at each well location and also transmitted to the MVA data center in the control building.
SS = sandstone.

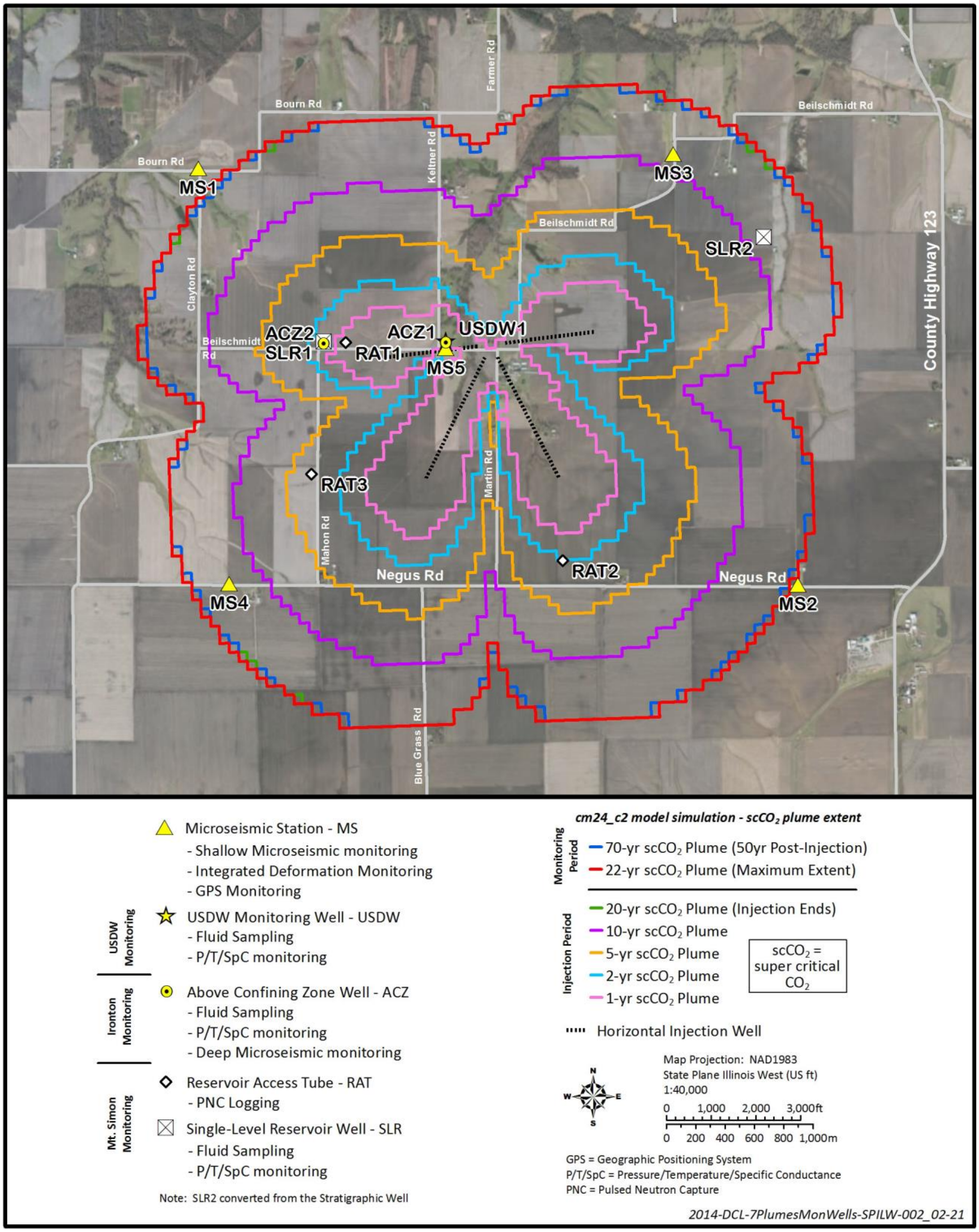

Figure A.3. Nominal Monitoring Well Layout and Modeled Supercritical CO_2 ($scCO_2$) Plume at different times. Note that the monitoring well locations are approximate and subject to landowner approval.

Groundwater Quality Monitoring

Fluid sampling (and subsequent geochemical analyses) and continuous monitoring of indicator parameters will be conducted at each ACZ and USDW monitoring well.

<u>*Indicator Parameter Monitoring*</u> – Fluid pressure, temperature, and specific conductance (P/T/SpC) will be monitored continuously. These are the most important parameters to be measured in real time within the monitoring interval of each well. These are the primary parameters that will indicate the presence of CO_2 or CO_2-induced brine migration into the monitored interval. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building.

In addition, in the two ACZ wells, a fiber-optic cable with integral geophones (fiber Bragg grating optical accelerometer) will extend from ground surface to the monitoring interval (i.e., to the annulus casing packer [ACP] just above the monitoring interval); this cable will be strapped to the outside of the casing and permanently cemented in place to support the microseismic monitoring program. Data from the fiber-optic sensors will be transmitted back to the MVA data center via a local-area fiber-optic network where the data-acquisition system will be located.

<u>*Geochemical Monitoring*</u> – Aqueous samples will be collected from each ACZ and USDW well, initially on a quarterly basis and decreasing in frequency as the system stabilizes over time, to determine the hydrochemistry in the monitoring interval fluids.

CO_2 Plume and Pressure-Front Tracking

Fluid sampling (and subsequent geochemical analyses) and continuous monitoring of indicator parameters will be conducted at each single-level in-reservoir (SLR) monitoring well.

<u>*Indicator Parameter Monitoring*</u> – Fluid P/T/SpC will be monitored continuously. They are the most important parameters to be measured in real time within the monitoring interval of each well. They are the primary parameters that will indicate the presence of CO_2 or CO_2-induced brine migration into the monitored interval. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building.

<u>*Geochemical Monitoring*</u> – Aqueous samples will be collected from each SLR well, initially on a quarterly basis and decreasing in frequency as the system stabilizes over time, to determine the hydrochemistry in the monitoring interval fluids. Aqueous sampling will not be used to assess CO_2 saturation levels. Once supercritical carbon dioxide ($scCO_2$) arrives, these wells can no longer provide representative fluid samples because of the two-phase fluid characteristics and buoyancy of $scCO_2$.

Indirect CO_2 Plume and Pressure-Front Tracking

The primary objectives of indirect (e.g., geophysical) monitoring are 1) tracking CO_2 plume evolution and CO_2 saturation levels; 2) tracking development of the pressure front; and 3) identifying or mapping areas of induced microseismicity, including evaluating the potential for slip along any faults or fractures identified by microseismic. Table A.4 summarizes potential geophysical monitoring technologies and identifies those included in the Testing and Monitoring Plan.

Pulsed-Neutron Capture Logging – The monitoring network will also include three reservoir access tube (RAT) installations designed for the collection of PNC logs to indirectly quantify CO_2 saturations within the Mount Simon injection zone or reservoir (Muller et al. 2007). PNC logging will serve as the primary measure for CO_2 saturation changes that occur within the injection zone. These monitoring points will be located within the predicted lateral extent of the 1- to 3-year CO_2 plume based on numerical simulations of injected CO_2 movement. The RAT locations were selected to provide information about CO_2 arrival at different distances from the injection wells and at multiple lobes of the CO_2 plume.

Geophysical Monitoring

Table A.4. Monitoring Technologies and Decision to Include in Monitoring Plans

Technology	Purpose	Analysis & Limitations
Pulsed-Neutron Capture Logging	Monitors CO_2 saturation changes along boreholes. Used for reservoir model calibration and leak detection.	Will provide quantitative CO_2 saturations. Sensitive only to region around the borehole.
Integrated Surface Deformation Monitoring	Monitors subtle changes in the Earth's surface due to geomechanical response to injection.	Will be able to measure expected deformation. Monitor for anomalies in pressure-front development. DInSAR can be difficult in vegetated areas.
Passive Microseismic	For locating fracture opening and slip along fractures or faults; may indicate location of the pressure front.	Can accurately detect seismic events. Not likely to detect limit of CO_2 plume.
Time-Lapse Gravity	Monitors changes in density distribution in the subsurface, caused by the migration of fluids. Relatively inexpensive.	Non-unique solution, must be used in conjunction with integrated surface deformation monitoring.

Passive Microseismic Monitoring – The objective of the microseismic monitoring network is to accurately determine the locations, magnitudes, and focal mechanisms of injection-induced seismic events with the primary goals of 1) addressing public and stakeholder concerns related to induced seismicity, 2) estimating the spatial extent of the pressure front from the distribution of seismic events, and 3) identifying features that may indicate areas of caprock failure and possible containment loss. The proposed seismic monitoring network consists of five shallow borehole stations, surface stations, and two deep borehole stations. The shallow borehole stations will be drilled to at least the uppermost competent bedrock (~100 m). Actual noise levels and sensor magnitude detection limits at the stations will not be determined until after the sensors have been emplaced and monitored for a period of time. The results of this preliminary evaluation will guide the location of a small number (fewer than five) of additional surface stations.

Deep borehole sensors will be clamped to the outside of the casing of the two ACZ monitoring wells and cemented in place. A 24-level three-component borehole array will be installed in each well. The use of 24-level arrays results in a slight improvement in event location, but more importantly offers redundant sensors in case of failure. Optical three-component accelerometers are technically optimal due to their designed long-term performance characteristics.

Time-Lapse Gravity – The objective of this technique is to estimate the areal extent of the CO_2 plume, based on observed changes in density distribution in the subsurface, caused by the migration of fluids. Gravity changes at the surface are expected to be small but averaging many measurements and/or analysis of long-term trends may allow for tracking of the CO_2 plume. The solution is non-unique and is most useful when combined with Differential Global Positioning System (DGPS) surveys and other integrated surface deformation methods and/or seismic surveys. The locations of permanent and proposed permanent station monuments are shown in Figure A.4.

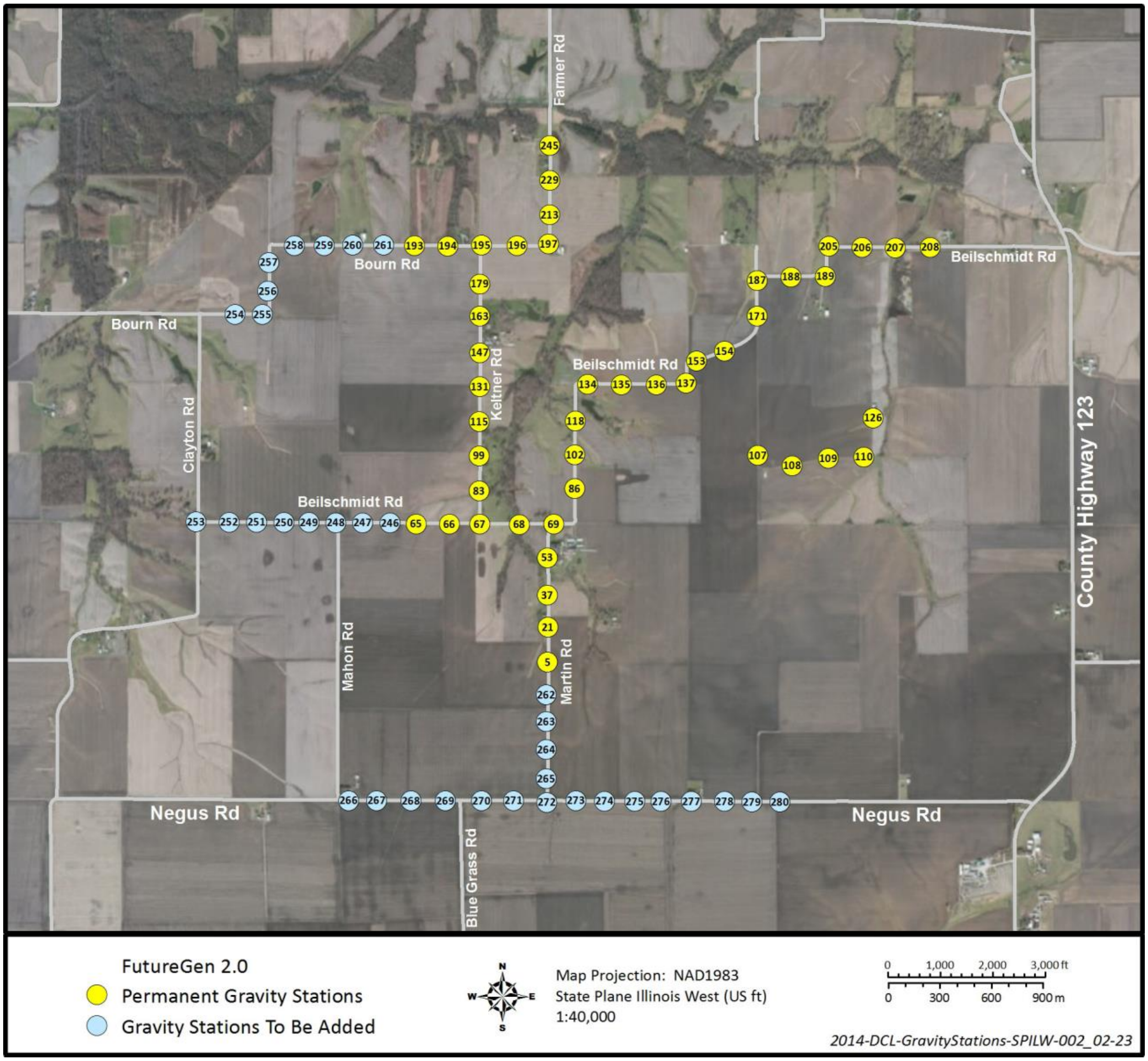

Figure A.4. Locations of Permanent and Proposed Permanent Gravity and Supplemental DGPS Stations

Integrated Deformation Monitoring – Integrated deformation monitoring integrates ground-surface data from permanent Global Positioning System (GPS) stations and tiltmeters, supplemented with annual DGPS surveys and larger-scale Differential Interferometric Synthetic Aperture Radar (DInSAR) surveys to detect and map temporal ground-surface deformation. The DInSAR and proposed GPS network are expected to resolve sub-centimeter surface changes and accurately measure the anticipated injection-induced surface deformation. Permanent GPS and tiltmeter stations will be co-located with the shallow microseismic locations and are expected to have the spatial coverage needed to characterize the overall shape and evolution of the geomechanical changes that occur as a result of CO_2 injection.

A.7 Quality Objectives and Criteria for Measurement Data

The primary goal of testing and monitoring activities is to verify that the Morgan County CO_2 storage site is operating as permitted and is not endangering any USDWs. The Class VI Rule requires that the owner or operator submit the results of testing and monitoring as part of the required semi-annual reports (40 CFR 146.91(a)(7)).

A.7.1 Quality Objectives

The overall Quality Assurance (QA) objective for testing and monitoring is to provide results, interpretation, and reporting that provide reasonable assurance that decision errors regarding compliance with permitting and protection of USDWs are unlikely. The EPA (2013 |EPA 816-R-13-001 – Testing and Monitoring Guidance|) provides a number of recommendations that can be used as qualitative measures/criteria against which the testing and monitoring results can be compared to evaluate compliance.

Mechanical Integrity Testing

Demonstrating and maintaining the mechanical integrity of a well is a key aspect of protecting USDWs from possible endangerment and a specific requirement for Class VI wells in the UIC Program. The Class VI Rule requires mechanical integrity testing (MIT) to be conducted prior to injection (40 CFR 146.87(a)(4)), during the injection phase (40 CFR 146.89), and prior to well plugging after injection has ceased (40 CFR 146.92(a)). The EPA further identified a number of acceptable MIT methods.

A Class VI well can be demonstrated to have mechanical integrity if there is no significant leak (i.e., fluid movement) in the injection tubing, packer, or casing (40 CFR 146.89(a)(1)), and if there is no significant fluid movement through channels adjacent to the injection well bore (40 CFR 146.89(a)(2)). Note that the UIC Program Director will evaluate the results and interpretations of MIT to independently assess the integrity of the injection wells.

Operational Testing and Monitoring During Injection

The Class VI Rule requires owners or operators to monitor injectate properties, injection rate, pressure, and volume, and corrosion of well materials, and perform pressure fall-off testing (40 CFR 146.90(a), (b), (c), and (f)), to indicate possible deviation from planned project operations, verify compliance with permit conditions, and to inform Area of Review (AoR) reevaluations. The results are expected to be interpreted with respect to regulatory requirements and past results. Note the UIC Program Director will evaluate the results to ensure that the composition of the injected stream is consistent with permit conditions and that it does not result in the injectate being classified as a hazardous waste.

Plume and Pressure-Front Tracking

The EPA (2013 |EPA 816-R-13-001 – Testing and Monitoring Guidance|) indicates that identification of the position of the injected CO_2 plume and the presence or absence of elevated pressure (i.e., the pressure front) are integral for verifying the storage reservoir is behaving as predicted, informing the reevaluation of the AoR, and protecting the USDWs. The temporal changes will be analyzed by comparing the new data to previously collected data, and time-series graphs will be developed and interpreted for each well, taking into consideration the injection rate and well location. Spatial patterns will also be analyzed by constructing maps that present contours of pressure and/or hydraulic head. Increases in pressure in wells above the confining zone may be indicative of fluid leakage. Increases in pressure within the injection zone will be compared to modeling predictions to determine whether the AoR is consistent with monitoring results. Pressure increases at a monitoring well location greater than predicted by the current site AoR model, or increases at a greater rate, may indicate that the model needs to be revised.

Geochemical Monitoring

The results of groundwater monitoring will be compared to baseline geochemical data collected during site characterization (40 CFR 146.82(a)(6)) to obtain evidence of fluid movement that may affect USDWs. The EPA (2013) suggests that trends in groundwater concentrations may be indicative of fluid leakage—such as changes in total dissolved solids, major cations and anions, increasing CO_2 concentrations, decreasing pH, increasing concentration of injectate impurities, increasing concentration of leached constituents, and/or increased reservoir pressure and/or static water levels. The EPA also suggests that geochemical data be compared to results from rock-water-CO_2 experiments or geochemical modeling.

Note that the UIC Program Director will evaluate the groundwater monitoring data to independently assess data quality, constituent concentrations (including potential contaminants), and the resulting interpretation to determine if there are any indications of fluid leakage and/or plume migration and whether any action is necessary to protect USDWs (EPA 2013 |EPA 816-R-13-001 – Testing and Monitoring Guidance|).

A.7.2 Measurement Performance/Acceptance Criteria

The qualitative and quantitative design objective of the FutureGen CO_2 Pipeline and Storage Project's testing and monitoring activities is to monitor the performance of the storage reservoir relative to permit and USDW protection requirements. The design of these activities is intended to provide reasonable assurance that decision errors regarding compliance with the permit and/or protection of the USDW are unlikely. In accordance with EPA 2013 |EPA 816-R-13-001 – Testing and Monitoring Guidance|, the well testing and monitoring program includes operational CO_2 injection stream monitoring, well MIT, geochemical and indicator parameter monitoring of both the reservoir and lowermost USDWs, and indirect geophysical monitoring. Table A.5 lists the field and laboratory analytical parameters, methods, and performance criteria for CO_2 injection stream monitoring. Table A.6 shows the MIT parameters, methods, and performance criteria. Table A.7 lists the groundwater geochemical and indicator parameters, methods, and performance criteria. Table A.8 lists the performance criteria for continuously recorded parameter measurements. Table A.9 lists the indirect geophysical parameters, methods, and performance criteria.

Table A.5. CO_2 Injectate Monitoring Requirements

Analytical Parameter	Analytical Method #	Detection Limit or (Range)	Typical Precision/Accuracy	QC Requirements
Pressure	Analog gauges, pressure transmitters	0-2500 psi	Accuracy: ±0.065% of span	CO_2 Pressure Transmitter, Mfg: Rosemount Part No: 3051TG4A2B21AS5M5Q4
Temperature	Thermocouples, or resistance temperature detectors	0-150 °F	Accuracy: ±0.03% of span	CO_2 Temperature Transmitter Mfg: Rosemount Part No: 644HANAXAJ6M5F6Q4
Flow	Coriolis mass meter	Range spanning maximum anticipated injection rate per well	±0.5 %	A single flow prover will be installed to calibrate the flow meters, and piping and valving will be configured to permit the calibration of each flow meter.
CO_2	GC/TCD	0.1-100%	± 10%	Replicate analyses within 10% of each other
O_2	GC/TCD	0.1-100%	± 10%	Replicate analyses within 10% of each other
Total sulfur	ISBT 14.0 (GC/SCD)	0.01 µL/L to 50 µL/L (ppmv) dilution dependent	± 10%	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Arsenic	ICP-MS, EPA Method 6020	1 ng/m^3 (filtered volume)	±10%	Daily calibration
Selenium	ICP-MS, EPA Method 6020	5 ng/m^3 (filtered volume)	±10%	Daily calibration
Mercury (Hg)	Cold vapor atomic absorption (CVAA)	0.25 µg/m^3	± 10%	Daily calibration
H_2S	ISBT 14.0 (GC/SCD)	0.01 µL/L to 50 µL/L (ppmv) dilution dependent	± 10%	Daily blank, daily standard within 10% of calibration, secondary standard after calibration
Ar	GC/TCD	0.1-100%	± 10%	Replicate analyses within 10% of each other
Water vapor (moisture)	GC/HID*	< 100 ppm	± 10%	Replicate analyses within 10% of each other

GC/TCD – gas chromatography with a thermal conductivity detector
ISBT – International Society of Beverage Technologists
GC/SCD – gas chromatography with a sulfur chemiluminescence detector
GC/HID - gas chromatography with helium Ionization detector
* Andrawes (1983) or equivalent. Method subject to change in subsequent revisions.

