Lorain

Class VI Injection Permit Application

Quality Assurance and Surveillance Plan (QASP)

US EPA ID Number: **TBD**

August 2021

Prepared by:
WSP USA

Distribution List

The following project participants should receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project. The Lorain Plant Manager will be responsible for ensuring that all those on the distribution list will receive the most current copy of the approved Quality Assurance and Surveillance Plan. Names in bold are the primary points of contact with addresses listed below.

<u>Lorain</u>
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A. Project Management

A.1. Project/Task Organization

A.1.a/b. Key Individuals and Responsibilities

The project, led by Lorain Zero Carbon Solutions, LLC (Lorain), includes participation from several subcontractors. The Testing and Monitoring Activities responsibilities will be shared between Lorain and WSP and their designated subcontractor and the program will be broken in six subcategories:

I) Deep Groundwater Sampling
II) Well Logging
III) Mechanical Integrity Testing (MIT)
IV) Pressure/Temperature Monitoring
V) CO_2 Stream Analysis
VI) Geophysical Monitoring

A.1.c. Independence from Project QA Manager and Data Gathering

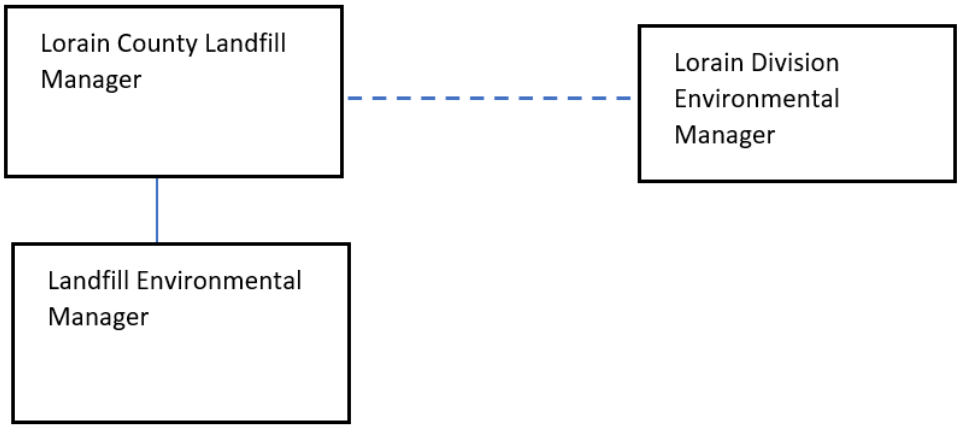
The majority of the physical samples collected, and data gathered as part of the MVA program is analyzed, processed, or witnessed by third parties independent and outside of the project management structure.

A.1.d. QA Project Plan Responsibility

Lorain will be responsible for maintaining and distributing official, approved QA Project Plan. Lorain will periodically review this QASP and consult with USEPA if/when changes to the plan are warranted.

A.1.e. Organizational Chart for Key Project Personnel

Figures 1 shows the organization structure of the project. Lorain will provide to the UIC Program Director a contact list of individuals fulfilling these roles.



A.2. Problem Definition/Background

A.2.a Reasoning

The Lorain Project's monitoring, verification, and accounting (MVA) program has operational monitoring, verification, and environmental monitoring components. Operation monitoring is used to ensure safety with all procedures associated with fluid injection, monitor the response of storage unit, and the movement of the CO_2 plume. Key monitoring parameters include the pressure of injection well tubing & annulus, storage unit, above seal strata, and the lowermost USDW reservoir. Other monitoring parameters include injection rate, total mass & volume injected, injection well temperature profile, and passive seismic. The verification component will provide information to evaluate if leakage of CO_2 through the caprock is occurring. This includes pulse-neutron logging, pressure, and temperature monitoring. The environmental monitoring components will determine if the injectate is being released into the shallow subsurface or biosphere. This monitoring includes pulse-neutron logging and ground water monitoring.

A robust MVA program has been developed for the Lorain project based on the experience gained through previously filed Carbon Capture Projects. The knowledge and experience gained through the provides a high level of confidence that the storage unit (Mt Simon) is capable to accept and permanently retain the injectate. The primary goal of the Lorain MVA program is to demonstrate that project activities are protective of human health and the environment. To help achieve this goal, this Quality Assurance Surveillance Plan (QASP) was developed to ensure the quality standards of the testing and monitoring program meet the requirements of the U.S. Environmental Protection Agency's (USEPA) Underground Injection Control (UIC) Program for Class VI wells.

A.2.b. Reasons for Initiating the Project

The goal of the Lorain injection project is to demonstrate the ability of the Mt. Simon Sandstone to accept and retain industrial-scale volumes of CO_2 for permanent geologic sequestration to reduce atmospheric concentrations of CO_2. To demonstrate that this can be done safely and at commercial scale, a rigorous MVA plan is proposed to ensure the injected CO_2 is retained within the intended storage reservoir.

A.2.c. Regulatory Information, Applicable Criteria, Action Limits

The Class VI Rule requires owners or operators of Class VI wells to perform several types of activities during the lifetime of the project in order to ensure that the injection well maintains its mechanical integrity, that fluid migration and the extent of pressure elevation are within the limits described in the permit application, and that underground sources of drinking water (USDWs) are not endangered. These monitoring activities include mechanical integrity tests (MITs), injection well testing during operation, monitoring of ground water quality in several zones, tracking of the CO_2 plume and associated pressure front. This document details both the measurements that will be taken as well as the steps to ensure that the quality of all the data is such that the data can be used with confidence in making decisions during the life of the project.

A.3. Project/Task Description

A.3.a/b. Summary of Work to be Performed and Work Schedule

Table 1 describes the Testing and Monitoring tasks, reasoning, responsible parties, locations and testing frequency. An in-depth description of the Testing and Monitoring Plan has been submitted in the Class VI permit application.

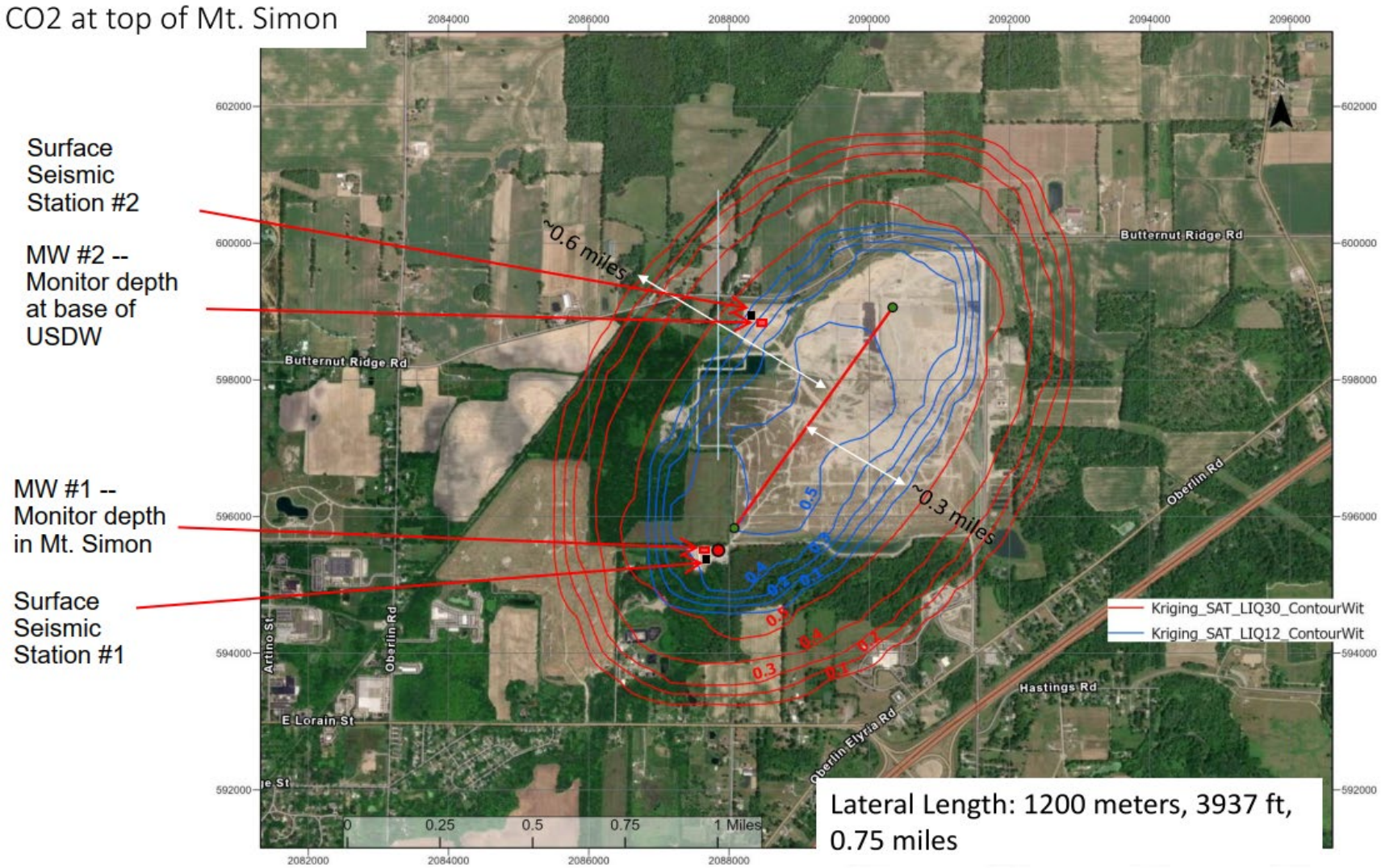
Table 1: Summary of Testing and Monitoring

Monitoring Method	Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct	USDW	Fluid sampling	MW #2 and CCS #1	Sampling interval at approximately 1850’	Quarterly for fluid sample
Direct	USDW	DTS	CCS #1	1 point location, distributed measurement 5000 MD BGL	Continuous
Direct	Conasuaga (Upper Confining Zone)	DTS	CCS #1	1 point location, distributed measurement 5000 MD BGL	Continuous
Direct	Conasuaga (Upper Confining Zone)	Pressure/Temperature Monitoring	CCS #1	1 point location, 1 interval: 4430 MD BGL	Continuous
Direct	Rome (Lower Confining Zone)	DTS	CCS #1	1 point location, distributed measurement 5000 MD BGL	Continuous
Direct	Rome (Lower Confining Zone)	Pressure/Temperature Monitoring	CCS #1	1 point location, 1 interval: 4430 MD BGL	Continuous
Direct	Mt. Simon (Injection Interval)	DTS	CCS #1	1 point location, distributed measurement 5000 MD BGL	Continuous
Direct	Mt. Simon (Injection Interval)	Fluid sampling	CCS#1 and MW #1	1 point location, 1 interval: collect sample at 4850’ GL (5’ into the open hole interval) in CCS #1, collect sample at 4600’ GL in MW #1.	Baseline; Year 1-3: Annual
Indirect	USDW	Pulse Neutron Logging/ Reservoir Saturation Tool (RST) logs	Monitor wells	1 point location (12 inches outside wellbore) and continuous down to full well depth.	Baseline, Year 2, Year 4

Monitoring Method	Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Indirect	Mt. Simon (Injection Interval)	Pulse Neutron Logging/RST	CCS #1	1 point location (12 inches outside wellbore) and continuous down to full well depth.	Baseline, Year 2, Year 4
Indirect	Mt. Simon (Injection Interval)	Time-Lapse VSP Survey	Either in MW #1 or temporary groundwater well	Fold image coverage ~ 30 acres	Year 1, Year 2, Year 3
Indirect	Mt. Simon (Injection Interval)	3D Surface Seismic Survey	Full coverage focusing on the northern extent of the plume near bottomhole location	Fold image coverage ~ 2,000 acres	Baseline, Year 2

A.3.c. Geographic Locations

Figure 2 shows the IL-ICCS site and monitoring infrastructure.



A.4.Quality Objectives and Criteria

A.4.a. Performance/Measurement Criteria

The overall QA objective for monitoring is to develop and implement procedures for subsurface monitoring, field sampling, laboratory analysis, and reporting which will provide results that will meet the characterization and non-endangerment goals of this project. Groundwater monitoring will be conducted during the pre-injection, injection, and post-injection phases of the project. Shallow and deep groundwater monitoring wells will be used to gather water-quality samples and pressure data. All the groundwater analytical and field monitoring parameters for each interval are listed in Table 4 through Table 7. Table 8, Table 9 and Table 10 show analytical parameters for CO_2 stream gas monitoring, corrosion coupon assessment, and gauge specifications. Table 11 shows the monitoring outputs. The list of analytes may be reassessed periodically and adjusted to include or exclude analytes based on their effectiveness to the overall monitoring program goals.

Key testing and monitoring areas include:

I. Shallow Groundwater Sampling

- Aqueous chemical concentrations

II. Deep Formation Fluid Sampling

- Aqueous chemical concentrations

III. Well Logging

- pulse neutron

IV. Mechanical Integrity Testing (MIT)

- Pulsed neutron, temperature, cement evaluation logging

V. Pressure/Temperature Monitoring

- Pressure/temperature from in-situ gauges
- Pressure/temperature from surface gauges

VI. CO_2 Stream Analysis

- CO_2 Purity (% v/v, [GC])

- Oxygen (O_2, ppm v/v)
- Nitrogen (N_2, ppm v/v)
- Carbon Monoxide (CO, ppm v/v)
- Oxides of Nitrogen (NOx, ppm v/v)
- Total Hydrocarbons (THC, ppm v/v as CH_4)
- Methane (CH_4, ppm v/v)
- Acetaldehyde (AA, ppm v/v)
- Sulfur Dioxide (SO_2, ppm v/v)
- Hydrogen Sulfide (H_2S ppm v/v)
- Ethanol (ppm v/v)

VII. Geophysical Monitoring

- Seismic data files (e.g., segd file)
- Processed time-lapse report

Table 2: Summary of analytical and field parameters for Mt. Simon groundwater samples. All analysis will be performed by Lorain or a designated 3rd party lab. ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography – pyrolysis.

Parameters	Analytical Methods(1)	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020	0.001 to 0.1 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B	0.005 to 0.5 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Anions: Br, Cl, F, NO3, and SO4	Ion Chromatography, EPA Method 300.0	0.02 to 0.13 mg/L (analyte, dilution and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved CO2	Coulometric titration, ASTM D513-11	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
Isotopes: δ13C of DIC	Isotope ratio mass spectrometry[2]	12.2 mg/L HCO3- for δ13C	±0.15‰ for δ13C	10% duplicates; 4 standards/batch
Total Dissolved Solids	Gravimetry; APHA 2540C	12 mg/L	±10%	Balance calibration, duplicate analysis
Alkalinity	APHA 2320B	4 mg/L	±3 mg/L	Duplicate analysis
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

(1) An equivalent method may be employed with the prior approval of the UIC Program Director

(2) Gas evolution technique by Atekwana and Krishnamurthy (1998), with modifications made by Hackley et al. (2007)

Table 3: Summary of analytical parameters for CO2 gas stream. All analysis will be performed by Lorain or a designated 3rd party lab.

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ISBT 4.0 (GC/DID)	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
	GC/TCD	0.1 % to 100 %	5 - 10 % relative across the range, RT ± 0.1 min	daily standard, duplicate analysis within 10 % of each other
Nitrogen	ISBT 4.0 GC/DID	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
	GC/TCD	0.1 % to 100 %	5 - 10 % relative across the range, RT ± 0.1 min	daily standard, duplicate analysis within 10 % of each other
Carbon Monoxide	ISBT 5.0 Colorimetric	5 uL/L to 100 uL/L (ppm by volume)	± 20 % of reading	duplicate analysis
	ISBT 4.0 (GC/DID)	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
Oxides of Nitrogen	ISBT 7.0 Colorimetric	0.2 uL/L to 5 uL/L (ppm by volume)	± 20 % of reading	duplicate analysis
Total Hydrocarbons	ISBT 10.0 THA (FID)	1 uL/L to 10,000 uL/L (ppm by volume	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Methane	ISBT 10.1 GC/FID)	0.1 uL/L to 1,000 uL/L (ppm by volume); dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Acetaldehyde	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume); dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Sulfur Dioxide	ISBT 14.0 (GC/SCD)	0.01 uL/L to 50 uL/L (ppm by volume); dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	0.01 uL/L to 50 uL/L (ppm by volume); dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Ethanol	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume); dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
CO_2 Purity	ISBT 2.0 Caustic absorption Zahm-Nagel	99.00% to 99.99%	± 10 % of reading	User calibration per manufacturer recommendation
	ALI method SAM 4.1 subtraction method (GC/DID)	1 ppm for each target analyte (analyte dependent) - refer to Oxygen and Nitrogen analysis.	5-10 % relative across the range	duplicate analysis within 10 % of each other
	GC/TCD	0.1 % to 100 %	5-10 % relative across the range, RT ± 0.1 min	standard with every sample, duplicate analysis within 10 % of each other

(1) An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 4: Summary of Analytical Parameters for corrosion coupons

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE RP077-2005	.005 MG	+/- 2%	Annual Calibration of Scale (3rd Party)
Thickness	NACE RP0775-2005	.001 mm	+/- .005 mm	Factory Calibration

Table 5: Summary of measurement parameters of field gauges

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Booster pump discharge pressure	ANSI Z540-1-1994	+/- 0.001 PSI / 0-3000 PSI	+/- 0.01 psi	Annual Calibration
Injection Tubing Temperature	ANSI Z540-1-1994	+/- 0.001 F / 0-500 F	+/- 0.01 F	Annual Calibration
Annulus Pressure	ANSI Z540-1-1994	+/- 0.001 PSI / 0-3000 PSI	+/- 0.01 psi	Annual Calibration
Injection Tubing Pressure	ANSI Z540-1-1994	+/- 0.001 PSI / 0-3000 PSI	+/- 0.01 psi	Annual Calibration
Injection Mass Flow Rate	UNKNOWN	+/- 0.1000% of rate / 50,522 – 303,133 lb/hr	+/- 0.01 lbs/hr	Annual Calibration

Table 6: Actionable testing and monitoring outputs

	Project Action Limit	**Detection Limit**	**Anticipated Reading**
MIT— Pulse neutron logging	Action taken when RST indicates CO_2 outside of expected range	+/- 0.5 SIGM	Brine saturated ~ 60 CO_2 saturated ~ 8
Wellbore integrity— annular pressure gauge	<5% pressure loss over 1 hour	Refer to Appendix A (annular pressure gauge table)	>5% pressure loss over 1 hour
Surface and downhole pressure gauges	Action will be taken when pressures are well outside of modeled/expected range	Refer to Table 11 and 12 for surface gauges Refer to Table 9 for downhole gauge	Within injection formation: >80% fracture gradient 0.71 psi/ft
Wellbore integrity—DTS fiber optic temperature	Action will be taken when there is an anomaly in temperature profile	Refer to Appendix A	DTS provides continuous temperature profile
Seismic data files	Detected CO_2 outside the AOR	Dependent on fluid saturation, and formation velocities	CO_2 plume migration similar to modeled outcome

A.4.b. Precision

For groundwater sampling, data accuracy will be assessed by the collection and analysis of field blanks to test sampling procedures and matrix spikes to test lab procedures. Field blanks will be taken no less than one per sampling event to spot check for sample bottle contamination. Laboratory assessment of analytical precision will be the responsibility of the individual laboratories per their standard operating procedures.

Table 7 summarizes the specifications of each monitoring method. For direct pressure and logging measurements, precision data is presented in Table 8.

A.4.c. Bias

Laboratory assessment of analytical bias will be the responsibility of the individual laboratories per their standard operating procedures and analytical methodologies. For direct pressure or logging measurements, there is no bias.

A.4.d. Representativeness

For groundwater sampling, data representativeness expresses the degree to which data accurately and precisely represents a characteristic of a population, parameter variations at a sampling point, a process condition, or an environmental condition. The sampling network has been designed to provide data representative of site conditions. For analytical results of individual groundwater samples, representativeness will be estimated by ion and mass balances. Ion balances with ±10% error or less will be considered valid. Mass balance assessment will be used in cases where the ion balance is greater than ±10% to help determine the source of error. For a sample and its duplicate, if the relative percent difference is greater than 10%, the sample may be considered non-representative.

A.4.e. Completeness

For groundwater sampling, data completeness is a measure of the amount of valid data obtained from a measurement system compared to the amount that was expected to be obtained under normal conditions. It is anticipated that data completeness of 90% for groundwater sampling will be acceptable to meet monitoring goals. For direct pressure and temperature measurements, it is expected that data will be recorded no less than 90% of the time.

A.4.f. Comparability

Data comparability expresses the confidence with which one data set can be compared to another. The data sets to be generated by this project will be very comparable to future data sets because of the use of standard methods and the level of QA/QC effort. If historical groundwater quality data become available from other sources, their applicability to the project and level of quality will be assessed prior to use with data gathered on this project. Direct pressure, temperature, and logging measurements will be directly comparable to previously obtained data.

A.4.g. Method Sensitivity

Table 9 through Table 12 provide additional details on gauge specifications and sensitivities.

Table 7. Pressure and temperature—downhole quartz gauge specifications.

Calibrated working pressure range	Atmospheric to 10,000 psi
Initial Pressure Accuracy	< +/- 2 psi over full scale
Pressure Resolution	0.005 psi at 1-s sample rate
Pressure drift stability	< +/0 psi per year over full scale
Calibrated working temperature range	77 – 266 ˚F
Initial temperature accuracy	< +/- 0.95 ˚F per +/0 0.27 ˚F
Temperature resolution	0.009 ˚F at 1-s sample rate
Temperature drift stability	< +/- 0.1 ˚F per year at 302 ˚F
Max temperature	302 ˚F

Table 8. Representative Logging tool specifications.

	RST	CBL	USI	Isolation Scanner
Logging Speed	1,800 ft/hr	3,600 ft/hr	Standard-res: 2,700 ft/hr High-res: 563 ft/hr	Standard-res: 2,700 ft/hr High-res: 563 ft/hr
Vertical resolution	15 in.	3 ft.	Standard-res: 0.6 in. High-res: 6 in.	High-res: 0.6 in. High speed: 6 in.
Investigation	Formation	Casing, annulus, and formation	Casing and annulus	Casing and annulus
Temperature rating	302 ˚F	350 ˚F	350 ˚F	350 ˚F
Pressure rating	15,000 psi	20,000 psi	20,000 psi	20,000 psi

Table 9. Pressure Field Gauge (TBD – typical quartz gauge) – Injection Tubing Pressure

Calibrated working pressure range	0 to 3,000 psi and 4-20 mA
Initial pressure accuracy	< 0.04375%
Pressure resolution	0.001 psi and 0.00001 mA
Pressure drift stability	TBD after 1st year

Table 10. Pressure Field Gauge (TBD – typical quartz gauge) – Annulus Pressure

Calibrated working pressure range	0 to 3,000 psi and 4-20 mA
Initial pressure accuracy	< 0.02500%
Pressure resolution	0.001 psi and 0.00001 mA
Pressure drift stability	TBD after 1st year

Table 11. Temperature Field Gauge (TBD) – Injection Tubing Temperature

Calibrated working temp. range	0 to 500 ˚F and 4-20 mA
Initial temperature accuracy	< 0.0055%
Temp resolution	0.001 ˚F and 0.0001 mA
Temp drift stability	TBD after 1st year

Table 12. Mass Flow Rate Field Gauge (TBD) – CO_2 Mass Flow Rate

Calibrated working flow rate range	50,522 to 303,133 lbs/hr and 4-20 mA
Initial mass flow rate accuracy	< 0.18%
Mass flow rate resolution	0.001 lb/hr
Mass flow rate drift stability	TBD after 1st year

A.5. Special Training/Certifications

A.5.a. Specialized Training and Certifications

The geophysical survey equipment and wireline logging tools will be operated by trained, qualified, and certified personnel, according to the service company which provides the equipment. The subsequent data will be processed and analyzed according to industry standards (Appendix B). No specialized certifications are required for personnel conducting groundwater sampling, but field sampling will be conducted by trained personnel. Groundwater sampling will be conducted by personnel trained to understand and follow the project specific sampling procedures. Upon request Lorain will provide the agency with all laboratory SOPs developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the samples will be trained on the SOP developed for each standard method. Lorain will include the technician's training certification with the biannual report.

A.5.b/c. Training Provider and Responsibility

Training for personnel will be provided by the operator or by the subcontractor responsible for the data collection activity.

A.6. Documentation and Records

A.6.a. Report Format and Package Information

A semi-annual report from Lorain to USEPA will contain all required project data, including testing and monitoring information as specified by the UIC Class VI permit. Data will be provided in electronic or other formats as required by the UIC Program Director.

A.6.b. Other Project Documents, Records, and Electronic Files

Other documents, records, and electronic files such as well logs, test results, or other data will be provided as required by the UIC Program Director.

A.6.c/d. Data Storage and Duration

Lorain or a designated contractor will maintain the required project data as provided elsewhere in the permit.

A.6.e. QASP Distribution Responsibility

The Lorain Manager will be responsible for ensuring that all those on the distribution list will receive the most current copy of the approved Quality Assurance and Surveillance Plan.

B. Data Generation and Acquisition

B.1. Sampling Process Design (Experimental Design)

Discussion in this section is focused on groundwater and fluid sampling and does not address monitoring methods that do not gather physical samples (e.g., logging, seismic monitoring, and pressure/temperature monitoring). During the pre-injection and injection phases, groundwater sampling is planned to include an extensive set of chemical parameters to establish aqueous geochemical reference data. Parameters will include selected constituents that: (1) have primary and secondary USEPA drinking water maximum contaminant levels, (2) are the most responsive to interaction with CO_2 or brine, (3) are needed for quality control, and (4) may be needed for geochemical modeling. The full set of parameters for each sampling interval is given in Table 4-Table 7. After a sufficient baseline is established, monitoring scope may shift to a subset of indicator parameters that are (1) the most responsive to interaction with CO_2 or brine and (2) are needed for quality control. Implementation of a reduced set of parameters would be done in consultation with the USEPA. Isotopic analyses will be performed on baseline samples to the degree that the information helps verify a condition or establish an understanding of non-project related variations. For non-baseline samples, isotopic analyses may be reduced in all monitoring wells if a review of the historical project results or other data determines that further sampling for isotopes is unneeded. During any period where a reduced set of analytes is used, if statistically significant trends are observed that are the result of unintended CO_2 or brine migration, the analytical list would be expanded to the full set of monitoring parameters. The Ironton-Galesville groundwater samples will be analyzed using a laboratory meeting the requirements under the USEPA Environmental Laboratory Accreditation Program. All other samples will be analyzed by the operator or a third party laboratory. Dissolved CO_2 will be analyzed by methods consistent with Test Method B of ASTM D 513-06, "Standard Test Methods for Total and Dissolved Carbon Dioxide in Water" or equivalent. Isotopic analysis will be conducted using established methods.

<u>B.1.a. Design Strategy</u>

CO_2 Stream Monitoring Strategy

The primary purpose of analyzing the carbon dioxide stream is to evaluate the potential interactions of carbon dioxide and/or other constituents of the injectate with formation solids and fluids. This analysis can also identify (or rule out) potential interactions with well materials. Establishing the chemical composition of the injectate also supports the determination of whether the injectate meets the qualifications of hazardous waste under the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6901 et seq. (1976), and/or the Comprehensive Environmental Response, Compensation, and Liability Act, (CERCLA) 42 U.S.C. 9601 et seq. (1980). Additionally, monitoring the chemical and physical characteristics of the carbon dioxide (e.g., isotopic signature, other constituents) may help distinguish the injectate from the native fluids and gases if unintended leakage from the storage reservoir

occurred. Injectate monitoring is required at a sufficient frequency to detect changes to any physical and chemical properties that may result in a deviation from the permitted specifications.

Calibration of transmitters used to monitor pressures, temperatures, and flow rates of CO_2 into the injection well at the injection well and at the verification well shall be conducted annually. Reports shall contain test equipment used to calibrate the transmitters, including test equipment manufacturers, model numbers, serial numbers, calibration dates and expiration dates.

Corrosion Monitoring Strategy

Corrosion coupon analyses will be conducted quarterly to aid in ensuring the mechanical integrity of the equipment in contact with the carbon dioxide. Coupons shall be sent quarterly to a company for analysis (e.g., SGS) and an analysis conducted in accordance with NACE Standard RP-0775 (or similar) to determine and document corrosion wear rates based on mass loss.

Shallow Groundwater Monitoring Strategy

Lorain does not anticipate drilling shallow groundwater wells.

Deep Groundwater Monitoring Strategy

Monitoring of the deeper USDW and the Upper (Conasuaga) and Lower (Rome) confining zones will be used for early leakage detection in formations that are much closer to the Mt. Simon Sandstone injection reservoir. Fluid sampling at wells MW #1, and MW #2 in combination with pressure monitoring, temperature monitoring, and pulse neutron logging will be used to determine if leakage is occurring at or near the injection well. The Conasuaga is directly above the Rome formation and any pressure increase would detect a failure of the lower confining zone should it occur. MIT testing and DTS monitoring at the injection well will also provide data to ensure the mechanical integrity of the well is maintained. With the planned sampling and monitoring frequencies, it is expected that baseline conditions can be documented, natural variability in conditions can be characterized, unintended brine or CO_2 leakage could be detected if it occurred, and sufficient data will be collected to demonstrate that the effects of CO_2 injection are limited to the intended storage reservoir. No groundwater fluid sampling is planned for the Mt Simon intervals where free phase CO_2 has broken through.

MW #2 Sampling

The geophysical monitoring well, MW #2, will be used for fluid sampling of the USDW, fluid sampling will occur using a portable swabbing rig or other available sampling technologies. Samples will be analyzed for constituents listed in Table 5 to document baseline fluid chemistry and to detect changes in fluid chemistry that could result from the movement of brine or CO_2 from the storage interval through the seal formation.

MW #1 Sampling

The verification well, MW #1, will allow monitoring within the Mt. Simon injection zone. This well will serve as an early leak detection system by allowing the operator to monitor for changes above the primary caprock. Pressure and temperature will be continuously monitored and recorded in the perforated intervals in the Mt. Simon and USDW with a two-packer system. The pressure inside the tubing just above the uppermost packer will be monitored and recorded. At prescribed frequencies (in consultation with USEPA), fluid sampling will occur by opening the appropriate sliding sleeve across from the zone to be sampled (either USDW or Mt. Simon). Each sample interval will be analyzed for constituents list in Table 7 for the Mt. Simon to document baseline fluid chemistry and to detect changes in fluid chemistry that could result from the movement of brine or CO_2 from the storage interval through the seal formation.

B.1.b Type and Number of Samples/Test Runs

Groundwater sampling frequencies are detailed in Table 1.