Table A.6. Mechanical Integrity Testing and Corrosion Requirements

Analytical Parameter	Analytical Method #	QC Requirements
Corrosion of Well Tubulars		
Corrosion of well casing and tubing	Corrosion coupon monitoring (visual, weight, and size); U.S. EPA SW846 Method 1110A – "Corrosivity Toward Steel" (or a similar standard method).	Proper preparation of coupons per ASTM G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens. Refer to SW846 Method 1110A for measurement QC requirements.
Corrosion of well casing (internal radius, wall thickness; general corrosion, pitting, and perforations)	Wireline logging (mechanical, ultrasonic, electromagnetic); casing evaluation would only be done during well workovers that require removal of tubing string.	Vendor calibration of well logging tool(s) per manufacturer recommendations.
Well cement corrosion (quality of cement bond to pipe, and channels in cement)	Wireline logging (acoustic, ultrasonic); casing evaluation would only be done during well workovers that require removal of tubing string.	Baseline cement evaluation logs prior to start of injection. Vendor calibration of well logging tool(s) per manufacturer recommendations
External Mechanical Integrity		
Temperature adjacent to the well	Temperature logging to identify fluid movement adjacent to well bore	Baseline temperature log prior to start of injection. Vendor calibration of well logging tool(s) per manufacturer recommendations
Fluid composition adjacent to the well; fluid movement	Pulsed-neutron logging in oxygen activation mode and thermal capture cross-section (sigma) mode	Baseline log prior to start of injection. Tool calibration per manufacturer recommendations
Internal Mechanical Integrity		
Continuous measurement of fluid pressure and fluid volume in annulus between tubing and long casing string during injection	Pressure and fluid volumes will be measured and logged automatically using electronic pressure sensors and fluid level indicators that are incorporated into the annulus pressurization system (APS).	Initial and ongoing calibration of pressure and fluid level sensors will be done as part of the Annulus Pressurization System Operations and Maintenance program.
Initial annulus pressure test prior to start of injection and following workovers that involve removing tubing and/or packer.	Annular pressure test per EPA UIC requirements	
Pressure Fall-Off Testing		
Well pressure; CO_2 injection rate-history.	Pressure transient analysis methods will be used to analyze pressure fall-off test data to assess well condition (skin) that could indicate need for well rehabilitation.	Initial and ongoing calibration of in-well pressure sensors. Initial and ongoing calibration (proving) of CO_2 flow-rate meters.

Table A.7. Groundwater Geochemical and Indicator Parameter Requirements

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si,	ICP-AES, EPA Method 6010B or similar	1 to 80 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Trace Metals: Sb, As, Cd, Cr, Cu, Pb, Se, Tl	ICP-MS, EPA Method 6020 or similar	0.1 to 2 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Cyanide (CN-)	SW846 9012A/B	5 µg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Mercury	CVAA SW846 7470A	0.2 µg/L	±20%	Daily calibration; blanks, LCS, and duplicates and matrix spikes at 10% level per batch of 20
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-	Ion Chromatography, EPA Method 300.0A or similar	33 to 133 µg/L (analyte dependent)	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Total and Bicarbonate Alkalinity (as $CaCO_3^{2-}$)	Titration, Standard Methods 2320B	1 mg/L	±10%	Daily calibration; blanks, LCS, and duplicates at 10% level per batch of 20
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C	10 mg/L	±10%	Balance calibration, duplicate samples
Water Density	ASTM D5057	0.01 g/mL	±10%	Balance calibration, duplicate samples
Total Inorganic Carbon (TIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of TIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Inorganic Carbon (DIC)	SW846 9060A or equivalent Carbon analyzer, phosphoric acid digestion of DIC	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Total Organic Carbon (TOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Dissolved Organic Carbon (DOC)	SW846 9060A or equivalent Total organic carbon is converted to carbon dioxide by chemical oxidation of the organic carbon in the sample. The carbon dioxide is measured using a non-dispersive infrared detector.	0.2 mg/L	±20%	Quadruplicate analyses, daily calibration
Volatile Organic Analysis (VOA)	SW846 8260B or equivalent Purge and Trap GC/MS	0.3 to 15 µg/L	±20%	Blanks, LCS, spike, spike 1 duplicate per batch of 20
Methane	RSK 175 Mod Headspace GC/FID	10 µg/L	±20%	Blanks, LCS, spike, spike 1 duplicate per batch of 20
Stable Carbon Isotopes $^{13/12}C$ ($1^{13}C$) of DIC in Water	Gas Bench for $^{13/12}C$	50 ppm of DIC	±0.2p	Duplicates and working standards at 10%

Table A.7. (contd)

Parameter	Analysis Method	Detection Limit or Range	Typical Precision/ Accuracy	QC Requirements
Radiocarbon ^{14}C of DIC in Water	AMS for ^{14}C	Range: 0 i 200 pMC	±0.5 pMC	Duplicates and working standards at 10%
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ ($1^{18}O$) of Water	CRDS H_2O Laser	Range: -500‰ to 200‰ vs. VSMOW	$^{2/1}H$: ±2.0‰ $^{18/16}O$: ±0.3‰	Duplicates and working standards at 10%
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline Prep & Dual Inlet IRMS for ^{13}C; AMS for ^{14}C	^{14}C Range: 0 & DupMC	^{14}C: ±0.5pMC ^{13}C: ±0.2‰ $^{2/1}H$: ±4.0‰	Duplicates and working standards at 10%
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H_{10}, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_6+)	Modified ASTM 1945D	1 to 100 ppm (analyte dependent)	Varies by compon-ent	Duplicates and working standards at 10%
Radon (^{222}Rn)	Liquid scintillation after pre-concentration	5 mBq/L	±10%	Triplicate analyses
pH	pH electrode	2 to 12 pH units	±0.2 pH unit *For indication only*	User calibrate, follow manufacturer recommendations
Specific Conductance	Electrode	0 to 100 mS/cm	±1% of reading *For indication only*	User calibrate, follow manufacturer recommendations

ICP-AES = inductively coupled plasma atomic emission spectrometry; ICP-MS = inductively coupled plasma mass spectrometry; LCS = laboratory control sample; GC/MS = gas chromatography–mass spectrometry; GC/FID = gas chromatography with flame ionization detector; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; LC-MS = liquid chromatography-mass spectrometry; ECD = electron capture detector

Table A.8. Required Minimum Specifications for Real-Time Parameter Measurements

Parameter	Range	Resolution	Accuracy	Additional Requirements
Pressure	0 – 2000 psi	0.05 psi	±2 psi	Calibration per manufacturer recommendations
Temperature	50 – 120 °F	0.1 °F	±2 °F	Calibration per manufacturer recommendations
Specific Conductance	0 – 85 mS/cm	0.002 mS/cm	±0.01 mS/cm	Calibration during sampling events

Table A.9. Indirect Geophysical Monitoring Requirements

Analytical Parameter	Analytical Method #	Detection Limit or (Range)	Typical Precision/Accuracy	QC Requirements
Sigma neutron capture cross section	PNC	Dependent on formation and well completion. Salinity >40 Kppm; porosity >0.10	0.5 c.u.	Manufacturer calibration and periodic recalibration
Carbon/Oxygen inelastic	PNC	Dependent on formation and well completion. Porosity >0.15;	Dependent on log time. Requires slow (5−8 ft/min) logging speed	Manufacturer calibration and periodic recalibration
Temperature	Temperature logging	0-350 °F	0.2 °F	Manufacturer calibration and periodic recalibration
Gamma	Gamma-ray logging	NA	1 count/API	Manufacturer calibration and periodic recalibration
Velocity	Passive seismic: geophone	145 dB; 1−350 Hz	10^{-7} m/s	Manufacturer calibration and periodic recalibration
Velocity	Passive seismic: seismometer	165dB ; 0.01−150 Hz	10^{-9} m/s	Manufacturer calibration and periodic recalibration
Acceleration	Passive seismic: force balance accelerometer	155 dB; DC-200 Hz	10^{-6} m/s^2	Manufacturer calibration and periodic recalibration
Acceleration	Passive seismic: fiber-optic accelerometer	0.01−2000 Hz	< 5. 10^{-7} m/s^2 / √Hz	Manufacturer calibration
Position	Integrated deformation: GPS	NA	5 mm+1 ppm horiz.; 10 mm +1 ppm vert.	Manufacturer calibration and periodic recalibration
Deformation	Integrated deformation: DInSAR	NA	<10 mm	Space Agency calibration
Acceleration	Time-lapse gravity	NA	10^{-8} m/s^2 (10^{-6} Gal)	Manufacturer calibration and periodic recalibration

A.8 Special Training/Certifications

Wireline logging, indirect geophysical methods, and some non-routine sampling will be performed by trained, qualified, and certified personnel, according to the service company's requirements. The subsequent data will be processed and analyzed according to industry standards (Appendix A).

Routine injectate and groundwater sampling will be performed by trained personnel; no specialized certifications are required. Some special training will be required for project personal, particularly in the areas of PNC logging, certain geophysical methods, certain data-acquisition/transmission systems, and certain sampling technologies.

Training of project staff will be conducted by existing project personnel knowledgeable in project-specific sampling procedures. Training documentation will be maintained as project QA records.

A.9 Documentation and Records

The Class VI Rule requires that the owner or operator submit the results of testing and monitoring as part of the required semi-annual reports (40 CFR 146.91(a)(7)). These reports will follow the format and content requirement specified in the final permit, including required electronic data formats.

All data are managed according to the Project Data Management Plan (Bryce et al. 2013). All project records are managed according to the project records management requirements. All data and project records will be stored electronically on secure servers and routinely backed-up.

The FutureGen CO_2 Pipeline and Storage Facility PM (assisted by the QEngineer) will be responsible for ensuring that all affected project staff (as identified in the distribution list) have access to the current version of the approved QASP.

B. Data Generation and Acquisition

The primary goal of testing and monitoring activities is to verify that the Morgan County carbon dioxide (CO_2) storage site is operating as permitted and is not endangering any underground sources of drinking water (USDWs). To this end, the primary objectives of the testing and monitoring program are to track the lateral extent of supercritical carbon dioxide ($scCO_2$) within the target reservoir; characterize any geochemical or geomechanical changes that occur within the reservoir, caprock, and overlying aquifers; monitor any change in land-surface elevation associated with CO_2 injection; determine whether the injected CO_2 is effectively contained within the reservoir; and detect any adverse impact on USDWs.

This element of the Quality Assurance and Surveillance Plan (QASP) addresses data-generation and data-management activities, including experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to each testing and monitoring method. It should be noted that not all of these QASP aspects are applicable to all testing and monitoring methods. Other QASP aspects, such as inspection/acceptance of supplies and consumables (Section B.12), non-direct measurements (e.g., existing data) (Section B.13), and data management (Section B.14), are applicable to all techniques and are discussed separately.

Well testing and monitoring activities are broken into eight main categories/subtasks, as listed below.

1. CO_2 Injection Stream Analysis – includes CO_2 injection stream gas sampling and chemical analyses. See Section B.1.
2. Continuous Recording of Injection Pressure, Rate, and Volume and Annulus Pressure. See Section B.2.
3. Corrosion Monitoring – includes sampling and analysis of corrosion coupons. See Section B.3.
4. Groundwater Quality Monitoring – includes formation fluid sampling within the Ironton Sandstone (Above Confining Zone) and St. Peter Sandstone (lowermost USDW) and subsequent geochemical analyses, as well as continuous monitoring of indicator parameters. See Section B.4.
5. External Mechanical Integrity Testing – includes temperature logging and pulsed-neutron capture (PNC) logging (both gas-view and oxygen-activation mode), as well as cement-evaluation and casing inspection logging. See Section B.5.
6. Pressure Fall-Off Testing. See Section B.6.
7. Direct CO_2 Plume and Pressure-Front Tracking − includes all formation fluid sampling within the Mount Simon Sandstone, as well as continuous monitoring of pressure, temperature, and fluid specific conductance. See Section B.7.
8. Indirect CO_2 Plume and Pressure-Front Tracking – includes PNC logging, passive seismic monitoring, integrated deformation monitoring, and time-lapse gravity. Optional supplementary methods may include three-dimensional (3D) multicomponent surface seismic, and multicomponent vertical seismic profiling. See Sections B.8 through B.11.

B.1 Carbon Dioxide Stream Analysis

The Alliance will conduct injection stream analysis to meet the requirements of 40 CFR 146.90(a). This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to CO_2 stream analysis monitoring activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.1.1 Sampling Process Design (Experimental Design)

Based on the anticipated composition of the CO_2 stream, a list of parameters has been identified for analysis. Samples of the CO_2 stream will be collected regularly (e.g., quarterly) for chemical analysis.

Table B.1. Parameters and Frequency for CO_2 Stream Analysis

Parameter/Analyte	Frequency
Pressure	Continuous
Temperature	Continuous
CO_2 (%)	quarterly
Water (lb/mmscf)	quarterly
Oxygen (ppm)	quarterly
Sulfur (ppm)	quarterly
Arsenic (ppm)	quarterly
Selenium (ppm)	quarterly
Mercury (ppm)	quarterly
Argon (%)	quarterly
Hydrogen Sulfide (ppm)	quarterly

B.1.2 Sampling Methods

Grab samples of the CO_2 stream will be obtained for analysis of gases, including CO_2, O_2, H_2S, Ar, and water moisture. Samples of the CO_2 stream will be collected from the CO_2 pipeline at a location where the material is representative of injection conditions. A sampling station will be installed in the ground or on a structure close to the pipeline and connected to the pipeline via small-diameter stainless steel tubing to accommodate sampling cylinders that will be used to collect the samples. A pressure regulator will be used to reduce the pressure of the CO_2 to approximately 250 psi so that the CO_2 is collected in the gas state rather than as a supercritical liquid. Cylinders will be purged with sample gas (i.e., CO_2) prior to sample collection to remove laboratory-added helium gas and ensure a representative sample.

B.1.3 Sample Handling and Custody

Samples will be transported to the Monitoring, Verification, and Accounting (MVA) laboratory space in the control building for processing, packaging, and shipment to the contracted laboratory, following standard sample handling and chain-of-custody guidance (EPA 540-R-09-03, or equivalent).

B.1.4 Analytical Methods

Analytical methods are listed in Table A.5

B.1.5 Quality Control

A wide variety of monitoring data will be collected specifically for this project, under appropriate quality assurance (QA) protocols. Data QA and surveillance protocols will be designed to facilitate compliance with requirements specified in 40 CFR 146.90(k).

B.1.6 Instrument/Equipment Testing, Inspection, and Maintenance

For sampling, field equipment will be maintained, serviced, and calibrated per manufacturers' recommendations. Spare parts that may be needed during sampling will be included in supplies on-hand during field sampling.

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory per method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.1.7 Instrument/Equipment Calibration and Frequency

Calibration of all laboratory instrumentation/equipment will be the responsibility of the analytical laboratory per method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.2 Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to continuous monitoring of injection parameters. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.2.1 Sampling Process Design (Experimental Design)

The Alliance will conduct continuous monitoring of injection parameters to meet the requirements of 40 CFR 146.90(b). These activities include continuous recording of injection pressure, temperature, flow rate, and volume, as well as the annulus pressure.

The injection wells will be completed with a string of 3.5-in.-OD tubing that extends from the wellhead at the surface to near the top of the perforated interval. A tubing string that is 4,000 ft long will extend approximately 11 ft below the top of the perforations. The tubing string will be held in place at the bottom by a packer that is positioned just above the uppermost perforations (approximate measured depth of 3,975 ft). An optical or electronic pressure-and-temperature (P/T) gauge will be installed on the outside of the tubing string, approximately 30 ft above the packer, and ported into the tubing to continuously measure CO_2 injection P/T inside the tubing at this depth. In addition, injection P/T will also be continuously measured at the surface via real-time P/T instruments installed in the CO_2 pipeline near the pipeline interface with the wellhead. Because the surface instruments can be more readily accessed and maintained than the bottom-hole gauge, they will be used to control injection operations and trigger shutdowns.

B.2.2 Sampling Methods

Continuous Recording of Injection Pressure and Temperature

An electronic P/T gauge will be installed on the outside of the tubing string, approximately 30 ft above the packer, and ported into the tubing to continuously measure CO_2 injection P/T inside the tubing at this depth. Mechanical strain gauges and thermocouples will be the primary monitoring devices for pressure and temperature.

Injection P/T will also be continuously measured at the surface via real-time P/T instruments installed in the CO_2 pipeline near the pipeline interface with the wellhead. The P/T of the injected CO_2 will be continuously measured for each well. The pressure will be measured by electronic pressure transmitter with analog output mounted on the CO_2 line associated with each injection well. The temperature will be measured by an electronic temperature transmitter mounted in the CO_2 line at a location near the pressure transmitter, and both transmitters will be located near the wellhead. The transmitters will be connected to the Annulus Pressurization System (APS) programmable logic controller (PLC) located at the injection well site. Because the surface instruments can be more readily accessed and maintained than the bottom-hole gauge, they will be used to control injection operations and trigger shutdowns.

Continuous Recording of Injection Mass Flow Rate

The mass flow rate of CO_2 injected into the well field will be measured by a flow meter skid with a Coriolis mass flow transmitter for each well. Each meter will have analog output (Micro Motion Coriolis Flow and Density Meter Elite Series or similar). A total of six flow meters will be supplied, providing for two spare flow meters to allow for flow meter servicing and calibration. Valving will be installed to select flow meters for measurement and for calibration. A single flow prover will be installed to calibrate the flow meters, and piping and valving will be configured to permit the calibration of each flow meter. The flow transmitters will each be connected to a remote terminal unit (RTU) on the flow meter skid.

The RTU will communicate with the Control Center through the APS PLC located at the injection well site. The flow rate into each well will be controlled using a flow-control valve located in the CO_2 pipeline associated with each well. The control system will be programmed to provide the desired flow rate into three of the four injection wells, with the fourth well receiving the balance of the total flow rate.

B.2.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Electronic sensor data (e.g., pressure data) will be networked through the local-area fiber-optic network using Ethernet network interfaces back to data-acquisition systems located in the MVA data center.

Electronic data and field records will be transferred to laptop and/or desktop computers and/or backed-up on secured servers at least quarterly, as well as scanned copies of all pertinent hardcopy field records/notes.

B.2.4 Analytical Methods

Continuously recorded injection parameters will be reviewed and interpreted on a regular basis, to evaluate the injection stream parameters against permit requirements. Trend analysis will also help evaluate the performance (e.g., drift) of the instruments, suggesting the need for maintenance or calibration.

B.2.5 Quality Control

Continuous monitoring equipment will be calibrated according to the manufacturers' recommendations. If trends or other unexplained variability in the data are observed that might indicate a suspect response, instruments will be evaluated and, if required, recalibrated or replaced.

B.2.6 Instrument/Equipment Testing, Inspection, and Maintenance

The surface instruments will be maintained according to manufacturers' recommendations; however, if data trends indicate a suspect response, instruments will be evaluated and, if required, recalibrated or replaced.

B.2.7 Instrument/Equipment Calibration and Frequency

Because the bottom-hole P/T gauge will be attached to the tubing string, the gauge will be recalibrated or replaced only when the injection well tubing string is pulled, which would occur only if warranted by a downhole issue that can only be addressed by performing a well workover. The surface P/T instruments will be calibrated according to manufacturers' recommendations.

B.3 Corrosion Monitoring

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to corrosion-monitoring activities. Refer to Sections B.12 through B.14 for general description of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.3.1 Sampling Process Design (Experimental Design)

The Alliance will conduct corrosion monitoring of well materials to meet the requirements of 40 CFR 146.90(c). Corrosion-monitoring activities are designed to monitor the integrity of the injection wells throughout the operational period. This includes using corrosion coupons as well as periodic cement-evaluation and casing inspection logs when tubing is removed from the well (i.e., during well workovers). Corrosion coupons will be made of the same materials as the long string of casing and the injection tubing, and will be placed in the CO_2 pipeline for ease of access.

B.3.2 Sampling Methods

Corrosion monitoring will include corrosion coupons as well as periodic cement-evaluation and casing inspection logs.

Corrosion Coupon Monitoring

Corrosion coupons will be made of the same material as the long string of casing and the injection tubing and placed in the CO_2 injection pipeline. The coupons will be removed quarterly and assessed for corrosion using the ASTM International (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). Upon removal, coupons will be inspected visually for evidence of corrosion (e.g., pitting). The weight and size (thickness, width, length) of the coupons will also be measured and recorded each time they are removed. The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

Cement-evaluation and Casing Inspection Logging

Cement-evaluation and casing inspection logs will be run periodically, on an opportunistic basis, whenever tubing is removed from the well (i.e., during well workovers). See Section B.5 on external mechanical integrity testing.

B.3.3 Sample Handling and Custody

Corrosion monitoring will include corrosion coupons as well as periodic cement-evaluation and casing inspection logs. No specialized sample handling or chain-of-custody procedures are needed. The coupons will be removed from the pipeline, then taken to the nearby mobile lab (field trailer) where they will be cleaned, inspected, weighed, and measured. They will be immediately returned to the pipeline. Cement-evaluation and casing inspection log data will be handled using best management practices. See Section B.5 on external mechanical integrity testing.

B.3.4 Analytical Methods

The corrosion coupons will be cleaned, inspected visually for evidence of corrosion (e.g., pitting), weighed, and measured each time they are removed (ASTM G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens). The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

See Section B.5 on external mechanical integrity testing for cement-evaluation and casing inspection logging analytical methods.

B.3.5 Quality Control

Two groups of four replicate corrosion coupons of each material type will be placed in proximity to each other within two different locations within the CO_2 injection pipeline. A third group of four replicate samples of each material type will placed in proximity to each other within a simulated injection pipeline as a control (not exposed to CO_2). All samples will be removed quarterly and subjected to the same visual and measurement methodologies. This approach will allow an evaluation of the potential spatial variability in corrosion rates within the injection tubing, as well as the natural variability between coupon samples. Corrosion rates (calculated as the weight loss during the exposure period divided by the duration, i.e., weight loss method) and statistical analyses (e.g., t-test) will be independently reviewed and documented.

See Section B.5 on external mechanical integrity testing for cement-evaluation and casing inspection logging quality control methods.

B.3.6 Instrument/Equipment Testing, Inspection, and Maintenance

Equipment and instrumentation for visual inspection and measurement of the corrosion coupons will consist of materials to clean corrosion products off the coupons as well as equipment and instrumentation for visual inspection and measurement in accordance with ASTM G1-03. Key inspection and measurement equipment may include calipers, an analytical balance (e.g., electronic scale), and a low-power microscope or hand lens (e.g., 7X to 30X). The analytical balance should be able to measure to with + or -0.2 to 0.02 mg. Calipers should be able to measure to about 1% of the area measured (ASTM G1-03).

Maintenance (e.g., charging, batteries, etc.) and instrument checks will be performed quarterly, prior to each sampling event. All equipment and materials will be visually inspected for damage, calibration dates, battery life, etc. prior to use. Fresh batteries and backup equipment/instrumentation will be stored in the mobile lab/field trailer.

See Section B.5 on external mechanical integrity testing for instrumentation and equipment testing, inspection, and maintenance relative to cement-evaluation and casing inspection logging.

B.3.7 Instrument/Equipment Calibration and Frequency

Calipers, analytical balances, and other measuring and testing instrumentation will be calibrated by the manufacturer, according to its recommended procedures and frequencies. See Section B.5 on external mechanical integrity testing for instrumentation and equipment calibration relative to cement-evaluation and casing inspection logging.

B.4 Groundwater Quality Monitoring (ACZ and USDW wells)

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to groundwater quality monitoring activities. Refer to Sections B.12 through B.14 for general description of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.4.1 Sampling Process Design (Experimental Design)

The Alliance will conduct ground-water-quality/geochemical monitoring above the confining zone to meet the requirements of 40 CFR 146.90(d).

The planned groundwater quality monitoring well network layout, number of wells, well design, and sampling regimen are based upon site-specific characterization data, and consider structural dip, the locations of existing wells, expected ambient flow conditions, and the potential for heterogeneities or horizontal/vertical anisotropy within the overburden materials (see also Section A.6.2). The planned monitoring network consists of two wells within the first permeable interval immediately above the primary confining zone (Ironton Sandstone), and one well within the lowermost USDW (St. Peter Sandstone) (Figure A.3). The above confining zone (ACZ) wells will be completed in the Ironton Sandstone and monitor for changes in pressure, groundwater chemistry, indicator parameters, and microseismicity. The ACZ monitoring interval is located immediately above the primary confining zone. One of these wells will be located ~1,000 ft west of the injection site adjacent to the western injection lateral; the other will be located ~1,500 ft west of the western injection lateral terminus. The USDW well (USDW1) will be installed at the base of the St. Peter Sandstone to monitor the groundwater quality of the lowermost USDW.

The Alliance plans to conduct periodic fluid sampling as well as continuous pressure, temperature, and specific conductance (P/T/SpC) monitoring throughout the injection phase in the two ACZ monitoring wells and the USDW well. (Table A.3 lists the parameters and instrumentation that will be used at each of the ACZ and USDW monitoring wells. Minimum specifications for the planned continuous measurements are listed in Table A.8.)

The Alliance will also conduct baseline surficial aquifer sampling in the shallow, semi-consolidated glacial sediments, using approximately nine local landowner wells and one well drilled for the project. Because near-surface environmental impacts are not expected, surficial aquifer (<100 ft bgs) monitoring will only be conducted for a sufficient duration to establish baseline conditions (minimum of three sampling events). Surficial aquifer monitoring is not planned during the injection phase; however, the need for additional surficial aquifer monitoring will be continually evaluated throughout the operational phases of the project, and may be reinstituted if conditions warrant.

B.4.2 Sampling Methods

Fluid samples will be collected at monitored formation depths and maintained at formation pressures within a closed pressurized sample container to prevent the escape of dissolved gases. Access to the monitored intervals at the ACZ and USDW monitoring wells will be through the 5-1/2-in. casing that is cemented into the borehole.

Aqueous samples will be collected from each monitoring well, initially on a quarterly basis and later less frequently, to determine the concentration of CO_2 and other constituents in the monitoring interval fluids. The fluid samples will be collected within the open interval of each monitoring well using a flow-through sampler with a 950-cc (or larger) sample chamber. The samples will be maintained at formation pressure within a closed sample container to prevent the escape of dissolved gases. Prior to sampling, the P/T/SpC probe will be monitored as the well is purged (up to three times the volume of the well-screen section will be discharged from the well before collecting the sample). The probe will then be removed from the well and the sampler will be run into the borehole on the same wireline cable to collect the pressurized fluid sample. Additional purging may be conducted just prior to collection of the pressurized fluid sample if mixing between the fluid column and sampling interval during insertion of the sampler is a concern.

B.4.3 Sample Handling and Custody

After removing the sampler from the well, the closed and pressurized sample container(s) will be transported to the MVA laboratory space in the control building for processing following standard chain-of-custody procedures.

B.4.4 Analytical Methods

The analytical methods for groundwater quality monitoring in the ACZ and USDW wells are summarized in Table A.7.. Where possible, methods are based on standard protocols from EPA or Standard Methods for the Examination of Water and Wastewater (American Public Health Association, American Water Works Association, Water Environment Federation, 19th edition orlater, Washington, D.C.). Laboratories shall have standard operating procedures for the analytical methods performed.

B.4.5 Quality Control

The quality control (QC) elements in this section are used to help evaluate whether groundwater samples are free of contamination and whether the laboratories performed the analyses within acceptable accuracy and precision requirements. Several types of field and laboratory QC samples are used to assess and enhance data quality (Table B.2)

Table B.2. Quality Control Samples

	Field QC	
Sample Type	Primary Characteristic Evaluated	Frequency
Trip Blank	Contamination from containers or transportation	1 per sampling event
Field Duplicates	Reproducibility	1 per sampling event
	Laboratory QC	
Sample Type	Primary Characteristic Evaluated	Frequency
Method Blank	Laboratory contamination	1 per batch
Lab Duplicate	Laboratory reproducibility	(a)
Matrix Spike	Matrix effects and laboratory accuracy	(a)
Matrix Spike Duplicate	Laboratory reproducibility/accuracy	(a)
Laboratory Control Sample	Method accuracy	1 per batch

(a) As defined in the laboratory contract and analysis procedures (typically 1 per 10 samples).

Field QC samples consist of trip blanks and duplicate samples. Trip blanks are preserved sample bottles that are filled with deionized water and transported unopened to the field in the same storage container that will be used for samples collected that day. Trip blanks evaluate bottle cleanliness, preservative purity, equipment decontamination, and proper storage and transport of samples. The frequency of collection for trip blanks is one per sampling event. Field duplicates are replicate samples that are collected at the same well. After each type of bottle is filled, a second, identical bottle is filled for each type of analysis. Both sets of samples are stored and transported together. Field duplicates provide information about sampling and analysis reproducibility. The collection frequency for field duplicates is one per sampling event.

Laboratory QC samples include method blanks, laboratory duplicates, matrix spikes, matrix spike duplicates, and laboratory control samples (defined below). These samples are generally required by EPA method protocols. Frequencies of analysis are specified in Table B.2 and in the laboratories' standard operating procedures.

- **Method blank** – an analyte-free matrix to which all reagents are added in the same volumes or proportions as used in sample processing. The method blank is carried through the complete preparation and analysis process. Method blanks are used to quantify contamination from the analytical process.
- **Laboratory duplicate** – an intra-laboratory split sample that is used to evaluate the precision of a method in a given sample matrix.
- **Matrix spike** – an aliquot of a sample that is spiked with a known concentration of target analytes(s). The matrix spike is used to assess the bias of a method in a given sample matrix. Spiking occurs prior to sample preparation and analysis.
- **Matrix spike duplicate** – a replicate spiked aliquot of a sample that is subjected to the entire sample preparation and analytical process. Matrix spike duplicate results are used to determine the bias and precision of a method in a given sample matrix.
- **Laboratory control sample** – a control matrix (typically deionized water) spiked with analytes representative of the target analytes or a certified reference material that is used to evaluate laboratory accuracy.

Besides these measures, the laboratories maintain internal QA programs and are subject to internal and external audits.

B.4.6 Instrument/Equipment Testing, Inspection, and Maintenance

For groundwater sampling, field equipment will be maintained, serviced, and calibrated according to the manufacturers' recommendations. Spare parts that may be needed during sampling will be included in supplies on-hand during field sampling.

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory according to method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.4.7 Instrument/Equipment Calibration and Frequency

Calibration of all laboratory instrumentation/equipment will be the responsibility of the analytical laboratory according to method-specific protocols and the laboratory's QA program, which will be reviewed by the Alliance prior to contract award.

B.5 External Mechanical Integrity Testing

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to external mechanical integrity testing (MIT) activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.5.1 Sampling Process Design (Experimental Design)

The Alliance will conduct external MIT to meet the requirements of 40 CFR 146.90(e). These tests are designed to include temperature logging, PNC logging, and cement-evaluation logging. An initial (baseline) temperature and PNC logs will be run on the well after well construction but prior to commencing CO_2 injection. These baseline log(s) will serve as a reference for comparing future temperature and PNC logs for evaluating external mechanical integrity.

Temperature Logging

Temperature logs can be used to identify fluid movement along channels adjacent to the well bore. In addition to identifying injection-related flows behind casing, temperature logs can often locate small casing leaks. Injection of CO_2 will have a cooling or heating effect on the natural temperature in the storage reservoirs, depending on the temperature of the injected CO_2 and other factors. Once injection starts, the flowing temperature will stabilize quickly (assuming conditions remain steady).

When an injection well is shut-in for temperature logging, the well bore fluid begins to revert toward ambient conditions. Zones that have taken injectate, either by design or not, will exhibit a "storage" signature on shut-in temperature surveys (storage signatures are normally cold anomalies in deeper wells, but may be cool or hot depending on the temperature contrast between the injectate and the reservoir). Losses behind pipe from the injection zone can be detected on both flowing and shut-in temperature surveys and exhibit a "loss" signature.

For temperature logging to be effective for detecting fluid leaks, there should be a contrast in the temperature of the injected CO_2 and the reservoir temperature. The greater the contrast in the CO_2 when it reaches the injection zone and the ambient reservoir temperature, the easier it will be to detect temperature anomalies due to leakage behind casing. Based on data from the stratigraphic well, ambient bottom-hole temperatures in the Mount Simon Sandstone are expected to be approximately 100°F; the temperature of the injected CO_2 is anticipated to be on the order of 72°F to 90°at the surface (depending on time of year) but will undergo some additional heating as it travels down the well. After the baseline (i.e., prior to injection) temperature log has been run to determine ambient reservoir temperature in each well, it will be possible to determine whether there will be sufficient temperature contrast to make the temperature log an effective method for evaluating external mechanical integrity.

The Alliance will consult the EPA Region 5 guidance for conducting temperature logging (EPA 2008) when performing this test.

Oxygen-Activation Logging

Oxygen activation is a geophysical logging technique that uses a PNC tool to quantify the flow of water in or around a borehole. For purposes of demonstrating external mechanical integrity, a baseline oxygen activation will be run prior to the start of CO_2 injection and compared to later runs to determine changing fluid flow conditions adjacent to the well bore (i.e., formation of channels or other fluid isolation concerns related to the well).

The PNC tool emits high-energy neutrons that interact with water molecules present in the casing-formation annular space, among others. This temporarily activates oxygen (^{16}O) to produce an isotope of nitrogen (^{16}N) that decays back to oxygen with a half-life of 7.1 seconds and emits an easily detected gamma ray. Typical PNC tools have two or three gamma-ray detectors (above and below the neutron source) to detect the movement of the activated molecules, from which water velocity can then be calculated. The depth of investigation for oxygen-activation logging is typically less than 1 ft; therefore, this log type provides information immediately adjacent to the well bore.

Repeat runs will be made under conditions that mimic baseline conditions (e.g., similar logging speeds and tool coefficients) as closely as possible to ensure comparability between baseline and repeat data.

The Alliance will consult the EPA Region 5 guidance for conducting the oxygen-activation logging (EPA 2008) when performing this test.

In addition to oxygen activation logging, the PNC tool will also be run in thermal capture cross-section (sigma) mode to detect the presence of CO_2 outside the casing.

PNC logging will be the primary method used to evaluate the external mechanical integrity of the injection wells.

Cement-Evaluation Logging

Cement evaluation beyond the preliminary cement-bond log is not required for Class VI wells under MIT or corrosion monitoring (40 CFR 146.89 and 146.90). However, it is recognized that cement integrity over time can influence the mechanical integrity of an injection well. Therefore, cement-evaluation logs will be run when tubing is removed from the well (i.e., during well workovers that involve removing the tubing string). Some cement-evaluation logs are also capable of providing information about the condition of the casing string, such as wall thickness and inside diameter (e.g., Schlumberger isolation scanner tool).

B.5.2 Sampling Methods

PNC logging will be the primary method used to evaluate the external mechanical integrity of the injection wells (EPA requires annual MIT demonstrations). PNC and temperature logging will be conducted on an opportunistic basis, for example, when each well is taken out of service. Temperature and PNC logging will be performed through the tubing and therefore will not require removal of the tubing and packer from the well. However, the cement-evaluation and casing-evaluation logging will be conducted only when tubing is removed from the well as this cannot be performed through tubing.

B.5.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Logging data will be recorded on a computer located in the wireline logging truck. All electronic data and field records will be transferred to laptop and/or desktop computers and backed-up on secure servers at the conclusion of each logging event, as will scanned copies of all pertinent hardcopy field records/notes.

B.5.4 Analytical Methods

Wireline log data will be processed following industry best practices and coordinated with the borehole-logging operator to optimize data-collection parameters. Modeling can be done to simulate near-borehole interferences and remove their effects from the signal. Modeling is a recommended procedure and requires knowledge of the target formations and fluids that must be obtained from cores and additional logging data. Each logging result will be compared for each well to the baseline or previous survey, as applicable, to determine changes.

B.5.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and are reproducible. Third-party logging and processing for a subset of boreholes and logging events can be used as part of the validation procedure. Failure of tool performance in the field or unreproducible "repeat sections" will result in non-acceptance of the data, and may trigger a return of the wireline tool to the manufacturer for recalibration or replacement. Off-normal results/comparisons to baseline will trigger additional evaluation and possible new logging runs.

B.5.6 Instrument/Equipment Testing, Inspection, and Maintenance

Examples of industry-published guidelines for calibration and field operation of the pulsed-neutron capture (PNC) wireline log hardware and data-collection software are provided in Appendix A.

B.5.7 Instrument/Equipment Calibration and Frequency

To ensure data acquisition quality, each logging tool will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. All tools and field operation software will be provided by the manufacturer with an auditable verification record to ensure traceability. In addition to the initial manufacturer calibration, tool recalibration will be performed monthly and both prior to and after each logging event following the manufacturer's guidelines. Examples of industry-published guidelines for calibration and field operation of wireline log hardware and data-collection software are provided in Appendix B.

B.6 Pressure Fall-Off Testing

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to pressure fall-off testing activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.6.1 Sampling Process Design (Experimental Design)

Pressure fall-off testing will be conducted upon completion of the injection wells to characterize reservoir hydrogeologic properties and aquifer response model characteristics (e.g., nonleaky vs. leaky reservoir; homogeneous vs. fractured media) as well as changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior in accordance with 40 CFR 146.87(e)(1). Pressure fall-off testing will also be conducted at least once every five (5) years after injection operations begin, or more frequently if required by the UIC Program Director (40 CFR 146.90 (f)). Specifically, the objective of the periodic pressure fall-off testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect well/reservoir performance (e.g., well injectivity, anomalous reservoir pressure behavior). Detailed descriptions for conducting and analyzing pressure fall-off tests are provided by the EPA (2002, 2003, and 2012). These guidelines will be followed when conducting pressure fall-off tests for the FutureGen 2.0 CO_2 Pipeline and Storage Project.

B.6.2 Sampling Methods

Controlled pressure fall-off tests are conducted by terminating injection for a designed period/duration of time. The pressure fall-off test is initiated by terminating injection, shutting-in the well by closing the surface wellhead valve(s), and maintaining continuous monitoring the surface and downhole pressure recovery within the well/test interval system during the fall-off/recovery period. The designed duration of the pressure fall-off recovery test is a function of a number of factors, including the exhibited pre-operational injection reservoir test response characteristics, the injection well history prior to termination (i.e., injection duration, rate history), and potential pressure interference effects imposed by any surrounding injection wells completed within the same reservoir. Because of the potential impact of injection-rate variability on early-time pressure fall-off recovery behavior, the EPA (2012) recommends that injection rates and pressures be uniform and held relatively constant prior to initiating a pressure fall-off test.

Upon shutting-in the well, in-well pressure measurements are monitored continuously in real time, both downhole (within or in proximity to the injection reservoir) and at the surface wellhead location. The EPA (2012) recommends the use of two pressure probes at each location, with one serving as a verification source and the other as a backup/replacement sensor if the primary pressure transducer becomes unreliable or inoperative. The duration of the shut-in period used in conducting the pressure fall-off test should be extended sufficiently beyond wellbore storage effects and when the pressure recovery is indicative of infinite-acting radial flow (IARF) conditions. The establishment of IARF conditions is best determined by using pressure derivative diagnostic analysis plots (Bourdet et al. 1989; Spane 1993; Spane and Wurstner 1993), and is indicated when the log-log pressure derivative/recovery time plot, plots as a horizontal line. When IARF pressure fall-off conditions are indicated, the pressure response vs. log of fall-off/recovery time plots as a straight line on a standard semi-log plot. The EPA (2012) recommends a general rule-of-thumb of extending pressure fall-off tests a factor of three to five beyond the time required to reach radial flow conditions, while Earlougher (1977) suggests extending recovery periods between 1 to 1.5 log cycles beyond when the pressure response starts to deviate from purely wellbore storage response characteristics (i.e., a unit slope, 1:1 on a standard log-log pressure fall-off recovery plot).