CO_2 gas stream and corrosion coupon frequencies are detailed in Table 1.

B.1.c. Site/Sampling Locations

Deep groundwater monitoring will use existing wells MW #1 and MW #2 (Figure 2) as noted in Section B.1.a. CO_2 gas stream and corrosion coupon sampling locations will occur in the compressor building after the last stage of compression.

B.1.d. Sampling Site Contingency

The shallow and deep groundwater monitoring wells are located on property of the project participants (e.g., Lorain) and access permissions have already been granted. No problems of site inaccessibility are anticipated. If inclement weather makes site access difficult, sampling schedules will be reviewed, and alternative dates may be selected that would still meet permit-related conditions.

No problems of site inaccessibility are anticipated for CO_2 gas stream or corrosion coupon sampling. If inclement weather makes site access difficult, sampling schedules will be reviewed, and alternative dates may be selected that would still meet permit related conditions.

B.1.e. Activity Schedule

The groundwater sampling activities and frequencies are summarized in Table 1. The CO_2 gas stream and corrosion coupon sampling activities and frequencies are summarized in Table 1.

B.1.f. Critical/Informational Data

During both groundwater sampling and analytical efforts, detailed field and laboratory documentation will be taken. Documentation will be recorded in field and laboratory forms and notebooks. Critical information will include time and date of activity, person/s performing activity, location of activity (well-field sampling) or instrument (lab analysis), field or laboratory instrument calibration data, field parameter values. For laboratory analyses, much of the critical data are generated during the analysis and provided to end users in digital and printed formats. Noncritical data may include appearance and odor of the sample, problems with well or sampling equipment, and weather conditions.

B.1.g. Sources of Variability

Potential sources of variability related to monitoring activities include (1) natural variation in fluid quality, formation pressure and temperature and seismic activity; (2) variation in fluid quality, formation pressure and temperature, and seismic activity due to project operations; (3) changes in recharge due to rainfall, drought, and snowfall; (4) changes in instrument calibration during sampling or analytical activity; 5) different staff collecting or analyzing samples; (6) differences in environmental conditions during field sampling activities; (7) changes in analytical data quality during life of project; and (8) data entry errors related to maintaining project database.

Activities to eliminate, reduce, or reconcile variability related to monitoring activities include (1) collecting long-term baseline data to observe and document natural variation in monitoring parameters, (2) evaluating data in timely manner after collection to observe anomalies in data that can be addressed be resampled or reanalyzed, (3) conducting statistical analysis of monitoring data to determine whether variability in a data set is the result of project activities or natural variation, (4) maintaining weather-related data using on-site weather monitoring data or data collected near project site (such as from local airports), (5) checking instrument calibration before, during and after sampling or sample analysis, (6) thoroughly training staff, (7) conducting laboratory quality assurance checks using third party reference materials, and/or blind and/or replicate sample checks, and (8) developing a systematic review process of data that can include sample-specific data quality checks (i.e., cation/anion balance for aqueous samples).

B.2. Sampling Methods

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section and is omitted.

B.2.a/b. Sampling SOPs

Groundwater samples will be collected primarily using a low-flow sampling method consistent with ASTM D6452-99 (2005) or Puls and Barcelona (1996). If a flow-through cell is not used, field parameters will be measured in grab samples. Groundwater wells will be purged to ensure samples are representative of formation water quality. Static water levels in each well will be determined using an

electronic water level indicator before any purging or sampling activities begin. Dedicated pumps (e.g., bladder pumps) will be installed in each monitoring well to minimize potential cross contamination between wells. Groundwater pH, temperature, specific conductance, and dissolved oxygen will be monitored in the field using portable probes and a flow-through cell consistent with standard methods (e.g., APHA, 2005) given sufficient flow rates and volumes. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions. When a flow-through cell is used, field parameters will be continuously monitored and will be considered stable when three successive measurements made three minutes apart meet the criteria listed in Table 13.

Table 13. Stabilization criteria of water quality parameters during shallow well purging.

FIELD PARAMETER	STABILIZATION CRITERIA
pH	+/- 0.2 units
Temperature	+/- 1°C
Specific Conductance	+/- 3% of reading in µS/cm
Dissolved Oxygen	+/- 10% of reading or 0.3 mg/L whichever is greater

After field parameters have stabilized, samples will be collected. Samples requiring filtration will be filtered through 0.45 µm flow-through filter cartridges as appropriate and consistent with ASTM D6564-00. Prior to sample collection, filters will be purged with a minimum of 100 mL of well water (or more if required by the filter manufacturer). For alkalinity and total CO_2 samples, efforts will be made to minimize exposure to the atmosphere during filtration, collection in sample containers, and analysis.

For deep groundwater sampling, it is anticipated to use a wireline sampling system with a sampling device (e.g., Kuster sampler or similar) capable of collecting a sample from a discrete interval. Samples from MW #1 and MW #2 will be processed in a manner consistent with Lorain's SOP. Prior to sampling, each zone will be purged to ensure representative samples are collected.

It is possible that air lifting with nitrogen will be used to draw fluid into the well for purging. A gas lift valve may be placed in the tubing string at the time of the completion to assist with air lifting. The sampler (run on wireline) will be positioned at the same elevation as the discrete perforated interval, and a sample would be collected after sufficient purging.

B.2.c. In-situ Monitoring.

In-situ monitoring of groundwater chemistry parameters is not currently planned.

B.2.d. Continuous Monitoring.

Pressure data will be collected from shallow groundwater wells on a periodic basis (e.g., hourly to daily) using dedicated pressure transducers with data loggers to generally characterize shallow water level trends. These data are informational only.

B.2.e. Sample Homogenization, Composition, Filtration.

Described in section B.2.b.

B.2.f. Sample Containers and Volumes

For CO_2 stream monitoring, samples will be collected in a clean sample container rated for the appropriate collection pressure (i.e. mini cylinders or polybags provided by Airborne Labs International Inc., Somerset, NJ).

Assay for CO_2 Quarterly Gas Analysis:

- CO_2 Purity (% v/v, [GC])
- Oxygen (O2, ppm v/v)
- Nitrogen (N2, ppm v/v)
- Carbon Monoxide (CO, ppm v/v)
- Oxides of Nitrogen (NOx, ppm v/v)
- Total Hydrocarbons (THC, ppm v/v as CH4)
- Methane (CH4, ppm v/v)
- Acetaldehyde (AA, ppm v/v)
- Sulfur Dioxide (SO2, ppm v/v)
- Hydrogen Sulfide (H2S ppm v/v)
- Ethanol (ppm v/v)

For shallow and deep groundwater samples, all sample bottles will be new. Sample bottles and bags for analytes will be used as received (ready for use) from the vendor or contract analytical laboratory for the analyte of interest. A summary of sample containers is presented in Table 22.

B.2.g. Sample Preservation

For groundwater and other aqueous samples, the preservation methods in Table 15 will be used.

No preservation is required or used for CO_2 gas stream, and additional details of sampling requirements are shown in Table 14. Corrosion coupon sampling only requires that the coupons be physically separated (e.g., sleeves, baggies) during transportation to prevent physical abrasion.

Table 14. Summary of sample containers, preservation treatments, and holding times for CO_2 gas stream analysis.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time (Max)
CO_2 gas stream	(2) 2L MLB Polybags (1) 75 cc Mini Cylinder	Sample Storage Cabinets	5 Business Days

B.2.h. Cleaning/Decontamination of Sampling Equipment

Dedicated pumps (e.g., bladder pumps) will be installed in each groundwater monitoring well to minimize potential cross contamination between wells. These pumps will remain in each well throughout the project period except for maintenance. Prior to installation, the pumps will be cleaned on the outside with a non-phosphate detergent. Pumps will be rinsed a minimum of three times with deionized water and a minimum of 1 L of deionized water will be pumped through pump and sample tubing. Individual cleaned pumps and tubing will be placed in plastic garbage bags for transport to the field for installation. All field glassware (pipets, beakers, filter holders, etc.) are cleaned with tap water to remove any loose dirt, washed in a dilute nitric acid solution, and rinsed three times with deionized water before use.

CO_2 gas stream sampling containers will be either disposed or decontaminated by the analytical lab. No sampling equipment will be utilized with the corrosion coupons or annual field gauge calibrations.

B.2.i Support Facilities

For sampling of groundwater, the following are required: air compressor, vacuum pump, generator, multi-electrode water quality sonde, analytical meters (pH, specific conductance, etc.). Field activities are usually completed in field vehicles and portable laboratory trailers located on site.

Sampling tubing, connectors and valves required to sample the CO_2 gas stream will be supplied by the analytical lab providing the sampling containers. Sampling will occur within the existing CO_2 compression building.

Similarly, corrosion coupons will be removed from the CO_2 injection line within the existing CO_2 compression building.

Field gauges will be removed from the injection well and verification well utilizing existing standard industry tools and equipment. Deployment and retrieval of verification well gauges will be done using procedures and equipment recommended by the vendor, subcontractor, or is standard per industry practice.

B.2.j. Corrective Action, Personnel, and Documentation

Field staff will be responsible for properly testing equipment and performing corrective actions on broken or malfunctioning field equipment. If corrective action cannot be taken in the field, then equipment will be returned to the manufacturer for repair or replaced. Significant corrective actions affecting analytical results will be documented in field notes.

B.3. Sample Handling and Custody

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section and is omitted.

Sample holding times (Table 22) will be consistent with those described in US EPA (1974), American Public Health Association (APHA, 2005), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at approximately 4°C until analysis. The samples will be maintained at their preservation temperature and sent to the designated laboratory within 24 hours. Analysis of the samples will be completed within the holding time listed in Table 22. As appropriate, alternative sample containers and preservation techniques approved by the UIC Program Director will be used to meet analytical requirements.

B.3.a Maximum Hold Time/Time Before Retrieval

See Table 22.

B.3.b. Sample Transportation

See description at the beginning of Section B.3.

B.3.c. Sampling Documentation

Field notes will be collected for all groundwater samples collected. These forms will be retained and archived as reference. The sample documentation is the responsibility of groundwater sampling personnel.

An analysis authorization form shall be provided with each CO_2 gas stream sample provided for analysis as shown by the example in Figure 4.

B.3.d. Sample Identification

All sample bottles will have waterproof labels with information denoting project, sampling date, sampling location, sample identification number, sample type (freshwater or brine), analyte, volume, filtration used (if any), and preservative used (if any). See Figure 3 for an example of a label.

Table 15. Summary of anticipated sample containers, preservation treatments, and holding times.

Target Parameters	*Volume/Container Material*	*Preservation Technique*	*Sample Holding Time*	*Relative Sampling Depth*
Cations: Ca, Fe, K, Mg, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Ti	250 ml/HDPE	Filtered, nitric acid, cool 4°C	60 days	Shallow
Dissolved CO_2	2 × 60 ml/HDPE	Filtered, cool 4°C	14 days	Shallow
Dissolved CO_2	60 ml/HDPE	Filtered, cool 4°C	14 days	Deep
Isotopes: 3H, δD, δ18O, δ34S, and δ13C	2 × 60 ml/HDPE	Filtered, cool 4°C	4 weeks	Shallow
Isotopes: δ34S	250 ml/HDPE	Filtered, cool 4°C	4 weeks	Deep
Isotopes: δD, δ18O, δ13C	60 ml/HDPE	Filtered, cool 4°C	4 weeks	Deep
Alkalinity, anions (Br, Cl, F, NO3, SO4	500 ml/HDPE	Filtered, cool 4°C	4 weeks	Shallow
Field Confirmation: Temperature, dissolved oxygen, specific conductance, pH	200 ml/glass jar	None	< 1 hour	Deep
Field Confirmation: Density	60 ml/HDPE	Filtered	< 1 hour	Deep

IL-ICCS_10LG_20A (fresh water)
01-23-2014
Metals, 60 ml, filtered, HNO_3

Figure 3*. Example label for groundwater sample bottles.*

B.3.e. Sample Chain-of-Custody

For CO_2 stream analysis, an analysis authorization form (Figure 4) will accompany the sample to the lab at which point a chain-of-custody accompanies the sample through their processes.

For groundwater samples, chain-of-custody will be documented using a standardized form. A typical form is shown in Figure 5, and it or a similar form will be used for all groundwater sampling. Copies of the form will be provided to the person/lab receiving the samples as well as the person/lab transferring the samples. These forms will be retained and archived to allow simplified tracking of sample status. The chain-of -custody form and record keeping is the responsibility of groundwater sampling personnel.

B.4. Analytical Methods

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section and is omitted.

B.4.a. Analytical SOPs

Analytical SOPs are referenced in Table 4-Table 7. Other laboratory specific SOPs utilized by the laboratory will be determined after a contract laboratory has been selected. Upon request Lorain will provide the agency with all laboratory SOPs developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the samples will be trained on the SOP developed for each standard method. Lorain will include the technician's training certification with the biannual report.

B.4.b. Equipment/Instrumentation Needed

Equipment and instrumentation are specified in the individual analytical methods referenced in Table 4-Table 7.

B.4.c. Method Performance Criteria

Nonstandard method performance criteria are not anticipated for this project.

B.4.d. Analytical Failure

Each laboratory conducting the analyses in Table 4-Table 7 will be responsible for appropriately addressing analytical failure according to their individual SOPs.

B.4.e. Sample Disposal

Each laboratory conducting the analyses in in Table 4-Table 7 will be responsible for appropriate sample disposal according to their individual SOPs.

B.4.f Laboratory Turnaround

Laboratory turnaround will vary by laboratory, but generally turnaround of verified analytical results within one month will be suitable for project needs.

B.4.g. Method Validation for Nonstandard Methods

Nonstandard methods are not anticipated for this project. If nonstandard methods are needed or proposed in the future, the USEPA will be consulted on additional appropriate actions to be taken.

Airborne Labs International, Inc.

22C World's Fair Drive, Somerset, NJ 08873 Fax: 732-302-3035 Phone: 732-302-1950
E-mail: airbornelabs@aol.com Website: www.airbornelabs.com

Analysis Authorization

*This form **MUST** be completed & returned with a sample shipment*

1.) Report Results to*:

Company: _____
Address: _____
Address: _____
Address: _____
Address: _____
Attention: _____
Telephone: (_____)_____
Fax: (_____)_____
E-Mail: _____

Sampled On (mm/dd/yy): _____
P.O. #: _____
Credit Card: Visa Amex MasterCard Discover
Card #: _____
Cardholder: _____
Exp. Date: _____
Check #: _____
Other: _____
Pricing Discussed/Quoted? Y N

*Please attach complete billing address if different from reporting address.

2.) Number of Samples Submitted: _____ Container Type(s): _____

3.) Sample Description (circle): Liquid CO_2 CO2 (Final) Vapor CO2 Feedgas* CO_2 In-Process Food Grade CO_2 LIN LOX LAR RELOX (Reboiler) ABO

*IF CO_2 Feedgas –Identify source (e.g. Ethanol/Ammonia/Nat. Well/Ethylene/Combustion, Self-Gen, etc.) _____

Aviator Breathing Oxygen (ABO) Natural Gas Refinery Gas Syn Gas Propane Butane Air Oxygen Nitrogen Argon Hydrogen Helium Neon Xenon Krypton Freon® Refrigerant Gas Mixture Fuel Oil Lubricant

Other (Describe): _____

4.) Sample Type (Check) : Industrial____ Medical_____ MilSpec_____ Other_____
(attach a log for multiple samples)

5.) Sample ID: _____

6.) Potential Hazards/Safety Issues: _____

7.) Analytical Test(s) Requested (check program or select individual tests required where applicable):

Std ISBT/Vendor CO_2 Test Program_____ Std CO_2 Feedgas Program_____ Std CGA Test Program_____ Std Medical Gas_____
Std Contract Program_____ Std ASTM Test Program____ MIL Spec Test Program____

%Purity THC CH_4 TNMHC Vol Hydrocarbons (C1-C6) BTEX Water Vapor NVR/NVOR Oil/Grease Total Sulfur H_2S SO_2 COS MeSH t-Butyl Mercaptan Vol Sulfur Compnds Odorants Total Nitrogen N_2 NO_x NH_3 NO NO_2 HCN Nitrous Oxide (N_2O) PH_3 Oxygen Argon Hydrogen Helium CO CO_2 Xenon Neon Krypton Vinyl Chloride Acetaldehyde Vol Oxygenates GC/MS Scan IR Scan IR Microscope Halogenated Hydrocarbons SF_6 Gas Mixture% Btu (Heat) Content % CHNO Sediment Wt Patch Test Viscosity Flash/Fire Point Density Specific Gravity Trace Metals TAN TBN XRF SEM-XRF Scan Light Microscope

Other Testing: _____

8.) Sample Disposition

Retain for _____ Period Perform Clean-up/Maintenance Actions & Return* ____ Report for Instructions ____

Other: _____

*Supply all return address & shipping instructions

9.) Report Disposition (circle one): E-Mail Fax Mail Telephone Other:_____
(Reports will be sent to the address & contact(s) specified at the top of this form)

10.) Priority Conditions (circle), Note: Additional fees will apply for non-std test scheduling:

Standard 2-Work Day 1-Work Day Same Day Emergency Other:_____

Analytical testing cannot be performed unless this form is completed & returned

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Figure 4. *Example of CO_2 gas stream analysis authorization form*

PRAIRIE RESEARCH INSTITUTE

CHAIN OF CUSTODY RECORD (Page __ of __)

Illinois State Water Survey – Analytical Services Group
Illinois State Geological Survey – Geochemistry Section

For Midwest Geological Sequestration Consortium (MGSC) Projects

	MGSC ID	ISGS MVA ID	Matrix	Date Collected	Time Collected	Sampling Team	Circle analyses to be performed
1							anions, cations, TDS, alk, NH_3, NVOC
2							anions, cations, TDS, alk, NH_3, NVOC
3							anions, cations, TDS, alk, NH_3, NVOC
4							anions, cations, TDS, alk, NH_3, NVOC
5							anions, cations, TDS, alk, NH_3, NVOC
6							anions, cations, TDS, alk, NH_3, NVOC
7							anions, cations, TDS, alk, NH_3, NVOC
8							anions, cations, TDS, alk, NH_3, NVOC
9							anions, cations, TDS, alk, NH_3, NVOC
10							anions, cations, TDS, alk, NH_3, NVOC
11							anions, cations, TDS, alk, NH_3, NVOC
12							anions, cations, TDS, alk, NH_3, NVOC
12							

CHAIN OF CUSTODY		
Relinquished by:	Print Name:	Date and Time:
Received by:	Print Name:	Date and Time:
General Remarks: - Field parameters are to be recorded on separate sheets by sampling teams. - Any special laboratory instructions or remarks should be made below.		
Data Contacts:	Fund:	
Billing Contact:	Billing Address:	
Send Data To:		

Remarks:

Rev. Oct. 2011 (RL)

Figure 5. *Example Chain-of-Custody Form*

B.5. Quality Control

Geophysical monitoring and pressure/temperature monitoring does not apply to this section and is omitted. For log quality control, please refer to Appendix B.

B.5.a. QC activities

Blanks

For shallow groundwater sampling, a field blank will be collected and analyzed for the inorganic analytes in Table 4-Table 7 at a frequency of 10% or greater. Field blanks will be exposed to the same field and transport conditions as the groundwater samples. Blanks will also be utilized for deep groundwater sampling and analyzed for the inorganic analytes in Table 4-Table 7 at a frequency of 10% or greater. Field blanks will be used to detect contamination resulting from the collection and transportation process.

Duplicates

For each shallow groundwater sampling round, a duplicate groundwater sample is collected from a well from a rotating schedule. Duplicate samples are collected from the same source immediately after the original sample in different sample containers and processed as all other samples. Duplicate samples are used to assess sample heterogeneity and analytical precision.

B.5.b. Exceeding Control Limits

If the sample analytical results exceed control limits (i.e., ion balances > ±10%), further examination of the analytical results will be done by evaluating the ratio of the measured total dissolved solids (TDS) to the calculated TDS (i.e., mass balance) per APHA method. The method indicates which ion analyses should be considered suspect based on the mass balance ratio. Suspect ion analyses are then reviewed in the context of historical data and interlaboratory results, if available. Suspect ion analyses are brought to the attention of the analytical laboratory for confirmation and/or reanalysis. The ion balance is recalculated, and if the error is still not resolved, suspect data are identified and may be given less importance in data interpretations.

B.5.c. Calculating Applicable QC Statistics

Charge Balance

The analytical results are evaluated to determine correctness of analyses based on anion-cation charge balance calculation. Because all potable waters are electrically neutral, the chemical analyses should yield equally negative and positive ionic activity. The anion-cation charge balance will be calculated using the formula:

$$\%\, difference = 100 * \frac{\Sigma\, Cations - \Sigma\, Anions}{\Sigma\, Cations + \Sigma\, Anions} \qquad \text{(Equation 1)}$$

where the sums of the ions are represented in milliequivalents (meq) per liter and the criteria for acceptable charge balance is ±10%

Mass Balance

The ratio of the measured TDS to the calculated TDS will be calculated in instances where the charge balance acceptance criteria are exceeded using the formula:

$$1.0 < \frac{measured\ TDS}{calculated\ TDS} < 1.2, \qquad \text{(Equation 2)}$$

where the anticipated values are between 1.0 and 1.2.

Outliers

A determination of one or more statistical outliers is essential prior to the statistical evaluation of groundwater. This project will use the USEPA's Unified Guidance (March 2009) as a basis for selection of recommended statistical methods to identify outliers in groundwater chemistry data sets as appropriate. These techniques include Probability Plots, Box Plots, Dixon's test, and Rosner's test. The EPA-1989 outlier test may also be used as another screening tool to identify potential outliers.

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

Logging tool equipment will be maintained as per wireline industry best practices (Appendix B).

For groundwater sampling, field equipment will be maintained, factory serviced, and factory calibrated per manufacturer's 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 standard practice, method-specific protocol, or NELAP requirement.

B.7. Instrument/Equipment Calibration and Frequency

Geophysical monitoring does not apply to this section and is omitted.

B.7.a. Calibration and Frequency of Calibration

Pressure/temperature gauge calibration information is located in Table 12-Table 17. Logging tool calibration will be at the discretion of the service company providing the equipment, following standard industry practices noted in Appendix B. Calibration frequency will be determined by standard industry practices.

For groundwater sampling, portable field meters or multiprobe sondes used to determine field parameters (e.g., pH, temperature, specific conductance, dissolved oxygen) are calibrated according to

manufacturer recommendations and equipment manuals (Hach, 2006) each day before sample collection begins. Recalibration is performed if any components yield atypical values or fail to stabilize during sampling.

B.7.b. Calibration Methodology

Logging tool calibration methodology will follow standard industry practices in Appendix B.

For groundwater sampling, standards used for calibration are typically 7 and 10 for pH, a potassium chloride solution yielding a value of 1413 microsiemens per centimeter (µS/cm) at 25°C for specific conductance, and a 100% dissolved O_2 solution for dissolved oxygen. Calibration is performed for the pH meters per manufacturer's specifications using a 2-point calibration bounding the range of the sample. For coulometry, sodium carbonate standards (typically yielding a concentration of 4,000 mg CO_2 /L) are routinely analyzed to evaluate instrument.

B.7.c. Calibration Resolution and Documentation

Logging tool calibration resolution and documentation will follow standard industry practices in Appendix B.

For groundwater sampling, calibration values are recorded in daily sampling records and any errors in calibration are noted. For parameters where calibration is not acceptable, redundant equipment may be used so loss of data is minimized.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.a/b. Supplies, Consumables, and Responsibilities

Supplies and consumables for field and laboratory operations will be procured, inspected, and accepted as required from vendors approved by Lorain or the respective subcontractor responsible for the data collection activity. Acquisition of supplies and consumables related to groundwater analyses will be the responsibility of the laboratory per established standard methodology or operating procedures.

B.9. Nondirect Measurements

Seismic Monitoring Methods

B.9.a Data Sources

For time lapse seismic surveys, repeatability is paramount for accurate differential comparison. Therefore, to ensure survey quality, the locations for the shots and acquisition methodology of sequential surveys will be consistent. Once these surveys are conducted, they will be compared to a baseline survey to track and monitor plume development.

For in-zone pressure monitoring, the in-zone pressure gauges in MW#2 will be used to gather pressure data.

B.9.b. Relevance to Project

Time lapse seismic surveys will be used to track changes in the CO_2 plume in the subsurface. Processing and comparing subsequent surveys to a baseline will allow project managers to monitor plume growth, as well as to ensure that the plume does not move outside of the intended storage reservoir. Numerical modeling will be used to predict the CO_2 plume growth and migration over time by combining the processed seismic data with the existing geologic model.

In-zone pressure monitoring data will be used in numerical modeling to predict plume and pressure front behavior and confirm the plume stage within the AOR.

B.9.c. Acceptance Criteria

Following standard industry practices will ensure that the gathered seismic data will be used for accurate modeling and monitoring. Similar ground conditions, shot points located within tolerable limits, functional geophones, and similar seismic input signal will be used from survey to survey to ensure repeatability.

When processing seismic data, several QA checks will be done in accordance with industry standards including reformatting to Omega structured files, geometry application, amplitude compensation, predictive deconvolution, elevation statics correction, RMS amplitude gain, velocity analysis every 2 km, NMO application using picked velocities, CMP stacking, random noise attenuation, and instantaneous gain.

B.9.d. Resources/Facilities Needed

Lorain will subcontract all necessary resources and facilities for the seismic monitoring, in-zone pressure monitoring, and groundwater sampling.

B.9.e. Validity Limits and Operating Conditions

For seismic surveys and numerical modeling, intraorganizational checks between trained and experienced personnel will ensure that all surveys and numerical modeling are conducted conforming to standard industry practices.

B.10. Data Management

B.10.a. Data Management Scheme

Lorain or a designated contractor will maintain the required project data as provided elsewhere in the permit. Data will be backed up on tape or held on secure servers.

B.10.b. Record-keeping and Tracking Practices

All records of gathered data will be securely held and properly labeled for auditing purposes.

B.10.c. Data Handling Equipment/Procedures

All equipment used to store data will be properly maintained and operated according to proper industry techniques. Lorain SCADA system and vendor data acquisition systems will interface with one another and all subsequent data will be held on a secure server.

B.10.d. Responsibility

The primary project managers will be responsible for ensuring proper data management is maintained.

B.10.e. Data Archival and Retrieval

All data will be held by Lorain. These data will be maintained and stored for auditing purposes as described in section B.10.a.

B.10.f. Hardware and Software Configurations

All Republic and vendor hardware and software configurations will be appropriately interfaced.

B.10.g. Checklists and Forms

Checklists and forms will be procured and generated as necessary.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.a. Activities to be Conducted

Please refer to Table 1 in section A.3.a/b. (Summary of work to be performed and work schedule); groundwater quality data will be collected at the frequency outlined in that table. After completion of sample analysis, results will be reviewed for QC criteria as noted in section B.5. If the data quality fails to meet criteria set in section B.5., samples will be reanalyzed, if still within holding time criteria. If outside of holding time criteria, additional samples may be collected, or sample results may be excluded from data evaluations and interpretations. Evaluation for data consistency will be performed according to procedures described in the USEPA 2009 Unified Guidance (USEPA, 2009).

C.1.b. Responsibility for Conducting Assessments

Organizations gathering data will be responsible for conducting their internal assessments. All stop work orders will be handled internally within individual organizations.

C.1.c. Assessment Reporting

All assessment information should be reported to the individual organizations project manager outlined in A.1.a/b.

C.1.d. Corrective Action

All corrective action affecting only an individual organization's data collection responsibility should be addressed, verified, and documented by the individual project managers and communicated to the other project managers as necessary. Corrective actions affecting multiple organizations should be addressed by all members of the project leadership and communicated to other members on the distribution list for the QASP. Assessments may require integration of information from multiple monitoring sources across organizations (operational, in-zone monitoring, above-zone monitoring) to determine whether correction actions are required and/or the most cost-efficient and effective action to implement. Lorain will coordinate multiorganization assessments and corrective actions as warranted.

C.2. Reports to Management

C.2.a/b. QA status Reports

QA status reports should not be needed. If any testing or monitoring techniques are changed, the QASP will be reviewed and updated as appropriate in consultation with USEPA. Revised QASPs will be distributed by Lorain to the full distribution list at the beginning of this document.

D. Data Validation and Usability

D.1. Data Review, Verification, and Validation

D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Groundwater quality data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All groundwater quality results will be entered into a database or spreadsheet with periodic data review and analysis. Lorain will retain copies of the laboratory analytical test results and/or reports. Analytical results will be reported on a frequency based on the approved UIC permit conditions. In the periodic reports, data will be presented in graphical and tabular formats as appropriate to characterize general groundwater quality and identify intrawell variability with time. After sufficient data have been collected, additional methods, such as those described in the USEPA 2009 Unified Guidance (USEPA, 2009), will be used to evaluate intrawell variations for groundwater constituents, to evaluate if significant changes have occurred that could be the result of CO_2 or brine seepage beyond the intended storage reservoir.

D.2. Verification and Validation Methods

D.2.a. Data Verification and Validation Processes

See sections D.1.a. and B.5.

Appropriate statistical software will be used to determine data consistency.

D.2.b. Data Verification and Validation Responsibility

Lorain or its designated subcontractor will verify and validate groundwater sampling data.

D.2.c. Issue Resolution Process and Responsibility

Lorain or its designated Coordinator will overview the groundwater data handling, management, and assessment process. Staff involved in these processes will consult with the Coordinator to determine actions required to resolve issues.

D.2.d. Checklist, Forms, and Calculations

Checklists and forms will be developed specifically to meet permit requirements. Table 23 provides an example of the type of information used for data verification of groundwater quality data.

Table 23...

D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

Statistical software will be used to determine groundwater data consistency using methods consistent with USEPA 2009 Unified Guidance (USEPA, 2009).

D.3.b. Data Limitations Reporting

The organization-level project managers will be responsible for ensuring that data developed by their respective organizations is presented with the appropriate data-use limitations.

Lorain will use the current operating procedure on the use, sharing, and presentation of results and/or data for the IL-ICCS project. This procedure has been developed to ensure quality, internal consistency and facilitate tracking and record keeping of data end users and associated publications.

References

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Appendices

APPENDIX A. DTS and Down-hole Pressure Gauge Information

SureVIEW™ with CoreBright™ Optical Fiber

Ensure industry-leading protection against hydrogen darkening in high-temperature applications

SureVIEW™ downhole cable by Baker Hughes uses CoreBright™ optical fiber, which leads the industry in hydrogen darkening resistance, the primary cause of failure for fiber optic systems in high- temperature applications. CoreBright fiber is constructed from pure silica that minimizes hydrogen darkening. The cable also includes a layer of hydrogen- absorbing gel. This combination provides the industry's best protection against hydrogen darkening.