For projects like FutureGen 2.0 that will use multiple injection wells completed within the same reservoir zone, the EPA (2012) recommends special considerations to be used for pressure fall-off testing to minimize the pressure response impacts from neighboring injection wells on the pressure fall-off test well recovery response. For the neighboring injection wells (i.e., those not being tested), the EPA (2012) recommends that injection at these wells either should be terminated prior to initiating the pressure fall-off test for a duration exceeding the planned shut-in period, or that injection rates at the neighboring injection wells be held constant and continuously recorded prior to and during the fall-off recovery test. After completion of the fall-off test, additional large-scale areal reservoir hydraulic/storativity characterization information may be derived for the injection reservoir by implementing a stepped-pulse pressure interference signal (by significantly increasing and/or decreasing injection rates) initiated from the neighboring injection wells. The arrival of the observed pulsed pressure signal at the fall-off test well provides information (i.e., due to arrival time and attenuation of the pressure pulse signal) about inter-well reservoir conditions (e.g., hydraulic diffusivity, directional lateral extent of injected CO_2), particularly if compared to pre-injection interference test response characteristics.

B.6.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Electronic sensor data (e.g., pressure data) will be recorded on data loggers. All electronic data and field records will be transferred to laptop and/or desktop computers and backed-up on secure servers at the conclusion of each test, as well as scanned copies of all pertinent hardcopy field records/notes.

B.6.4 Analytical Methods

Quantitative analysis of the pressure fall-off test response recorded following termination of injection for the test well provides the basis for assessing near well and larger-scale reservoir behavior. Comparison of diagnostic pressure fall-off plots established prior to operational injection of CO_2 and periodic fall-off tests conducted during operational injection phases can be used to determine whether significant changes in well or injection reservoir conditions have occurred. Diagnostic derivative plot analysis (Bourdet et al. 1989; Spane 1993; Spane and Wurstner 1993) of the pressure fall-off recovery response is particularly useful for assessing potential changes in well and reservoir behavior.

The EPA (2002, 2003) provides a detailed discussion on the use of standard semi-log and log-log diagnostic and analysis procedures for pressure fall-off test interpretation. The plotting of downhole temperature concurrent with the observed fall-off test pressure is also useful diagnostically for assessing any observed anomalous pressure fall-off recovery response. Commercially available pressure gauges typically are self-compensating for environmental temperature effects within the probe sensor (i.e., within the pressure sensor housing). However, as noted by the EPA (2012), if temperature anomalies are not accounted for correctly (e.g., well/reservoir temperatures responding differently than registered within the probe sensor), erroneous fall-off pressure response results maybe be derived. As previously discussed, concurrent plotting of downhole temperature and pressure fall-off responses is commonly useful for assessing when temperature anomalies may be affecting pressure fall-off/recovery behavior. In addition, diagnostic pressure fall-off plots should be evaluated relative to the sensitivity of the pressure gauges used to confirm adequate gauge resolution (i.e., excessive instrument noise).

Standard diagnostic log-log and semi-log plots of observed pressure change and/or pressure derivative plots versus recovery time are commonly used as the primary means for analyzing pressure fall-off tests. In addition to determining specific well performance conditions (e.g., well skin) and aquifer hydraulic property and boundary conditions, the presence of prevailing flow regimes can be identified (e.g., wellbore storage, linear, radial, spherical, double-porosity, etc.) based on characteristic diagnostic fall-off pressure derivative patterns. A more extensive list of diagnostic derivative plots for various formation and boundary conditions is presented by Horne (1990) and Renard et al. (2009).

As discussed by the EPA (2002), early pressure fall-off recovery response corresponds to flow conditions within and in proximity to the well bore, while later fall-off recovery response is reflective of progressively more distant reservoir conditions from the injection well location. Significant divergence in pressure fall-off response patterns from previous pressure fall-off tests (e.g., accelerated pressure fall-off recovery rates) may be indicative of a change in well and/or reservoir conditions (e.g., reservoir leakage). A more detailed discussion of using diagnostic plot analysis of pressure fall-off tests for discerning possible changes to well and reservoir conditions is presented by the EPA (2002, 2003).

As indicated by the EPA (2012), quantitative analysis of the pressure fall-off test data can be used to determine formation hydraulic property characteristics (e.g., permeability, transmissivity), and well skin factor (additional pressure change effects due to altering the permeability/storativity conditions of the reservoir/well injection interval boundary). Determination of well skin is a standard result for pressure fall-off test analysis and is described in standard well-test analysis texts such as that by Earlougher (1977). Software programs are also commercially available (e.g., Duffield 2007, 2009) for analyzing pressure fall-off tests. Significant changes in well and reservoir property characteristics (as determined from pressure fall-off analysis), compared to those used in site computational modeling and AoR delineation, may signify a reevaluation of the AoR, as may be required by the UIC Program Director, as noted by the EPA (2012).

B.6.5 Quality Control

Periodic QC checks will be routinely made in the field, and on occasion, where permanent pressure gauges are used, a second pressure gauge with current certified calibration will be lowered into the well to the same depth as the permanent downhole gauge.

B.6.6 Instrument/Equipment Testing, Inspection, and Maintenance

All field equipment will be visually inspected and tested prior to use. Spare instruments, batteries, etc. will be stored in the field support trailer.

B.6.7 Instrument/Equipment Calibration and Frequency

Pressure gauges that are used to conduct fall-off tests will be calibrated in accordance with manufacturers' recommendations, and current calibration certificates will be provided with test results to the EPA. In lieu of removing the injection tubing to regularly recalibrate the downhole pressure gauges, their accuracy will be demonstrated by comparison to a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Calibration curves, based on annual calibration checks (using the second calibrated pressure gauge) developed for the downhole gauge, can be used for the purpose of the fall-off test. If used, these calibration curves (showing all historic pressure deviations) will accompany the fall-off test data submitted to the EPA.

B.7 Carbon Dioxide Plume and Pressure-Front Tracking

This section describes the experimental design, sampling methods, sample handling and custody, analytical methods, quality controls, and instrumentation/equipment specific to CO_2 plume and pressure-front tracking activities. Refer to Sections B.12 through B.14 for general descriptions of material inspection/acceptance methods, non-direct measurements (e.g., existing data), and data management.

B.7.1 Sampling Process Design (Experimental Design)

The Alliance will conduct direct and indirect CO_2 plume and pressure-front monitoring to meet the requirements of 40 CFR 146.90(g). The planned reservoir-monitoring well network design is based on the Alliance's current conceptual understanding of the site and predictive simulations of injected CO_2 fate and transport. The number, layout, design, and sampling regimen of the monitoring wells are based upon site-specific characterization data collected from the stratigraphic well, as well as structural dip, expected ambient flow conditions, and potential for heterogeneities or horizontal/vertical anisotropy within the injection zone and model predictions.

The planned monitoring well network for direct plume and pressure-front monitoring consists of two sets of monitoring wells: single-level in-reservoir (SLR) wells and reservoir access tube (RAT) wells (Figure A.3). Two SLR wells will monitor the injection zone beyond the east and west ends of the horizontal CO_2-injection laterals. One of the SLR wells (SLR2; reconfigured stratigraphic well) will be located to the east-northeast of the injection well pad between the projected 10- to 20-year plume boundaries and the other well (SLR1) will be located to the west of the injection well pad within the projected 2-year plume boundary.

Three RAT wells will be installed within the boundaries of the projected 1- to 3-year CO_2 plume. The RAT well locations were selected to provide information about CO_2 arrival at different distances from the injection wells and at multiple lobes of the CO_2 plume. The RATs will be completed with nonperforated, cemented casings and will be used to monitor CO_2 arrival and quantify saturation levels via downhole PNC (geophysical logging across the reservoir and confining zone.

The reservoir-monitoring network will address transport uncertainties by using an "adaptive" or "observational" approach to monitoring (i.e., the monitoring approach will be adjusted as needed based on observed monitoring and updated modeling results). It is recognized that additional contingency wells may be required in out-years to monitor evolution of the CO_2 plume and fully account for the injected CO_2 mass.

Direct Pressure Monitoring

Continuous monitoring of P/T/SpC will be conducted in the SLR monitoring wells to track the pressure front and inform the monitoring and modeling programs.

Instruments will be installed at each SLR monitoring well to facilitate near-continuous monitoring of indicator parameters of CO_2 arrival and/or changes in brine composition. (Tables A.3 and A.8 list the parameters and instrumentation that will be used in the SLR wells.)

Fluid P/T/SpC are the most important parameters to be measured in real time within the monitoring interval of each well. These are the primary parameters that will indicate the presence of CO_2 or CO_2-induced brine migration into the monitored interval. In addition, pH and Eh (oxidation potential) measurements may be useful for detecting dissolved CO_2 and assessing water chemistry changes in the monitored interval. An initial evaluation of probes that are capable of measuring the desired parameters will assess the measurement accuracy, resolution, and stability for each parameter prior to selection and procurement of sensors for the full monitoring well network.

Pressure is expected to increase at the SLR monitoring wells installed within the injection reservoir soon after the start of injection and before the arrival of CO_2 because of the pressurization of the reservoir.

Pressure will also be monitored to ensure that pressure within the injection interval does not exceed design specifications and to determine whether any observed pressure changes above the primary confining zone could be associated with a leakage response. Changes in other parameters are expected to occur later in time than the initial increase of pressure.

Direct Geochemical Plume Monitoring

Fluid samples will be collected from the SLR monitoring wells before, during, and after CO_2 injection. The samples will be analyzed for chemical parameter changes that are indicators of the presence of CO_2 and/or reactions caused by the presence of CO_2. Baseline monitoring will involve collection and analysis of a minimum of three rounds of aqueous samples from each well completed in the targeted injection zone prior to initiation of CO_2 injection. A comprehensive suite of geochemical and isotopic analyses will be performed on fluid samples collected from the reservoir. These analytical results will be used to characterize baseline geochemistry and provide a metric for comparison during operational phases. Aqueous sampling will not be used to assess CO_2 saturation levels. Once $scCO_2$ arrives, these wells can no longer provide representative fluid samples because of the two-phase fluid characteristics and buoyancy of $scCO_2$.

B.7.2 Sampling Methods

Direct Pressure Monitoring

A single probe incorporating electronic sensors that will monitor indicator parameters (P/T/SpC) will be placed at reservoir depth in each monitored well. Each parameter will be measured at a 10-minute sampling interval and will be transmitted to the surface via the wireline cable. Additional sensors may be installed at the wellhead for measuring parameters such as wellhead pressure, barometric pressure, and ambient surface temperature. A data-acquisition system will be located at the surface to store the data from all sensors at the well site and will periodically transmit the stored data to the MVA data center in the control building.

Direct Geochemical Plume Monitoring

Fluid samples will be collected at monitored formation depths and maintained at formation pressures within a closed pressurized sample container to prevent the escape of dissolved gases. Access to the monitored interval at the SLR wells will be through an inner 2-7/8-in. tubing string extending to the monitoring interval and packed-off just above the screen.

Fluid samples will be collected within the open interval of each monitoring well using a flow-through sampler with a 950-cc (or larger) sample chamber. The samples will be maintained at formation pressure within a closed sample container to prevent the escape of dissolved gases. Prior to sampling, the P/T/SpC probe will be monitored as the well is purged (up to three times the volume of the well-screen section will be discharged from the well before collecting the sample). The probe will then be removed from the well and the sampler will be run into the borehole on the same wireline cable to collect the pressurized fluid sample. Additional purging may be conducted just prior to collection of the pressurized fluid sample if mixing between the fluid column and sampling interval during insertion of the sampler is a concern.

B.7.3 Sample Handling and Custody

Direct Pressure Monitoring

P/T/SpC measurements will be recorded by a data logger at each well site and also transmitted to data-acquisition systems located in the MVA data center.

Electronic data and field records will be transferred to laptop and/or desktop computers and/or backed-up on secured servers at least quarterly, as well as scanned copies of all pertinent hardcopy field records/notes.

Direct Geochemical Plume Monitoring

After removing the aqueous sampler from the well, the closed and pressurized sample container(s) will be transported to the MVA laboratory space in the control building for processing using standard chain-of-custody procedures.

B.7.4 Analytical Methods

Table A.7 summarizes the analytical methods for groundwater quality monitoring in the SLR wells. Where possible, methods are based on standard protocols from the EPA or Standard Methods for the Examination of Water and Wastewater (American Public Health Association, American Water Works Association, Water Environment Federation, 19th ed. or later, Washington, D.C.). Laboratories shall be required to have standard operating procedures for the analytical methods performed.

B.7.5 Quality Control

Direct P/T/SpC and other continuous monitoring equipment will be calibrated according to manufacturers' recommendations. If trends or other unexplained variability in the data are observed that might indicate a suspect response, instruments will be evaluated and, if required, recalibrated or replaced.

The QC practices for groundwater monitoring of the geochemical plume are the same as those specified for groundwater monitoring above the confining zone (Section B.4.5). Field QC samples include field blanks and field duplicates; a minimum of one of each type of sample shall be collected at each sampling event. Laboratory QC samples include method blanks, laboratory duplicates, matrix spikes, matrix spike duplicates, and laboratory control samples. The frequencies of these samples will be determined by the laboratory contract and standard method protocols. Typically, method blanks and laboratory control samples are analyzed with every analytical batch, while the remaining QC samples are run at a frequency of 1 per 10 samples. Table A.8 lists additional, method-specific requirements.

B.7.6 Instrument/Equipment Testing, Inspection, and Maintenance

High-quality (high-accuracy, high-resolution) gauges with low drift characteristics will be used.

- Gauge components (gauge, cable head, cable) will be manufactured of materials designed to provide a long life expectancy for the anticipated downhole conditions.
- Upon acquisition, a calibration certificate will be obtained for every pressure gauge. The calibration certificate will provide the manufacturer's specifications for range, accuracy (% full scale), resolution (% full scale), and drift (< psi per year), and calibration results for each

parameter. The calibration certificate will also provide the date that the gauge was calibrated, the methods and standards used, and the date calibration will expire.

- Gauges will be installed above any packers so they can be removed if necessary for recalibration by removing the tubing string. Redundant gauges may be run on the same cable to provide confirmation of downhole pressure and temperature.
- Upon installation, all gauges will be tested to verify that they are functioning (reading/transmitting) correctly.

For groundwater sampling, field equipment will be maintained, factory serviced, and factory calibrated according to the manufacturers' recommendations. Spare parts that may be needed during sampling will be included in supplies on-hand during field sampling.

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory per method-specific protocols and the laboratory's QA program. The laboratory's QA program will be reviewed by the Alliance prior to submission of samples for analysis.

B.7.7 Instrument/Equipment Calibration and Frequency

Pressure gauges that are used for direct pressure monitoring will be calibrated according to manufacturers' recommendations, and current calibration certificates will be kept on file with the monitoring data.

B.8 Pulsed-Neutron Capture Logging

PNC wireline logs will be used to quantify CO_2 saturation relative to depth in each of three monitoring RAT wells. These indirect measurements of CO_2 saturation will be used to detect and quantify CO_2 levels over the entire logged interval. The PNC logging data will be used for calibration of reservoir models and to identify any unforeseen occurrences of CO_2 leakage across the primary confining zone. Numerical modeling will be used to predict the CO_2 plume growth and migration over time by integrating the calculated CO_2 saturations in the three RAT wells with the geologic model and other monitoring data.

B.8.1 Sampling Process Design (Experimental Design)

PNC logs operate by generating a pulse of high-energy neutrons and subsequently measuring the neutron decay over time and across a wide energy spectrum. PNC logs can measure specific energy bins or a composite of energies, the latter of which is termed the thermal capture cross-section (sigma) operational mode. In sigma mode, all elements that capture and slow neutrons contribute to the measurement rather than just the characteristic energy levels associated with specific elements. Both measurement modes are useful for determining CO_2 saturation from PNC logs and will be simultaneously acquired.

PNC logging has been successfully implemented at a number carbon sequestration sites and while the PNC method has been shown to work quite well, problems associated with CO_2 flooding the casing and perforation zones have been identified. PNC logs are only sensitive to a localized region surrounding the borehole (15–30 cm) and are therefore susceptible to interference from features very near the borehole, such as changing borehole fluids, poor cement, or invaded drilling fluids. The monitoring RAT wells are designed with small-diameter, nonperforated casings to minimize near-borehole interference effects. Borehole effects will also be accounted for by analyzing response times from multiple detectors in the tool. Porosities within the reservoir at the FutureGen 2.0 storage site are moderate and the PNC logs are expected to adequately quantify CO_2 saturation along the RAT boreholes in order to calibrate reservoir models as well as identify possible leakage through the sealing layers.

B.8.2 Sampling Methods

Quarterly PNC logging will be conducted in RAT wells 1, 2, and 3. The locations of the RAT wells was chosen to sample various stages of the CO_2 plume migration, with the emphasis on the areas with large expected changes in the first five (5) years. Downhole repeatability of the tool performance will be verified by conducting a "repeat section" of the logging run. Repeatability is used to validate the measurement acquired during the main logging pass, as well as to identify anomalies that may arise during the survey for re-logging. Measurement depth is of critical importance in all borehole logs. Depth will be measured with respect to a fixed reference throughout the lifetime of the project. Verification of proper tool operation will be performed prior to each logging event following the manufacturer's recommended procedure. Elastic cable stretch and slippage will be automatically compensated. Repeatability of logging depths will also be checked by repeat gamma-ray depth location of key strata or drill collar locators and can be used to correct depth measurements after logging is complete.

B.8.3 Sample Handling and Custody

No specialized sample-/data-handling procedures are required. PNC tool readings will be recorded on a computer located in the wireline logging truck. All electronic data and field records will be transferred to laptop and/or desktop computers and backed-up, on secure servers at the conclusion of each logging event, as will scanned copies of all pertinent hardcopy field records/notes.

B.8.4 Analytical Methods

PNC log data will be processed following industry best practices and coordinated with the borehole-logging operator to optimize data-collection parameters. Modeling can be done to simulate near-borehole interferences and remove their effects from the signal. Modeling is a recommended procedure and requires knowledge of the target formations and fluids that must be obtained from cores and additional logging data. Each logging result will be compared for each RAT well to the baseline or previous survey, as applicable, to determine changes in saturation.

B.8.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and that calculations of CO_2 saturations are reproducible. Third-party PNC logging and processing for a subset of boreholes and logging events can be used as part of the validation procedure. Failure of tool performance in the field or unreproducible "repeat sections" will result in non-acceptance of the data and may trigger a return of the PNC tool to the manufacturer for recalibration or replacement. Off-normal CO_2 saturation calculations will trigger additional evaluation and possible new logging runs.

B.8.6 Instrument/Equipment Testing, Inspection, and Maintenance

Examples of industry-published guidelines for calibration and field operation of the PNC wireline log hardware and data-collection software are provided in Appendix B.

B.8.7 Instrument/Equipment Calibration and Frequency

To ensure data-acquisition quality, the logging tool will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. All tools and field operation software will be provided by the manufacturer with an auditable verification record to ensure traceability. In addition to the initial manufacturer calibration, PNC tool recalibration will be performed monthly and both prior to and after each logging event using an onsite calibration vessel following the manufacturer's guidelines. Examples of industry-published guidelines for calibration and field operation of the PNC wireline log hardware and data-collection software are provided in Appendix B.

B.9 Integrated Deformation Monitoring

B.9.1 Sampling Process Design (Experimental Design)

The deformation monitoring will include orbital DInSAR data (X-band TerraSAR-X, C-band Radarsat-2, X-Band Cosmo-Skymed, or any other satellite data that will be available at the time of data collection) and a field survey validation using permanent Global Positioning System (GPS) stations, permanent tiltmeters, and annual Differential Global Positioning System (DGPS) surveys. This approach will be used for the baseline before the injection and during the injection phase with modifications based on the experience gained during the two-year baseline-monitoring period.

Differential Synthetic Aperture Radar (SAR) Interferometry (DInSAR) is a method of generating surface displacement maps from two images acquired by radar aboard a satellite at distinct times. Specific and complex processing is applied to obtain time series of displacements of the ground surface. All DInSAR deformation measurements are corrupted by spatiotemporal variations in the atmosphere and surface scattering properties. Advanced DInSAR time-series analyses exploit a subset of pixels in a stack of many SAR images to reduce atmospheric artifacts and decorrelation effects. These pixels exhibit high phase stability through time. The output products from these advanced techniques include a pixel average velocity accurate to 1−2 mm/yr and a pixel time series showing cumulative deformation accurate to 5−10 mm for each of the SAR acquisition times. It should be noted that accuracy improves with time as the time series becomes larger.

B.9.2 Sampling Methods

Orbital SAR data will be systematically acquired and processed over the storage site with at least one scene per month to obtain an advanced DInSAR time series. These data will be obtained from the available orbital instruments available at the time of collection. It should be noted that the existing TerraSAR-X, Radarsat-2 and Cosmo-Skymed systems provide frequent systematic revisits of 11, 24, and 4 days, respectively.

Widespread overall temporal decorrelation is anticipated except in developed areas (e.g., roads, infrastructure at the site, and the neighboring towns) and for the six corner cube reflectors that will be deployed on site. These isolated coherent pixels will be exploited to measure deformation over time, and different algorithms (e.g., persistent scatters, small baseline subsets, etc.) will be used to determine the best approach for the site.

Data from five permanent tiltmeters and GPS stations will be collected continuously. In addition, annual geodetic surveys will be conducted using the Real-Time Kinematic (RTK) technique where a single reference station gives the real-time corrections, providing centimeter-level or better accuracy.

Deformations will be measured at permanent locations chosen to measure the extent of the predicted deformation in the AoR and also used by the gravity surveys (see Section B.10).

B.9.3 Sample Handling and Custody

DInSAR data will be acquired, processed, and archived by the vendor. Displacement maps and deformation time series will be archived on digital media by the Alliance.

Permanent GPS and tiltmeter data will be collected in real time by the Alliance and stored on digital media on site. Differential GPS (DGPS) survey data will be archived on digital media by the Alliance.

B.9.4 Analytical Methods

To establish a more comprehensive geophysical and geomechanical understanding of the FutureGen 2.0 site, DInSAR and field deformation measurements will be integrated and processed with other monitoring data collected at the site: microseismicity, gravity, pressure, and temperature. This unique and complete geophysical data set will then be inverted to constrain the CO_2 plume shape, extension, and migration in the subsurface.

B.9.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and results reproducible.

B.9.6 Instrument/Equipment Testing, Inspection, and Maintenance

Testing of the whole DInSAR chain acquisition is routinely conducted by the space agencies.

Permanent tiltmeters and GPS instruments installed onsite will be checked annually.

The Trimble R8 receivers used for the annual DGPS surveys will be checked annually.

B.9.7 Instrument/Equipment Calibration and Frequency

Calibration of DInSAR chain acquisition is routinely conducted by the space agencies and the results will be compared to field measurements.

Tiltmeters and GPS instruments installed onsite will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. The Trimble R8 receivers used for the annual DGPS surveys will also be calibrated and verified by the manufacturer.

All equipment and software will be provided by the manufacturer with an auditable verification record to ensure traceability.

B.10 Time-Lapse Gravity Monitoring

B.10.1 Sampling Process Design (Experimental Design)

Four-dimensional (4D or time-lapse) microgravimetry—the temporal change of gravity at the microGal scale (1 μGal = 10^{-6} m/s^2)—is a cost-effective and relatively rapid means of observing changes in density distribution in the subsurface, particularly those caused by the migration of fluids.

Time-lapse gravity monitoring is accomplished using repetitive annual surveys at a series of points located at the ground surface (permanent stations). Changes in gravity anomaly with time are determined and then interpreted in terms of changes in subsurface densities. These changes could be linked for example to replacement of water by CO_2. providing an indirect method of tracing the displacement of the CO_2 plume at depth. Due to the non-uniqueness of the solution, this monitoring method could rarely be used alone and gives the best results when used with other methods (deformation or seismic).

B.10.2 Sampling Methods

Permanent station locations were established in November 2011 for the purpose of future reoccupation surveys (Figure A.4). These stations are located on the roadways inside the survey area, the reference being the KC0540 station (Central Plaza Park monument, Jacksonville, Illinois). The emplacement of each permanent station on the roadway is designated by a marker. Markers are approximately half-inch-diameter nails with a three-quarter-inch heads to provide good visibility from the surface.

Because all the gravity measurements are relative, a tie to a gravity station outside the surveyed area must be made. This reference is station NGS# KC0540, a monument located in Central Plaza Park in Jacksonville, Illinois, which was tied to the absolute gravity station NGS# KC0319 located in Hannibal, Missouri.

To compensate for the instrumental drift, measurements are taken on a 2-hour cycle at a local reference station at the center of the surveyed area (station 137) and at an offsite location (station KC0540) twice a day.

B.10.3 Sample Handling and Custody

Data will be archived on a digital media by the Alliance.

B.10.4 Analytical Methods

Data reduction will be performed using the standardized methods to obtain Free Air and Bouguer anomalies. These anomalies will then be interpreted in terms of subsurface density anomalies by gravity direct or inverse modeling using the commercial software ENcom Model Vision™ 12.0.

B.10.5 Quality Control

Repeat measurements at the same field point is the only way to evaluate their quality. At least three measurements for each point will be recorded.

B.10.6 Instrument/Equipment Testing, Inspection, and Maintenance

The gravity meter used will be a LaCoste & Romberg Model D belonging to Pacific Northwest National Laboratory. It is a steel mechanism, "zero length" spring meter with a worldwide range that is less prone to drift than quartz meters. The instrument is thermostatically controlled to approximately 50°C during the duration of the surveys. A full maintenance and inspection of the instrument needs to be completed every 10 years at the LaCoste and Romberg factory; the next one is scheduled in 2021.

B.10.7 Instrument/Equipment Calibration and Frequency

No calibration of the instrument is required.

B.11 Microseismic Monitoring

Elevated pressures in the reservoir due to injection of CO_2 have the potential to induce seismic events. The objective of the microseismic monitoring network is to accurately determine the locations, magnitudes, and focal mechanisms of seismic events.

B.11.1 Sampling Process Design (Experimental Design)

A microseismic monitoring system must be able to detect a seismic event at a number of monitoring stations and use the signals to accurately determine the event location and understand the brittle failure mechanisms responsible for the event. The monitoring network consists of an array of seismic sensors placed either at the near-surface or within deeper monitoring boreholes. The accuracy of the network is dependent on both the geometry of the sensor array and the signal-to-noise ratio (SNR) at each of the sensor locations. The number and spatial distribution of sensors in a microseismic monitoring network must be designed to minimize the errors in estimating event location and origin times. The subsurface seismic velocity model also has a large influence on the predicted data and must be estimated as accurately as possible using borehole logs and data from vertical seismic profiling. Sensors need to have high sensitivity, flat response over the intended frequency range, a low noise floor, and stable performance over time.

External noise sources often occur at the surface or from nearby subsurface activities such as drilling. Surface noise attenuates with distance below the surface and it is therefore advantageous to emplace surface sensors within shallow boreholes in order to reduce external noise to an acceptable level. Surface or shallow borehole sensors provide multiple sensing azimuths and offsets, but surface sensors typically suffer from lower SNRs. Shallow borehole installations, however, can achieve a noise floor approaching that of sensors located in deep boreholes. Deep borehole monitoring can provide a higher SNR if the microseismic event occurs close enough to the array, but precise event location can be difficult due to geometric constraints on the array.

B.11.2 Sampling Methods

The microseismic network will consist of an array of near-surface shallow borehole sensors in addition two deep borehole sensor arrays installed within the ACZ wells. The network incorporates the benefits of both array types to improve the overall performance of the system and is expected to perform well for monitoring seismic events that occur in the AoR.

Commonly used sensors for seismic applications include moving coil geophones that that have frequency bandwidths from 5−400 Hz. These devices are often built with signal conditioning and digitizer circuitry located on the sensor to improve the electrical performance; however, because of the complexity of their assembly, their long-term deployment in a deep borehole environment results in reduced lifetimes. Permanent emplacement of standard moving coil geophones within a deep borehole would not be expected to last the lifetime of the FutureGen 2.0 project. Geophones will be placed in the shallow borehole stations and are expected to perform well in that environment, particularly for higher-frequency signals.

Surface sensors also require higher sensitivities and lower noise floors than sensors placed in deep boreholes because the distance from the event to the surface is often much greater. High-quality broadband seismometers exhibit much higher sensitivity and extremely low noise floors compared to standard geophones. These seismometers have long working lifetimes and an excellent frequency response from 1 mHz to 200Hz. Seismometers will also be installed in each shallow borehole along with a borehole geophone. To minimize signal attenuation and site noise, the boreholes will be drilled to at least the uppermost bedrock unit, and the casing will be sealed and pumped dry prior to sensor emplacement.

Fiber-optic-based seismic sensors use backscattered light from a laser pulse that has been introduced into an optical fiber to measure the movement of a sensing element. The fiber can be coupled to a device to mechanically amplify the strain on the fiber and produce a sensor with performance as good as, or better than, standard geophones. A key feature of these sensors is that because they have no electronics located within a borehole they are extremely robust; their lifetimes and performance stability are designed to last several decades. Due to their superior sensitivity and expected longevity, an array of fiber-optic accelerometers will be installed within two, deep ACZ wells. Optical cables will be extended from each of the wells back to a central control building that will house the data-acquisition and storage systems.

B.11.3 Sample Handling and Custody

No specialized sample/data handling procedures are required. Microseismic signals from the shallow boreholes will be continuously recorded on a data logger located at each of the stations. All electronic data will be continuously transferred to a data storage and processing system located at a central control building. Digital copies of all pertinent hardcopy field records/notes will also be transferred to the central data server.

B.11.4 Analytical Methods

Microseismic data will be processed and stored following industry best practices.

B.11.5 Quality Control

Verification of vendor processing software and results will ensure that the acquired data are acceptable and that determinations of event locations and focal mechanisms are accurate.

B.11.6 Instrument/Equipment Testing, Inspection, and Maintenance

Regular maintenance and testing of the seismic hardware and data-collection software are critical to ensuring high-quality results. All hardware will be maintained in accordance with manufacturer recommendations. Software updates will be incorporated as they are released by the manufacturer.

B.11.7 Instrument/Equipment Calibration and Frequency

All microseismic equipment will be calibrated for accuracy, checked to be in good working order, and verified by the manufacturer. All equipment and software will be provided by the manufacturer with an auditable verification record to ensure traceability. In addition to the initial manufacturer calibration, seismometers and geophones will be periodically recalibrated following the manufacturers' guidelines. In the event that damage is identified, it will be immediately reported and the equipment removed and replaced.

B.12 Inspection/Acceptance of Supplies and Consumables

Testing and monitoring supplies and consumables that may affect the quality of the results will be procured, inspected, and accepted in accordance with the Alliance representative's administrative procedures (e.g., Pacific Northwest National Laboratory's HDI Workflows and Work Controls).

Critical items and responsible personnel will be identified in task-specific sampling and analysis plans, as appropriate.

B.13 Non-direct Measurements (e.g., existing data)

Existing data, including literature files and historic data from surrounding areas and previous onsite characterization, testing, and monitoring activities, have been used to guide the design of the testing and monitoring program. However, these data are only ancillary to the well testing and monitoring program described here. These existing data will be used primarily for qualitative comparison to newly collected data.

All data will continue to be evaluated for their acceptability to meet project needs, that is, that the results, interpretation, and reports provide reasonable assurance that the project is operating as permitted and is not endangering any USDWs.

B.14 Data Management

All project data, record keeping, and reporting will be conducted to meet the requirements of 40 CFR 146.91(f).

B.14.1 Data Management Process

Project data will be managed in accordance with the Project Data Management Plan (Bryce et al. 2013). Management of all monitoring data is controlled by the subtier Monitoring Data Management Plan (Vermeul et al. 2014; not publicly available). Management of well MIT data is controlled by the subtier Well Construction Data Management Plan (Lanigan et al. 2013; not publicly available). All data will be managed by Alliance representatives throughout the duration of the project plus at least 10 years.

B.14.2 Recordkeeping Procedures

Project records will be managed according to project record management requirements and Alliance representatives' internal records management procedures.

B.14.3 Data Handling Equipment and Procedures

All data will be managed in a centralized electronic data management system. The underlying electronic servers will be routinely maintained, updated, and backed-up to ensure the long-term preservation of the data and records.

The centralized data-management system acts as a “data hub” to support collaborative analyses, enabling a diverse spectrum of experts—including geologists, hydrologists, numerical modelers, model developers, and others—to share data, tools, expertise, and computational models. This data-management system also acts as a “turn-key” data-management system that can be transferred to any future Alliance representatives or storage site operators.

B.14.4 Configuration Management and Change Control

The project’s Configuration Management Plan (Alliance 2013b) identifies configuration-management requirements and establishes the methodology for configuration identification and control of releases and changes to configuration items. Each Alliance contractor is required to use configuration management to establish document control and to implement, account for, and record changes to various components of the project under its responsibility. The project’s data configuration process is detailed in the Project Data Management Plan (Bryce et al. 2013) and its subsequent subtier data management plans. This data configuration process controls how changes are made should errors or loss of data be detected during the course of routine data quality and readiness review checks and/or peer reviews.

QC mechanisms, checklists, forms, etc. used to detect errors are highly data-specific, but generally rely on spot-checks against field and laboratory records, as well as and manual calculations to validate electronic manipulation of the data.

C. Assessment and Oversight

C.1 Assessments and Response Actions

As described in Section A.6 and detailed in Table A.2, the Monitoring, Verification, and Accounting (MVA) program for the FutureGen 2.0 CO_2 Pipeline and Storage Project includes numerous categories, methods, and frequencies of monitoring the performance of the CO_2 storage site. FutureGen staff responsible for the associated technical element or discipline will analyze the monitoring data and initiate any needed responses or corrective actions. Management will have ready access to performance data and will receive monitoring and performance reports on a regular basis.

In addition to the activities covered by the MVA program, data quality assessments will be performed to evaluate the state of configuration-controlled technical information in the FutureGen technical data repository to ensure that the appropriate data, analyses, and supporting information are collected, maintained, and protected from damage, deterioration, harm, or loss. These data quality assessments will be performed by a team consisting of the FutureGen 2.0 Data Manager, Project Quality Engineer, Subject Matter Experts, and additional knowledgeable and trained staff as appropriate for the scope and nature of the assessment. Assessments will be scheduled to occur at logical points in the project lifecycle, such as after completion and submission of a major deliverable that incorporates controlled technical information. Assessment results will be reported to management; deficiencies, weaknesses, opportunities for improvement, and noteworthy practices will be identified in the assessment reports. Assessment results will also be communicated to affected parties. Management will assign responsible staff to correct deficiencies and other nonconforming conditions and will ensure that corrective actions are implemented and verified in a timely manner. The Project Quality Engineer and FutureGen Data Manager will conduct follow-up surveillances to verify and document completion of corrective actions and to evaluate effectiveness.

C.2 Reports to Management

Management will be informed of the project status via the regular monitoring and performance reports generated by the MVA program, as well as reports of assessments conducted to verify data quality and surveillances performed to verify completed corrective actions. These reports are described in Section C.1; additional periodic reporting is not anticipated at this time. However, as directed by FutureGen management, targeted assessments by the Data Manager, Project Quality Engineer, or others will be conducted and reported to apprise management of project performance in areas of particular interest or concern.

D. Data Validation and Usability

D.1 Data Review, Verification, and Validation

The FutureGen 2.0 CO_2 Pipeline and Storage Support Project has established a Project Data Management Plan (PDMP) (Bryce et al. 2013) to identify how information and data collected or generated for the project will be stored, organized, and accessed to support all phases of the project. The PDMP describes the institutional responsibilities and requirements for managing all relevant data, including the intended uses and level of quality assurance needed for the data, the types of data to be acquired, and how the data will be managed and made available to prospective users. In addition to the PDMP, the FutureGen 2.0 project has issued discipline-specific subtier Technical Data Management Plans (TDMPs) to tailor data management processes to the needs of specific technical elements (e.g., computational modeling, geophysical, monitoring, site characterization). The PDMP and each TDMP define several categories of data, or Data Levels (consistent among all of the Data Management Plans), with corresponding data management, review, verification, validation, and configuration control requirements. The PDMP and TDMPs establish roles (e.g., Data Manager, Data Steward, Data Reviewer, Subject Matter Expert) and responsibilities for key participants in the data management process; project management assigns appropriate staff members to each role. Project staff who generate, review, verify, validate, or manage data are trained to the requirements of one or more Data Management Plans. Raw data (resulting from the use of a procedure or technology), defined as Level 1, are put under configuration control in the data management system at the time of upload to the system. Data defined at other Data Levels are put under configuration control when the data become reportable or decision-affecting. The procedures used to verify, validate, process, transform, interpret, and report data at each Data Level are documented and captured as part of the data management process.

D.2 Verification and Validation Methods

The Data Management Plans described in Section D.1 require that data packages undergo rigorous peer reviews. These reviews both *validate* the data—confirm that the appropriate types of data were collected using appropriate instruments and methods—and *verify* that the collected data are reasonable, were processed and analyzed correctly, and are free of errors. Data that have not undergone the peer-review process and are not yet under configuration control can be provided as preliminary information when accompanied by a disclaimer that clearly states that data are 1) preliminary and have not been reviewed in accordance with FutureGen's quality assurance practices, 2) considered "For Information Only", and 3) not to be used for reporting purposes nor as the basis for project management decisions. Once data are placed under configuration control, any changes must be approved using robust configuration-management processes described in the Data Management Plans. The peer-review and configuration-management processes include methods for tracking chain-of-custody for data, ensuring that custody is managed and control is maintained throughout the life of the project.

If issues are identified during a peer review, they are addressed and corrected by the data owner and peer reviewer (involving others, as necessary) as part of the peer-review process. These unreviewed data will not have been used in any formal work product nor as the basis for project management decisions, so the impacts of data errors will be minimal. If an error is identified in data under configuration control, in addition to correcting the error, affected work products and management decisions will be identified, affected users will be notified, and corrective actions will be coordinated to ensure that the extent of the error's impact is fully addressed.

D.3 Reconciliation with User Requirements

During the course of a long-duration project such as the FutureGen 2.0 CO_2 Pipeline and Storage Project, personnel changes over time can result in loss of "tribal knowledge" about the organization's data, thereby reducing the value of the data. New project staff may have little understanding of the content, intended uses, and pedigree of existing data sets. Metadata can help protect the organization's investment in data by providing context and pedigree, as well as describing interrelationships between various data sets. The Data Management Plans described in Section D.1 provide for Subject Matter Experts (SMEs) to establish and document metadata requirements for the data sets created by the FutureGen 2.0 project. Complete metadata will support data interpretation, provide confidence in the data, and encourage appropriate use of the data. To establish meaningful metadata requirements, SMEs must understand how data users and decision-makers will use the data. By adhering to metadata requirements when loading data into the project data repository, project staff ensure that user requirements addressed by the metadata are satisfied.

Data reviews, identification and resolution of data issues, and limitations on data use are discussed in Section D.2.

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Appendix A

Quality Assurance for Logging and Vendor Processing of Pulsed-Neutron Capture (PNC) Logs

This appendix contains wireline logging, indirect geophysical methods, and some non-routine sampling data processing and analysis industry standards.

Example of Vendor QA for Pulsed-Neutron Capture Logging: Schlumberger registered brand name RST

Reference: Schlumberger Wireline Log Quality Reference Manual accessed January 2014 http://www.slb.com/resources/publications/books/lqcrm.aspx.

The sigma mode of PNC logs will also be used both for monitoring carbon dioxide transport and for mechanical integrity tests.

Schlumberger

RST and RSTPro

Overview

The dual-detector spectrometry system of the through-tubing RST* and RSTPro* reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst* thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

Calibration

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

The sigma, WFL* water flow log, and PVL* phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

Specifications

Measurement Specifications

	RST and RSTPro Tools
Output	Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing
Logging speed†	Inelastic mode: 100 ft/h [30 m/h] (formation dependent) Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent) RST sigma mode: 1,800 ft/h [549 m/h] RSTPro sigma mode: 2,800 ft/h [850 m/h]
Range of measurement	Porosity: 0 to 60 V/V
Vertical resolution	15 in [38.10 cm]
Accuracy	Based on hydrogen index of formation
Depth of investigation‡	Sigma mode: 10 to 16 in [20.5 to 40.6 cm] Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm]
Mud type or weight limitations	None
Combinability	RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS)

† See Tool Planner application for advice on logging speed.
‡ Depth of investigation is formation and environment dependent.

Mechanical Specifications

	RST-A and RST-C	RST-B and RST-D
Temperature rating	302 degF [150 degC] With flask: 400 degF [204 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa] With flask: 20,000 psi [138 MPa]	15,000 psi [103 MPa]
Borehole size—min.	1 13/16 in [4.60 cm] With flask: 2¼ in [5.72 cm]	2⅞ in [7.30 cm]
Borehole size—max.	9⅝ in [24.45 cm] With flask: 9⅝ in [24.45 cm]	9⅝ in [24.45 cm]
Outside diameter	1.71 in [4.34 cm] With flask: 2.875 in [7.30 cm]	2.51 in [6.37 cm]
Length	23.0 ft [7.01 m] With flask: 33.6 ft [10.25 m]	22.2 ft [6.76 m]
Weight	101 lbm [46 kg] With flask: 243 lbm [110 kg]	208 lbm [94 kg]
Tension	10,000 lbf [44,480 N] With flask: 25,000 lbf [111,250 N]	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N] With flask: 1,800 lbf [8,010 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The RST and RSTPro standard curves are listed in Table 1.