Fabricating a downhole optical cable with the performance and reliability demanded by the oil and gas industry requires a sophisticated understanding of fiber design, fiber coatings, cable manufacturing processes, and cable construction. Optical, chemical, and physical disciplines are combined with extensive oilfield experience to offer a superior cable.

CoreBright fiber offers its extended lifetime through a simple principle: Rather than attempt to avoid hydrogen damage by trying to block hydrogen (a near impossibility in enhanced oil recovery operations due to high temperatures), CoreBright optical fiber avoids the hydrogen damage by preventing the reaction between SiO_2 structure of the optical fiber and the hydrogen. Thus, CoreBright fiber tolerates the presence of hydrogen without suffering lifetime limiting damage.

In this way, our solution is unique: The fiber will never darken, and reliable readings over the full life of the installation are assured. Independent testing has concluded that CoreBright optical fiber is the only fiber in the industry that is suitable for oil and gas environments over a long duration; it is the only known fiber designed for, and has demonstrated, long-term immunity to first and second-order hydrogen darkening effects.[1]

Applications

- Downhole fiber optic monitoring systems

Features and Benefits

- Industry leading reliability
- Proprietary glass composition delivers industry-leading resistance to hydrogen darkening
- Extreme temperature rating
- 100% dynamically proof-tested before cabling

Multiple applications

- CoreBright fiber can be used in a variety of applications from SAGD to Leak Detection to Acid Stimulation and many more

Baker Hughes

Technical Specifications - SureVIEW Downhole	
Description	**Specifications**
Maximum Pressure	25,000 psi
Overpressure	1.2x maximum pressure
Operating Temperature	• 150°C / 302°F for standard • 250°C / 482°F for high temperature • Higher temperature solutions available upon request
Sheath Material	A825, 316LSS
Crush	>5,000lbf
Fibers	Maximum of 12, any combination of SM and MM
Fiber Protection	• Standard Temperature: Hydrogen-scavenging gel, carbon coating, acrylate buffer • High Temperature: High-temperature stabilized gel, polyimide buffer, optional carbon coating
Dimensions	0.25 inch outside diameter (excluding encapsulation)
Encapsulation Options	• 0.43 inch square encapsulation • 0.41 inch round encapsulation • Variety of encapsulation materials can be utilized

Call your local Baker Hughes representative today to learn more about how SureVIEW fiber optic monitoring solutions can reliably monitor and deliver the downhole wellbore and reservoir data you need, when you need it.

1. van Rooyen, A. (Royal Dutch Shell), "Fibre Testing at Elevated Temperatures Under Hydrogen Conditions", SEAFOM Industry Meeting (Dec. 2012)

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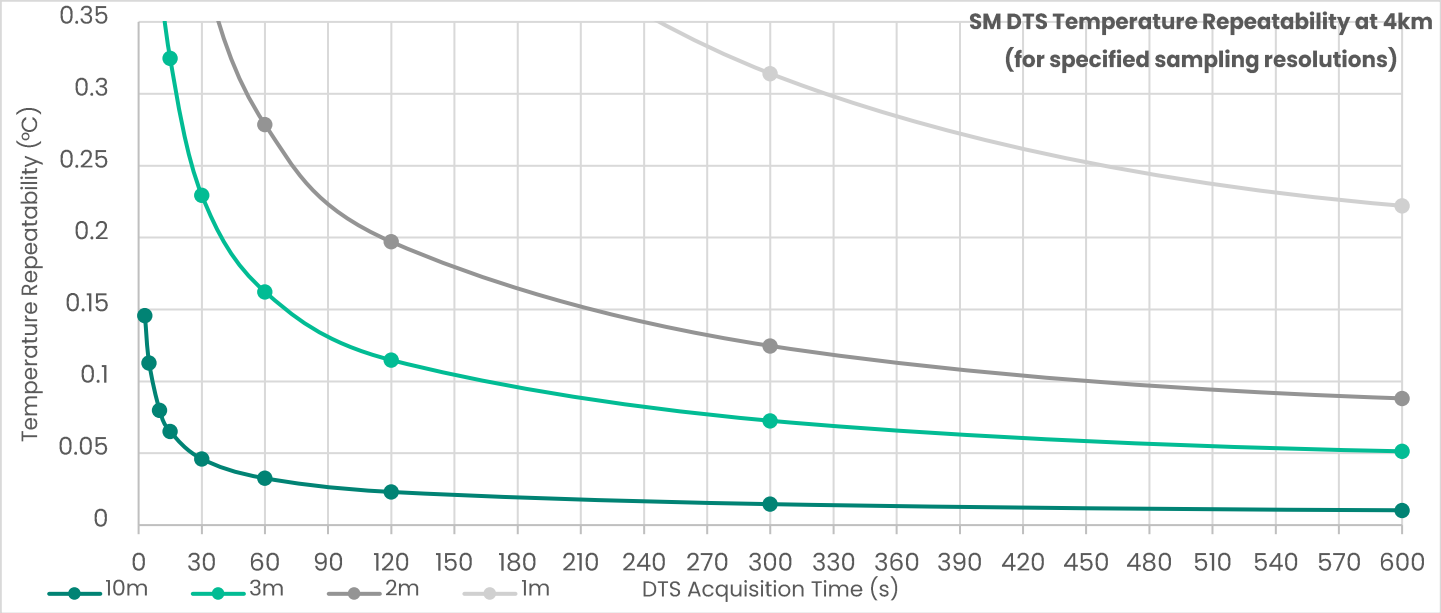
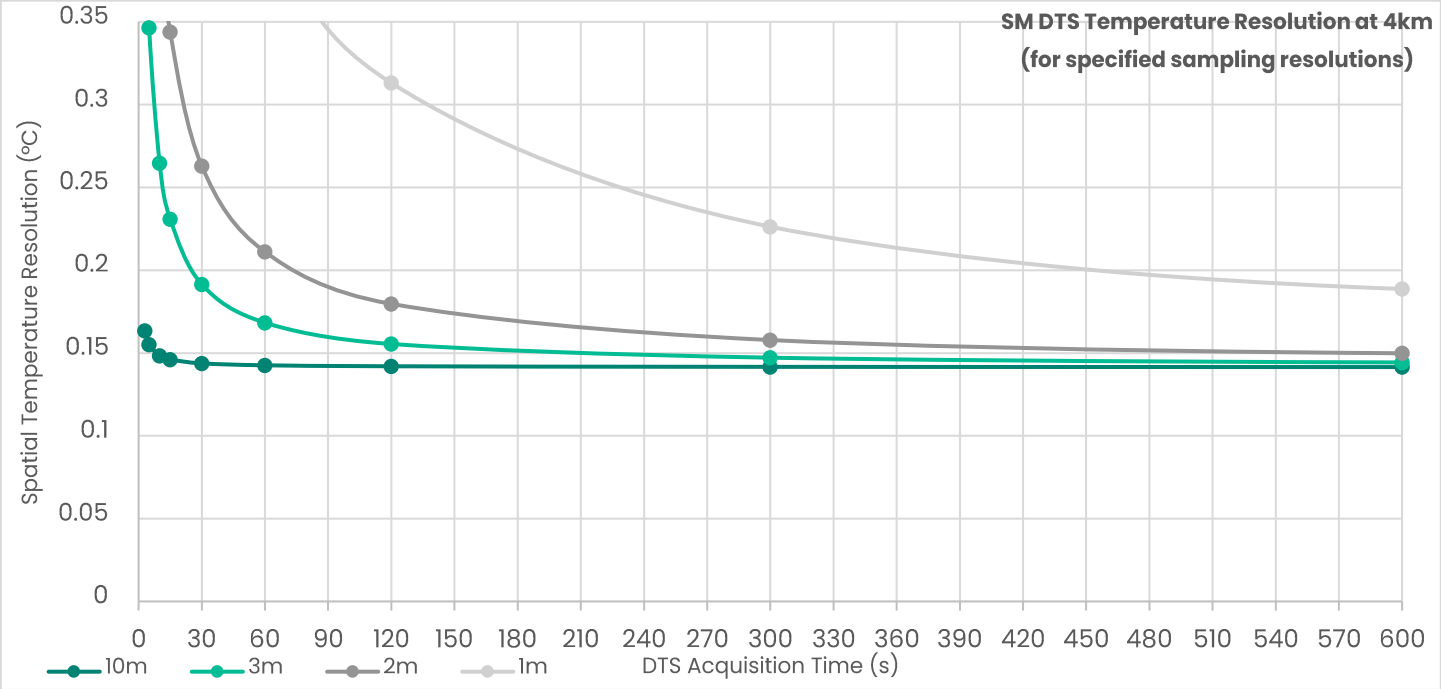
SureVIEW™ DTS Interrogator

The SureVIEW™ DTS fiber optic interrogator provides convenient multi-well performance monitoring with continuous, rapidly updating temperature profiles along the length of the completion. The interrogator is designed to provide highly accurate temperature data from a single SM fiber, which reduces cost by eliminating the need for dual-ended fibre configurations.

SureVIEW™ DTS Surface Interrogator Specifications	
Description	**Value**
Form Factor	19 in. Rack
Height	2U
Depth (in.)	19.8
Certifications	TUV (US, Can), CE
Public Software Interfaces	OPC/UA, Modbus
Maximum Distance Range (km)	20+
Minimum Spatial Resolution (m)	1.0
Minimum Sampling Interval (m)	0.33
Fastest Acquisition Rate (sec)	3.3
Number of Channels	8 or 16
Internal Data Storage Capability	250 GB
Fiber Types	9/125 µm SMF CoreBright™
Optical Connectors	Fiber Pigtails
Computer Interfaces	Ethernet, DPI, USB
Power Consumption (W)	100 W maximum

SureVIEW™ DTS Surface Interrogator Specifications	
Description	**Value**
Voltage Input	22-27 VDC
Differential Attenuation Compensation	Yes
Fiber Configuration	Single-Ended or J-Type
Absolute Temperature Accuracy (°C)	±2 (worst-case, rapid cycling over full operating range)
Operating temperature (°C)	0 to 40
Storage temperature (°C)	-40 to 80
Operating relative humidity (%)	5 to 95
Sensing temperature Range (°C)	0 to 300





Call your local Baker Hughes representative today to learn more about how SureVIEW monitoring systems can reliably enhance your production operations.

bakerhughes.com

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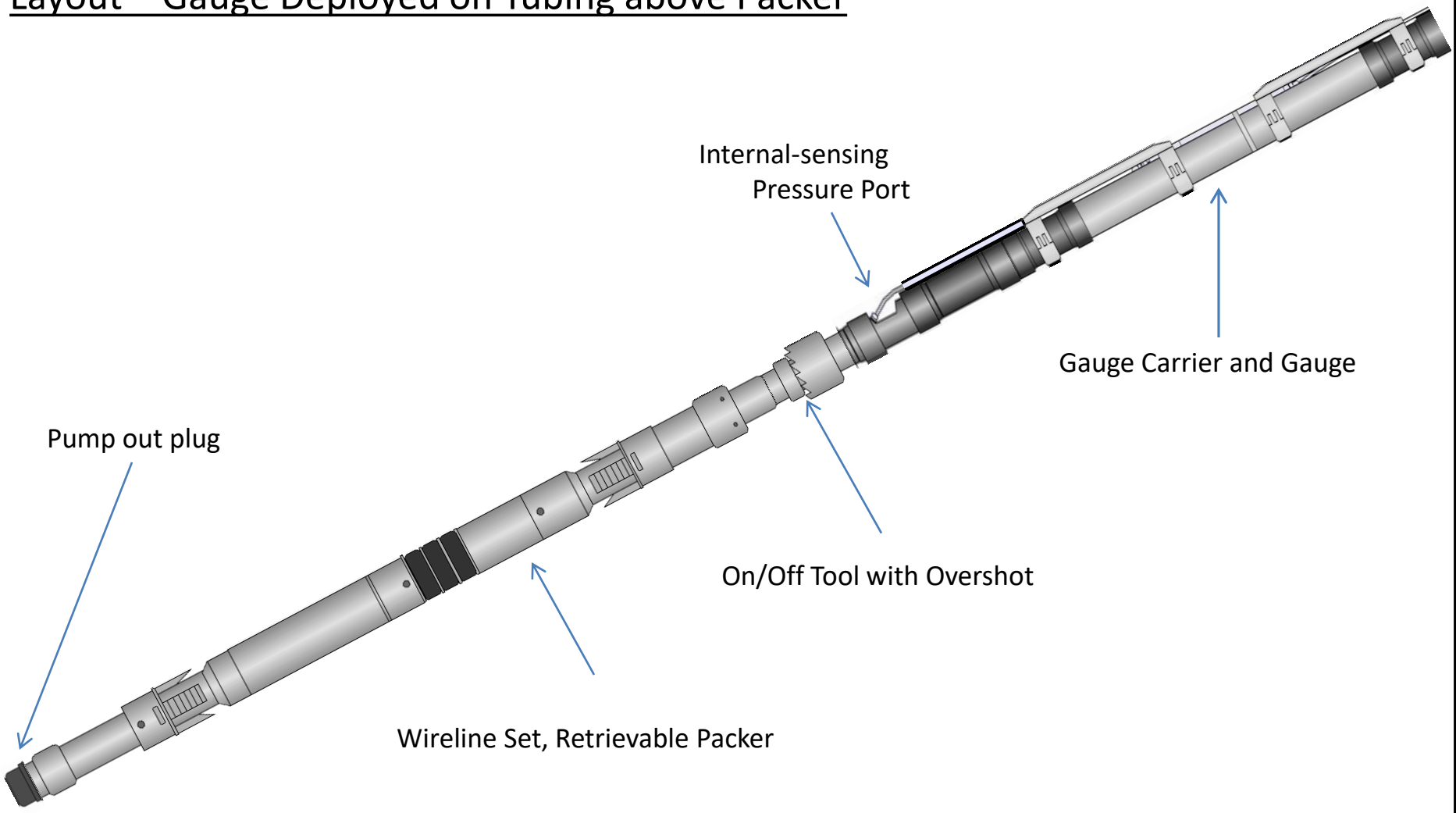
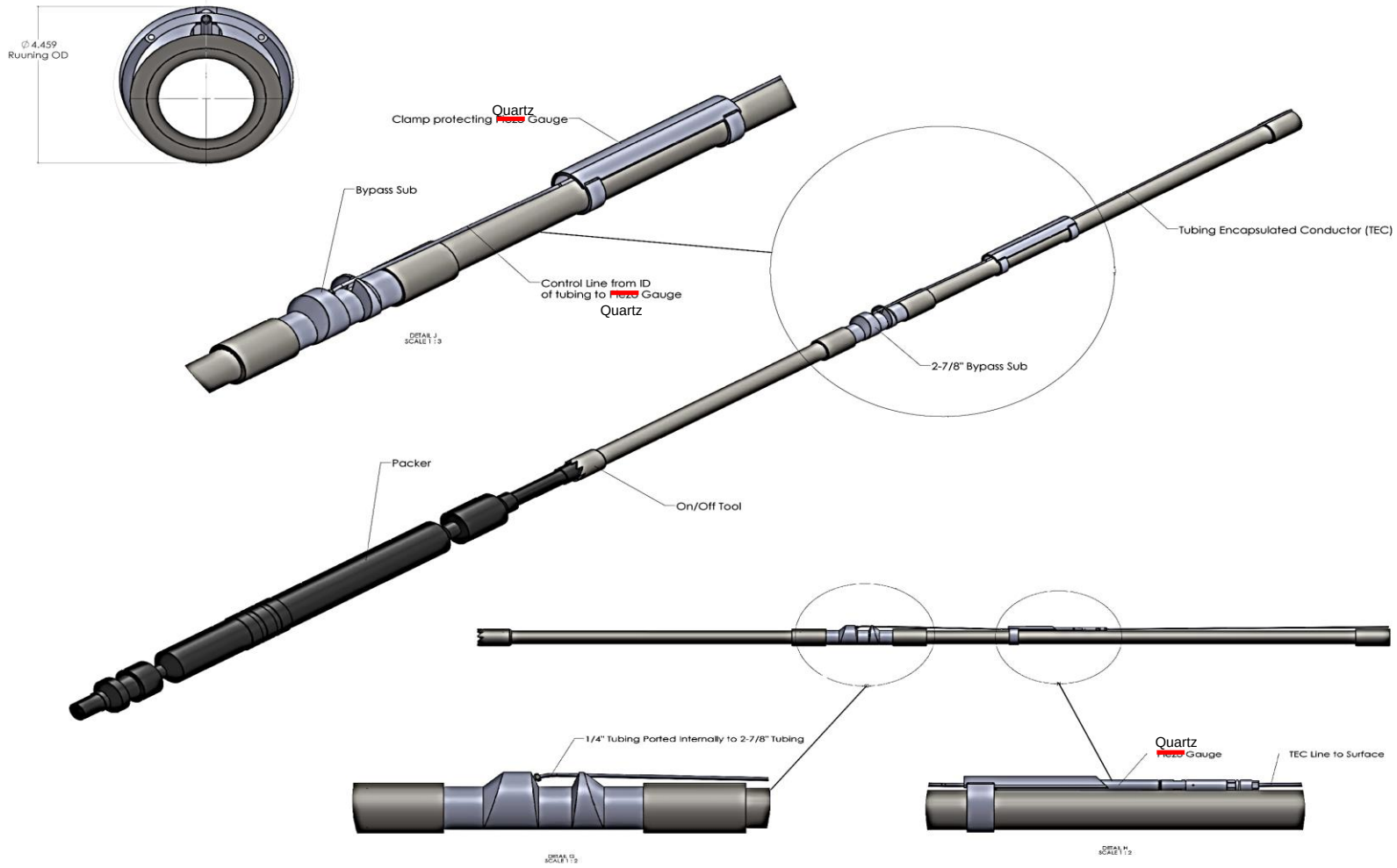
SAGE RIDER

Layout – Gauge Deployed on Tubing above Packer





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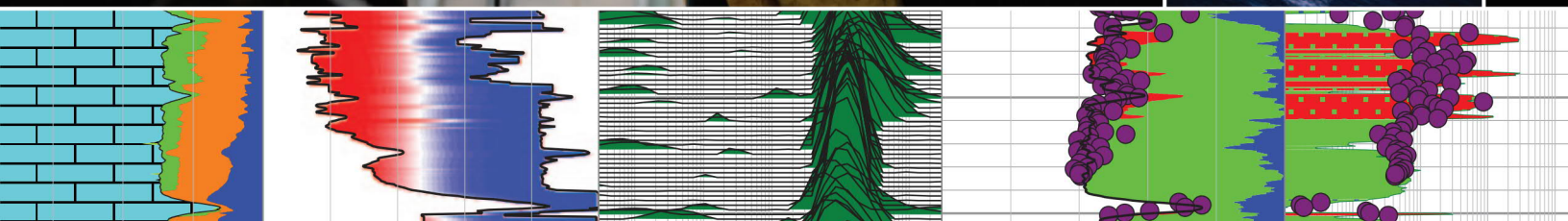
APPENDIX B. Log Quality Control Reference Manual (LQCRM)

Schlumberger

Wireline Log Quality Control Reference Manual



Schlumberger

Wireline Log Quality Control Reference Manual

Schlumberger
3750 Briarpark Drive
Houston, Texas 77042

www.slb.com

Produced by Schlumberger Oilfield Marketing Communications

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11-FE-0131

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Other company, product, and service names are the properties of their respective owners.

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TDT* thermal decay time 277

Foreword

The certification of acquired data is an important aspect of logging. It is performed through the observation of quality indicators and can be completed successfully only when a set of specified requirements is available to the log users.

This Log Quality Control Reference Manual (LQCRM) is the third edition of the log quality control specifications used by Schlumberger. It concisely provides information for the acquisition of high-quality data at the wellsite and its delivery within defined standards. The LQCRM is distributed to facilitate the validation of Schlumberger wireline logs at the wellsite or in the office.

Because the measurements are performed downhole in an environment that cannot be exhaustively described, Schlumberger cannot and does not warrant the accuracy, correctness, or completeness of log data.

Large variations in well conditions require flexibility in logging procedures. In some cases, important deviations from the guidelines given here may occur. These deviations may not affect the validity of the data collected, but they could reduce the ability to check that validity.

Catherine MacGregor
President, Wireline

Introduction

Data is a permanent asset of energy companies that may be used in unforeseen ways. Schlumberger is committed to and accountable for managing and delivering quality data. The quality of the data is the cornerstone of Schlumberger products and services.

Data quality

Quality is conformance to predefined standards with minimum variation. This document defines the standards by which the quality of the data of Schlumberger wireline logs is determined. The attributes that form the data quality model are

- accuracy
- repeatability
- integrity
- traceability
- timeliness
- relevance
- completeness
- sufficiency
- interpretability
- reputation
- objectivity
- clarity
- availability
- accessibility
- security.

Accuracy

Accuracy is how close to the true value the data is within a specified degree of conformity (e.g., metrology and integrity). Accuracy is a function of the sensor design; the measurement cannot be made more accurate by varying operating techniques, but it can fail to conform to the defined accuracy as a result of several errors (e.g., incorrect calibration).

Repeatability

Repeatability of data is the consistency of two or more data products acquired or processed using the same system under the same conditions. Reproducibility, on the other hand, is the data consistency of two or more data products acquired or processed using different systems or under different conditions. The majority of wireline measurements have a defined repeatability range, which is applicable only when the measurement is conducted under the same conditions. Repeatability is used to validate the measurement acquired during the main logging pass, as well as identify anomalies that may arise during the survey for relogging.

Integrity

The integrity of data is essential for the believability of data. Data with integrity is not altered or tampered with. There are situations in which data is altered in a perfectly acceptable manner (e.g., applying environmental corrections, using processing parameters for interpretation). Any such changes, which involve an element of judgment, are not done to intentionally produce results inconsistent with the measurements or processed data and are to the best and unbiased judgment of the interpreter. Results of interpretation activities are auditable, clearly marked, and traceable.

Traceability

Traceability of data refers to having a complete chain defining a measurement from its point of origin (sensor) to its final destination (formation property). At each step of the chain, appropriate measurement standards are respected, well documented, and auditable.

Timeliness

Timeliness is the availability of the data at the time required. Timeliness ensures that all tasks in the process of acquiring data are conducted within the time window defined for such tasks (e.g., wellsite calibrations and checks are done within the time window defined).

Relevance

Relevance is the applicability and helpfulness of the acquired dataset within the business context (e.g., selection of the right service for the well conditions). Most services have a defined operating envelope in which the measurement is considered valid. Measurements conducted outside their defined envelope, although the measurement process may have been completed satisfactorily, are almost always irrelevant (e.g., recording an SP curve in an oil-base mud environment).

Completeness

Completeness ensures that the data is of sufficient breadth, depth, and scope to meet predefined requirements. This primarily means that all required measurements are available over the required logging interval, with no missing curves or gaps in curves over predefined required intervals of the log.

Sufficiency

Sufficiency ensures that the amount of data that is acquired or processed meets the defined objectives of the operation. For example, when the defined objective is to compute the hole volume of an oval hole, a four-arm caliper service—at minimum—must be used. Using a single-arm caliper service would not provide sufficient information to achieve the defined objective and would inadvertently result in overestimation of the hole volume.

Interpretability

Interpretability of data requires that the measurement is specified in appropriate terminology and units and that the data definitions are clear and documented. This is essential to ensure the capability of using the data over time (i.e., reusability).

Reputation

Reputation refers to data being trusted or highly regarded in terms of its source, content, and traceability.

Objectivity

The objectivity of data is an essential attribute of its quality, unbiased and impartial, both at acquisition and at reuse.

Clarity

Clarity refers to the availability of a clear, unique definition of the data by using a controlled data dictionary that is shared. For example, when "NPHI" is referred to, it must be understood by all that NPHI is the thermal neutron porosity in porosity units (m^3/m^3 or ft^3/ft^3), computed from a thermal neutron ratio that is calibrated using a single-point calibration mechanism (gain only), and is the ratio of counts from a near and a far receiver, with the counts corrected only for hole size and not corrected for detector dead time.

Clarity ensures objectivity and interpretability over time.

Availability

Availability of data ensures the distribution of data only to the intended parties at the requested time (i.e., no data is disclosed to any other party than the owner of the data without prior written permission).

Accessibility

Accessibility ensures the ease of retrievability of data using a classification model. Wireline data are classified into three datasets:

- Basic dataset is a limited dataset suitable for quicklook interpretation and transmission of data.
- Customer dataset consists of a complete set of data suitable for processing (measurements with their associated calibrations), recomputing (raw curves), and validating (log quality control [LQC] curves) the measurements of the final product delivered. The customer dataset includes all measurements required to fully reproduce the data product with a complete and auditable traceability chain.
- Producer dataset includes Schlumberger-proprietary data, which are meaningful only to the engineering group that supports the tool in question (e.g., the 15th status bit of ADC015 on board EDCIB023 in an assembly).

Security

The security of data is essential to maintain its confidentiality and ensure that data files are clean of malware or viruses.

Calibration theory

The calibration of sensors is an integral part of metrology, the science of measurement. For most measurements, one of the following types of calibrations is employed:

- single-point calibration
- two-point calibration
- multiple-point calibration.

Because most measurements operate in a region of linear response, any two points on the response line can be compared with their associated calibration references to determine a gain and an offset (two-point calibration) or a gain (single-point calibration). The gain and offset values are used in the calibration value equation, which converts any measured value to its associated calibrated value.

There are three events that measurements may have one or more of:

- Master calibration: Performed at the shop on a quarterly or monthly basis, a master calibration usually comprises a primary measurement done to a measurement standard and a reference measurement that serves as a baseline for future checks. The primary measurement is the calibration of the sensor used for converting a raw measurement into its final output.
- Wellsite before-survey calibration or check: Measurements that have a master calibration are normally not calibrated at the wellsite; rather, the reference measurement conducted in the master calibration is repeated at the wellsite before conducting the survey to ensure that the tool response has not changed. Measurements that do not have a master calibration may employ a wellsite calibration that is conducted prior to starting the survey.
- Wellsite after-survey check: Some measurements employ an after-survey check (optional for most measurements) to ensure that the tool response has not changed from before the survey.

All such events are recorded in a calibration summary listing (CSL) (Fig. 1).

The calibration summary listing contains an auditable trail of the event:

- equipment with serial numbers
- actual measurement and the associated range (minimum, nominal, and maximum)
- time the event was conducted.

For the event to be valid, the measurement must fall within the defined minimum and maximum limits, using the same equipment (verified through the mnemonics and serial numbers), and performed on time (verified through the time stamp on the summary listing).

More details on the calibrations associated with the wide range of Schlumberger wireline measurements are in the *Logging Calibration Guide*, which is available through your local Schlumberger representative.

Hostile Natural Gamma Ray Sonde / Equipment Identification

Primary Equipment:	
HNGS Sonde	HNGS - BA
Auxiliary Equipment:	
HNGS Sonde Housing	HNSH - BA
Gamma Source Radioactive	GSR - U

Hostile Natural Gamma Ray Sonde Master Calibration

Detector 1 Calibration

Phase	Na 511 Peak Set Point	Value	Phase	Th Peak Loc	Value	Phase	Th Peak Res %	Value
Master		42.00	Master		211.9	Master		7.396
38.00 (Minimum)	40.00 (Nominal)	42.00 (Maximum)	201.0 (Minimum)	209.6 (Nominal)	218.3 (Maximum)	5.000 (Minimum)	7.000 (Nominal)	9.000 (Maximum)
Phase	Background Count Rate CPS	Value	Phase	Gain Ratio	Value			
Master		96.67	Master		0.9936			
20.00 (Minimum)	142.5 (Nominal)	265.0 (Maximum)	0.9400 (Minimum)	1.000 (Nominal)	1.060 (Maximum)			

Master:

Hostile Natural Gamma Ray Sonde Master Calibration

Detector 2 Calibration

Phase	Na 511 Peak Set Point	Value	Phase	Th Peak Loc	Value	Phase	Th Peak Res %	Value
Master		41.00	Master		211.1	Master		6.985
38.00 (Minimum)	40.00 (Nominal)	42.00 (Maximum)	201.0 (Minimum)	209.6 (Nominal)	218.3 (Maximum)	5.000 (Minimum)	7.000 (Nominal)	9.000 (Maximum)
Phase	Background Count Rate CPS	Value	Phase	Gain Ratio	Value			
Master		96.01	Master		1.017			
20.00 (Minimum)	142.5 (Nominal)	265.0 (Maximum)	0.9400 (Minimum)	1.000 (Nominal)	1.060 (Maximum)			

Master:

Figure 1. Example of a master calibration.

*Mark of Schlumberger
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Depth Control and Measurement

Overview

Depth is the most fundamental wireline measurement made; therefore, it is the most important logging parameter. Because all wireline measurements are referenced to depth, it is absolutely critical that depth is measured in a systematic way, with an auditable record to ensure traceability.

Schlumberger provides through its wireline services an absolute depth measurement and techniques to apply environmental corrections to the measurement that meet industry requirements for subsurface marker referencing.

The conveyance of tools and equipment by means of a cable enables the determination of an absolute wellbore depth under reasonable hole conditions through the strict application of wellsite procedures and the implementation of systematic maintenance and calibration programs for measurement devices. The essentials of the wireline depth measurement are the following:

- Depth is measured from a fixed datum, termed the depth reference point, which is specified by the client.
- The Integrated Depth Wheel (IDW) device (Fig. 1) provides the primary depth measurement, with the down log taken as the correct depth reference.
- Slippage in the IDW wheels is detected and automatically compensated for by the surface acquisition system.
- The change in elastic stretch of the cable resulting from changing direction at the bottom log interval is measured and applied to the log depth as a delta-stretch correction.
- Other physical effects on the cable in the borehole, including changes in length owing to wellbore profile, temperature, and other hole conditions, are not measured but can be corrected for after logging is complete.
- Subsequent logs that do not require a primary depth measurement are correlated to a reference log specified by the client, provided that enough information exists to validate the correctness of the depth measured on previous logs.
- Traceability of the corrections applied should be such that recovery of absolute depth measurements is possible after logging, if required.

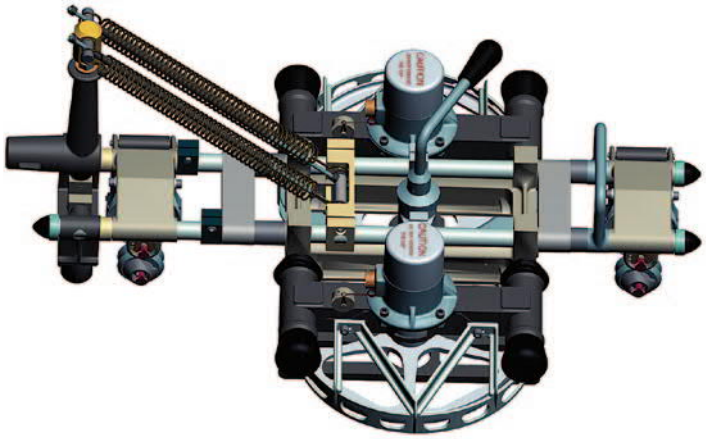

Figure 1. Integrated Depth Wheel device.