Table 1. RST and RSTPro Standard Curves

Output Mnemonic	Output Name
BADL_DIAG	Bad level diagnostic
CCRA	RST near/far instantaneous count rate
COR	Carbon/oxygen ratio
CRRA	Near/far count rate ratio
CRRR	Count rate regulation ratio
DSIG	RST sigma difference
FBAC	Multichannel Scaler (MCS) far background
FBEF	Far beam effective current
FCOR	Far carbon/oxygen ratio
FEGF	Far capture gain correction factor
FEOF	Far capture offset correction factor
FERD	Far capture resolution degradation factor (RDF)
FIGF	Far inelastic gain correction
FIOF	Far inelastic offset correction factor
FIRD	Far inelastic RDF
IC	Inelastic capture
IRAT_FIL	RST near/far inelastic ratio
NBEF	Near beam effective current
NCOR	Near carbon/oxygen ratio
NEGF	Near capture gain correction factor
NEOF	Near capture offset correction factor
NERD	Near capture RDF
NIGF	Near inelastic gain correction
NIOF	Near inelastic offset correction factor
NIRD	Near inelastic RDF
RSCF_RST	RST selected far count rate
RSCN_RST	RST selected near count rate
SBNA	Sigma borehole near apparent
SFFA_FIL	Sigma formation far apparent
SFNA_FIL	Sigma formation near apparent
SIGM	Formation sigma
SIGM_SIG	Formation sigma uncertainty
TRAT_FIL	RST near/far capture ratio

Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

Formats

The format in Fig. 1 is used mainly as a hardware quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Track 1
  - CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.
- Track 6
  - The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.
- Track 7
  - The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between –2 and 2.
- Track 8
  - Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

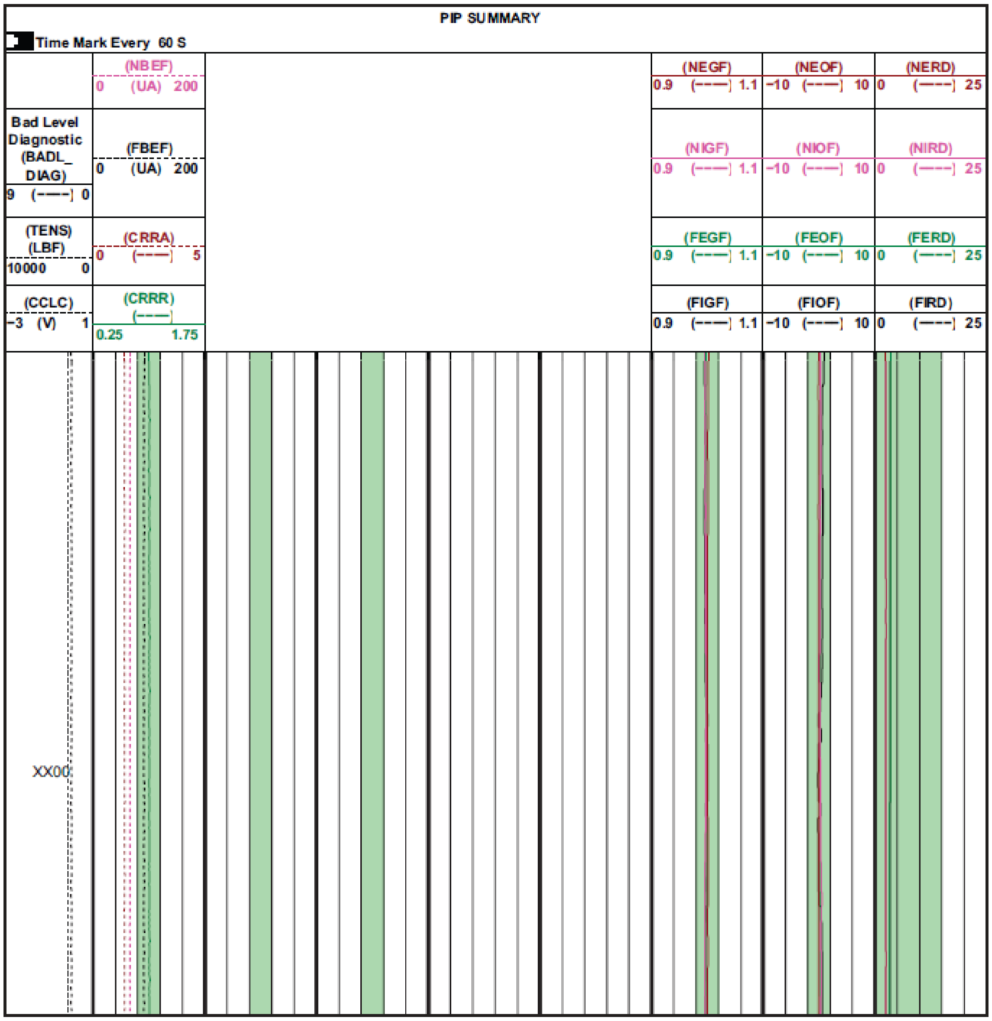


Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Tracks 2 and 3
  - The IRAT_FIL inelastic ratio increases in gas and decreases with porosity.
  - DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

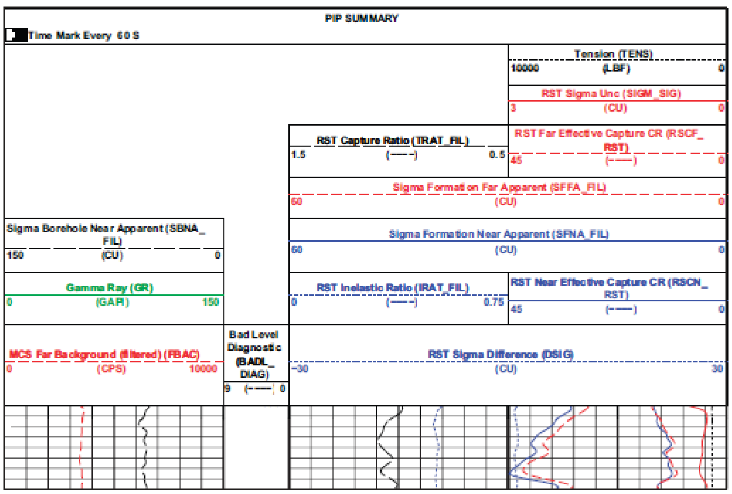


Figure 2. RST and RSTPro sigma standard format.

Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

Table 2. Contributing Materials to RST and RSTPro Yields

Element	Contributing Material
C and O	Matrix, borehole fluid, formation fluid
Si	Sandstone matrix, shale, cement behind casing
Ca	Carbonates, cement
Fe	Casing, tool housing

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

Table 3. RST and RSTPro Capture and Sigma Modes

Medium	Sigma, cu
Oil	18 to 22
Gas	0 to 12
Water, fresh	20 to 22
Water, saline	22 to 120
Matrix	8 to 12
Shale	35 to 55

Quality Control in Processing Pulsed-Neutron Capture Logs

The following is an example from one vendor.

Reference: Albertin, I. et al., 1996, Many Facets of Pulsed Neutron Cased Hole Logging: Schlumberger Oilfield Review Summer 1996. Available at:
http://www.slb.com/~/media/Files/resources/oilfield_review/ors96/sum96/06962841.pdf

Additional information about the PNC tool is available at:
http://www.slb.com/~/media/PremiumContent/evaluation/petrophysics/porosity/rst_client_book.pdf

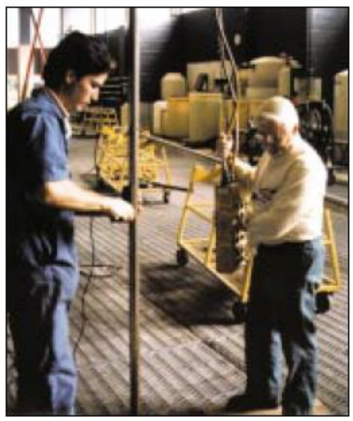
□The Schlumberger Environmental Effects Calibration Facility, Houston, Texas, USA. Over 4000 measurements were made in more than thirty formations of differing lithology and porosity, with different combinations of formation salinities, borehole salinities, and completions to produce the sigma data base.

□EUROPA facility, Aberdeen, Scotland.

Diffusion, borehole and lithology effects must be considered when transforming raw pulsed neutron capture measurements to actual physical quantities. These effects are difficult to account for in direct analytical approaches across the entire range of oilfield conditions. Therefore, an extensive data base of laboratory measurements is used to correct for these effects in real time.[1]

Over several years, the data base was acquired for the RST-A, RST-B and TDT-P logging tools at the Schlumberger Environmental Effects Calibration Facility (EECF), Houston, Texas *(above and right)*. This enables raw tool measurements to be referenced to calibrated values of formation sigma, borehole salinity and formation porosity for a variety of environmental conditions. Each tool was run in over 30 formations of different lithologies and porosities. Formation and borehole fluid salinities were varied and different completions were introduced into the borehole representing different casing sizes and cement thicknesses.

Altogether more than 1000 formation-borehole combinations were measured for each tool. Modeling was used to extend the range of available sandstone formations. To date, the data base contains over 4000 points.



The sigma values of the database formations are calculated classically

$$\Sigma = (1-\Phi)\,\Sigma_{ma} + \Phi\, S_{fl}\Sigma_{fl}$$

where Φ is the formation porosity, Σ_{ma} is matrix sigma, S_{fl} is the formation fluid saturation and Σ_{fl} is fluid sigma.

Porosity of the EECF tank formations was determined by carefully measuring all weights and volumes of the rocks, fluids and tanks used. CNL Compensated Neutron Log measurements verified the porosity values and the homogeneity of the formations.

Matrix sigma values were determined by gross macroscopic cross-section measurements provided by commercial reactor facilities and by processing complete elemental analyses through Schlumberger Nuclear Parameter (SNUPAR) cross-section tables.[2]

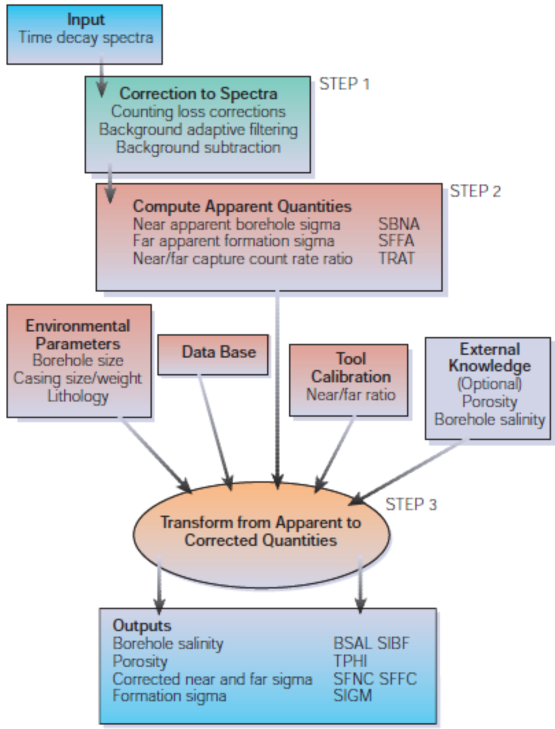
Water salinity was determined by a calibrated titration procedure and then converted into fluid sigma again using SNUPAR cross-section tables.

Algorithm—RST Sigma Processing

A three-step sequence is performed to translate raw log measurements into borehole salinity, porosity, corrected near and far sigma and formation sigma *(next page, top)*.

The first step is to correct the near and far detector time-decay spectra for losses in the detection and counting system, and for back-

1. Plasek RE et al, reference 3, main text.
2. McKeon DC and Scott HD: "SNUPAR—A Nuclear Parameter Code for Nuclear Geophysics Applications," *Nuclear Physics* 2, no. 4 (1988): 215-230.



Simplified RST sigma processing.

ground radiation. Typically the background is averaged to improve statistics.

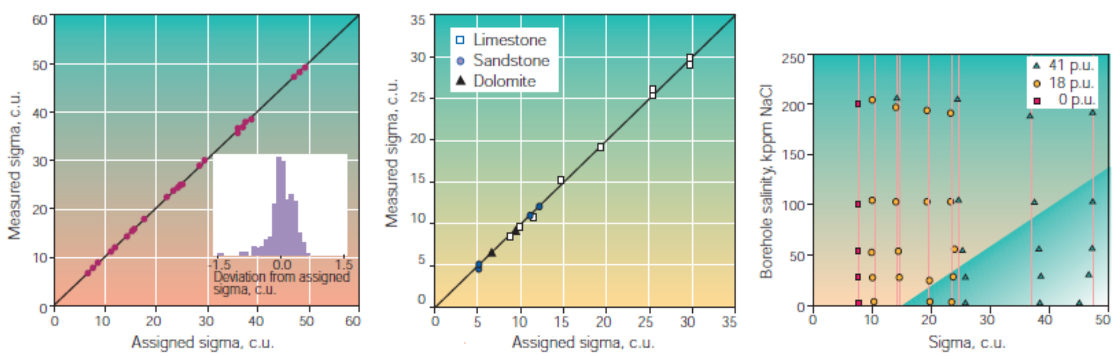
The next step is to generate the apparent quantities from the spectra, such as near and far apparent formation sigmas. These quantities are not environmentally corrected.

The third step is to apply transforms and environmental corrections to the apparent tool quantities to arrive at borehole salinity, porosity and formation sigma. The technique uses dynamic database parameterization that handles both the transformation and environmental corrections.

Accuracy

A series of benchmark measurements has been made to assess the accuracy of the algorithm used with the data base to compute borehole salinity, porosity and formation sigma *(below)*. These benchmark measurements include reprocessing the entire data base as well as logging in industry standard facilities such as the EUROPA sigma facility in Aberdeen, Scotland *(previous page, top right)* and the API porosity test pit, at the University of Houston, in Texas.

Database points were reprocessed with the dynamic parameterization algorithm and the results were compared with the assigned values.



Processing accuracy. Benchmark measurements were made to assess the accuracy of the algorithm in computing formation and borehole sigma, porosity and borehole salinity. Sigma measured with the RST-A tool versus assigned database sigma *(left)* shows average errors are small—0.22 c.u. Sigma measured at the EUROPA facility in Aberdeen *(middle)* again shows excellent agreement with the assigned values. Comparison of RST-A tool sigma *(right)* versus borehole salinity shows that corrected sigma is independent of borehole salinity—vital for time-lapse surveys or log-inject-log operations. In the crossover region *(shaded area)*, formation sigma approaches or even exceeds borehole sigma. Historically, pulsed neutron capture tools erroneously identify the borehole decay as formation sigma and formation decay as borehole sigma in this region. However, the RST dynamic parameterization method solves this long-standing problem, correctly distinguishing between formation and borehole sigma components.

The algorithm does exceptionally well in matching the assigned values. For example, the average errors for formation sigma were 0.22 capture units (c.u.) for the RST-A tool and 0.20 c.u. for the RST-B tool.

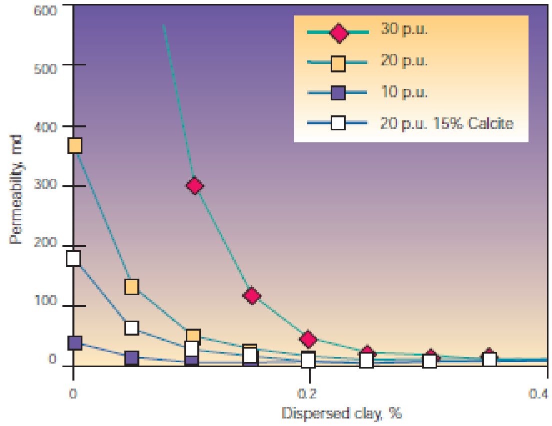
The EUROPA facility is an independent sigma calibration facility partially funded by the UK Atomic Energy Authority with major support from a consortium of 15 oil companies and government agencies. The RST-A tool was run in all the openhole formations and several cased-hole formations. A smaller number of measurements were made with the RST-B tool. Both tools read the true formation sigma over a wide range of lithologies, porosities, formation and borehole fluids, borehole sizes and completions. Even in the difficult crossover region, where formation sigma approaches or exceeds borehole sigma, the errors are small and the tool does not lock on to the wrong sigma component.

Both EUROPA and the University of Houston API pits were used to check porosity readings. The agreement between the two sets of porosities was excellent.

Precision

Key to time-lapse monitoring techniques is repeatability or precision. Time-lapse uses differences in measured quantities to monitor, for example, the progress of waterflooding, the expansion of gas caps and the depletion of reservoirs. The RST tool has been benchmarked to log nearly three times faster than previous generation tools for the same level of precision.[3]

3. For examples of repeatability—precision—see: Plasek et al, reference 3, main text.



Effect of clay and calcite on permeability. A small percentage of clay has a dramatic effect on permeability. Calcite also reduces permeability. So to determine a well's producibility or the cause of any formation damage, it is important to understand the mineralogy.

techniques, which by definition look at differences from one log to another over a period of several months. RST data can be gathered at logging speeds nearly three times those of previous-generation tools for the same precision.[4]

Lithology

Assessing reservoir deliverability and enhancing zone productivity rely on a thorough understanding of the rock matrix. For example, clay content dramatically affects permeability (*above*).[5] Elemental yields derived from RST spectroscopy measurements provide the input to determine clay and other mineral content and hence improve understanding of the rock matrix.

Elemental yields—Neutrons interact with the formation in several ways. Inelastic and capture interactions produce spontaneous release of gamma radiation at energy levels that depend on the elements involved. Measurement of the gamma ray spectra produced by these interactions can then be used to quantify the abundance of elements in the formation. Elemental yields are often used in various combinations or ratios to aid complex lithology interpretation, to determine shale volume or to augment incomplete openhole data (see "Making Full Use of RST Data in China," *page 36*).

At high neutron energies, inelastic interactions dominate. After a few collisions, neutron energy is reduced below the threshold for inelastic events. The probability of an inelastic interaction occurring is also reasonably constant for all major elements.

As neutrons slow to thermal energy levels, capture interactions dominate. Some elements are more likely to capture neutrons than others and so contribute more to the capture gamma ray spectrum.

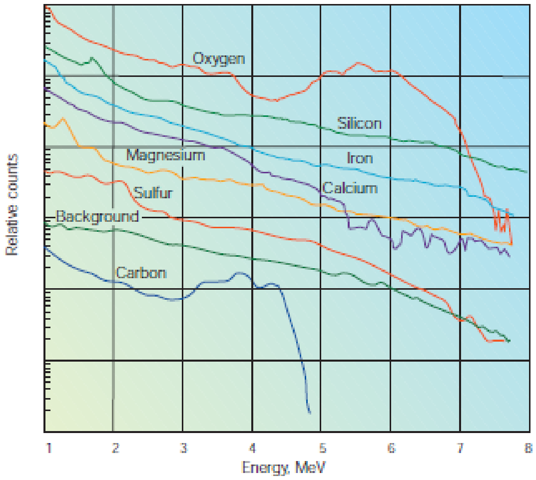
Inelastic and capture gamma ray spectra are recorded by opening counting windows at the appropriate time after a neutron burst from the RST neutron generator. Tool design allows not only for much higher gamma ray count rates than previous generation tools, but also for gain stabilization that enables lower gamma ray energy levels to be recorded for both inelastic and capture measurements. A major advantage of this is the inclusion of the inelastic gamma ray peaks on the spectrum at 1.37 MeV for magnesium and at 1.24 MeV and 1.33 MeV for iron.[6]

A library of standard elemental spectra, measured in the laboratory for each type of tool, is used to determine individual elemental contributions (*next page*).

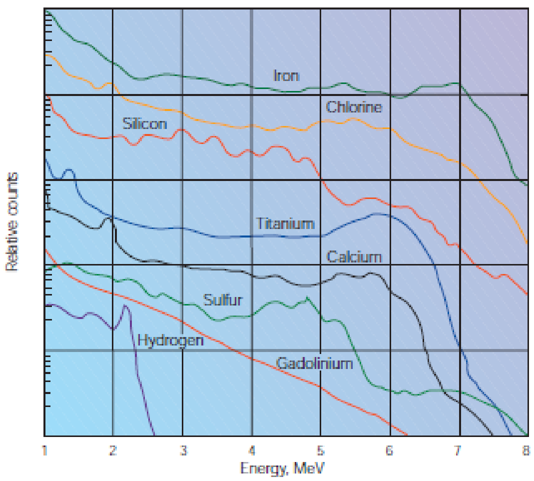
SpectroLith interpretation—SpectroLith processing is a quantitative mineral-based

4. For more details on time-lapse monitoring see sections on precision and auxiliary measurements: Plasek RE et al, reference 3.
5. Herron M: "Estimating the Intrinsic Permeability of Clastic Sediments from Geochemical Data," *Transactions of the SPWLA 28th Annual Logging Symposium*, London, England, June 29-July 2, 1987, paper HH.
6. Roscoe B, Grau J, Cao Minh C and Freeman D: "Non-Conventional Applications of Through-Tubing Carbon-Oxygen Logging Tools," *Transactions of the SPWLA 36th Annual Logging Symposium*, Paris, France, June 26-29, 1995, paper QQ.
7. Herron SL and Herron MM: "Quantitative Lithology: An Application for Open and Cased Hole Spectroscopy," *Transactions of the SPWLA 37th Annual Logging Symposium*, New Orleans, Louisiana, USA, June 16-19, 1996, paper E.
8. See Roscoe B et al, reference 6.

Inelastic Spectra



Capture Spectra



□*Elemental standards for the RST-A tool. Lower gamma ray energy levels are recorded by the RST tools than by previous generation pulsed neutron tools. This allows measurement of elemental contributions from elements such as magnesium and iron. Elemental yields are processed from standard spectra obtained using laboratory measurements. Shown are the standards for inelastic* (top) *and capture* (bottom) *spectra for the $1^{11}/_{16}$-in. RST-A tool.*

lithology interpretation derived from elemental yields. Traditional lithology interpretation relied on measurements of elements such as aluminum and potassium to determine clay content. Aluminum, especially, is difficult to measure and requires a combination of logging tools; the interpretation is also complex.

A recent detailed study of cores showed that a linear relationship exists between aluminum and total clay concentration. Of more importance, it also showed that silicon, calcium and iron can be used to produce an accurate estimation of clay without knowledge of the aluminum concentration.[7] The concentrations of these three elements can be obtained from RST spectroscopy measurements.

In addition, carbonate concentrations—defined as calcite plus dolomite—can be determined from the calcium concentration alone with the remainder of the formation being composed of quartz, feldspar and mica minerals.

SpectroLith interpretation involves three steps:

- production of elemental yields from gamma ray spectra
- transformation of yields into concentration logs
- conversion of concentration logs into fractions of clay, carbonate and framework minerals.

Borehole Fluid

The producing wellbore environment may include a combination of oil, water and gas phases in the borehole as well as flow behind casing. Borehole fluid interpretation is primarily based on fluid velocities and borehole holdup. The RST equipment makes these measurements using several independent methods, with enough redundancy to provide a quality control cross check:

- The WFL Water Flow Log measures water velocity and water flow rate using the principle of oxygen activation. This method detects water flowing inside and outside pipe, and in up and down flow.
- The Phase Velocity Log (PVL) measures oil and water velocities separately by injecting a marker fluid, which mixes and travels with the specified phase. This method may be applied to up and down flow, but only fluids in the pipe are marked and therefore detected.
- Two-phase—oil and water—borehole holdup may be measured in continuous logging mode with the RST-B tool.[8]
- Three-phase—oil, water and gas—borehole holdup is currently an RST-A station measurement based on a combination of C/O and inelastic count rate ratio data.
- Borehole salinity is one of the computations made as part of the sigma and porosity log and may be used to compute a borehole water holdup with either the RST-A or the RST-B tool.

(continued on page 39)

Appendix B

Quality Assurance for Wireline Logs Used in Mechanical Integrity Tests

This appendix contains examples of vendor quality assurance (QA) on the following tools:

- Ultrasonic Cement Evaluation tool: Example shown here is Schlumberger's Isolation Scanner (registered trademark)
- Cement Bond Log tool: Example shown is Schlumberger's Cement Bond Tool (CBT) registered trademark
- Cement Bond Logging QA
- Cased hole temperature log
- Cased hole gamma log
- NOTE: Pulsed-neutron capture (PNC) logs are covered in Appendix A

Reference: Schlumberger Wireline Log Quality Reference Manual accessed January 2014 at http://www.slb.com/resources/publications/books/lqcrm.aspx.

Schlumberger

Isolation Scanner

Overview

Isolation Scanner* cement evaluation service combines the classic pulse-echo technology of the USI* ultrasonic imager with a new ultrasonic technique—flexural wave imaging—to accurately evaluate any type of cement, from traditional slurries and heavy cements to lightweight cements.

In addition to confirming the effectiveness of a cement job for zonal isolation, Isolation Scanner service pinpoints any channels in the cement. The tool's azimuthal and radial coverage readily differentiates low-density solids from liquids to distinguish lightweight cements from contaminated cement and liquids. The service also provides detailed images of casing centralization and identifies corrosion or drilling-induced wear through measurement of the inside diameter and thickness of the casing.

Flexural wave imaging is used by Isolation Scanner service as a significant complement to pulse-echo acoustic impedance measurement. It relies on the pulsed excitation and propagation of a casing flexural mode, which leaks deep-penetrating acoustic bulk waves into the annulus. Attenuation of the first casing arrival, estimated at two receivers, is used to unambiguously determine the state of the material coupled to the casing as solid, liquid, or gas (SLG). Third-interface reflection echoes arising from the annulus/formation interface yield additional characterization of the cased hole environment:

- acoustic velocity (P or S) of the annulus material
- position of the casing within the borehole or a second casing string
- geometrical shape of the wellbore.

Because acoustic impedance and flexural attenuation are independent measurements, their combined analysis provides borehole fluid properties without requiring a separate fluid-property measurement.

Specifications

Measurement Specifications	
Output†	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Logging speed	Standard resolution: 2,700 ft/h [823 m/h] High resolution: 563 ft/h [172 m/h]
Range of measurement	Min. casing thickness: 0.15 in [0.38 cm] Max. casing thickness: 0.79 in [2.01 cm]
Vertical resolution	High resolution: 0.6 in [1.52 cm] High speed: 6 in [15.24 cm]
Accuracy	Acoustic impedance:‡ 0 to 10 Mrayl (range); 0.2 Mrayl (resolution); 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15% (accuracy) Flexural attenuation:§ 0 to 2 dB/cm (range), 0.05 dB/cm (resolution), ±0.01 dB/cm (accuracy)
Depth of investigation	Casing and annulus up to 3 in [7.62 cm]
Mud type or weight limitations††	Conditions simulated before logging

† Investigation of annulus width depends on the presence of third-interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including a Variable Density* log of the annulus waveform and polar movies in AVI format.
‡ Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 Mrayl between the fluid behind the casing and a solid.
§ For 0.3-in [8-mm] casing thickness
†† Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Casing size—min.†	4½ in (min. pass-through restriction: 4 in [10.16 cm])
Casing size—max.†	9⅝ in
Outside diameter	IBCS-A: 3.375 in [8.57 cm] IBCS-B: 4.472 in [11.36] IBCS-C: 6.657 in [16.91 cm]
Length	Without sub: 19.73 ft [6.01 m] IBCS-A sub: 2.01 ft [0.61 m] IBCS-B sub: 1.98 ft [0.60 m] IBCS-C sub: 1.98 ft [0.60 m]
Weight	Without sub: 333 lbm [151 kg] IBCS-A sub: 16.75 lbm [7.59 kg] IBCS-B sub: 20.64 lbm [9.36 kg] IBCS-C sub: 23.66 lbm [10.73 kg]
Sub max. tension	2,250 lbf [10,000 N]
Sub max. compression	12,250 lbf [50,000 N]

† Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine).

Calibration

A master calibration of the near and far flexural transducers to identical sensitivities is required to avoid introducing a bias in the attenuation measurements. Within a pressurized sleeve filled with de-aired water, the tool is calibrated to an accurately machined stainless-steel target mounted relative to it to minimize any eccentering effects.

Tool quality control

Standard curves

Isolation Scanner standard curves are listed in Table 1.

Operation

The Isolation Scanner tool must be run centralized in the borehole. It is highly recommended to run the GPIT* general purpose inclinometry tool in combination for image orientation in a nonvertical well.

The Isolation Scanner tool planner must be run before the job with the following inputs: casing diameter, casing weight, logging fluid, and bit size. This is necessarily to obtain the transducer angle and job set-up parameters.

Table 1. Isolation Scanner Standard Curves

Output Mnemonic	Output Name	Output Mnemonic	Output Name
AGMA	Maximum allowed USI ultrasonic imager electronic programmable gain	THAV	Average thickness
AWAV	Average amplitude	THMN	Minimum thickness
AWBK	Amplitude of echo minus maximum	THMX	Maximum thickness
AWMN	Minimum amplitude	UFAI	USI fluid acoustic impedance (inverted)
AWMX	Maximum amplitude	UFDX	USI far maximum waveform delay
AZEC	Azimuth of eccentering	UFGA	USI far maximum allowed UPGA
CCLU	Casing collar locator from ultrasonic	UFGI	USI far minimum allowed UPGA
CFVL	Computed fluid velocity	UFGN	USI far minimum value of UPGA
CS	Cable speed	UFGX	USI far maximum value of UPGA
CZMD	Computed acoustic impedance of fluid	UFLG	USI processing flag
DFAI	USI discretized fluid acoustic impedance (inverted)	UFSL	USI fluid slowness (inverted)
ECCE	Eccentralization	UFWB	USI far window begin
ERAV	External radius average	UFWE	USI far window end
ERMN	Minimum external radius	UFZQ	USI inverted fluid acoustic impedance quality control
ERMX	Maximum external radius	UNDX	USI near window maximum delay
FSOD	Fluid slowness fitting casing outside diameter (parameter: 0 = off, 2 = use feedback on velocity and acoustic impedance, 5 = use feedback on velocity only, fixed or zoned impedance)	UNGA	USI near maximum allowed UPGA
GNMN	USI minimum value of programmable gain amplitude of waves (UPGA)	UNGI	USI near minimum allowed UPGA
GNMX	USI maximum value of UPGA	UNGN	USI near minimum value of UPGA
HPKF	USI histogram of far peaks	UNGX	USI near maximum value of UPGA
HPKN	USI histogram of near peaks	UNWB	USI near window begin
HRTF	USI histogram of far transit time	UNWE	USI near window end
HRTN	USI histogram of near transit time	UPGA	USI programmable gain amplitude of waves
HRTT	USI histogram of raw transit time	WDMA	USI waveform delay window end
IRAV	Internal radius average	WDMI	USI waveform delay window begin
IRMN	Internal radius minimum	WDMN	USI minimum waveform delay
IRMX	Internal radius maximum	WDMX	USI maximum waveform delay
RSAV	Motor resolution sub average velocity	WPKA	USI peak histogram

Formats

The format in Fig. 1 is used mainly for quality control of Isolation Scanner signals, enabling a quick view of the component USI, near, and far waveforms and arrival peak detection with histograms.

- Track 1
  - CS is the speed at which the cable is moving.
  - RSAV is the motor rotational velocity. It is important for confirming motor rotation during acquisition.
  - CCLU spikes in front of casing collars and is used for correlation.
- Track 2
  - The WPKA histogram is a distribution of the amplitude of the waveform measured by the USI transducer. The image scale and color represent the number of samples and their corresponding peak amplitude in binary bits.
- Track 3
  - GNMX and GNMN represent the minimum and maximum gains, respectively, of the amplifier responsible for image acquisition. The gain should be kept between 0 and 10 dB. If the gain is above 10 dB, the signal from the transducer is too small and the power should be increased by the engineer. If the gain is below 0 dB, the situation is reversed.
- Track 4
  - HRTT should be centered as shown in Fig. 2.
- Track 5
  - WDMN and WDMX should be close to each other. Depending on the sensor-to-casing standoff, the window in which the tool may locate the peak of the echo has to be set.
- Tracks 6 through 13
  - The log quality control concepts listed for Tracks 2 through 5 also apply in these tracks for the near and far transducers.

The purpose of the format in Fig. 3 is to check the quality of the fluid properties measurement (velocity and acoustic impedance) inversion.

- Track 1
  - ECCE decreases the signal-to-noise ratio of the ultrasonic measurements, resulting in the appearance of dark vertical bands on the amplitude map. ECCE should remain low throughout the logging interval represented in this figure.
- Track 2
  - The UFLG flags represent a diagnostic for processing. In normal cases, this track should be free of flags except at collars, which interrupt the model fitting by flagging.
- Track 3
  - The AWBK image track presents the reflectivity of the internal face of the casing. It corresponds to internal casing roughness and is also a good indicator of excessive eccentering. The color scale is in decibels, with black meaning low signal and white meaning high signal.
- Track 4
  - U-USIT_UFSL is the fluid slowness calculated assuming that the averaged outer casing OD is constant.
  - U-USIT_DFSL is the quantized value of UFSL. It compares the slowness between the current and previous depths and selects which will be used for processing.
  - CSVL is the actual fluid velocity input for processing. It may be equal to the discretized fluid slowness (DFSL) or the default fluid velocity (DFVL) depending on the software parameter setting of FSOD.
- Track 5
  - ERAV, IRAV, IRMX, and IRMN provide a view of the pipe.
- Track 6
  - U-USIT_UFAI is inverted from the flexural attenuation (UFAK) and the raw acoustic impedance (AIBK).
  - U-USIT_DFAI is a quantized value from the inverted fluid acoustic impedance.
  - CZMD is the acoustic impedance used in the processing. Its value depends on the software parameter setting of FSOD.
- Track 6
  - U-USIT_UFZQ is proportional to the number of points below the critical impedance that are considered liquid. Below a low threshold of 20%, it is flagged with red, and above a high threshold of 50%, it is flagged as green.

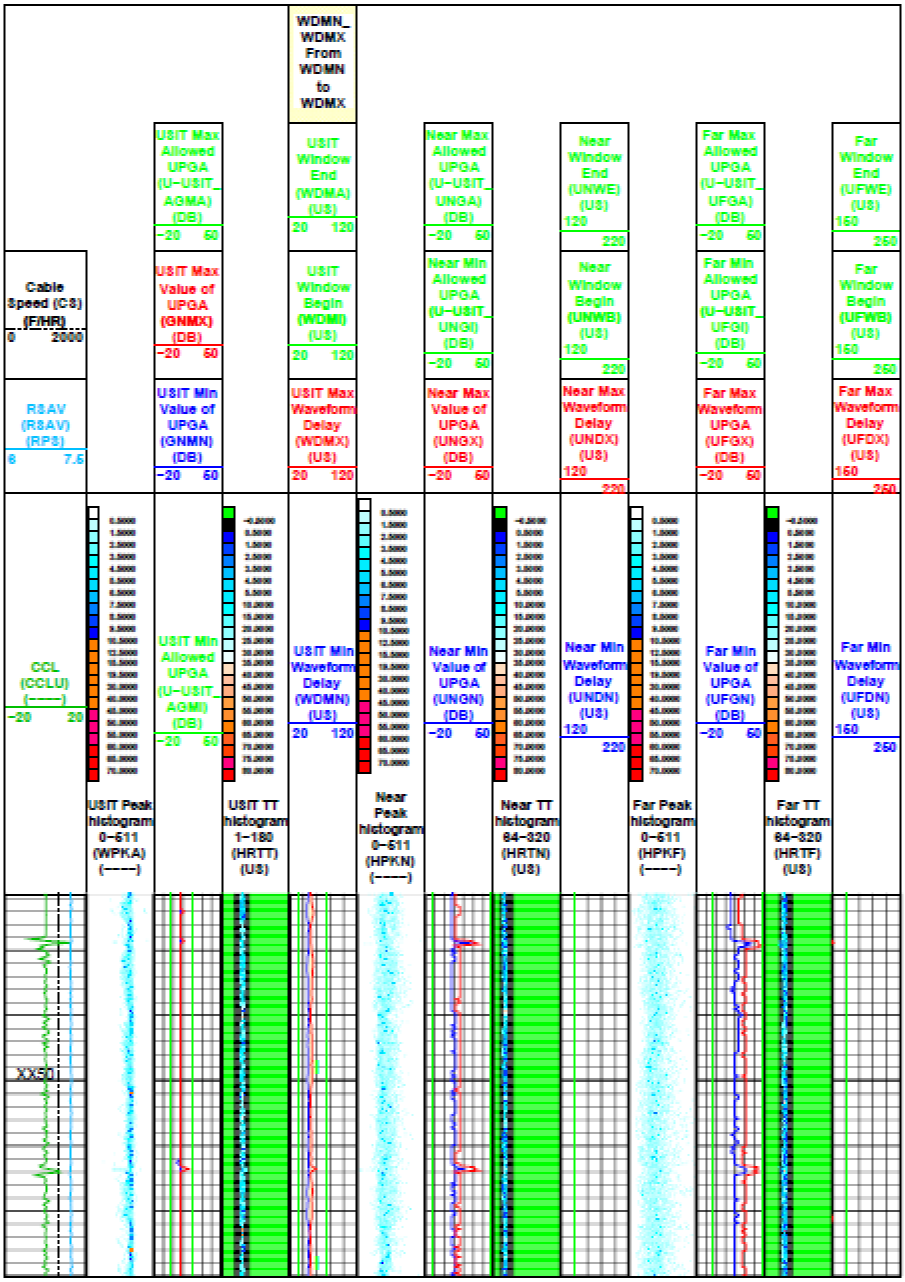


Figure 1. Isolation Scanner signal and waveforms quality control format.

App. B-5

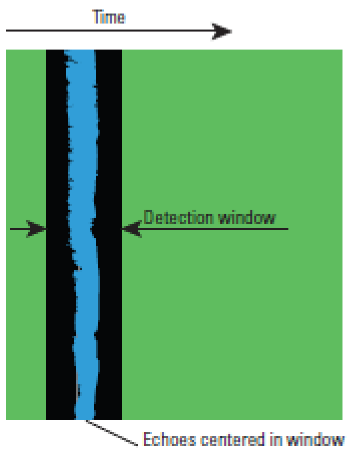


Figure 2. The USI transit-time histogram should be centered in the detection window.

Response in known conditions

The fluid slowness (DFSL) is checked for consistency with expected values in Table 2.

Table 2. Typical Isolation Scanner Fluid Slowness Ranges in Known Conditions

Fluid	DFSL, us/ft	Velocity, mm/us
Oil, oil-base, or heavy water-base mud	218 to 254	1.2 to 1.4
Water, light brine, or light water-base mud	184 to 218	1.4 to 1.65
Brine	160 to 184	1.65 to 1.9

The median internal radius is checked that it is reasonably close to what is expected from the casing size (±0.07 in [±2 mm]) to the casing inside diameter in noncorroded casing.

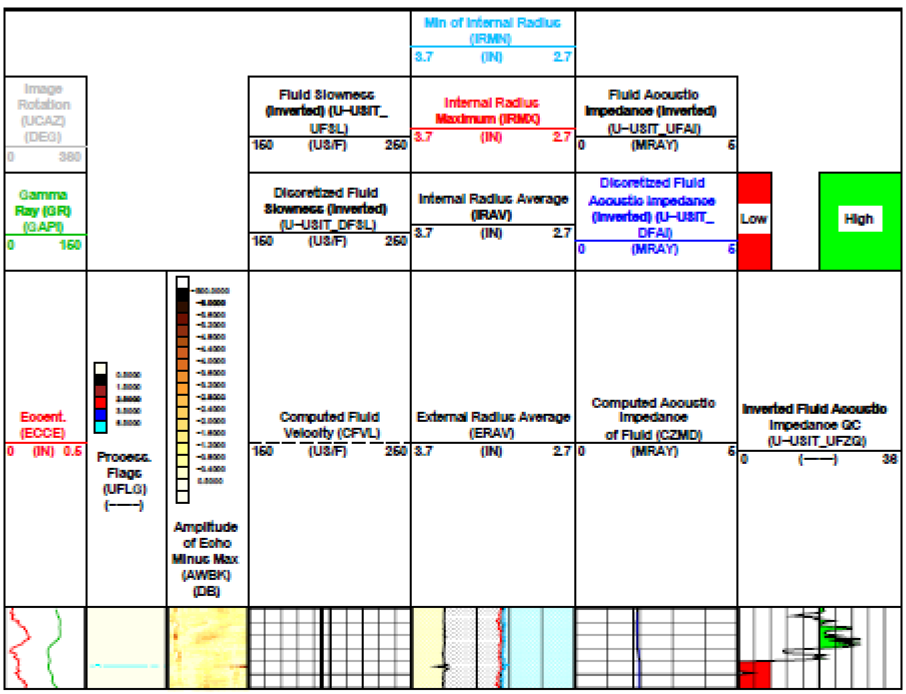


Figure 3. Isolation Scanner fluid property measurement quality control format.