By strict application of this procedure, Schlumberger endeavors to deliver depth measurement with an accuracy of ±5 ft per 10,000 ft and repeatability of ±2 ft per 10,000 ft [±1.5 m and ±0.6 m per 3,050 m, respectively] in vertical wells.

Specifications

Measurement Specifications	
Accuracy	±5 ft per 10,000 ft [±1.5 m per 3,050 m]
Repeatability	±2 ft per 10,000 ft [±0.6 m per 3,050 m]

Calibration

The IDW calibration must be performed every 6 months, after 50 wellsite trips, or after 500,000 ft [152,400 m] have passed over the wheel, whichever comes first. The IDW device is calibrated with a setup that is factory-calibrated with a laser system, which provides traceability to international length standards.

Tension devices are calibrated every 6 months for each specific cable by using a load cell.

For more information, refer to the *Logging Calibration Guide*, which is available through your local Schlumberger representative.

The high-precision IDW device uses two wheels that measure cable motion at the wireline unit. Each wheel is equipped with an encoder, which generates an event for every 0.1 in [0.25 cm] of cable travel. A wheel correction is applied to obtain the ideal of one pulse per 0.1 in of cable travel.

Integration of the pulses results in the overall measured depth, which is the distance measured along the actual course of the borehole from the surface reference point to a point below the surface.

A tension device, commonly mounted on the cable near the IDW device, measures the line tension of the cable at the surface.

Depth control procedure

On arrival at the wellsite, the wireline crew obtains all available information concerning the well and the depth references (wellsite data) from the client's representative. Information related to the calibrations of the IDW device and the tension device is entered in the surface acquisition system.

First trip

First log

The procedure for the first log in a well consists of the following major steps:

1. Set up the depth system, and ensure that wheel corrections are properly set for each encoder.
2. Set tool zero (Fig. 2) with respect to the client's depth reference.
3. Measure the rig-up length (Fig. 3) between the IDW device and the rotary table at the surface. Investigate, and correct as necessary, any significant change in the rig-up length from that measured with the tool close to the surface.
4. Run in the hole with the toolstring.
5. Measure the rig-up length (Fig. 3) between the IDW device and the rotary table at bottom.
6. Correct for the change in elastic stretch resulting from the change in cable or tool friction when logging up.
7. Record the main log.
8. Record one or more repeat sections for repeatability analysis.†
9. Pull the toolstring out of the hole and check the depth on return to surface.

To set tool zero on a land rig, fixed platform, or jackup, the toolstring is lowered a few feet into the hole and then pulled up, stopping when the tool reference is at the client's depth reference point (Fig. 2).

Figure 2. Tool zero.

†Operational considerations may dictate a change in the order of Steps 6–8.

The following procedure for setting tool zero is used on floating vessels, semisubmersible rigs, and drillships equipped with a wave motion compensator (WMC):

1. With the WMC deactivated, stop the tool reference at the rotary table, and set the system depth to zero.
2. Lower the tool until the logging head is well below the riser slip joint, then flag the cable at the rotary table and record the current depth.
3. Have the driller pull up slowly on the elevators, until the WMC is stroking about its midpoint.
4. Raise or lower the tool until the cable flag is back at the rotary table.
5. Set the system depth to the depth recorded in Step 2.

Measuring the cable rig-up length ensures that the setup has not changed while running in the well (e.g., slack in the logging cable, movement of the logging unit, the blocks, or the sheaves). The following procedure is used to measure the rig-up length of the cable (Fig. 3):

1. Run in the hole about 100 ft [30 m], flag the cable at the IDW device, and note the depth.
2. Lower the toolstring until the flag is at the rotary table. Subtract the depth recorded in Step 1 from the current depth. The result is the rig-up length at surface (RULS).
3. Record RULS.

The speed used to proceed in the hole should avoid tool float (caused by excessive force owing to mud viscosity acting on the tool) or birdcaging of the cable. To the extent possible and operational considerations permitting, a constant speed should be maintained while running downhole. At the bottom of the hole, the measurement process is conducted to obtain the rig-up length at bottom (RULB), which is also recorded. If RULB differs from RULS by more than 1 ft [0.3 m], the rig-up has changed and the cause of the discrepancy must be investigated and eliminated or corrected for.

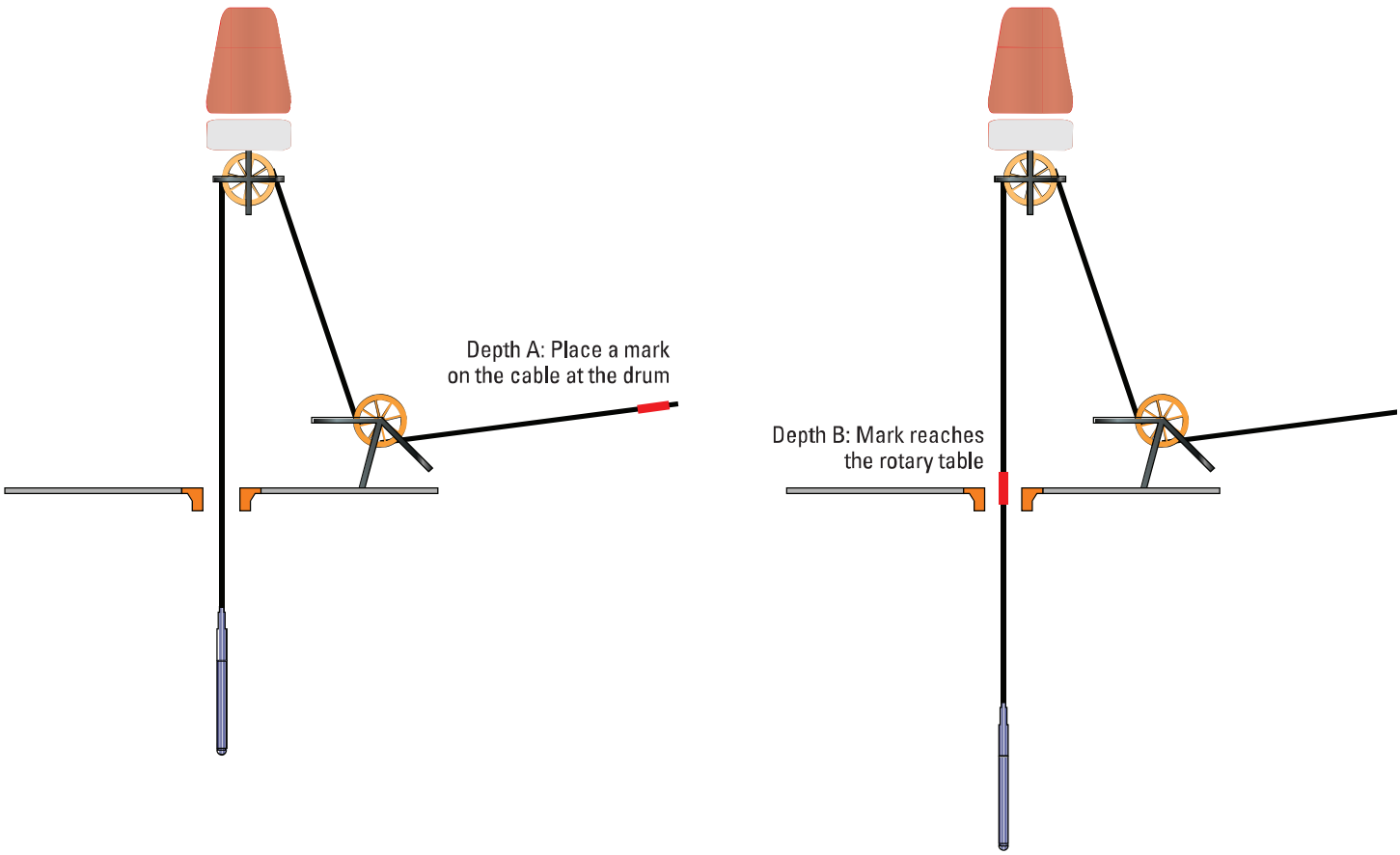

Figure 3. Rig-up length measurement procedure.

The rig-up length correction (RULC = RULS – RULB) is applied by adding RULC to the system depth. RULC is recorded in the Depth Summary Listing (Fig. 5).

To correct for the change of elastic stretch, the log-down/log-up method (Fig. 4) is applied as close as is reasonable to the bottom log interval:

1. Continue toward the bottom of the well at normal speed.
2. Log down a short section (minimum 200 ft [60 m]) close to the bottom, making sure to include distinctive formation characteristics for correlation purposes.
3. At the bottom, open calipers (if applicable) and log up a section overlapping the down log obtained in Step 2.
4. Using the down log as a reference, adjust the up-log depth to match the down log.
5. The adjustment is the stretch correction (SCORR) resulting from the change in tension. SCORR should be added to the hardware depth before logging the main pass.
6. Record SCORR and the depth at which it was determined in the Depth Summary Listing (Fig. 5).

If it is determined to be too risky to apply the delta-stretch correction before starting the log, the log can be recorded with no correction and then depth-shifted after the event with a playback. This procedure must be documented clearly in the Depth Summary Listing remarks. Such a procedure is justified when the well is excessively hot or sticky, and following the steps previously outlined could lead to a significant risk of tool problems or failure to return to bottom (and thus to loss of data).

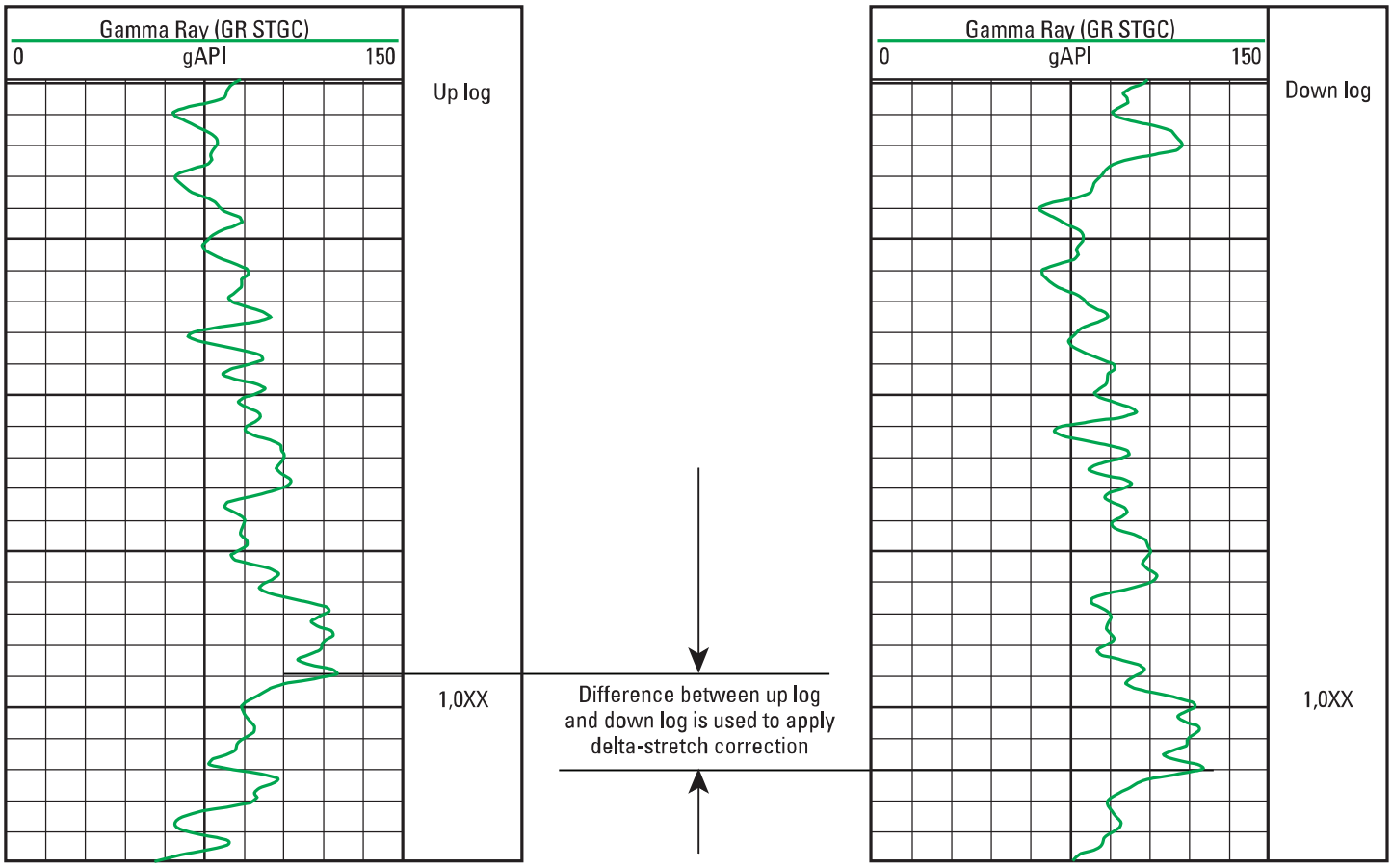

Figure 4. Stretch correction.

After pulling out of the hole, tool zero is checked at the surface, as was done before running in the hole, and the difference is recorded in the Depth Summary Listing (Fig. 5). In deviated wells in particular, environmental effects may lead to a re-zero error, with the depth system reading other than zero when the tool reference is positioned opposite the log reference point after return to the surface. Recording this difference is an essential step in controlling the quality of any depth correction computed after the log, because that depth correction process should include an estimate of the expected re-zero error.

All information related to the procedure followed for depth control should be recorded in the Depth Summary Listing (Fig. 5) for future reference.

DEPTH SUMMARY LISTING

Date Created: 10-Dec-20XX 12:09:15

Depth System Equipment

Depth Measuring Device		Tension Device		Logging Cable	
Type :	IDW-B	Type :	CMTD-B/A	Type :	7-46P
Serial Number:	4XX	Serial Number:	82XXX	Serial Number:	83XX
Calibration Date:	10-Dec-20XX	Calibration Date:	10-Dec-20XX	Length:	18750 FT
Calibrator Serial Number:	15XX	Calibrator Serial Number:	98XX	Conveyance Method:	Wireline
Calibration Cable Type:	7-46P	Number of Calibration Points:	10	Rig Type:	LAND
Wheel Correction 1:	-3	Calibration RMS:	11		
Wheel Correction 2:	-2	Calibration Peak Error:	15		

Depth Control Parameters

Log Sequence:	First Log in the Well
Rig Up Length At Surface:	352.00 FT
Rig Up Length At Bottom:	351.00 FT
Rig Up Length Correction:	1.00 FT
Stretch Correction:	5.00 FT
Tool Zero Check At Surface:	0.50 FT

Depth Control Remarks

1. Subsequent trip to the well. Downlog correlated to reference log XXX by YYY company dated DD-MM-YYYY.
2. Non-Schlumberger reference log. Full 1st trip to the well depth control procedure applied, which required the addition of XX ft to the down log.
3. Delta-stretch correction was conducted at 12XXX ft and applied to depth prior to recording the main log.
4. Z-chart used as a secondary depth check.

Figure 5. Depth Summary Listing for the first trip, first log in the well.

Subsequent logs

The depth of subsequent logs on the same trip is tied into the first log using the following procedure:

1. Properly zero the tool as for the first log.
2. The rig-up length does not need to be measured if the setup has not changed since the previous log.
3. Match depths with the first log by using a short up-log pass.
4. Run the main log and repeat passes as necessary.
5. Record the re-zero error in the Depth Summary Listing. This is part of the traceability that makes possible the determination of absolute depth after the event, if required.

Subsequent logs should be on depth with the first log over the complete interval logged. However, particularly when toolstrings of different weights are run in deviated wells, the relative depths of the logs can change over long logging intervals. Subsequent correction should enable removing all discrepancies.

The amount and sign of the correction applied and the depth at which it was determined must be recorded in the Depth Summary Listing. For any down log made, the delta-stretch correction should also be recorded, as well as the depth at which it was determined.

All information related to the procedure followed for depth control of subsequent logs of the first trip should be recorded in the Depth Summary Listing (Fig. 6).

DEPTH SUMMARY LISTING

Date Created: 10-Dec-20XX 14:38:50

Depth System Equipment

Depth Measuring Device		Tension Device		Logging Cable	
Type :	IDW-B	Type :	CMTD-B/A	Type :	7-46P
Serial Number:	4XX	Serial Number:	82XXX	Serial Number:	83XX
Calibration Date:	10-Dec-20XX	Calibration Date:	10-Dec-20XX	Length:	18750 FT
Calibrator Serial Number:	15XX	Calibrator Serial Number:	98XX	Conveyance Method:	Wireline
Calibration Cable Type:	7-46P	Number of Calibration Points:	10	Rig Type:	LAND
Wheel Correction 1:	-3	Calibration RMS:	11		
Wheel Correction 2:	-2	Calibration Peak Error:	15		

Depth Control Parameters

Log Sequence:	Subsequent trip In the Well
Reference Log Name:	AIT-GR
Reference Log Run Number:	1
Reference Log Date:	10-Dec-20XX

Depth Control Remarks

1. Subsequent log on 1st trip correlated to first log in the well from XX000 to XX200 ft
2. Speed correction not applied.
3. Z-chart used as a secondary depth check.
4. Correction applied to match reference log = XX ft, determined at depth XXX00 ft.
5. No rigup changes from previous log.

Figure 6. Depth Summary Listing for first trip, subsequent logs.

Subsequent trips

If there is not enough information in the Depth Summary Log from previous trips to ensure that correct depth control procedures have been applied, subsequent trips are treated as a first trip, first log in the well.

If sufficient information from previous trips was recorded to show that correct depth control procedures were applied, the previous logs can be used as a reference. The subsequent trips proceed as if running the initial trip with the following exceptions:

1. In conjunction with the client, decide which previous log to use as the downhole depth reference. Ensure that a valid copy of the reference log is available for correlation purposes. If the depth reference is a wireline log from a oilfield service provider other than Schlumberger, proceed as for the first log in the well, and investigate and document any discrepancies found with respect to the reference log.
2. Run in the hole and record a down log across an overlap section at the bottom of the reference log. If the overlap section is off by less than 5 ft per 10,000 ft, adjust the depth to match the current down log with the reference log. This adjustment ensures that the down section of the current log is using the same depth reference as the correlation log. Record any corrections made as the subsequent trip down log correction.
3. If the overlap log is off by more than 5 ft per 10,000 ft, investigate and resolve any problems. Record any depth discrepancies. Consult with the client to decide which log to use as the depth reference.
4. Run down to the bottom of the well at a reasonable speed so that the tool does not float.
5. Log main and repeat passes, correcting for stretch following the first trip procedure.
6. The logging pass should overlap with the reference log by at least 200 ft, if possible. The depth should match the reference log. Any discrepancies should be noted in the Depth Summary Listing or the log remarks.

All information related to the depth control procedure followed should be recorded in the Depth Summary Listing (Fig. 7).

DEPTH SUMMARY LISTING

Date Created: 10-Dec-20XX 14:26:56

Depth System Equipment

Depth Measuring Device		Tension Device		Logging Cable	
Type :	IDW-B	Type :	CMTD-B/A	Type :	7-46P
Serial Number:	4XX	Serial Number:	82XXX	Serial Number:	83XX
Calibration Date:	10-Dec-20XX	Calibration Date:	10-Dec-20XX	Length:	18750 FT
Calibrator Serial Number:	15XX	Calibrator Serial Number:	9851	Conveyance Method:	Wireline
Calibration Cable Type:	7-46P	Number of Calibration Points:	10	Rig Type:	LAND
Wheel Correction 1:	-3	Calibration RMS:	11		
Wheel Correction 2:	-2	Calibration Peak Error:	15		

Depth Control Parameters

Log Sequence:	Subsequent trip to the well
Reference Log Name:	AIT-GR
Reference Log Run Number:	1
Reference Log Date:	10-Dec-20XX
Subsequent Trip Down Log Correction:	1.00 FT

Depth Control Remarks

1. Subsequent trip to the well.
2. Down pass correlated to reference log within +/- 0.05%.
3. Correlation to reference log performed from XX000 to XX200 ft.
4. Correction applied to match reference log = XX ft, determined at depth XXX00 ft..
5. Z-chart used as a secondary depth check.

Figure 7. Depth Summary Listing for subsequent trips.

Spudding

Spudding is not a recommended procedure, but it is sometimes necessary to get past an obstruction in the borehole. It generally involves making multiple attempts from varying depths or using varying cable speed to get past an obstruction.

If the distance pulled up is small, the error introduced is also small. In many cases, however, the tool is pulled back up for a considerable distance (i.e., increasing cable over wheel) in an attempt to change its orientation. Then, the correction necessary to maintain proper depth control becomes sizeable.

If multiple attempts are made, the correction necessary to maintain proper depth control also becomes sizeable.

When possible, log data is recorded over the interval where spudding occurs in case consequent damage occurs to the equipment that prevents further data acquisition. If it is not possible to pass an obstruction in the well, data is recorded while pulling out of the hole for remedial action.

Absolute depth

Measurements made with wireline logs are often used as the reference for well depth. However, differences are usually noted between wireline depth and the driller's depth. Which one is correct? The answer is neither. For more information, refer to SPE 110318, "A Technique for Improving the Accuracy of Wireline Depth Measurements."

Wireline depth measurement is subject to environmental corrections that vary with many factors:

- well profile
- mud properties
- toolstring weight
- cable type
- temperature profile
- wellbore pressure
- logging speed.

All these effects may differ from one well to another, so the depth corrections required also differ. Because of the number of factors involved, the corrections can be applied through a numerical model.

Logging down

Any short element of cable that is spooled off the winch drum as a tool is lowered downhole takes up a tension sufficient to support the weight of the tool in the well plus the weight of the cable between the winch and the tool, minus any frictional force that helps support the tool and cable. This prestretched cable passes the IDW device and its length is thus measured in the stretched condition. When this element of cable is downhole, the tension at the surface can be quite different. However, the tension on this element remains the same because it is still supporting the weight of the tool plus the weight of the cable between itself and the tool minus the frictional force.

If it is assumed that the frictional force is constant and that temperature and pressure do not affect the cable length, the tension on the cable—and thus the cable length—stays constant as the tool is lowered in the hole. Considering that all such elements remain at constant length once they have been measured, it follows that the down log is on depth. This means that the encoder-measured depth incorporates the stretched cable length, and no additional stretch correction is required.

Logging up

When the tool reaches the bottom of the well, the winch direction is reversed. This has the effect of inverting the sign of the frictional component acting on the tool and cable. In addition, if a caliper is opened, the magnitude of the frictional force can change. As a result, the cable everywhere in the borehole is subject to an increase in tension, and thus an increase in stretch.

For the surface equipment to track the true depth correctly, a delta-stretch correction must be added to compensate for the friction change (Fig. 4). Once the correction has been applied, the argument used while running in hole is again applicable, and the IDW correctly measures the displacement of the tool provided there are no further changes in friction.[‡]

Deviated wells

In deviated wells, the preceding depth analysis applies only to the vertical section of the well. Once the tool reaches the dogleg, lateral force from the wellbore supports part of the tool weight. The tool is thus shallower than the measured depth on surface; i.e., the recorded data appear deeper than the actual tool position. This is commonly referred to as tool float.

Correction modeling

Correction modeling software estimates the delta-stretch correction to be applied at the bottom of the well, as well as the expected tool re-zero depth upon return to the surface. This software can be used to correct the depth after logging. Contact your local Schlumberger representative for more information.

[‡]The main assumptions remain that the friction is constant (other than the change due to reversal of direction of cable motion), and that temperature and pressure effects on the cable may be ignored.

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Platform Express

Overview

Platform Express* integrated wireline logging technology employs either the AIT* array induction imager tool or High-Resolution Azimuthal Laterolog Sonde (HALS) as the resistivity tool. The Three-Detector Lithology Density (TLD) tool and Micro-Cylindrically Focused Log (MCFL) are housed in the High-Resolution Mechanical Sonde (HRMS) powered caliper. Above the HRMS are a compensated thermal neutron and gamma ray in the Highly Integrated Gamma Ray Neutron Sonde (HGNS) and a single-axis accelerometer. The real-time speed correction provided by the single-axis accelerometer for sensor measurements enables accurate depth matching of all sensors even if the tool cannot move smoothly while recording data. The resistivity, density, and microresistivity measurements are high resolution. Logging speed is twice the speed at which a standard triple-combo is run.

Specifications

Measurement Specifications	
Output	HGNS: Gamma ray, neutron porosity, tool acceleration HRMS: Bulk density, photoelectric factor (PEF), borehole caliper, microresistivity HALS: Laterolog resistivity, spontaneous potential (SP), mud resistivity (R_m) AIT: Induction resistivity, SP, R_m
Logging speed	3,600 ft/h [1,097 m/h]
Mud weight or type limitations	None
Combinability	Bottom-only toolstring with HALS or AIT tool Combinable with most tools
Special applications	Good-quality data in sticky or rugose holes Measurement close to the bottom of the well

Platform Express Component Specifications				
	HGNS	**HRMS**	**HALS**	**AIT-H and AIT-M**
Range of measurement	Gamma ray: 0 to 1,000 gAPI Neutron porosity: 0 to 60 V/V	Bulk density: 1.4 to 3.3 g/cm^3 PEF: 1.1 to 10 Caliper: 22 in [55.88 cm]	0.2 to 40,000 ohm.m	0.1 to 2,000 ohm.m
Vertical resolution	Gamma ray: 12 in [30.48 cm] Porosity: 12 in [30.48 cm]	Bulk density: 18 in [45.72 cm] in 6-in [15.24-cm] borehole	Standard resolution: 18 in [45.72 cm] High resolution: 8 in [20.32 cm] in 6-in [15.24-cm] borehole	1, 2, and 4 ft [0.30, 0.61, and 1.22 m]
Accuracy	Gamma ray: ±5% Porosity: 0 to 20 V/V = ±1 V/V, 30 V/V = ±2 V/V, 45 V/V = ±6 V/V	Bulk density: ±0.01 g/cm^3 (accuracy[†]), 0.025 g/cm^3 (repeatability) Caliper: 0.1 in [0.25 cm] (accuracy), 0.05 in [0.127 cm] (repeatability) PEF: 0.15 (accuracy[‡])	1 to 2,000 ohm.m: ±5%	Resistivities: ±0.75 ms/m (conductivity) or 2% (whichever is greater)
Depth of investigation	Gamma ray: 24 in [61.0 cm] Porosity: ~9 in [~23 cm] (varies with hydrogen index of formation)	Density: 5 in [12.70 cm]	32 in [81 cm] (varies with formation and mud resistivities)	AO/AT/AF10[§]: 10 in [25.40 cm] AO/AT/AF20: 20 in [50.80 cm] AO/AT/AF30: 30 in [76.20 cm] AO/AT/AF60: 60 in [152.40 cm] AO/AT/AF90: 90 in [228.60 cm]
Outside diameter	3.375 in [8.57 cm]	4.77 in [12.11 cm]	3.625 in [9.21 cm]	3.875 in [9.84 cm]
Length	10.85 ft [3.31 m]	12.3 ft [3.75 m]	16 ft [4.88 m]	16 ft [4.88 m]
Weight	171.7 lbm [78 kg]	313 lbm [142 kg]	221 lbm [100 kg]	AIT-H: 255 lbm [116 kg] AIT-M: 282 lbm [128 kg]

[†] Bulk density accuracy defined only for the range of 1.65 to 3.051 g/cm^3

[‡] PEF accuracy defined for the range of 1.5 to 5.7

[§] AO = 1-ft [0.30-m] vertical resolution, AT = 2-ft [0.61-m] vertical resolution, AF= 4-ft [1.22-m] vertical resolution

Calibration

Master calibration of the HGNS compensated neutron tool must be performed every 3 months. Master calibration of the HRDD density tool must be performed monthly.

For calibration of the gamma ray tool of the HGNS, the area must be free from outside nuclear interference. Gamma ray background and plus calibrations are typically performed at the wellsite with the radioactive sources removed so that no contribution is made to the signal. Calibration of the tool in a vertical position is recommended. 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.

Calibration of the HGNS compensated neutron tool uses an aluminum insert sleeve seated in a tank filled with fresh water. The bottom edge of the tank is at least 33 in [84 cm] above the floor, and an 8-ft [2.4-m] perimeter around the tank is clear of walls or stationary items and all equipment, tools, and personnel. The tool is vertically lowered into the tank and sleeve so that only the taper of a centering clamp placed on the tool housing at the centering mark enters the water and the clamp supports the weight of the tool.

Calibration of the HRDD density tool uses an aluminum block and a magnesium block with multiple inserts.

Tool quality control

Standard curves

The Platform Express standard curves are listed in Table 1.

Table 1. Platform Express Standard Curves

Output Mnemonic	Output Name	Output Mnemonic	Output Name
AHF10, AHF20, AHF30, AHF60, AHF90	Array induction resistivity with 4-ft [1.2-m] vertical resolution and median depth of investigation of 10, 20, 30, 60, or 90 in [25.4, 50.8, 76.2, 152.4, or 228.6 cm]	HTNP	High-resolution thermal neutron porosity
AHO10, AHO20, AHO30, AHO60, AHO90	Array induction resistivity with 1-ft [0.3-m] vertical resolution and median depth of investigation of 10, 20, 30, 60, or 90 in	MVRA	Monitoring to resistivity of the invaded zone (R_{xo}) voltage ratio
AHT10, AHT20, AHT30, AHT60, AHT90	Array induction resistivity with 2-ft [0.6-m] vertical resolution and median depth of investigation of 10, 20, 30, 60, or 90 in	NPHI	Thermal neutron porosity borehole-size corrected
ATEMP	HGNS accelerometer temperature	NPOR	Enhanced-resolution processed thermal porosity
CFGR	Gamma ray borehole-correction factor	PEF8	Formation photoelectric factor at standard 8-in [20.3-cm] resolution
CFTC	Corrected far thermal count	PEFI	Formation photoelectric factor at standard 2-in [5.1-cm] resolution
CNTC	Corrected near thermal count	PEFZ	Formation photoelectric factor at standard 18-in [45.7-cm] resolution
CTRM	MCFL hardware contrast indicator	RHO8	Formation density at standard 8-in resolution
DNPH	Delta neutron porosity	RHOI	Formation density at standard 2-in resolution
ECGR	Environmentally corrected gamma ray	RHOZ	Formation density at standard 18-in resolution
EHGR	High-resolution environmentally corrected gamma ray	RSO8	High-resolution resistivity standoff
EHMR	Confidence on resistivity standoff	RVV	MCFL vertical voltage
ERBR[*n*]	Resistivity reconstruction error	RXGR	Global current-based resistivity
ERMC	Confidence on standoff zone resistivity	RXIB	Bucking (A1) current
ERXO	Confidence on invaded zone resistivity	RXIG	Global (A0) current
E*x*SZ[*n*]	*x*S reconstruction error	RXIGIO	Global to B0 current ratio
GDEV	HGNS deviation	RXO8	Micro-cylindrically focused R_{xo} measurement at 8-in resolution
GR	Gamma ray	RXOI	Micro-cylindrically focused R_{xo} measurement at 2-in resolution
GREZ	High-Resolution Density Detector (HRDD) cost function	RXOZ	Micro-cylindrically focused R_{xo} measurement at standard 18-in resolution
GTHV	HGNS gamma ray test high voltage	RXV	R_{xo} (A0) voltage
HAZ01	HGNS high-resolution acceleration	RXVB	Bucking (A1) voltage
HCAL	Caliper to measure borehole diameter	TNPH	Thermal neutron porosity environmentally corrected
HDRA	HRDD density correction	TREF	HGNS ADC reference
HDRX	B0 correction factor	U8	Formation volumetric photoelectric factor at standard 8-in resolution
HGR	High-resolution gamma ray	UI	Formation volumetric photoelectric factor at standard 2-in resolution
HLLD	HALS laterolog deep low-resolution measurement	UZ	Formation volumetric photoelectric factor at standard 18-in resolution
HLLS	HALS laterolog shallow low-resolution measurement	*x*CQR	*x*S crystal resolution
HMIN	Micro-inverse resistivity	*x*DTH	HRDD detector dither frequency
HMINO	Micro-normal resistivity	*x*LEW	*x*S low-energy window count rate
HNPO	High-resolution enhanced thermal neutron porosity	*x*OFC	HRDD detector offset control value
HRLD	HALS laterolog deep high-resolution measurement	*x*PHV	*x*S photomultiplier high voltage (command)
HRLS	HALS laterolog shallow high-resolution measurement	*x*SFF	*x*S form factor
HTEM	Cartridge temperature	*x*WTO	*x*S uncalibrated total count rate

Operation

The HGNS section of the Platform Express toolstring must be eccentered with a bow spring. The HRMS is positively eccentered with its own caliper, giving a borehole reaction force centered on the skid face.

The resistivity tool at the bottom of the Platform Express toolstring must be run with standoffs positioned at the top and bottom of the tool. It is important that the standoff size is the same at the top and bottom so that the sonde is not tilted with respect to the borehole.

Planning for selection of the induction or laterolog tool is important. See the "Resistivity Logging" section of this *Log Quality Control Reference Manual* for more details.

Formats

There are several quality control formats for Platform Express logs.

The HGNS format is shown in Fig. 1.

- Flag track
  - This track should show a deep green coherent pattern.
- Track 1
  - CFGR is the coefficient applied to the calibrated gamma ray to take into account the borehole corrections. Normally it is between 0.5 and 1.5.
  - GDEV output from the calibrated accelerometer should be between –10° and 90°, depending on the well.
  - DNPH is the difference between the environmentally corrected porosity and the uncorrected porosity. Usually the difference is within –10 to 10 V/V.

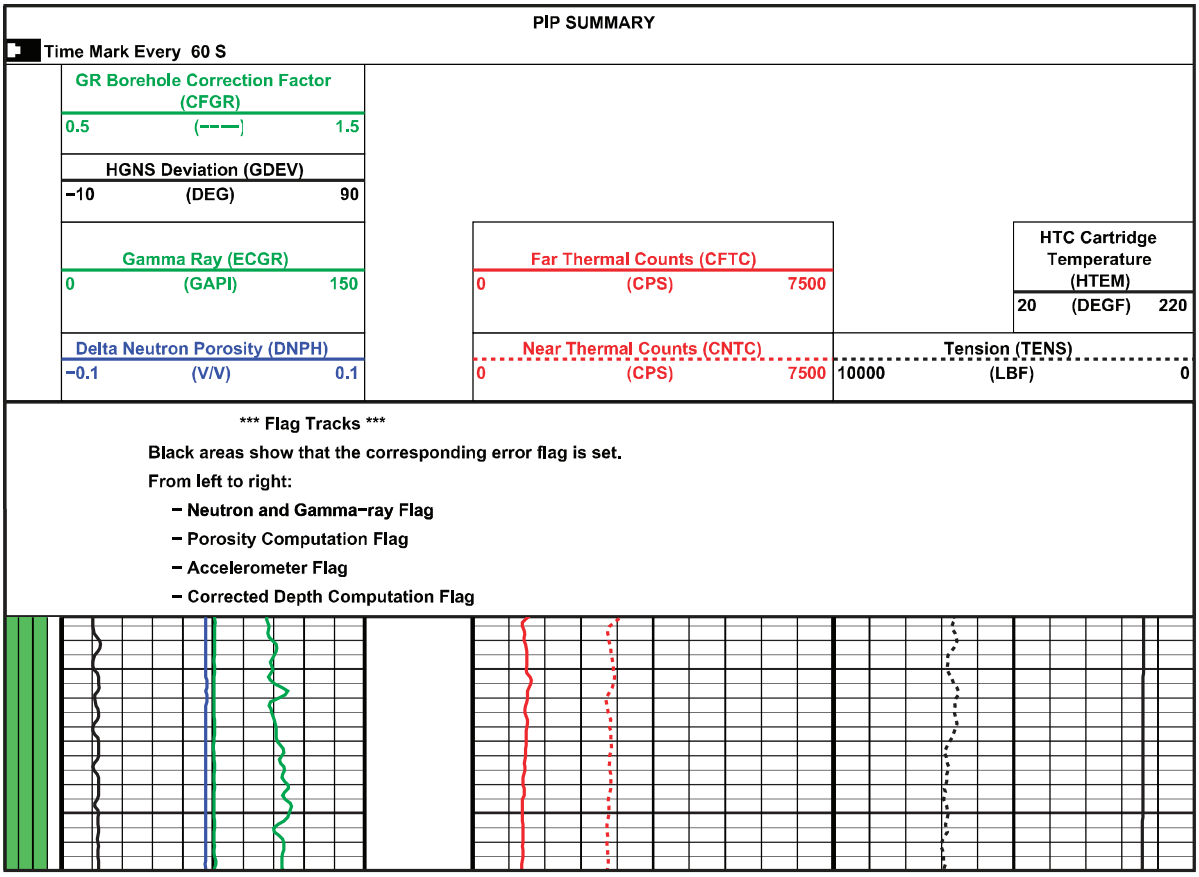

Figure 1. HGNS standard format for hardware.

The HRDD hardware format is in Fig. 2.

- Flag tracks
  - Three flag tracks aid in checking the backscatter (BS), short-spacing (SS), and long-spacing (LS) detector measurements. All bits in the tracks must show a deep green coherent color. Any other color may indicate a hardware failure.
- Tracks 1, 3, and 4
  - The *x*WTO total count rate varies according to the density. In general, for BS, 300,000 counts/s < BWTO < 1,000,000 counts/s; for SS, 10,000 counts/s < SWTO < 500,000 counts/s; and for LS, 1,000 counts/s < LWTO < 50,000 counts/s (cps on the logs). A large count rate change may indicate a problem with the detector.
  - The value of *x*SFF varies about zero (typically ±0.125%). If the form factor is higher than the permissible value, there may be a problem with the detector.
  - Variation of *x*CQR detector resolution is according to temperature and the presence of the logging source. Table 2 lists limits for the crystal resolution.
  - Valid count rates for *x*LEW are 0 to 10,000 counts/s for BS, 0 to 5,000 counts/s for SS, and 0 to 1,000 counts/s for LS. Any value outside its range may indicate a problem with the respective detector.
  - The *x*OFC unitless integer controls the average offset value and should ranges from 5 to 20.
  - HRDD backscatter dither frequency (*x*DTH) can range from 1 to 900 Hz.
  - The *x*PHV photomultiplier tube high voltage should be near the value given during master calibration, but it changes with temperature.

Table 2. HRDD Limits for *x*CQR Crystal Resolution

Detector	Stabilization Source Alone		With Logging Source	
	77 degF [25 degC]	257 degF [125 degC]	77 degF [25 degC]	257 degF [125 degC]
BS (BCQR)	13%	16%	12%	15%
SS (SCQR)	10%	10%	10%	10%
LS (LCQR)	9%–10%	11%	9%	11%

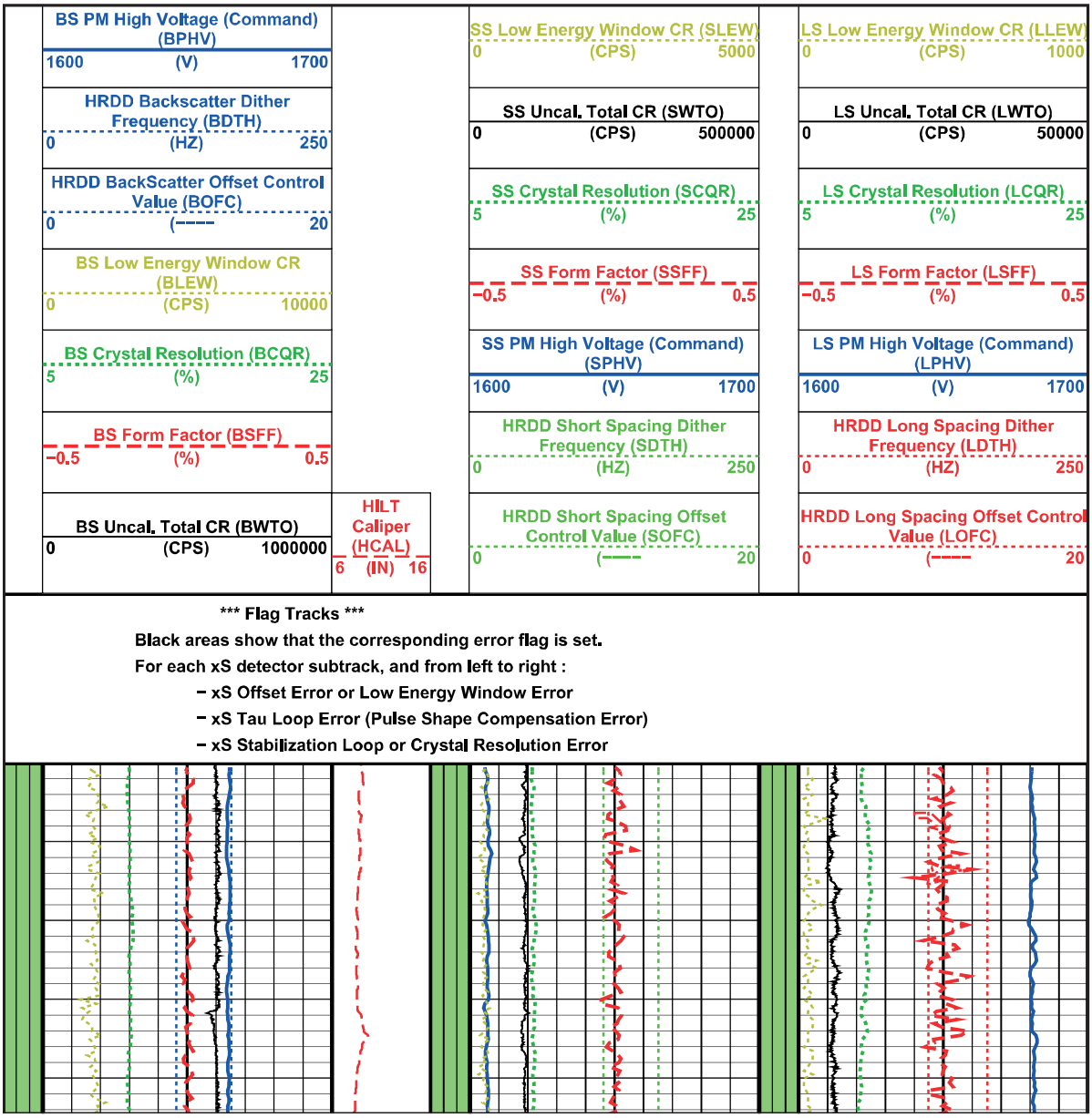

Figure 2. HRDD standard format for hardware.

The HRDD processing format is in Fig. 3.

- Tracks 1, 2, and 3
  - ExSZ[n] for each detector shows how close the reconstructed count rates are to the calibrated measured count rates. Ideally, they should vary about zero. A large bias observed on these errors for one or more energy windows is generally due to a problem in the calibration, excessive pad wear, or incorrect inversion algorithm selection.
  - GREZ indicates the confidence level in the estimations done in the model. The valid range is 0 < GREZ < 25.

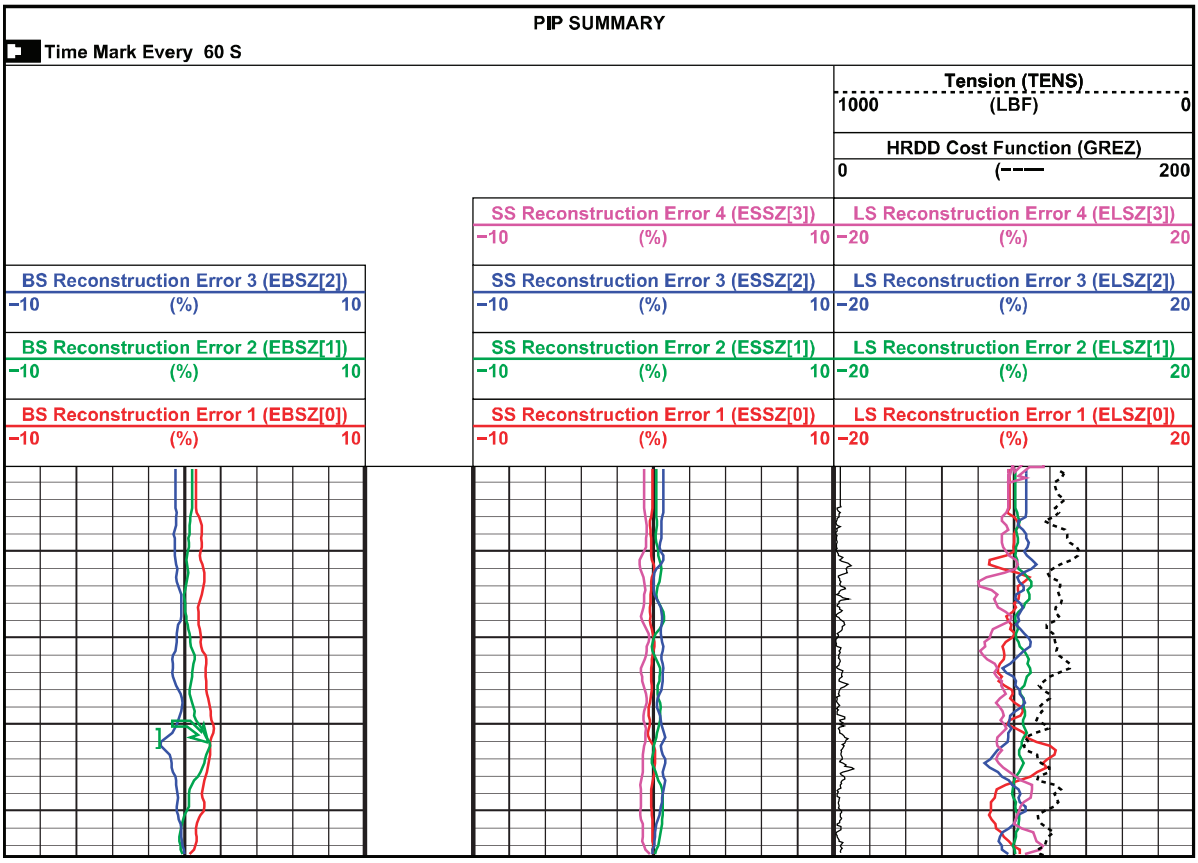

Figure 3. HRDD standard format for processing.

The MCFL hardware format is in Fig. 4.

- Flag track
  - The flag track should show a deep green coherent color. If a flag appears, it indicates a hardware malfunction.
- Track 1

  RXIB and RXIG from A0 and A1 (the guard electrodes on the tool) should range from 2 to 2,000 mA. The ratio between both curves should be constant, with the value depending on the hole size.
  - RXV between the A0 electrode and the sonde body is typically about 50 to 200 mV for R_{xo} > 10 ohm.m. It is smaller when R_{xo} < 10 ohm.m, but it should not go below 5 mV.
  - RVV between A0 and the reference electrode N should read about one-half the value of RXV (R_{xo} voltage).

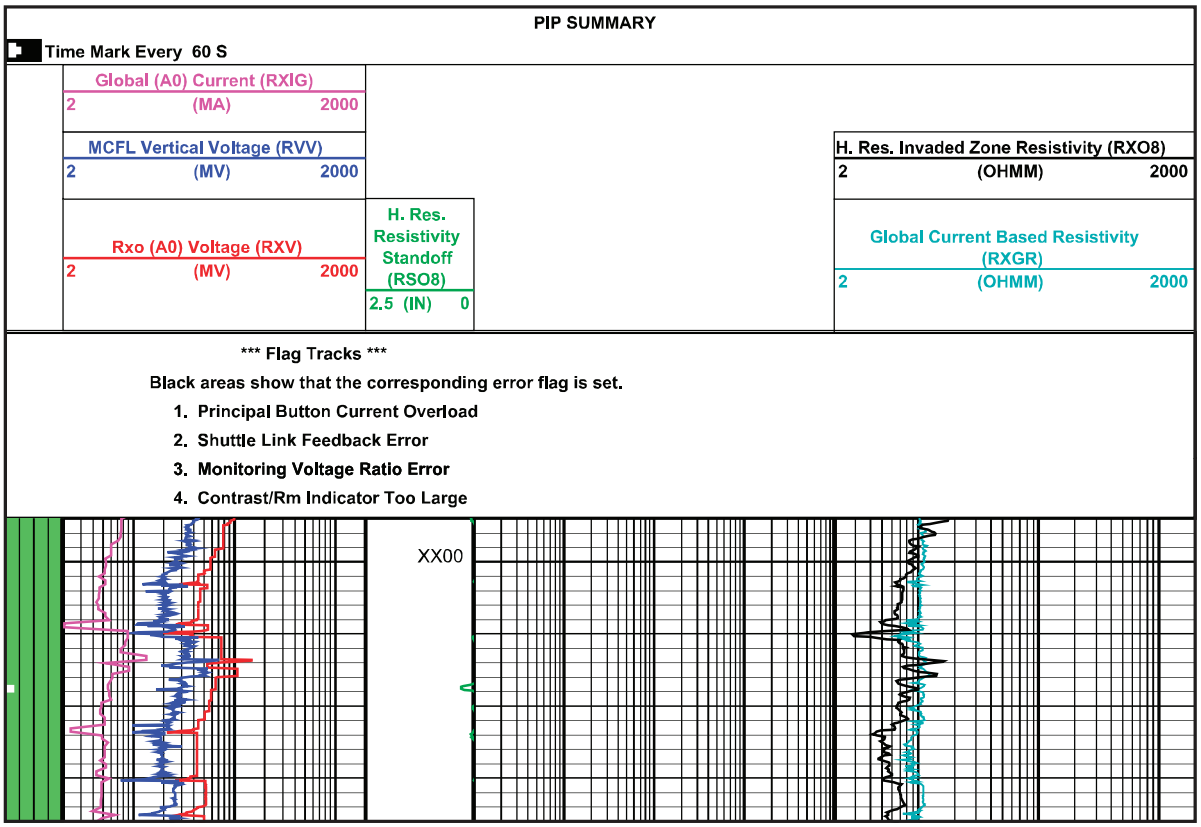

Figure 4. MCFL standard format for hardware.

The MCFL processing format is in Fig. 5.

- Track 1
  - ERBR[n] for the response of each button is used to determine how close the reconstructed measurements are to the actual ones. High error values can indicate abnormal noise level, non-homogeneous R_{xo} value, or standoff resulting from sonde tilt.
- Track 2
  - ERXO, ERMC, and EHMR confidence indicators for R_{xo}, R_{mc}, and mudcake thickness, respectively, indicate the amount of error associated with the results of the MCFL inversion. These curves should remain close to zero.
- Track 3
  - HDRX applied to the main button to match the inverted output RXOZ should range between 0.5 and 1.5.

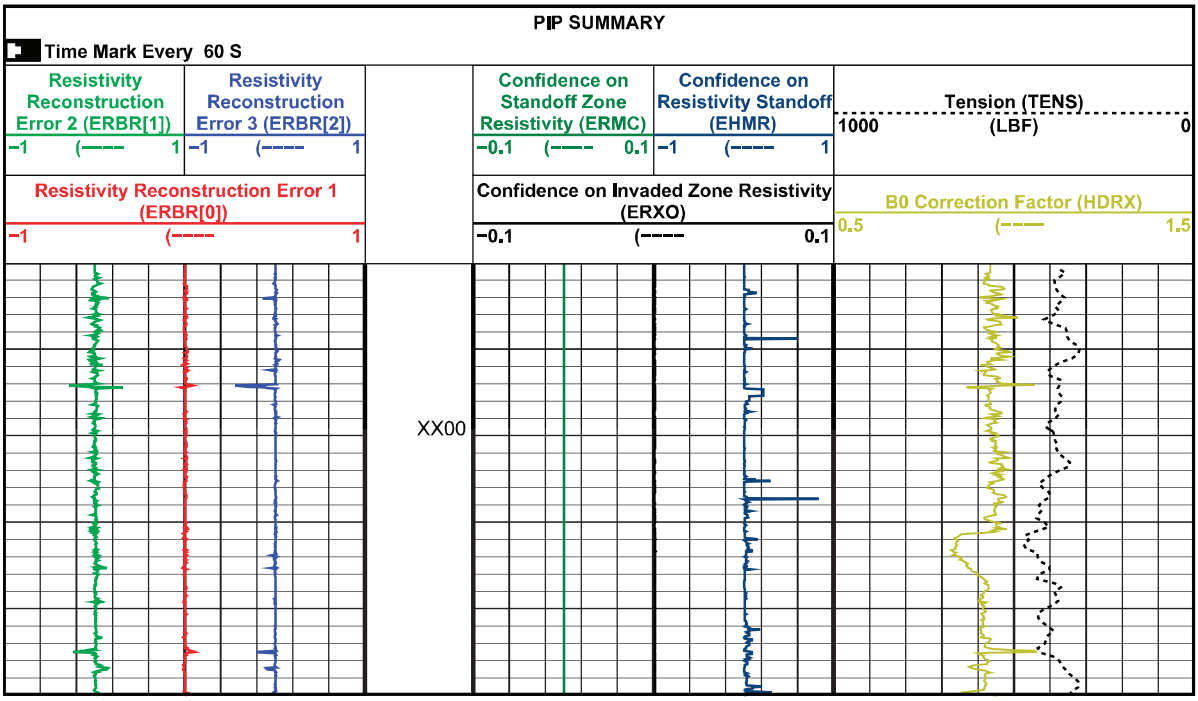

Figure 5. MCFL standard format for processing.

Response in known conditions

HGNS neutron response

The values in Table 3 assume that the matrix parameter is set to limestone (MATR = LIME), hole is in gauge, and borehole corrections are applied.

HRDD density response

Typical values for the HRDD response are in Table 4.

MCFL microresistivity response

- In impermeable zones, the R_{xo} curve should equal the induction or resistivity measurements.
- In permeable zones, the R_{xo} curve should show a coherent profile as an indication of invasion.

AIT and HALS resistivity response

- In impermeable zones, the resistivity curves should overlay.
- In permeable zones, the relative position of the curves should show a coherent profile depending on the values of the resistivity of the mud filtrate (R_{mf}) and the resistivity of the water (R_w), the respective saturation, and the depth of invasion. In salt muds, generally the invasion profile is such that deeper-reading curves have a higher value than shallower-reading curves, with deep investigation curves approaching the true formation resistivity (R_t) and shallow investigation curves approaching R_{xo}.

Table 3. Typical HGNS Response in Known Conditions

Formation	NPHI,† V/V	TNPH or NPOR,‡ V/V
Sandstone, 0% porosity	–1.7	–2.0
Limestone, 0% porosity	0	0
Dolomite, 0% porosity	2.4	0.7
Sandstone, 20% porosity§	15.8 if formation salinity = 0 ug/g	15.1 if formation salinity = 250 ug/g
Limestone, 20% porosity	20.0	20.0
Dolomite, 20% porosity§	27.2 if formation salinity = 0 ug/g	22.6 if formation salinity = 0 ug/g 24.1 if formation salinity = 250 ug/g
Anhydrite	–0.2	–2.0
Salt	–0.0	–3.0
Coal	38 to 70	28 to 70
Shale	30 to 60	30 to 60

† After borehole correction with MATR = LIME. Refer to Chart CP-1c in Schlumberger *Log Interpretation Charts*.
‡ After borehole correction with MATR = LIME. Refer to Charts CP-1e and -1f in Schlumberger *Log Interpretation Charts*.
§ The reason that sandstone or dolomite with a porosity of 20% reads differently after environmental correction with MATR = LIME for different formation salinities is that the formation salinity correction is matrix dependant, and a formation salinity correction made assuming MATR = LIME is incorrect if the matrix is different. Refer to Chart Por-13b in Schlumberger *Log Interpretation Charts*.

Table 4. Typical HRDD Response in Known Conditions

Formation	RHOB, g/cm^3	PEF†
Sandstone, 0% porosity	2.65 to 2.68	1.81
Limestone, 0% porosity	2.71	5.08
Dolomite, 0% porosity	2.87	3.14
Anhydrite	2.98	5.05
Salt	2.04	4.65
Coal	1.2 to 1.7	0.2
Shale	2.1 to 2.8	1.8 to 6.3

† PEF readings are restricted to not read below 0.8.

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PS Platform

Overview

The PS Platform* production services platform uses a modular design comprising the following main tools:

- Platform Basic Measurement Sonde (PBMS) for measuring pressure, temperature, gamma ray, and casing collar location
- Gradiomanometer* (PGMC) sonde for measuring the density of the well fluid and well deviation
- PS Platform Inline Spinner (PILS) for measuring high-velocity flow in small-diameter tubulars
- Flow-Caliper Imaging Sonde (PFCS) for measuring fluid velocity and water holdup and also has a dual-axis caliper.

Additional production logging tools combinable with the PS Platform system are

- GHOST* gas optical holdup sensor tool for measuring gas holdup and also has a caliper
- Digital Entry and Fluid Imaging Tool (DEFT) for measuring water and also has a caliper
- Flow Scanner* horizontal and deviated well production logging system for measuring three-phase flow rate in horizontal wells
- RST* reservoir saturation tool for measuring water velocity and three-phase holdup.

Also combinable with the PS Platform system are

- SCMT* slim cement mapping tool for a through-tubing cement quality log
- PS Platform Multifinger Imaging Tool (PMIT) for multifinger caliper surveys of pitting and erosion
- EM Pipe Scanner* electromagnetic casing inspection tool for electromagnetic inspection of corrosion and erosion
- RST reservoir saturation tool for capture sigma saturation logging, carbon/oxygen saturation logging, capture lithology identification, and silicon-activation gravel-pack quality logging.

In horizontal wells the PBMS can be replaced by the MaxTRAC* downhole well tractor system or the TuffTRAC* cased hole services tractor.

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Dielectric Scanner

Overview

Dielectric Scanner* multifrequency dielectric dispersion service introduces a new petrophysical measurement concept that uses multiple-frequency technology to measure dielectric dispersion downhole. The service provides a continuous, high-resolution measurement of dielectric dispersion, which is the variation of formation conductivity and permittivity as a function of frequency. The dielectric dispersion measurement is input to a petrophysical model to obtain water-filled porosity (hence, water saturation in comparison with total porosity), water salinity, and textural parameters. Pressure, temperature, and the permittivity and conductivity of the borehole are also measured to correct for environmental effects.

In carbonates, Dielectric Scanner analysis of textural effects provides a continuous in situ measurement of the Archie *mn* exponents. In shaly sands, processing provides a continuous log of the cation exchange capacity (CEC), accounting for the effects of the clay volume.

The Dielectric Scanner articulated pad improves contact with the formation in rugose boreholes, a condition that previous mandrel-type electromagnetic propagation tools were sensitive to.

Calibration

Caliper calibration for the Dielectric Scanner tool is performed with two jig measurements. The jigs are usually calibration rings with a specified diameter. A zero measurement is taken using the smaller of the two rings. A plus measurement is taken using the larger ring. The calibration rings must be continuous, without notched or removed sections, not have any visible damage, and not be ovalized.

The Dielectric Scanner tool does not require transmitter and receiver gain calibrations because the antenna layout on the pad provides autocalibrated measurements and the symmetric pad design allows averaging the measurement at top and bottom to correct for pad tilt and account for pad standoff.

Specifications

Measurement Specifications	
Output	Relative dielectric permittivity and conductivity at four frequencies
Logging speed	0.4-in sampling rate: 1,800 ft/h [549 m/h] 0.8-in sampling rate: 3,600 ft/h [1,097 m/h]
Range of measurement	Permittivity: 1 to 100 Conductivity: 0.1 to 3,000 mS
Vertical resolution	1 in [2.5 cm]
Accuracy†	Permittivity: +1% [+0.1] Conductivity: +1% [+5 mS]
Depth of investigation	4 in [10 cm]
Mud type or weight limitations	Oil-base mud under specific conditions‡

† Corresponding to 0.002-ft^3/ft^3 water-filled porosity

‡ Contact your Schlumberger representative

Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa]
Borehole size—min.	5⅞ in [14.92 cm]
Borehole size—max.	22 in [55.88 cm]
Outside diameter	4.77 in [12.12 cm]
Length	11.27 ft [3.44 m]
Weight	262 lbm [119 kg]
Tension	50,000 lbf [222,411 N]
Compression	4,400 lbf [19.572 N]

Tool quality control

Standard curves

The Dielectric Scanner standard curves are listed in Table 1.