Cement Bond

The example shown below is the QA for the sonic-based Schlumberger Cement Bond Tool (CBT) registered trademark.

Reference : Schlumberger Wireline Log Quality Reference Manual accessed January 2014 http://www.slb.com/resources/publications/books/lqcrm.aspx.

Schlumberger

Cement Bond Tool

Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

Specifications

Measurement Specifications	
Output	Attenuation measurement, CBL, VDL image, transit times
Logging speed	1,800 ft/h [549 m/h]†
Range of measurement	Formation and casing dependent
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement map: 2 ft [0.61 m]
Accuracy	Formation and casing dependent
Depth of investigation	CBL: casing and cement interface VDL: depends on bonding and formation
Mud type or weight limitations	None

† Speed can be reduced depending on data quality.

Measurement Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	3.375 in [8.57cm]
Borehole size—max.	13.375 in [33.97 cm]
Outside diameter	2.75 in [6.985 cm]
Weight	309 lbm [140 kg]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBT standard curves are listed in Table 1.

Table 1. CBT Standard Curves

Output Mnemonic	Output Name
CCL	Casing collar locator amplitude
DATN	Discriminated BHC attenuation
DBI	Discriminated bond index
DCBL	Discriminated synthetic CBL
DT	Interval transit time of casing (delta-*t*)
DTMD	Delta-*t* mud (mud slowness)
GR	Gamma ray
NATN	Near 2.4-ft attenuation
NBI	Near bond index
NCBL	Near synthetic CBL
R32R	Ratio of receiver 3 sensitivity to receiver 2 sensitivity, dB
SATN	Short 0.8-ft attenuation†
SBI	Short bond index†
SCBL	Short synthetic CBL†
TT1	Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3])
TT2	Transit time for mode 2 (UT-R2)
TT3	Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2])
TT4	Transit time for mode 4 (LT-R3)
TT6	Transit time for mode 6 (UT-R1)
ULTR	Ratio of upper transmitter output strength to the lower transmitter output strength
VDL	Variable Density log

† In fast formations only

Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

- Track 1
  - DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
  - CCL deflects in front of casing collars.
  - GR is used for correlation purposes.
- Track 2
  - DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.
- Track 3
  - VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

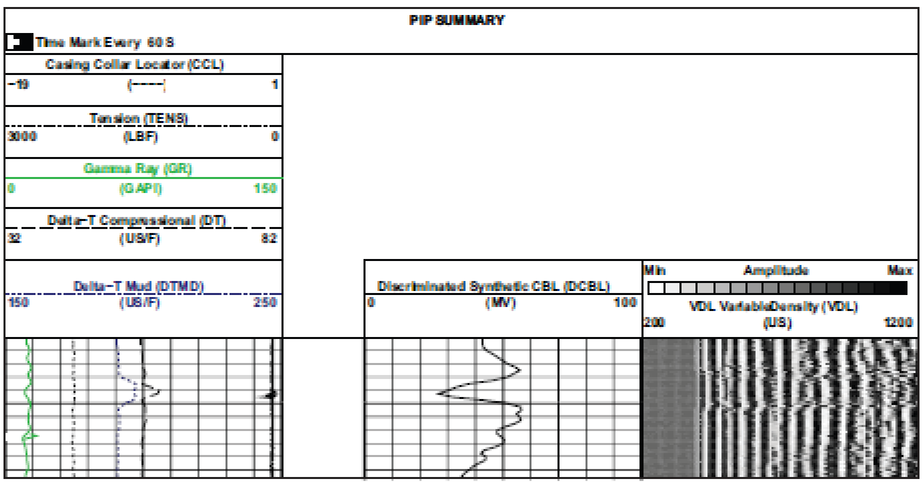


Figure 1. CBT standard format for CBL and VDL.

The format in Fig. 2 is also used both as an acquisition and quality control format.

- Track 1
  - The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.
- Track 2
  - The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.
- Track 3
  - DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.
- Track 4
  - VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

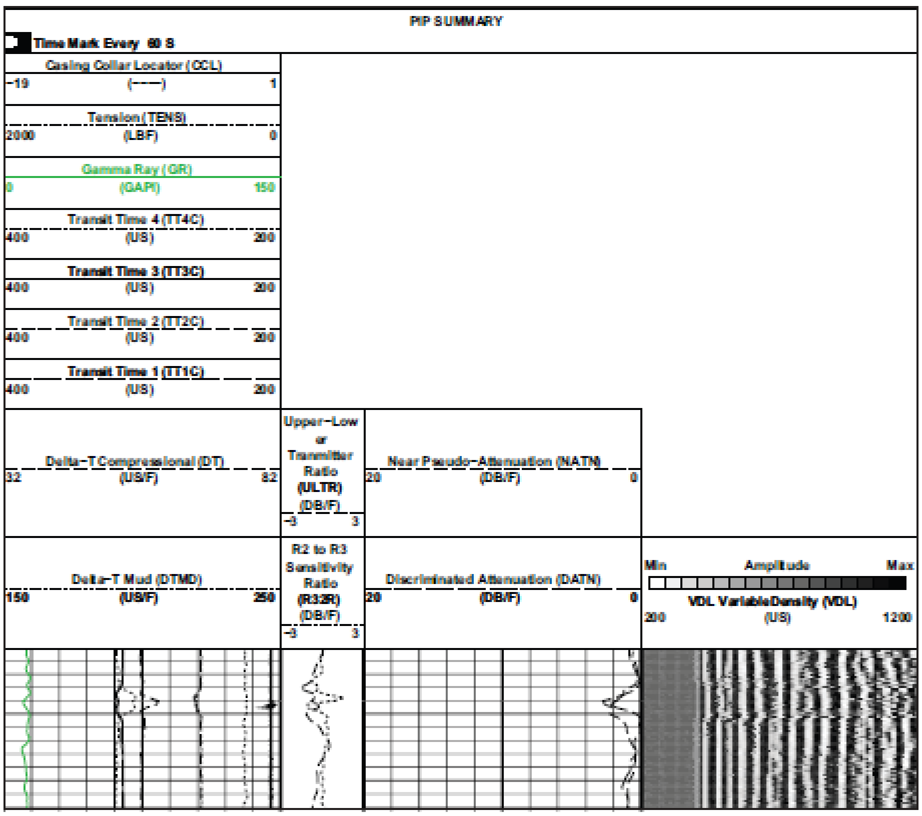


Figure 2. Additional CBT standard format for CBL and VDL.

Response in known conditions

- DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m ± 6.6 us/m]).
- DTMD should be compared with known velocities (water-base mud: 180–200 us/ft [590–656 us/m], oil-base mud: 210–280 us/ft [689–919 us/m]).
- Typical responses for different casing sizes and weights are listed in Table 2.

Table 2. Typical CBT Response in Known Conditions

Casing Size, in	Casing Weight, lbm/ft	DCBL in Free Pipe, mV	TT1, us	TT2, us	TT5, us
4.5	11.6	84 ± 8	252	195	104
5	13	77 ± 7	259	203	112
5.5	17	71 ± 7	267	210	120
7	24	61 ± 6	290	233	140
8.625	38	55 ± 6	314	257	166
9.625	40†	52 ± 5	329	272	NM‡

† Although the CBT operates in up to 13⅜-in casing, the VDL presentation mainly shows casing arrivals where casings of 9⅝ in and larger are logged.
‡ NM = not meaningful

Schlumberger

Cement Bond Logging

Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

Specifications

Measurement Specifications

	Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC)	Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT)
Output	SLS-C, SLS-D, SLS-W, and SLS-E:† 3-ft [0.91-m] CBL Variable Density waveforms	3-ft [0.91-m] CBL and attenuation 1-ft [0.30-m] attenuation 5-ft [1.52-m] Variable Density waveforms
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]
Vertical resolution	Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]	Near attenuation: 1 ft [0.30 m] Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface VDL: Depends on cement bonding and formation properties	DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties
Mud type or weight limitations	None	None
Special applications		Conveyed on wireline, drillpipe, or coiled tubing Logging through drillpipe and tubing, in small casings, fast formations

† The DSLT uses the Sonic Logging Sonde (SLS) to measure cement bond amplitude and VDL evaluation.

Mechanical Specifications				
	DSLT	HSLT	SSLT	QSLT
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	302 degF [150 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	25,000 psi [172 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]
Casing ID—min.	5 in [12.70 cm]	5 in [12.70 cm]	3½ in [8.89 cm]	4 in [10.16 cm]
Casing ID—max.	18 in [45.72 cm]	18 in [45.72 cm]	8 in [20.32 cm]	8 in [20.32 cm]
Outside diameter	3⅝ in [9.21 cm]	3¾ in [9.53 cm]	2½ in [6.35 cm]	3 in [7.62 cm]
Length	SLS-C and SLS-D: 18.7 ft [5.71 m] SLS-E and SLS-W: 20.6 ft [6.23 m]	With HSLS-W sonde: 25.5 ft [7.77 m]	23.1 ft [7.04 m] With inline centralizers: 29.6 ft [9.02 m]	23 ft [7.01 m] With inline centralizers: 29.9 ft [9.11 m]
Weight	SLS-C and SLS-D: 273 lbm [124 kg] SLS-E and SLS-W: 313 lbm [142 kg]	With HSLS-W sonde: 440 lbm [199 kg]	232 lbm [105 kg] With inline centralizers: 300 lbm [136 kg]	295 lbm [134 kg] With inline centralizers: 407 lbm [185 kg]
Tension	29,700 lbf [132,110 N]	29,700 lbf [132,110 N]	13,000 lbf [57,830 N]	13,000 lbf [57,830 N]
Compression	SLS-C and SLS-D: 1,700 lbf [7,560 N] SLS-E and SLS-W: 2,870 lbf [12,770 N]	With HSLS-W sonde: 2,870 lbf [12,770 N]	4,400 lbf [19,570 N]	4,400 lbf [19,570 N]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBL standard curves are listed in Table 1.

Table 1. CBL Standard Curves

Output Mnemonic	Output Name
BI	Bond index
CBL	Cement bond log (fixed gate)
CBLF	Fluid-compensated cement bond log
CBSL	Cement bond log (sliding gate)
CCL	Casing collar log
GR	Gamma ray
TT	Transit time (fixed gate)
TTSL	Transit time (sliding gate)
VDL	Variable Density log

Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a microannulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

- Track 1
  - TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations..
- Track 2
  - CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.
- Track 3
  - VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

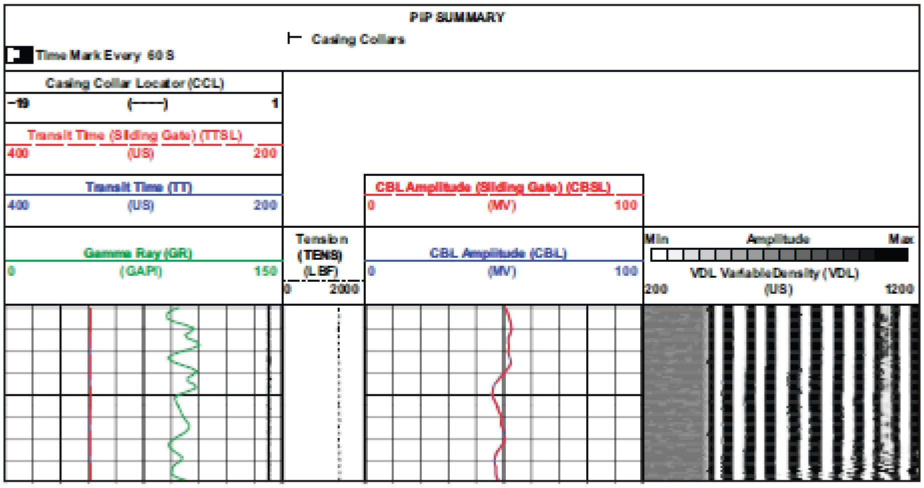


Figure 1. DSLT standard format.

Response in known conditions

The responses in Table 2 are for clean, free casing.

Table 2. Typical CBL Response in Known Conditions

Casing OD, in	Weight, lbm/ft	Nominal Casing ID, in	CBL Amplitude Response in Free Pipe, mV
5	13	4.494	77 ± 8
5.5	17	4.892	71 ± 7
7	23	6.366	62 ± 6
8.625	36	7.825	55 ± 6
9.625	47	8.681	52 ± 5
10.75	51	9.850	49 ± 5
13.375	61	12.515	43 ± 4
18.625	87.5	17.755	35 ± 4

Cased Hole Temperature Logging

Cased hole temperature logging tools are often run as part of a multi-tool tool string, as described in the following Schlumberger example.

Platform Basic Measurement Sonde

Overview

Platform Basic Measurement Sonde (PBMS) of the PS Platform* integrated production services system houses the gamma ray and casing collar locator (CCL) for correlation and also measures well pressure and temperature.

Specifications

Measurement Specifications	
Output	Wellbore pressure, wellbore temperature, gamma ray, casing collar locator
Logging speed	Recommended for accurate gamma ray response: 1,800 ft/h [549 m/h] Typically logged at 30, 60, and 90 ft/min [10, 20, and 30 m/min]
Range of measurement	Sapphire* gauge: 1,000 to 10,000 psi [6.9 to 69 MPa] CQG* gauge: 4.5 to 15,000 psi [0.1 to 103 MPa] Temperature: Ambient to 302 degF [150 degC]
Vertical resolution	Point of measurement
Accuracy	Sapphire gauge: ±6 psi [±41,370 Pa] (accuracy), 0.1 psi [689 Pa] at 1-s gate time (resolution) CQG gauge: ±(1 psi [6,894 Pa] + 0.01% of reading) (accuracy), 0.01 psi [69 Pa] at 1-s gate time (resolution) Temperature: ±1.8 degF[±1 degC] (accuracy), 0.018 degF [0.01 degC] (resolution)
Depth of investigation	Borehole
Mud type or weight limitations	None

Mechanical Specifications	
Temperature rating	302 degF [150 degC] PBMS-E: 347 degF [175 degC] HBMS: 392 degF [200 degC] for a limited time
Pressure rating	Sapphire gauge: 10,000 psi [69 MPa] CQG gauge: 15,000 psi [103 MPa]
Borehole size—min.	2⅛-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	No limit
Outside diameter	1.6875 in [4.29 cm] HBMS: 2.125 in [5.4 cm]
Length	8.27 ft [2.52 m]
Weight	38.3 lbm [17.4 kg]

Calibration

The PBMS requires calibration for two sensors: the temperature sensor and the pressure sensor. Both calibrations are performed at the same time but cannot be done at the wellsite or field operating locations because of the equipment and personnel required. The sonde alone is placed in a bath of oil for thermal inertia effects and various pressures are applied at various temperatures. The measurements are then used to build a mathematical model that models the tool response.

The gamma ray sensor of the PBMS does not require calibration because the detector is hardwired to operate at the correct settings for the high voltage.

Tool quality control

Standard curves

The PBMS standard curves are listed in Table 1.

Table 1. PBMS Standard Curves

Output Mnemonic	Output Name
CCLD	Discriminated casing collar locator
GR	Gamma ray
MWFD	Pressure gradient derived density
WPRE	Well pressure
WTEP	Well temperature

Operation

The tool can be run centered, eccentered, or tilted.

Response in known conditions

Casing collars should be observed approximately 30 ft [9 m] apart in tubing and 41 ft [12.5 m] apart in casing. Pressure and temperature should increase with true vertical depth in a shut-in well without cross flow. Gamma ray logs should repeat from pass to pass.

Cased Hole Gamma-Ray Logging

Schlumberger

Gamma Ray Tools

Overview

Gamma ray tools record naturally occurring gamma rays in the formations adjacent to the wellbore. This nuclear measurement indicates the radioactive content of the formations. Effective in any environment, gamma ray tools are the standard devices used for the correlation of logs in cased and open holes.

Calibration

The calibration area for gamma ray tools must be free from outside nuclear interference. Background and plus calibrations are typically performed at the wellsite with the radioactive sources removed from the area so that no contribution is made to the signal. The background measurement is made first, and then a plus measurement is made by wrapping the calibration jig around the tool housing and positioning the jig on the knurled section of the gamma ray tool.

Specifications

Measurement Specifications

	Highly Integrated Gamma Neutron Sonde (HGNS)	Hostile Environment Telemetry and Gamma Ray Cartridge (HTGC)	Scintillation Gamma Ray Tool (SGT)	Slim Telemetry and Gamma Ray Cartridge (STGC)	SlimXtreme* Telemetry and Gamma Ray Cartridge (QTGC)	Combinable Gamma Ray Sonde (CGRS)
Output	Formation gamma ray	Formation gamma ray	Formation gamma ray	Formation gamma ray	Formation gamma ray	Gamma ray activity
Logging speed	3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] Correlation logging: 3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] Correlation logging: 3,600 ft/h [1,097 m/h]	1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] Correlation logging: 3,600 ft/h [1,097 m/h]	Up to 3,600 ft/h [1,097 m/h]
Range of measurement	0 to 1,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI	0 to 2,000 gAPI
Vertical resolution	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]	12 in [30.48 cm]
Accuracy	±5%	±7%	±7%	±7%	±7%	±5%
Depth of investigation	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]	24 in [60.96 cm]
Mud type or weight limitations	None	None	None	None	None	None
Combinability	Part of Platform Express* integrated system	Combinable with most tools	Combinable with most tools	Combinable with most tools	Combinable with most tools	Combinable with most tools
Special applications						H_2S service

Mechanical Specifications

	HNGS	HTGC	SGT	STGC	QTGC	CGRS
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	350 degF [177 degC]	302 degF [150 degC]	500 degF [260 degC]	350 degF [177 degC]
Pressure rating	15,000 psi [103 MPa]	25,000 psi [172 MPa]	20,000 psi [138 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]	20,000 psi [138 MPa]
Borehole size—min.	4½ in [11.43 cm]	4⅞ in [12.38 cm]	4⅞ in [12.38 cm]	3⅜ in [8.57 cm]	3⅞ in [9.84 cm]	$1\frac{13}{16}$-in [4.61-cm] seating nipple
Borehole size—max.	No limit	No limit	No limit	No limit	No limit	No limit
Outside diameter	3.375 in [8.57 cm]	3.75 in [9.53 cm]	3.375 in [8.57 cm]	2.5 in [6.35 cm]	3.0 in [7.62 cm]	1.6875 in [4.29 cm]
Length	10.85 ft [3.31 m]	10.7 ft [3.26 m]	5.5 ft [1.68 m]	7.70 ft [2.34 m]	10.67 ft [3.25 m]	3.2 ft [0.97 m]
Weight	171.7 lbm [78 kg]	312 lbm [142 kg]	83 lbm [38 kg]	68 lbm [31kg]	180 lbm [82 kg]	16 lbm [7 kg]
Tension	50,000 lbf [222,410 N]	120,000 lbf [533,790 N]	50,000 lbf [222,410 N]	50,000 lbf [222,410 N]	120,000 lbf [533,790 N]	10,000 lbf [44,480 N]
Compression	37,000 lbf [164,580 N]	28,000 lbf [124,550 N]	23,000 lbf [103,210 N]	17,000 lbf [75,620 N]	13,000 lbf [57,830 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The gamma ray tool standard curves are listed in Table 1.

Table 1. Gamma Ray Tool Standard Curves

Output Mnemonic	Output Name
ECGR	Gamma ray environmentally corrected
GR	Gamma ray

Operation

The tool can be run centered or eccentered.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

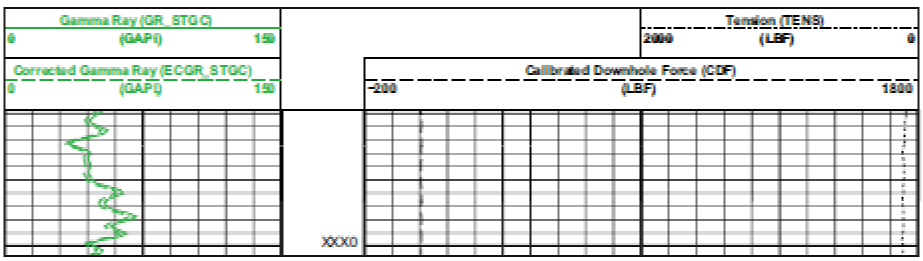


Figure 1. Gamma ray standard format.

Response in known conditions

- In shales, the gamma ray reading tends to be relatively high.
- In sands, the gamma ray reading tends to be relatively low.
- Gamma ray logs recorded in wells that have been on production may exhibit very high readings in the producing interval compared with the original logs recorded when the well was drilled. Mud additives such as potassium chloride and loss-control material can affect log readings.