Table 1. Dielectric Scanner Standard Curves

Output Mnemonic	Output Name
BHPR	Borehole pressure
CALI	Dielectric Scanner calibrated caliper
COND_DTR1_F3	Frequency 3 transverse near conductivity
COND_DTR2_F3	Frequency 3 transverse medium conductivity
COND_DTR3_F3	Frequency 3 transverse far conductivity
COND_DTR4_F3	Frequency 3 transverse very far conductivity
COND_XON	Dielectric Scanner invaded zone conductivity
EPSI_DTR1_F3	Frequency 3 transverse near dielectric permittivity
EPSI_DTR2_F3	Frequency 3 transverse medium dielectric permittivity
EPSI_DTR3_F3	Frequency 3 transverse far dielectric permittivity
EPSI_DTR4_F3	Frequency 3 transverse very far dielectric permittivity
EPSI_XON	Dielectric Scanner invaded zone dielectric permittivity
MTEM	Mud temperature
PWXO	Invaded zone water-filled porosity
RWXO	Invaded zone water resistivity
RXO	Dielectric Scanner invaded zone resistivity
THMC	Mudcake thickness
WSALXO	Invaded zone water salinity

Operation

The recommended maximum logging speed is 1,800 ft/h [9 m/min] for a 0.4-in sampling rate (Table 2). The Dielectric Scanner tool can be logged at 3,600 ft/h [18 m/min] for an 0.8-in sampling rate.

The Dielectric Scanner is combinable with all wireline services and can be run in any position within the toolstring.

To minimize environmental effects, the short, fully articulated antenna pad is applied firmly against the borehole wall by a hydraulically operated eccentering caliper to enable pad contact even in rugose boreholes. The caliper also provides hole-size measurements.

Table 2. Dielectric Scanner Acquisition Parameters

Output Mnemonic	Output Name	Unit	Default	Options
ACQRESOLUTION	Acquisition depth resolution	Unitless	0.4 in	0.2 in 0.4 in 0.8 in

Formats

The format in Fig. 1 is the real-time log from the Dielectric Scanner and AIT* array induction imager tools. The high-frequency (frequency 3) response from the symmetric receiver arrays is borehole corrected and used to produce the following curves in real time:

- water-filled porosity (PWXO)
- invaded zone fluid salinity (WSALXO)
- invaded zone resistivity (RXO_ADT)
- mudcake thickness (THMC)
- Dielectric Scanner caliper (CALI_ADT).

At a Schlumberger processing center, the raw Dielectric Scanner data are processed with Dielectric Pro* dielectric dispersion interpretation software (Table 3). Dielectric Pro software is used for quality control and advanced interpretation of the full data spectrum of all four operating frequencies of the Dielectric Scanner tool. After preprocessing and applying borehole corrections to the raw data, Dielectric Pro software performs a radial interpretation of the different spacing and polarization measurements to provide the dielectric dispersion data. A multimineral analysis for lithology and porosity from other tools is performed in the same application to determine the total porosity and formation matrix permittivity. These outputs are used with the dielectric dispersion in a final interpretation step, in which petrophysical models determine the water-filled porosity, water salinity, and textural outputs. The final log includes the real-time outputs combined with the textural outputs.

Table 3. Dielectric Scanner Processing Parameters

Output Mnemonic	Output Name	Unit	Default	Options
MATRIXEPSILON	Matrix dielectric permittivity	Unitless	4.65	Float value
RMFS	Resistivity of mud-filtrate sample	ohm.m	1.0	Float value
MFST	Mud-filtrate sample temperature	degF	77	Float value

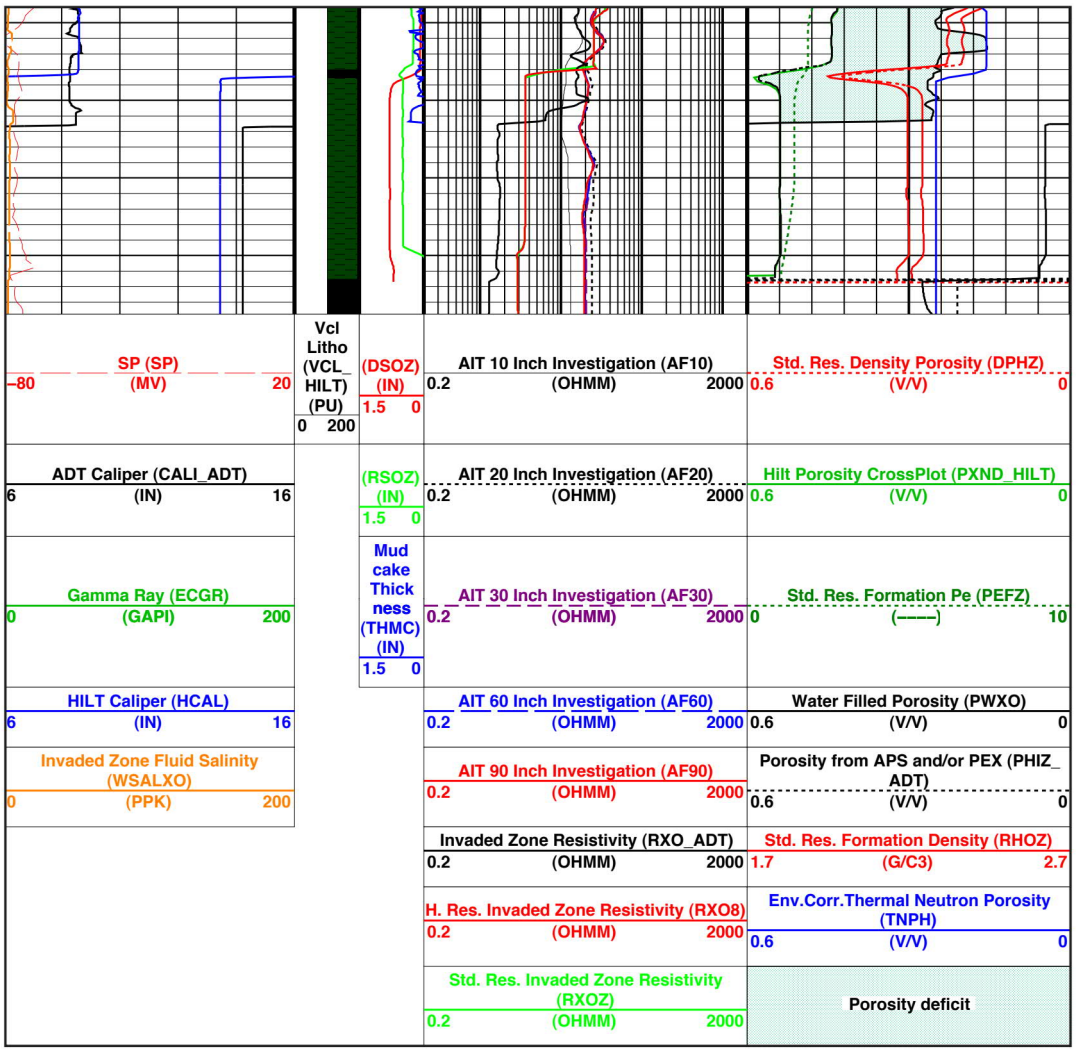

Figure 1. Dielectric Scanner and AIT array induction imager tool real-time log format.

The Dielectric Scanner format for log quality control is shown in Fig. 2.

- Track 1
  - The frequency monitor is displayed as color maps versus depth. The first four maps on the left-hand side of Track 1 show the status of the four Dielectric Scanner operating frequencies. Each incremental color shift from basic green represents progressively larger signal saturation for that frequency. Solid green represents a desirable coherent pattern, whereas degradation in the signal causes a shift toward yellow. Some intermittent saturation, particularly on frequency 3, can be expected, especially in thick mudcake.
  - The electrical stability monitor is displayed as the three color maps versus depth on the right-hand side of Track 1. From left to right are the electrical communication status, internal tool power status, and acquisition status. The three flags monitor the electrical stability of the tool downhole and the validity of the acquired raw data stream.
- Tracks 3 and 4
  - Array conductivity and permittivity from frequency 3 are displayed for inspection for random noise. Inspection of the different curves is conducted to verify that all receiver arrays are operational, although owing to the wealth of data acquired, one array spacing can sacrificed without undermining the final answer product.
- Track 5
  - PWXO is generated in real time using only frequency 3. It should be used for quality control primarily as a check against the total porosity, if available, particularly in a known water zone. It is common for real-time PWXO to be overestimated in shale sections. The final answer from Dielectric Pro processing for PWXO should be the main source for any analysis or interpretation.

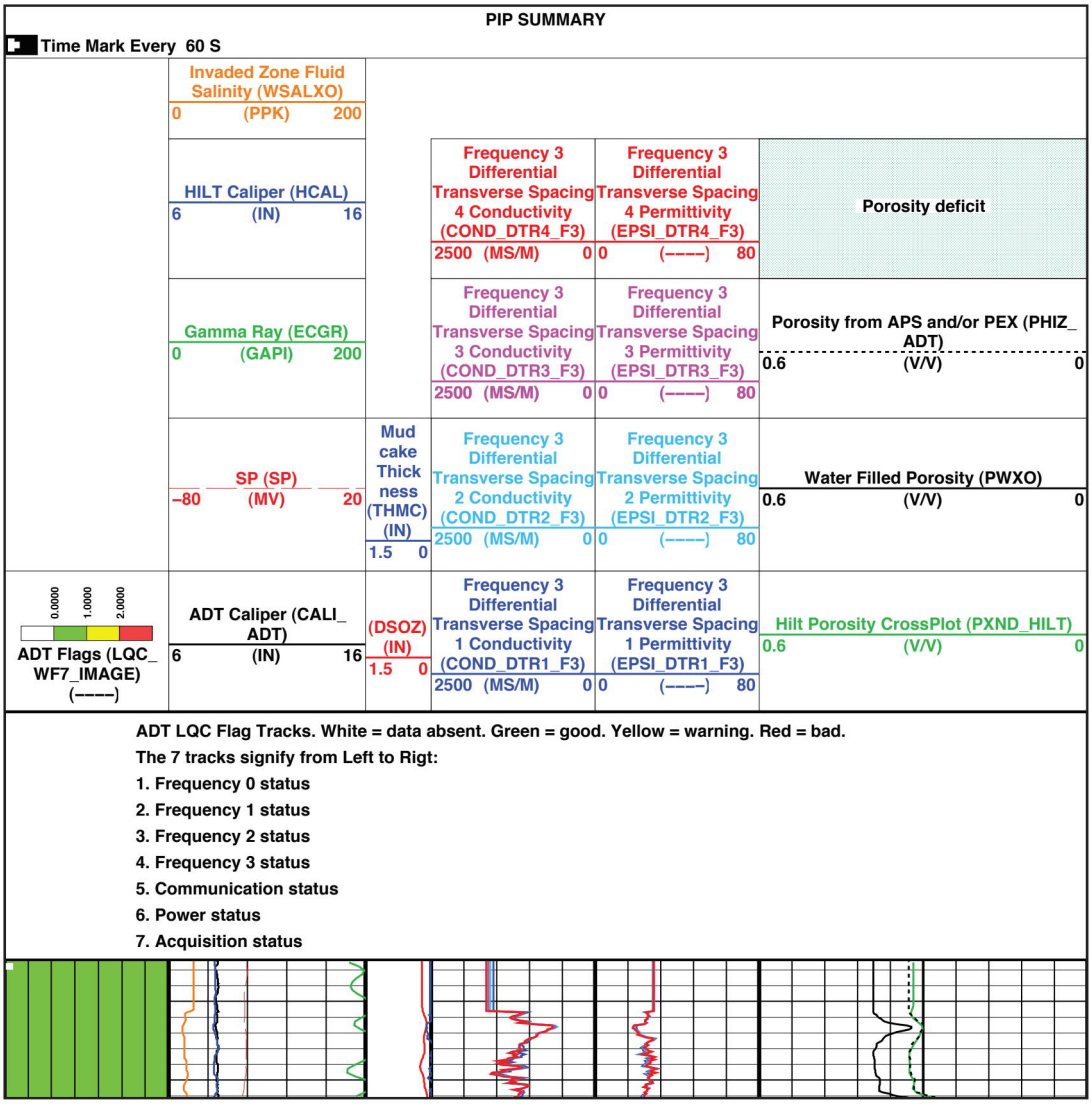

Figure 2. Dielectric Scanner log quality control format.

Response in known conditions

- In a clean water sand interval, the Dielectric Scanner water-filled porosity (PHIW_ADT) can be checked against the Platform Express* total porosity from density-neutron (PXND_HILT). Both curves should indicate similar values, overlaying on the same scale.
- The Dielectric Scanner invaded zone resistivity (RXO_ADT) and Micro-Cylindrically Focused Log (MCFL) standard-resolution invaded zone resistivity (RXOZ) should read similar values, with both curves overlaying on the same scale. In a shale interval, RXO_ADT is usually slightly lower than RXOZ.
- For all oil-base mud (OBM) environments, job planning must be conducted with the local Schlumberger petrophysics domain champion to ensure that
  - borehole conditions are suitable, with minimum hole rugosity for optimal pad contact
  - resistivity of the invaded or shallow zone is >3 ohm.m
  - textural outputs (Archie *mn* exponents) are possible for the job conditions.

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EPT

Overview

The EPT* electromagnetic propagation tool transmits microwave energy into the formation. The measured propagation enables computation of the ratio of water to hydrocarbon. Because of the high operating frequency and the nature of the pad design, the fields penetrate only a short distance into the formation. The water saturation measurements are therefore considered valid for the flushed zone near the borehole. This is an advantage particularly for comparing water saturations derived from deep investigation tools with those derived from shallow-reading tools such as the EPT tool. The difference in water saturation can often be attributed to hydrocarbon movability, which can then be linked to the ultimate productivity of the reservoir.

Calibration

EPT downhole sensor readings are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are again compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified in the after-survey calibration.

EPT wellsite calibration is subdivided into two tasks:

- electronics calibration check (tool check)
- detector calibration check (not used during log or playback processing; the values are included on the calibration summary listing for comparative purposes only).

Specifications

Measurement Specifications	
Output	Water saturation
Logging speed	1,800 ft/h [549 m/h]
Range of measurement	EPT-D: for invaded zone resistivity (R_{xo}) > 0.5 ohm.m, attenuation (EATT) < 800 dB/m EPT-G (EMD-L): for R_{xo} > 1.0 ohm.m, EATT < 600 dB/m EPT-G (BMD-S): for R_{xo} > 0.5 ohm.m, EATT < 1,200 dB/m
Accuracy	EATT: ± 25 dB/m Time of propagation (TPL): ±0.3 ns/m Micro-inverse (MINV) and micro-normal (MNOR) resistivity: ± 3.0 ohm.m
Depth of investigation	1 to 2 in [2.54 to 5.08 cm]

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	6.5 in [16.5 cm] without microlog (ML) 8.5 in [21.6 cm] with ML pad on the Powered Caliper Device (PCD)
Borehole size—max.	17 in [43.2 cm]
Outside diameter	4.62 in [11.7 cm] at antenna skid 5.87 in [14.9 cm] with ML pad
Length	11.96 ft [3.65 m]
Weight	205 lbm [93 kg]
Tension	50,000 lbf [222,410 N]
Compression	7,600 lbf [33,800 N]

Tool quality control

Standard curves

The EPT standard curves are listed in Table 1.

Table 1. EPT Standard Curves

Output Mnemonic	Output Name
APCT	Attenuation propagation time correlation
EADI	EPT attenuation differential
EAPW	Attenuation plane wave equivalent
EATT	Attenuation
EPTF	EPT fatal flag
EPTW	EPT warning flag
FVD	Far voltage down
FVR	Far voltage reference
FVU	Far voltage up
HD	Hole diameter (short arm and large arm)
LA	Large arm caliper
MINV	Micro-inverse
MNOR	Micro-normal
NVD	Near voltage down
NVR	Near voltage reference
NVU	Near voltage up
PSDO	Phase shift down
PSUP	Phase shift up
SA	Short arm caliper
TENS	Tension
TPDI	Time of propagation differential
TPL	Time of propagation
TPPW	Time of propagation plane wave equivalent

Operation

Good contact of the EPT skid with the borehole wall is essential to achieve a usable log. It is highly recommended to eccentralize the EPT tool with a caliper device.

Salt-saturated muds at low-resistivity formations may cause saturation of the EPT attenuation.

Formats

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

- Track 1
  - EATT is a function of the borehole environment. It should positively correlate with TPL when the tool is functioning properly.
- Tracks 2 and 3
  - TPL is the primary measurement of the tool, namely, the electromagnetic wave propagation speed. It should be checked against the responses in normal conditions to make sure tool is reading properly.
  - The FVU and FVD curves should be stable and not negative. A negative excursion of those voltages indicates a fatal condition and a bad log. The difference between FVU and FVD should be less than 0.3 V.

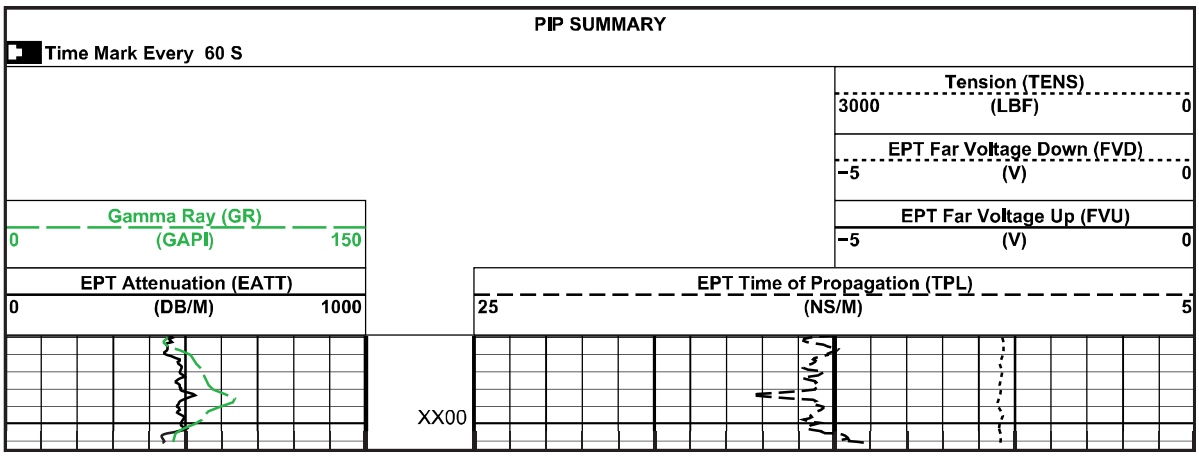

Figure 1. EPT standard format.

Response in known conditions

The typical values in Table 2 should be observed within the repeatability tolerance on the measurement (±0.09 ns/ft [±0.3 ns/m]).

Table 2. Typical EPT Tool Response in Known Conditions

Formation	TPL, ns/ft [ns/m]
Sandstone, 0% porosity	2.2 [7.2]
Limestone, 0% porosity	2.8 to 3.1 [9.1 to 10.2]
Dolomite, 0% porosity	2.7 [8.7]
Anhydrite	2.6 [8.4]

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Rt Scanner

Overview

The Rt Scanner* triaxial induction service calculates vertical and horizontal resistivity (R_v and R_h, respectively) from direct measurements while simultaneously solving for formation dip at any well deviation. Making measurements at multiple depths of investigation in three dimensions ensures that the derived resistivities are true 3D measurements. The enhanced hydrocarbon and water saturation estimates computed from these measurements result in a more accurate reservoir model and reserves estimates, especially for laminated, anisotropic, or faulted formations.

The compact, one-piece Rt Scanner tool has six triaxial arrays measuring at various depths into the formation. Each triaxial array contains three collocated coils for measurements along the x, y, and z directions. R_v and R_h are calculated at each of the six triaxial spacings. Three single-axis receivers and electrodes on the sonde housing are used to fully characterize the borehole signal to remove it from the triaxial measurements. In addition to the resistivity measurements, formation dip and azimuth are calculated for structural interpretation.

Along with advanced resistivity and structural information, the tool delivers standard AIT* array induction imager tool measurements. Innovative design provides this complete resistivity information with no additional hardware.

The Rt Scanner tool is also fully combinable with Platform Express* intergrated wireline logging system and most openhole services.

Specifications

Measurement Specifications	
Output	R_v, R_h, AIT logs, spontaneous potential (SP), mud resistivity (R_m), dip, azimuth
Logging speed	Max.: 3,600 ft/h [1,097 m/h]
Depth of investigation	AIT logs: 10, 20, 30, 60, and 90 in [25.4, 50.8, 76.2, 152.4, and 228.6 cm]
Mud type or weight limitations	Determined during job planning
Vertical resolution	AIT logs: 1, 2, and 4 ft [0.30, 0.61, and 1.22 m] 1D inversion: R_h: 3 ft [0.91 m], R_v: 10 ft [3.0 m]
Combinability	Bottom-only tool, combinable with Platform Express service and most openhole tools

Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	ZAIT-xA: 20,000 psi [138 MPa] ZAIT-xB: 25,000 psi [172 MPa]
Borehole size—min.	6 in [15.24 cm]
Borehole size—max.	20 in [50.8 cm]
Outside diameter	3.875 in [9.84 cm]
Length	19.6 ft [5.97 m]
Weight	404 lbm [183 kg]
Tension	25,000 lbf [111,205 N]
Compression	6,000 lbf [26,690 N]

Calibration

There are no master calibration procedures for the field. The field engineer conducts the electronic calibration check routine, which checks the basic status of most of the Rt Scanner electronics, and the sonde error routine, which checks for out of tolerance indications. This check must not be performed when the tool is exposed to direct sunlight because the tool is highly sensitive to thermal gradients.

Tool quality control

Standard curves

The Rt Scanner standard curves are listed in Table 1.

Table 1. Rt Scanner Standard Curves

Output Mnemonic	Output Name
A010	Array induction resistivity with 1-ft [0.3-m] vertical resolution and median depth of investigation of 10 in [25.4 cm]
A020	Array induction resistivity with 1-ft vertical resolution and median depth of investigation of 20 in [50.8 cm]
A030	Array induction resistivity with 1-ft vertical resolution and median depth of investigation of 30 in [76.2 cm]
A060	Array induction resistivity with 1-ft vertical resolution and median depth of investigation of 60 in [152.4 cm]
A090	Array induction resistivity with 1-ft vertical resolution and median depth of investigation of 90 in [228.6 cm]
ABFR	AIT borehole/formation signal ratio
AD1	Rt Scanner inside diameter of invasion
AD2	Rt Scanner outside diameter of invasion
AE10	Environmentally corrected resistivity with median depth of investigation of 10 in
AE20	Environmentally corrected resistivity with median depth of investigation of 20 in
AE30	Environmentally corrected resistivity with median depth of investigation of 30 in
AE60	Environmentally corrected resistivity with median depth of investigation of 60 in
AE90	Environmentally corrected resistivity with median depth of investigation of 90 in
AF10	Array induction resistivity with 4-ft vertical resolution and median depth of investigation of 20 in
AF20	Array induction resistivity with 4-ft vertical resolution and median depth of investigation of 20 in
AF30	Array induction resistivity with 4-ft vertical resolution and median depth of investigation of 30 in
AF60	Array induction resistivity with 4-ft vertical resolution and median depth of investigation of 60 in
AF90	Array induction resistivity with 4-ft vertical resolution and median depth of investigation of 90 in
AMF	Rt Scanner array measurement of mud resistivity
ART	Rt Scanner true formation resistivity
ARX	Rt Scanner invaded zone resistivity
AT10	Array induction resistivity with 2-ft [0.6-m] vertical resolution and median depth of investigation of 10 in
AT20	Array induction resistivity with 2-ft vertical resolution and median depth of investigation of 20 in
AT30	Array induction resistivity with 2-ft vertical resolution and median depth of investigation of 30 in
AT60	Array induction resistivity with 2-ft vertical resolution and median depth of investigation of 60 in
AT90	Array induction resistivity with 2-ft vertical resolution and median depth of investigation of 90 in
AVM	Volume of mud filtrate estimation
DPAA54_1D	3D 1D apparent hole azimuth
DPAP54_1D	3D 1D apparent dip
DPAZ54_1D	3D 1D true hole azimuth
DPAZ_BHC	3D borehole-compensated (BHC) derived true azimuth
DPTR54_1D	3D 1D true dip
DPTR_BHC	3D BHC derived true dip
DQ54_1D	3D 1D dip quality factor
DQ_BHC	3D BHC derived dip quality factor
MF54_1D	3D 1D inversion misfit
RA54_1D	3D filtered 1D resistivity anisotropy
RH54_1DF	3D filtered 1D horizontal resistivity
RH_BHC	3D BHC derived horizontal resistivity
RV54_1DF	3D filtered 1D vertical resistivity
RV_BHC	3D BHC derived vertical resistivity
SP	Spontaneous potential
SPAR	Armor-compensated SP
TRIES	Tool electronics monitor
TRIQRI	Rt Scanner array ratio monitor
TRIRSD[1,3,5,7,9,11]	3D invertability *n*-in high-frequency array residual
TRISC[0,1,2, . . ., 11]	3D quality control sigma combos

Operation

The Rt Scanner tool should always be run eccentralized with standoffs, caliper tool, and GPIT* general purpose inclinometry tool in the same string. The GPIT tool is necessary to provide the tool orientation with respect to the borehole and the Earth's magnetic field. The GPIT tool should be run with at least 4 ft [1.2 m] of nonmagnetic housing above and below it, and it should be at least 6 ft [18 m] from the Rt Scanner tool.

To ensure that the tool maintains a constant standoff against the formation, normally two knuckle joints must be used between the Rt Scanner tool and the next tool above it.

Job planning requires knowledge of the expected true resistivity (R_t) and R_m to determine that the tool is within operational limits (Fig. 1).

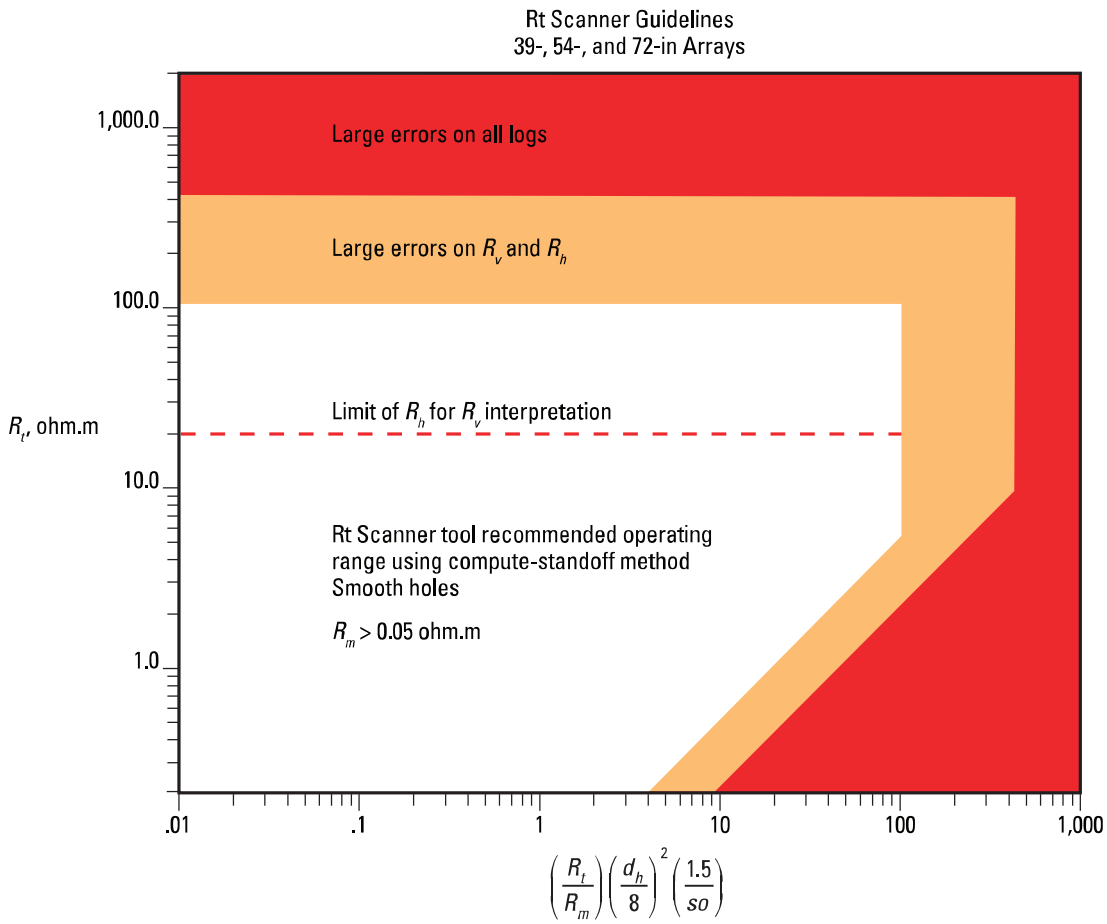

Figure 1. Rt Scanner resistivity measurement operating range.

Formats

There are three formats available for quality control.

The ZAIT quality control image format is similar to the AIT quality control image. For a detailed explanation of this format, please refer to the AIT document in the Log Quality Control Reference Manual.

The 3D quality control image format is used to analyze the quality and validity of the triaxial measurements by comparing the transverse couplings with the zz couplings. This format is shown in Fig. 2 and is described as follows.

- Track 1
  - The first six divisions plot the ZAIT array ratio monitor (TRIQRI data); which is a graphical representation of the zz–xx and zz–yy comparison conductivities for each of the six triaxial arrays with the 15-in [38-cm] array (A4) in division 1 and the 72-in [183-cm] array (A9) in the sixth division. The TRIQRI data drives a set of green-to-yellow stripes, with problems related to array issues or borehole correction errors changing the corresponding stripe from green through yellow shades depending on the severity of the problem.
  - The seventh division represents the electronics monitor track, similar to that of the AIT tool. White means no problems, blue is a warning flag that problems have occurred but are not serious enough to affect the log, and red indicates that a serious problem has occurred that can affect the log. This stripe commonly turns blue or red as the tool enters the casing.
  - The remaining part of Track 1 displays the borehole correction monitor, which is a ratio of the borehole signal to formation signal for the 39-in [99-cm] zz array. Light gray shading indicates significant borehole signal. Black indicates a critical level of signal from the borehole.

    The caliper input used for processing is also plotted here.
- Track 2
  - The zz–xx and zz–yy comparison conductivities for each of the six triaxial arrays are plotted to help identify anomalies in the transverse (xx and yy) and zz couplings. The spread depends on invasion, similar to the AIT AQABN raw curves. Curves that stand out from the others also flag the corresponding stripes in Track 1.
  - The mud resistivity from the bottom-nose R_m sensor is also plotted to ensure that it is correlating well with what is expected based on the mud measurement made at the surface.
- Track 3
  - The quality of the triaxial cross-terms (xy, xz, yz, yx, zx, and zy) can be observed in displays of the rotational residuals of the y-containing cross-terms. High residuals (>0.4) indicate an increased error between the 1D model and the tool response or cross-term errors (from misalignment of the transmitter and receiver coils).

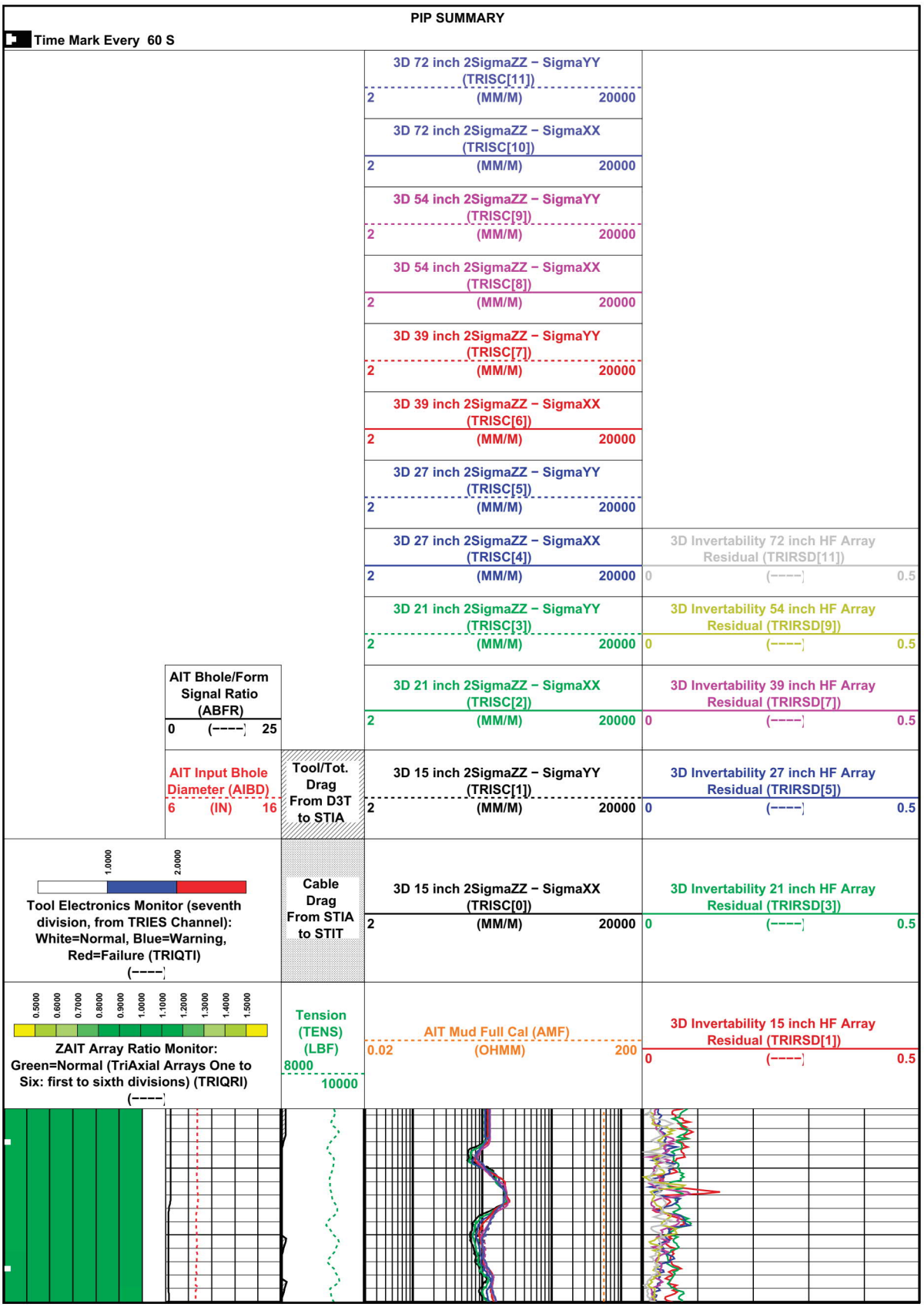

Figure 2. Rt Scanner standard format.

The current Rt Scanner wellsite answer products include R_h, R_v, dip, and azimuth derived using two mathematical inversions: 1D inversion and RADAR BHC. There is a quality control format for each of the methods, but both have the same guidelines. There are also corresponding dip formats. The 1D answer product quality control format is shown in Fig. 3. The main curves are as follows.

- Track 1
  - The misfit curve tests the quality of the inversion using a normalized least-squares difference between the computed data and the model data in the inversion. A consistently low value indicates that the computed wellsite answers are reasonably accurate, although further processing by Schlumberger Data & Consulting Services is preferred.
- Tracks 2 and 3
  - The computed R_h and R_v for the 54-in [137-cm] array are plotted in Tracks 2 and 3, respectively. These tracks also contain the corresponding 90%, 50%, and 10% likelihood values of R_h and R_v generated using a statistical error propagation model. Red, green, and yellow bands respectively visually define the high (90%), medium (50%), and low (10%) likelihood uncertainty widths.

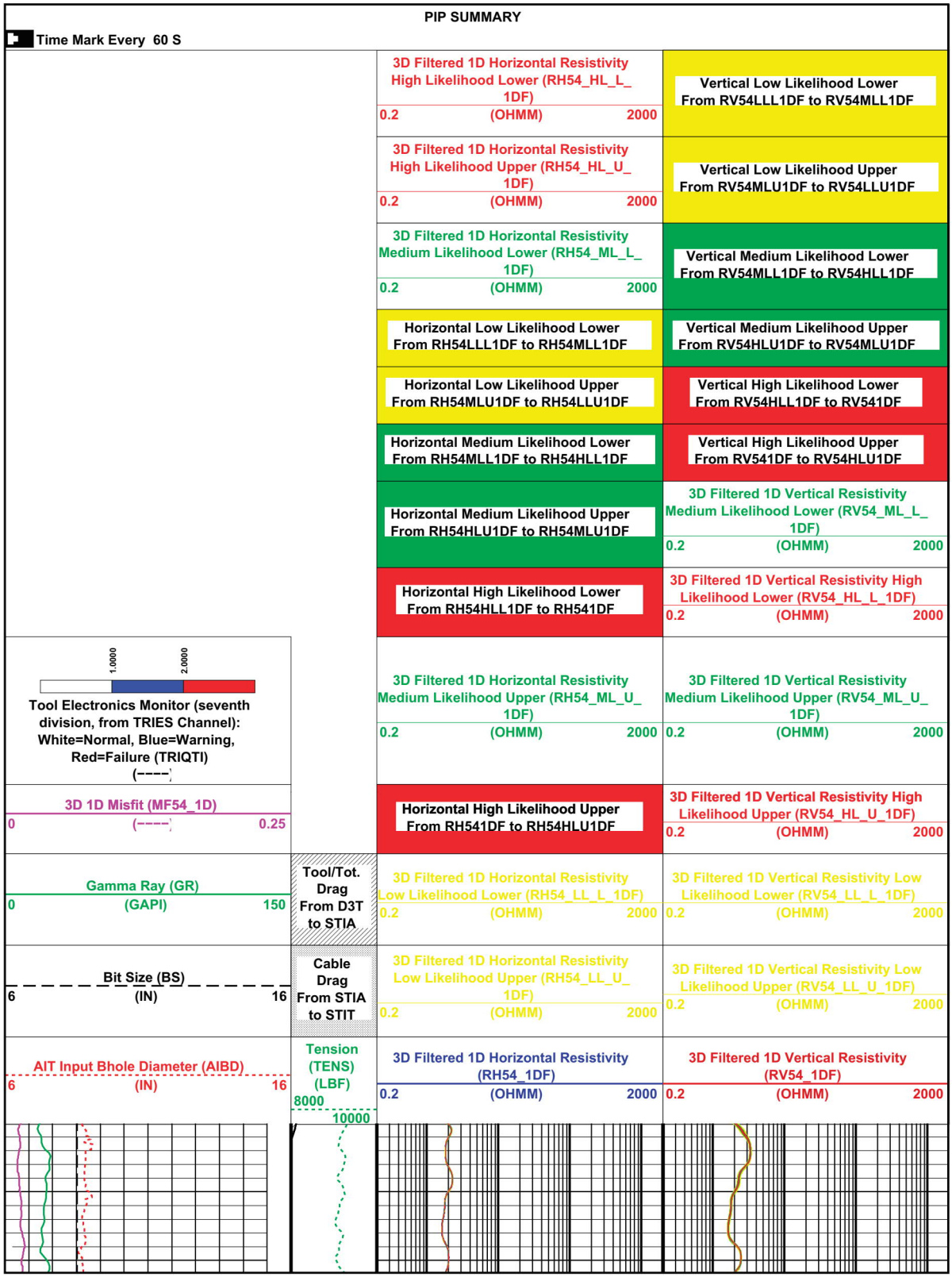

Figure 3. Rt Scanner welllsite answer products format.

The dip and azimuth are plotted in a special dip format (Fig. 4). The error propagation models are used to quantify the actual error in dip or azimuth. The dip quality curve (Track 1) and the tadpole shading reflect the confidence in the displayed dips and azimuth (Table 2).

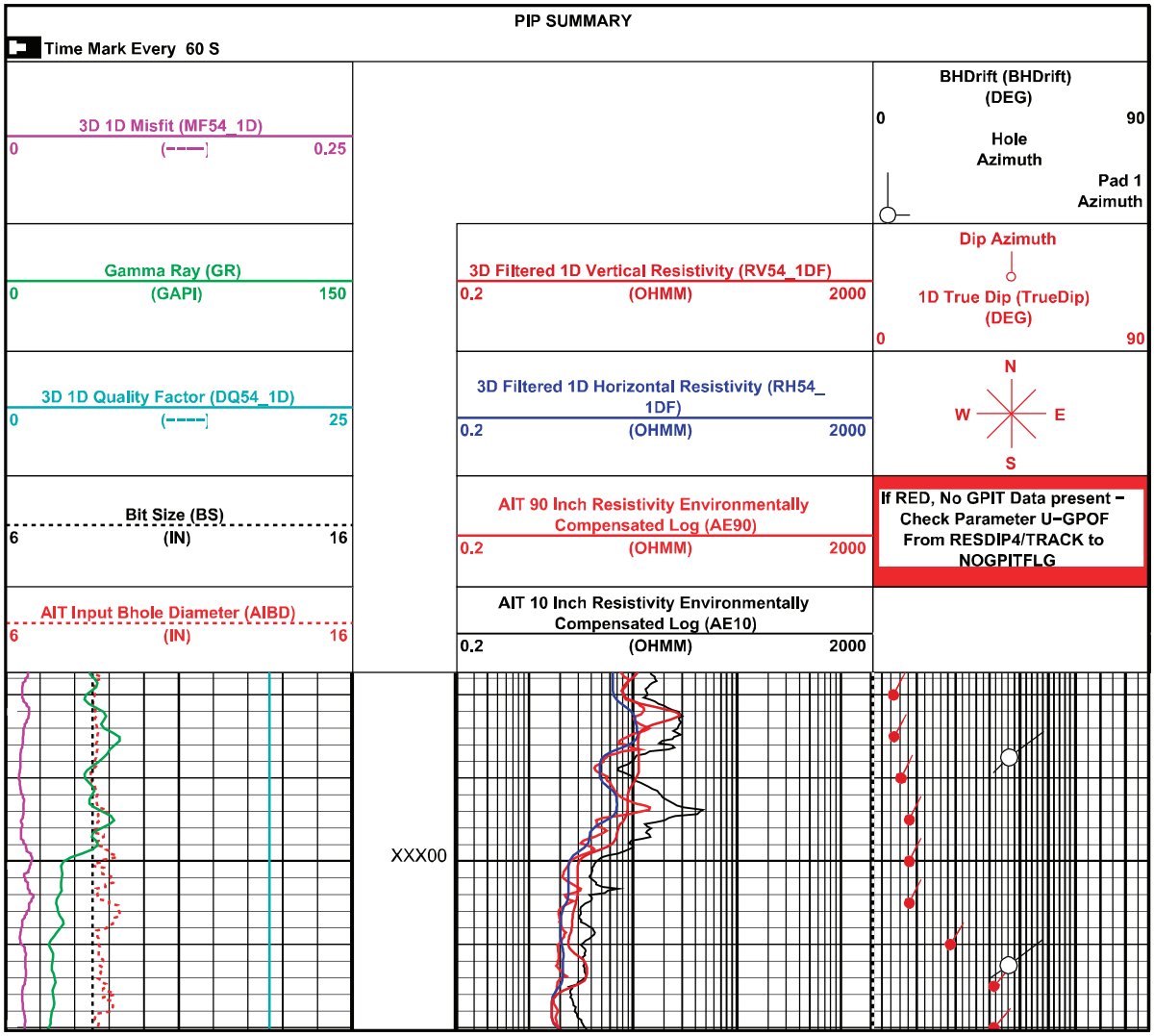

Figure 4. Scanner dip format for plotting dip and azimuth.

Table 2. Rt Scanner Dip and Azimuth Confidence

Quality Factor	Tadpole Code	Dip Quality and Confidence
18	Solid color	High
10	Open	Medium
4	Open gray or not plotted	Poor

Response in known conditions

- In impermeable zones, the standard AIT resistivity curves overlay and match each other.
- In permeable zones, the relative position of the curves shows a monotonic profile that depends on the values of the resistivity of water (R_w) and resistivity of mud filtrate (R_{mf}). In casing, the measurement is invalid.
- R_v can read a little higher than the other curves in shale owing to anisotropy.
- R_h < AF90 < R_v.
- Computed dips should be consistent with those from dipmeter tools (Fig. 5).
- The 1D inversion likelihood band tends to skew (biased to the right) in high-resistivity zones.

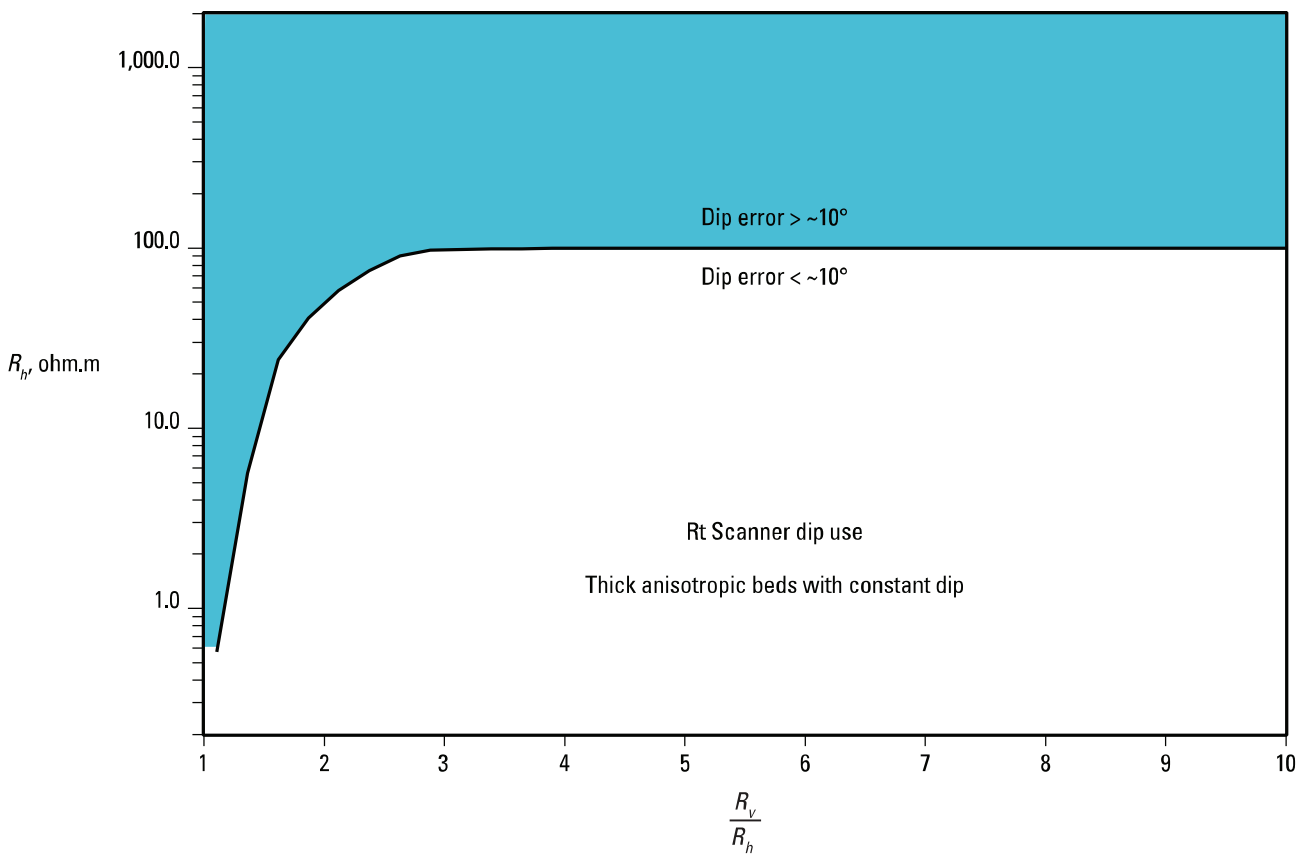

Figure 5. Rt Scanner dip measurement operating range.

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AIT

Overview

Induction logging tools accurately measure borehole formation conductivity as a function of both well depth and radius into the formation at different borehole conditions and environments. Various tools cater to special operating environments, including slim wells and high-pressure, high-temperature (HPHT) hostile environments.

Wireline array induction tools use an array induction coil that operates at multiple frequencies. Software focusing of the received signals generates a series of resistivity logs with different depths of investigation. Multichannel signal processing provides enhanced radial and vertical resolution and correction for environmental effects. Quantitative two-dimensional (2D) imaging of formation resistivity provides bedding and invasion features to describe the presence of transition zones, annuli, and water saturation (S_w).

Array induction measurements are available from several tools:

- Standard AIT* array induction imager tools (AIT-B and AIT-C) are used in moderate-environment wellbore conditions.
- Platform Express* array induction imager tools (AIT-H and AIT-M) are designed expressly for the Platform Express logging suite and are used primarily in standard logging conditions of pressure to 15,000 psi [103 MPa] and temperature to 257 degF [125 degC].
- Slim Array Induction Tool (SAIT) is used mainly for slim wellbores and severe doglegs.
- Hostile Environment Imager Tool (HIT) is a component of the Xtreme* platform for logging hostile environments.
- SlimXtreme* Array Induction Imager Tool (QAIT) is similar to the SAIT tool but is also used in HPHT environments.

Specifications

Measurement Specifications

	AIT-B and AIT-C	AIT-H and AIT-M	SAIT	HIT	QAIT
Output	10-, 20-, 30-, 60-, and 90-in [25.4-, 50.8-, 76.2-, 152.4-, and 228.6-cm] deep induction resistivities, spontaneous potential (SP), mud resistivity (R_m)				
Logging speed	3,600 ft/h [1,097 m/h]				
Range of measurement	0.1 to 2,000 ohm.m				
Vertical resolution	1, 2, and 4 ft [0.30, 0.61, and 1.22 m]				
Accuracy	Resistivity: ±0.75 us/m (conductivity) or 2% (whichever is greater)				
Depth of investigation†	AO/AT/AF10: 10 in [25.4 cm] AO/AT/AF20: 20 in [50.8 cm] AO/AT/AF30: 30 in [76.2 cm] AO/AT/AF60: 60 in [152.4 cm] AO/AT/AF90: 90 in [228.6 cm]				
Mud type or weight limitations	Salt-saturated muds are usually outside the operating range of the induction tools.				
Combinability	Combinable with most services	Platform Express platform	SlimAccess* platform	Xtreme platform	SlimXtreme platform
Special applications			Slim wellbores Severe doglegs H_2S service	High temperature H_2S service	Slim wellbores High pressure and temperature

† AO = 1-ft [0.30-m] vertical resolution, AT = 2-ft [0.61-m] vertical resolution, AF = 4-ft [1.22-m] vertical resolution

Mechanical Specifications						
	AIT-B and AIT-C	**AIT-H**	**AIT-M**	**SAIT**	**HIT**	**QAIT**
Temperature rating	350 degF [177 degC]	257 degF [125 degC]	302 degF [150 degC]	302 degF [150 degC]	500 degF [260 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	15,000 psi [103 MPa]	15,000 psi [103 MPa]	14,000 psi [97 MPa]	25,000 psi [172 MPa]	30,000 psi [207 MPa]
Borehole size—min.	4¾ in [12.07 cm]	4¾ in [12.07 cm]	4¾ in [12.07 cm]	4 in [10.16 cm]	4⅞ in [12.38 cm]	3⅞ in [9.84 cm]
Borehole size—max.	20 in [50.80 cm]	20 in [50.80 cm]	20 in [50.80 cm]	9 in [22.86 cm]	20 in [50.80 cm]	20 in [50.80 cm]
Outside diameter	3.875 in [9.84 cm]	3.875 in [9.84 cm]	3.875 in [9.84 cm]	2.75 in [6.99 cm] with 0.25-in [0.64-cm] standoff	3.875 in [9.84 cm]	3 in [7.62 cm]
Length	33.5 ft [10.21 m]†	16 ft [4.88 m]	16 ft [4.88 m]	23.6 ft [7.19 m]†	29.2 ft [8.90 m]†	30.8 ft [9.39 m]†
Weight	575 lbm [261 kg]	255 lbm [116 kg]	282 lbm [128 kg]	238 lbm [108 kg]	625 lbm [283 kg]	499 lbm [226 kg]
Tension	16,500 lbf [73,400 N]	20,000 lbf [88,960 N]	20,000 lbf [88,960 N]	20,000 lbf [88,960 N]	20,000 lbf [88,960 N]	20,000 lbf [88,960 N]
Compression	2,300 lbf [10,230 N]	6,000 lbf [26,690 N]	6,000 lbf [26,690 N]	3,300 lbf [14,680 N]	6,000 lbf [26,690 N]	2,000 lbf [8,900 N]

† Without spontaneous potential (SP) sub

Calibration

Calibration of the AIT-B, AIT-C, AIT-H, and AIT-M induction tools uses a standard array induction calibration area, which has a two-height calibration stand consisting of four wooden support posts set vertically in a concrete pad and positioned along a straight line. Each post has blocks for positioning the AIT tool at rest at 4- and 12-ft [1.2- and 3.6-m] elevations. The concrete pad is reinforced with nylon mesh or fiberglass rebar because the 80- by 60-ft [24- by 18-m] area surrounding the calibration stand must remain free of all conductive objects, including tools, debris, fences, and personnel.

The advanced array induction calibration area is used for the SAIT, HIT, and QAIT versions. The advanced area is similar to the standard calibration area but has three additional support posts to keep these less rigid or heavier tools from sagging during calibration. The other dimensions, such as the nonconductive perimeter, are the same for both calibration areas.

Tool quality control

Standard curves

The AIT standard curves are listed in Table 1.

Table 1. AIT Standard Curves

Output Mnemonic	Output Name	Output Mnemonic	Output Name
A010	Array induction resistivity with 1-ft [0.3-m] vertical resolution and median depth of investigation of 10 in [25.4 cm]	AF90	Array induction resistivity with 4-ft vertical resolution and median depth of investigation of 90 in
A020	Array induction resistivity with 1-ft vertical resolution and median depth of investigation of 20 in [50.8 cm]	AHD1	AIT inside diameter of invasion
A030	Array induction resistivity with 1-ft vertical resolution and median depth of investigation of 30 in [76.2 cm]	AHD2	AIT outside diameter of invasion
A060	Array induction resistivity with 1-ft vertical resolution and median depth of investigation of 60 in [152.4 cm]	AHQABN	Array induction quality control borehole-corrected nonfiltered array signal
A090	Array induction resistivity with 1-ft vertical resolution and median depth of investigation of 90 in [228.6 cm]	AHRT	AIT true formation resistivity
ACRB	AIT computed mud resistivity	AHRX	AIT invaded zone resistivity
AE10	Environmentally corrected resistivity with median depth of investigation of 10 in	AHVM	Volume of mud filtrate estimation
AE20	Environmentally corrected resistivity with median depth of investigation of 20 in	AHMF	Array induction fully calibrated mud resistivity
AE30	Environmentally corrected resistivity with median depth of investigation of 30 in	AT10	Array induction resistivity with 2-ft [0.6-m] vertical resolution and median depth of investigation of 10 in
AE60	Environmentally corrected resistivity with median depth of investigation of 60 in	AT20	Array induction resistivity with 2-ft vertical resolution and median depth of investigation of 20 in
AE90	Environmentally corrected resistivity with median depth of investigation of 90 in	AT30	Array induction resistivity with 2-ft vertical resolution and median depth of investigation of 30 in
AF10	Array induction resistivity with 4-ft [1.2-m] vertical resolution and median depth of investigation of 10 in	AT60	Array induction resistivity with 2-ft vertical resolution and median depth of investigation of 60 in
AF20	Array induction resistivity with 4-ft vertical resolution and median depth of investigation of 20 in	AT90	Array induction resistivity with 2-ft vertical resolution and median depth of investigation of 90 in
AF30	Array induction resistivity with 4-ft vertical resolution and median depth of investigation of 30 in	SP	Spontaneous potential
AF60	Array induction resistivity with 4-ft vertical resolution and median depth of investigation of 60 in	SPAR	Armor-compensated SP

Operation

The AIT tool is run eccentralized with standoffs and a caliper measurement. Tool location in the borehole is important for correcting for borehole conditions. There are three options for borehole correction:

- compute mud resistivity (R_m)
- compute electrical diameter (d_h)
- compute standoff (so).

Job planning requires knowledge of the expected true resistivity (R_t) and R_m (Fig. 1) to decide on the optimal borehole-correction method.

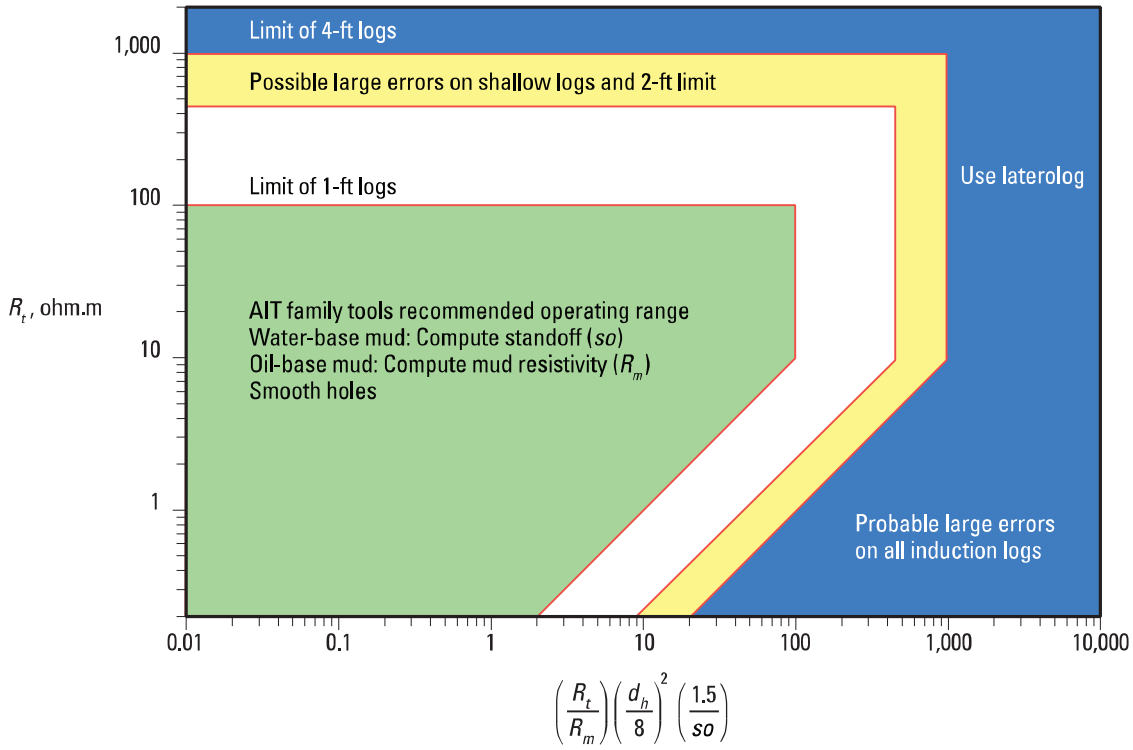

Figure 1. Openhole operating range for induction and laterolog resistivity tools.

Formats

The format in Fig. 2 is used mainly as a quality control.

- Track 1
  - AHQRI AIT array ratio monitor displays flags for the eight array receiver coils in the tool. Deep green represents a coherent pattern. A yellow strip shows a malfunctioning array or a deficiency in the borehole correction resulting from the borehole shape or condition.
  - AHQTI tool electronics monitor has flags that indicate hardware problems with the tool.
  - AEFL AIT ECLP flags are environmental correction flags triggered when the environmental parameters are outside the valid range.
  - AEMF magnetic mud flag is triggered by ferromagnetic material in the borehole because the measured X-signal is different from the expected X-signal computed from the model.
  - AHBFR AIT borehole/formation signal ratio displays a curve that may be shaded under certain conditions. Dotted shading appears if the borehole correction becomes significant for production of 10-in investigation logs, and solid shading appears when the borehole correction depends critically on the input parameters.
- Track 2
  - AHQABN[x] quality control curves correspond to the eight array measurements after corrections and depth matching have been applied. They react to the formation and borehole resistivity and should be free of large spikes.
  - AHMF should correlate with Chart GEN-9 "Sound Velocity of Hydrocarbons" in the Schlumberger *Log Interpretation Charts*. The shape should be smooth, with no abrupt or sharp changes.

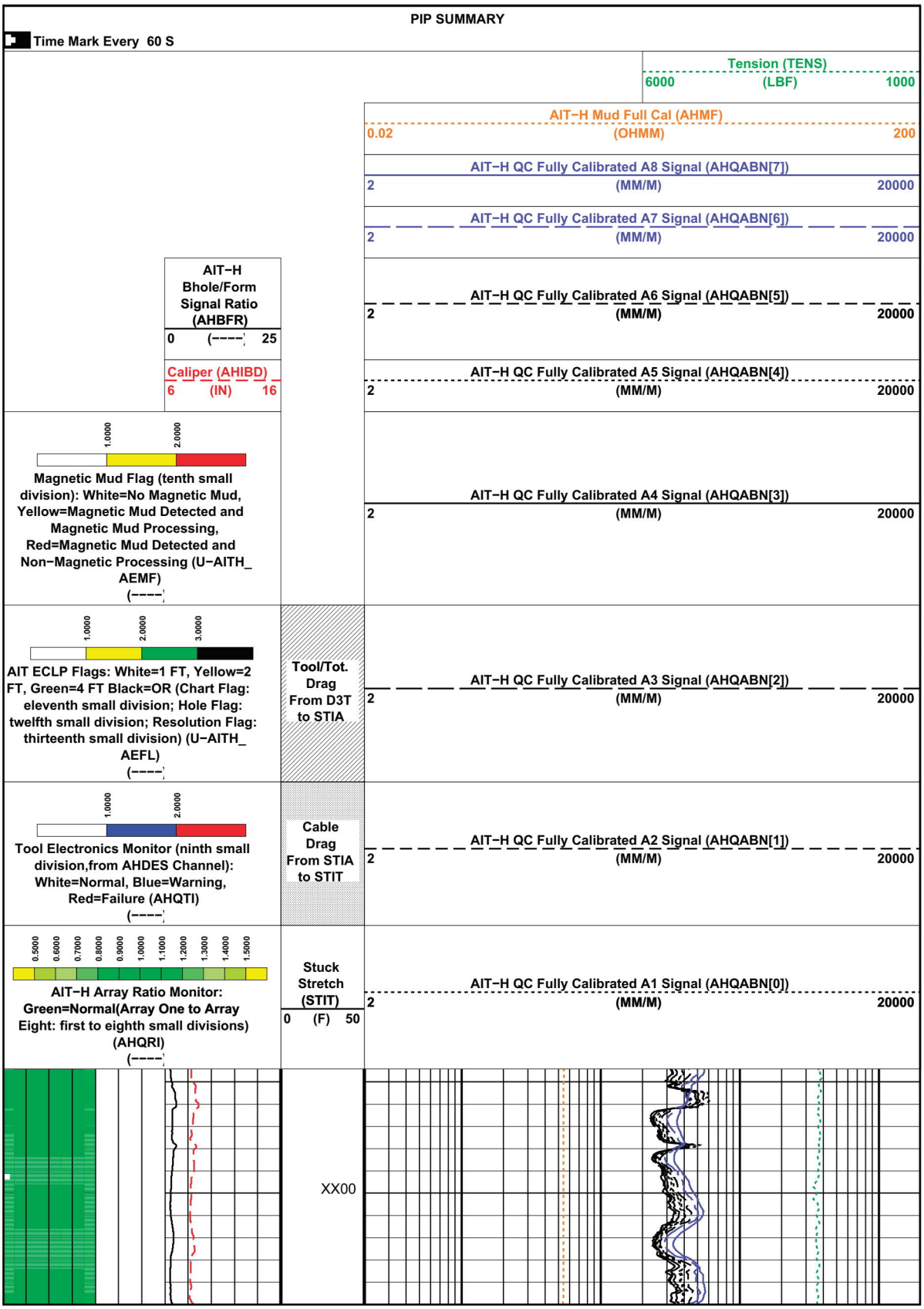

Figure 2. AIT standard format.

Response in known conditions

- In impermeable zones, all curves overlay and match each other.
- In permeable zones, the relative position of the curves shows a monotonic profile that depends on the resistivity of the water (R_w) and resistivity of the mud filtrate (R_{mf}). In casing, the measurement is invalid.

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ARI

Overview

The ARI* azimuthal resistivity imager combines standard laterolog measurements with a 12-channel azimuthal resistivity image and a high-resolution deep resistivity measurement. The resistivity image has 100% borehole coverage and complements high-resolution borehole images from the FMI* fullbore formation microimager by differentiating between natural deep fractures and shallow drilling-induced cracks. Azimuthal resistivity measurements also enable the detection of nearby conductive beds in horizontal wells.

Calibration

The downhole sensor readings of ARI tools are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration.

Specifications

Measurement Specifications	
Output	Deep laterolog, shallow laterolog, high-resolution deep laterolog, Gröningen laterolog, azimuthal resistivity, resistivity images
Logging speed	1,800 ft/h [549 m/h]
Range of measurement	0.2 to 100,000 ohm.m
Vertical resolution	Deep and shallow laterolog: 29-in [73.66-cm] beam width High-resolution laterolog: 8-in [20.32-cm] beam width
Accuracy	1 to 2,000 ohm.m: ±5% 2,000 to 5,000 ohm.m: ±10% 5,000 to 100,000 ohm.m: ±20%
Depth of investigation	40 in [101.6 cm] (varies with formation and mud resistivity)
Mud type or weight limitations	Mud resistivity (R_m) < 5 ohm.m
Combinability	Combinable with most tools

Measurement Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	4½ in [11.43 cm]
Borehole size—max.	21 in [53.34 cm]
Outside diameter†	3.875 in [9.21 cm] 7.25 in [18.41 cm]
Length	33.25 ft [10.13 m]
Weight	579 lbm [263 kg]
Tension	3,000 lbf [13,345 N]
Compression	2,000 lbf [8,900 N]

† The ARI tool is available in two sizes to fit different borehole sizes.

Tool quality control

Standard curves

The ARI standard curves are listed in Table 1.

Table 1. ARI Standard Curves

Output Mnemonic	Output Name
AR*n*	Corrected azimuthal resistivity
CC*n*	Caliper conductivity
DI90/DI0	Ratio of quadrature to in-phase voltages for the deep measurement
DV0	Voltage of the deep measurement
DV90/DV0	Ratio of quadrature to in-phase current for the deep measurement
GV0	Time-aligned voltage of the deep measurement referenced to the bridle electrode
IQ*xx*/IP*xx*	Ratio of quadrature to in-phase current for each azimuthal channel
IT0	Deep total current
LLCH	Corrected high-resolution resistivity
LLD	Laterolog deep resistivity
LLDC	Corrected laterolog deep resistivity
LLG	Laterolog Gröningen resistivity
LLHD	High-resolution laterolog deep resistivity
LLHR	High-resolution resistivity
LLHS	High-resolution laterolog shallow resistivity
LLS	Laterolog shallow resistivity
LLSC	Corrected laterolog shallow resistivity
RRi	Azimuthal resistivity
SI90/SI0	Ratio of quadrature to in-phase currents for the shallow measurement
SV90/SV0	Ratio of quadrature to in-phase voltages for the shallow measurement
VM0	Voltage of the azimuthal measurement
VM90/VM0	Ratio of quadrature to in-phase voltages for the azimuthal measurement

Operation

The ARI tool should be run centered as much as possible. In deviated wells, the tool should be run with maximum possible standoffs.

A GPIT* general purpose inclinometry tool must be run in combination with the ARI tool to provide orientation for the image.

Formats

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

- Track 1
  - The voltage curves generally read the same value, unless the Gröningen effect is present.
- Flag track
  - This track should ideally be free of flags because they indicate a problem with the named conditions for the track.
- Track 2
  - The SI and SV ratios are normally close to zero. If the Gröningen effect exists or in conditions with a low ratio of R_m to the true resistivity (R_t) the SV90/SV0 and SI90/SI0 ratios may be nonzero.
- Track 3
  - The SI and SV ratios should be close to zero.
- Track 4
  - The IQ*xx*/IP*xx* ratios are close to zero unless fractures are present.

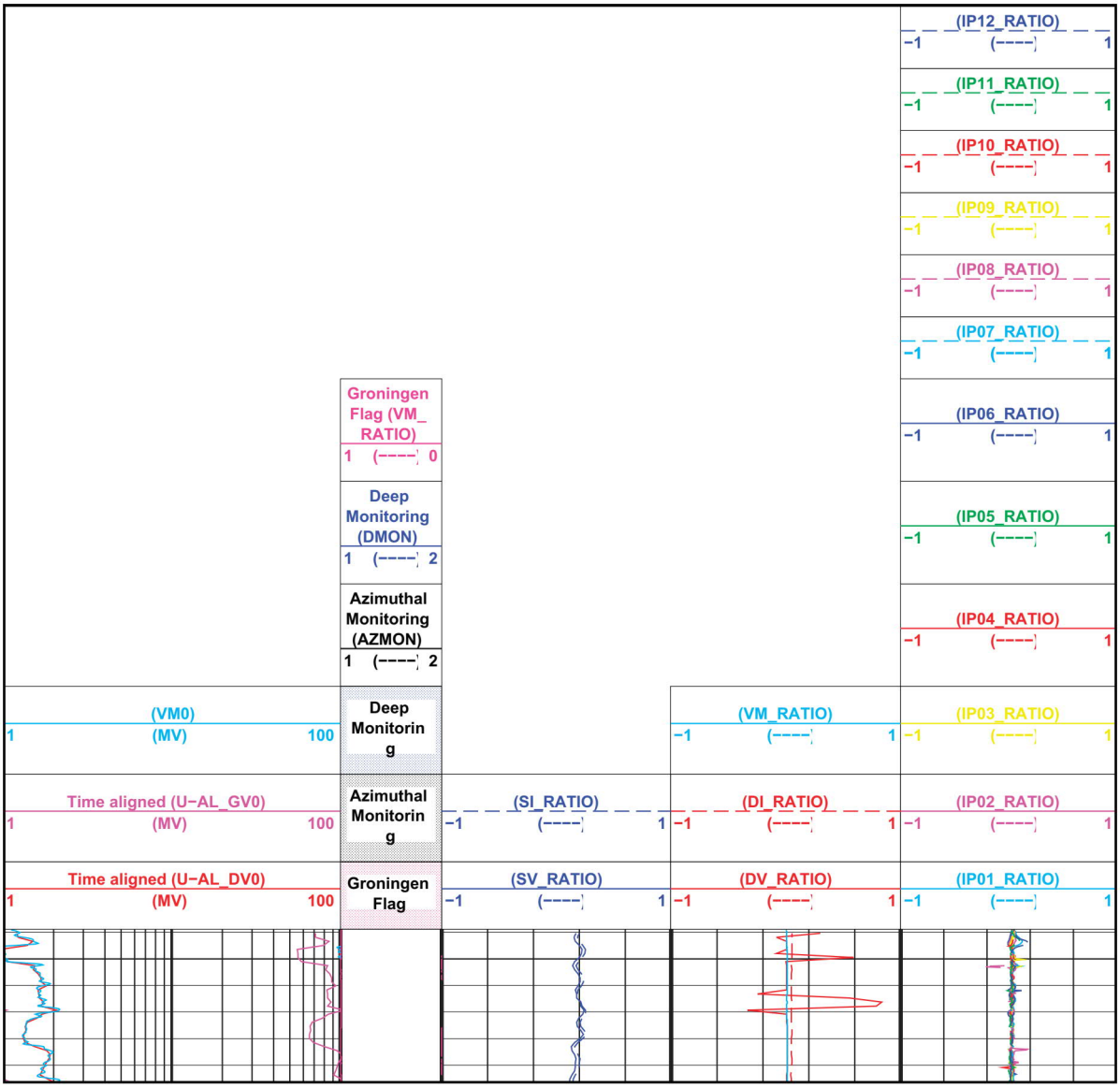

Figure 1. ARI standard format.

Response in known conditions

- In impermeable zones, borehole-corrected LLDC, LLSC, and LLCH should overlay.
- In permeable zones, the relative position of the curves should show a coherent profile depending on the value of the resistivity of the mud filtrate (R_{mf}) and the resistivity of the water (R_w), the respective saturation, and the depth of invasion. In salt muds, generally the invasion profile is such that the deeper-reading curves have a higher value than shallower-reading curves, with LLDC approaching R_t and LLSC approaching the resistivity of the invaded zone (R_{xo}).
- In fractured formations, and depending on the I/R_m contrast, spiking may be present on the azimuthal resistivity curves.
- The Gröningen effect causes LLD and LLHR to read too high.

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HRLA

Overview

The HRLA* high-resolution laterolog array provides five independent, actively focused, depth- and resolution-matched measurements that can resolve the true formation resistivity (R_t) in thinly bedded and deeply invaded formations. The absence of a current return at surface and no required use of a bridle greatly improve wellsite efficiency.

Calibration

To ensure measurement accuracy, the downhole sensors are calibrated with a series of precision resistors located inside the tool. Calibration is conducted at the wellsite because master calibration is not necessary for the HRLA tool. The before-survey calibration is conducted with the HRLA tool downhole, before logging. At the end of the survey, sensor readings are verified in the after-survey calibration.

Specifications

Measurement Specifications†	
Output	Deep laterolog, shallow laterolog, high-resolution resistivity, diameter of invasion, resistivity images, mud resistivity (R_m)
Logging speed	3,600 ft/h [1,097 m/h]
Range of measurement	R_m = 1 ohm.m: 0.2 to 100,000 ohm.m R_m = 0.02 ohm.m: 0.2 to 20,000 ohm.m
Vertical resolution	12 in [30.48 cm]
Accuracy	1 to 2,000 ohm.m: ±5% 2,000 to 5,000 ohm.m: ±10% 5,000 to 100,000 ohm.m: ±20%
Depth of investigation	50 in [127.0 cm]‡
Mud type or weight limitations	Conductive mud systems only
Combinability	Combinable with most tools

† HRLA performance specifications are for 8-in [20.32-cm] borehole.
‡ Median response at 10:1 contrast of true to invaded zone resistivity

Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa]
Borehole size—min.	5 in [12.70 cm]
Borehole size—max.	16 in [40.64 cm]
Outside diameter	3.625 in [9.21 cm]
Length	24.1 ft [7.34 m]
Weight	394 lbm [179 kg]
Tension	30,000 lbf [133,450 N]
Compression	With fin standoff: 3,600 lbf [16,010 N] With rigid centralizers: 7,800 lbf [34,700 N]

Tool quality control

Standard curves

The HRLA standard curves are listed in Table 1.

Table 1. HRLA Standard Curves

Output Mnemonic	Output Name
DI_HRLT	HRLA tool (HRLT) diameter of invasion
RLA1	HRLT mode 1 resistivity curve
RLA2	HRLT mode 2 resistivity curve
RLA3	HRLT mode 3 resistivity curve
RLA4	HRLT mode 4 resistivity curve
RLA5	HRLT mode 5 resistivity curve
RM_HRLT	HRLT mud resistivity
RT_HRLT	HRLT true formation resistivity
RXO_HRLT	HRLT invaded zone resistivity

Operation

The HRLA tool is run eccentralized with standoffs and a caliper measurement. Knowledge of tool positioning in the borehole is critical to ensure that the appropriate borehole corrections are applied. RLA1 through RLA5 are automatically corrected for eccentralization, hole size, and R_m.

The HRLA tool requires a conductive medium around the tool to carry the current to the formation. Job planning requires knowledge of expected R_t and R_m (Fig. 1).

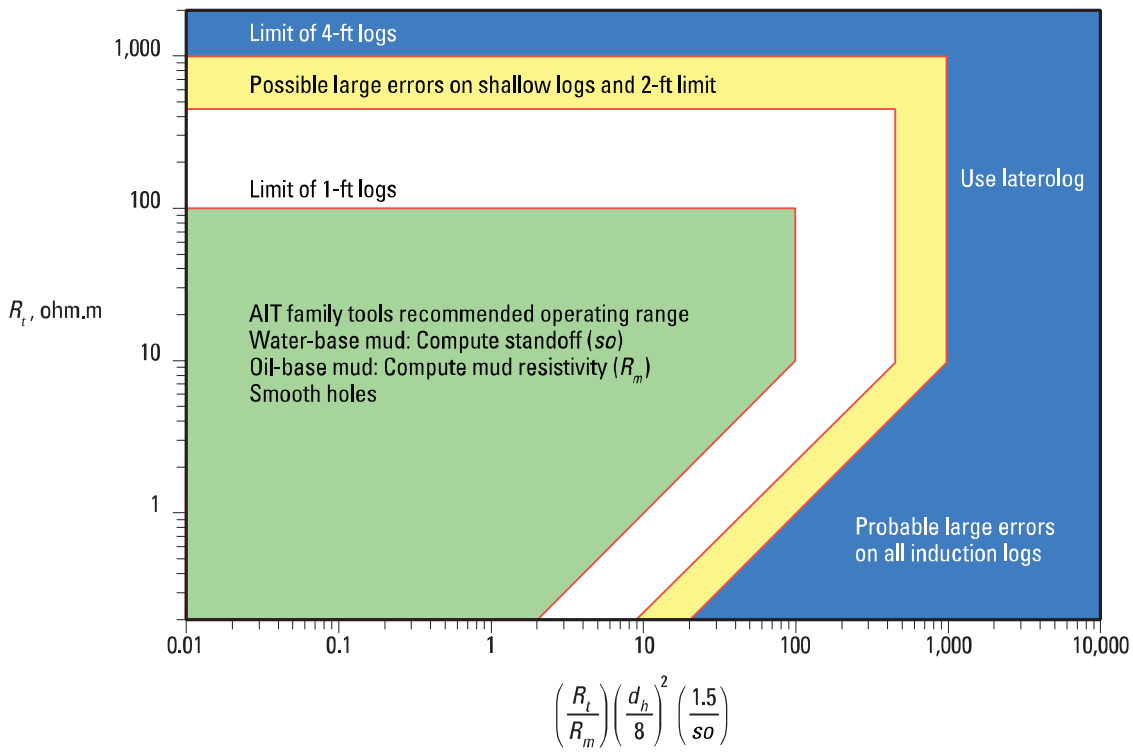
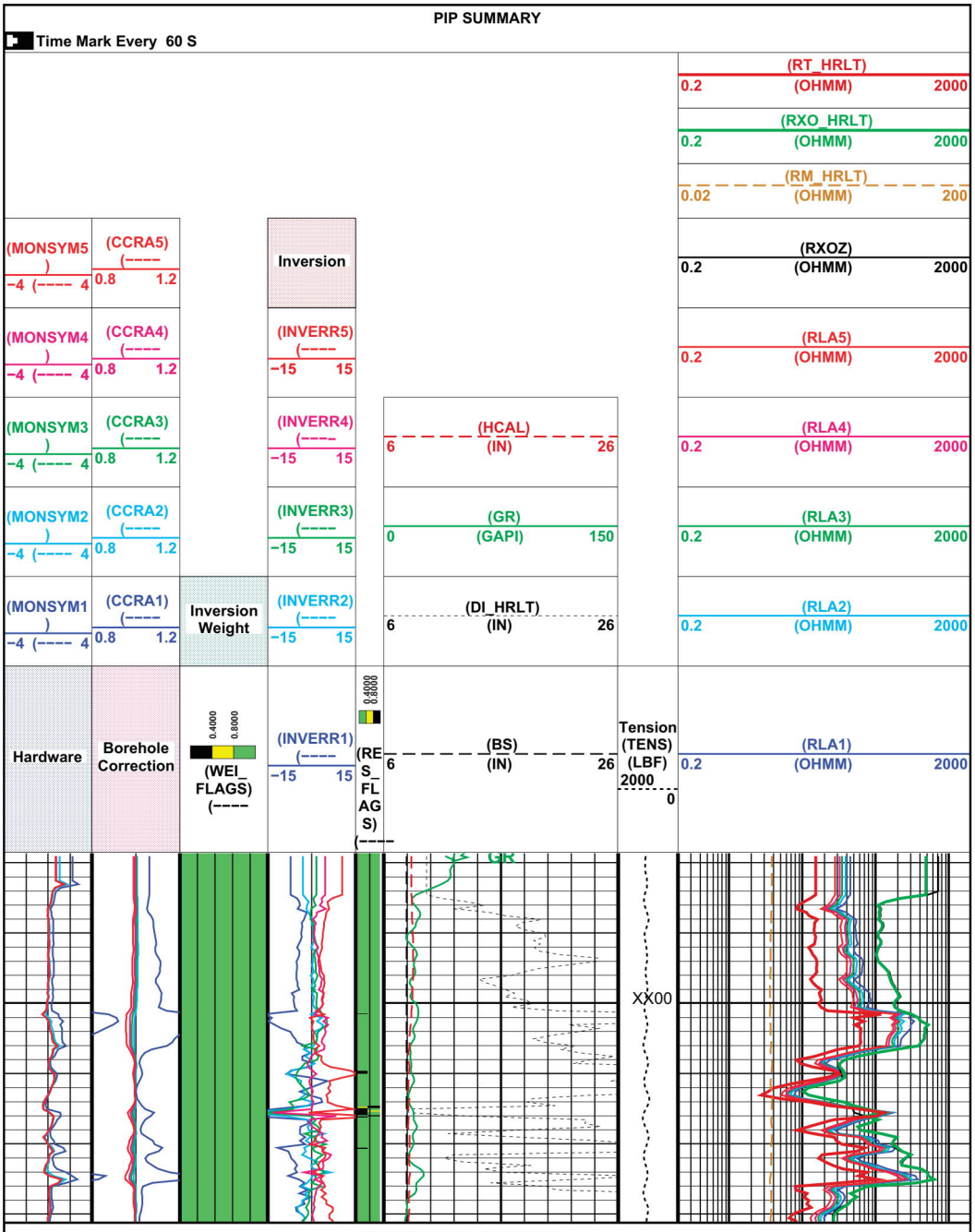


Figure 1. Openhole operating range for AIT array induction imager tools and laterolog resistivity tools.*

Formats

The format in Fig. 2 is used mainly as a quality control.

- Track 1
  - MONOSYM1 through MONOSYM5 give the ratio of the current flowing up or down the borehole at the center of the tool to the current flowing out into the formation. Shading may indicate a hardware problem with the tool.
- Track 2
  - CCRA1 through CCRA5 are the borehole correction coefficients applied to compensate for the influence of the borehole, R_t/R_m contrast, and tool eccentering.
- Track 3
  - The Inversion Weight flags are the estimated contribution of each of the HRLA measurements to the inversion. Deep green represents a desired coherent pattern, yellow indicates questionable contribution, and black may indicate unreliable contribution. The weight of each curve is adjusted at each depth level as a function of the sensitivity of the measurement to the borehole parameters.
- Track 4
  - INVER1 through INVER 5 are the ratios between the reconstructed and borehole-corrected input curves of the 1D inversion. Typically, the reconstruction errors are close to 1. At bed boundaries, it is normal to see them increasing. The errors can also be caused by imperfect borehole corrections when the contrast is high or borehole is large.
- Flag track
  - RES_FLAGS checks the consistency of the input resistivity data with respect to the 1D formation model. It is split as the RXO_HRLT and RT_HRLT flags. A flag is triggered when one or more of the resistivity measurements are out of sequence with the other resistivity curves and hence the inversion result is questionable. The flag is black if the algorithm fails to give a realizable answer. In such cases, GeoFrame* 2D inversion is recommended for reprocessing the log.
- Track 7
  - The RXOZ micro-cylindrically focused measurement of the resistivity of the invaded zone (R_{xo}) (at standard 18-in [45.7-cm] resolution from the Platform Express* integrated wireline logging tool) can be compared with the RXO_HRLT curve because of their similar vertical resolution.



*** HRLT FLAG TRACKS ***

BLACK areas show that the corresponding error flag is set.

TRACK R3_LQC INVERSION WEIGHT

Contribution from each hrlt channel in Inversion algorythm, and from left to right :

| Wei1 | Wei2 | Wei3 | Wei4 | Wei5 |

GREEN = OK YELLOW = Contribution QUESTIONABLE BLACK = Contribution UNRELIABLE

TRACK R5_LQC RESISTIVITY QUALITY INDICATOR

LQC flags on RXO_HRLT & RT_HRLT, and from left to right :

| RxoFlag | RTFlag |

GREEN = OK YELLOW = SHOULDER BED EFFECT BLACK = NOK

Figure 2. HRLA standard format.

Response in known conditions

- In impermeable zones, all curves should overlay and match each other. HRLA data should overlay any R_{xo}-measured data (MSFC, RXOZ, or RXO8) assuming good borehole conditions.
- In permeable zones, the relative position of the curves should show a coherent profile depending on the resistivity of the mud filtrate (R_{mf}) and resistivity of the water (R_w), the respective saturation, and depth of invasion. In salt muds, generally the invasion profile is such that deeper-reading curves read a value higher than shallower-reading curves, with RLA5 approaching R_t and RLA1 approaching R_{xo}.

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High-Resolution Azimuthal Laterolog Sonde

Overview

The High-Resolution Azimuthal Laterolog Sonde (HALS) component of the Platform Express* system uses a central azimuthal array of electrodes to produce deep and shallow resistivity images and an image of the electrical standoff. A computed focusing scheme increases the accuracy of the measurement and enables the simultaneous computation of standard and high-resolution curves by changing the focusing conditions.

Calibration

The HALS downhole sensor readings are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are again compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified in the after-survey calibration.

Specifications

Measurement Specifications	
Output	High-resolution deep laterolog, high-resolution shallow laterolog, resistivity images, mud resistivity
Logging speed	3,600 ft/h [1,097 m/h]
Range of measurement	0.2 to 40,000 ohm.m
Vertical resolution	Standard resolution: 18 in [45.72 cm] in 6-in [15.24-cm] borehole High resolution: 8 in [20.32 cm] in 6-in [15.24-cm] borehole
Accuracy	1 to 2,000 ohm.m: ±5%
Depth of investigation	1 to 2 in [2.54 to 5.08 cm]
Mud type or weight limitations	Conductive mud systems only
Combinability	Bottom component of Platform Express system

Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa]
Borehole size—min.	5 in [12.70 cm]
Borehole size—max.	16 in [40.64 cm]
Outside diameter	3.625 in [9.21 cm]
Length	24.1 ft [7.34 m]
Weight	394 lbm [179 kg]
Tension	30,000 lbf [133,450 N]
Compression	With fin standoff: 3,600 lbf [16,010 N] With rigid centralizers: 7,800 lbf [34,700 N]

Tool quality control

Standard curves

The HALS standard curves are listed in Table 1.

Table 1. HALS Standard Curves

Output Mnemonic	Output Name
HLLD	HALS laterolog deep low-resolution measurement
HLLS	HALS laterolog shallow low-resolution measurement
HRLD	HALS laterolog deep high-resolution measurement
HRLS	HALS laterolog shallow high-resolution measurement

Operation

The HALS tool is part of the Platform Express system. It is normally run eccentralized with standoffs and a caliper measurement. Knowledge of tool positioning in the borehole is critical to ensure that appropriate borehole corrections are applied.

The measurements are corrected for borehole conditions and Gröningen effect. Other corrections such as for the use of the TLC* tough logging conditions system and for a long string can also be applied.

The HALS requires a conductive medium around the tool to carry the current to the formation. Job planning requires knowledge of the expected true formation resistivity (R_t) and mud resistivity (R_m) (Fig. 1).

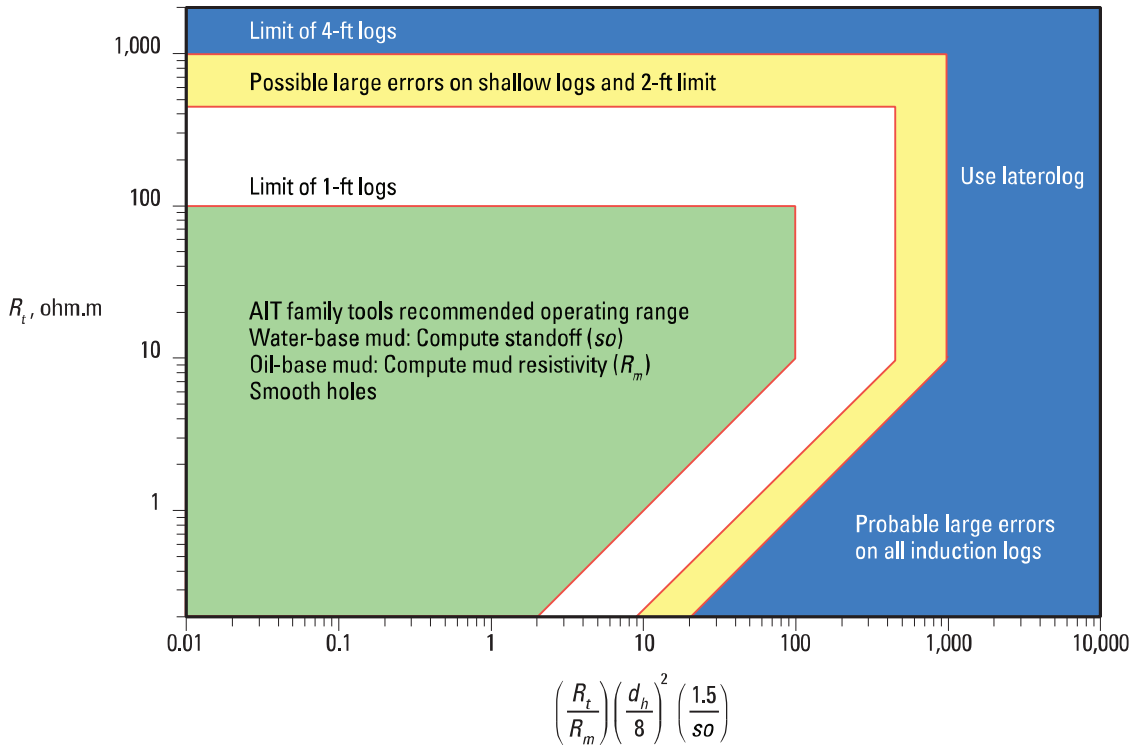

Figure 1. Openhole operating range for AIT array induction imager tools and laterolog resistivity tools.*

Formats

The format in Fig. 2 is used mainly as a quality control.

- Track 1
  - The 11 flags remain green unless triggered by the conditions or errors listed.
- Track 2
  - Monitoring Voltage Q/P ratios are the quadrature (Q) to in-phase (I) signal ratios for the three monitoring voltages. A large ratio indicates a tool failure.
- Depth track
  - The Gröningen Flag appears only when Gröningen effect is expected or in extreme low-resistivity formations. Algorithms correct for abnormally high deep resistivity readings when the measurement occurs in a conductive bed just below a thick resistive bed.
- Track 3
  - The Vertical/Monitoring Voltage mode (ZVVM1 and ZVVM2) curves are the ratios of the vertical mode voltage over the monitoring voltage. A small ratio value indicates correct focusing of the loop.
  - Aux Loop Errors (EHRLD and EHLLD) indicate a hardware malfunction. Normally the error is negligible. An error reaching 10% would certainly be a hardware malfunction.
  - HRMD/HRMS (HRMR) is the ratio between the raw mud resistivity in the deep focused and shallow focused modes. Normally, the mud resistivities should be identical in holes with diameters of 6 in to 11 in, which results in a ratio of 1. If the ratio differs significantly from this value, it may indicate loss of accuracy or tool failure.
- Track 4
  - Monitoring Voltage mode (ZVM1, ZVM2, and ZVM3) curves represent the amplitude of the three modes monitoring in-phase voltages. They should be close to each other.
  - Torpedo Voltage mode 1 (ZVT1) should not be noisy, but it may increase as a function of the R_t/R_m contrast.
  - Total Current mode 1 (ZIT1) is the total current that penetrates into the formation and flows back to surface in the deep measurement. It should not be noisy, but it may increase as a function of the R_t/R_m contrast.

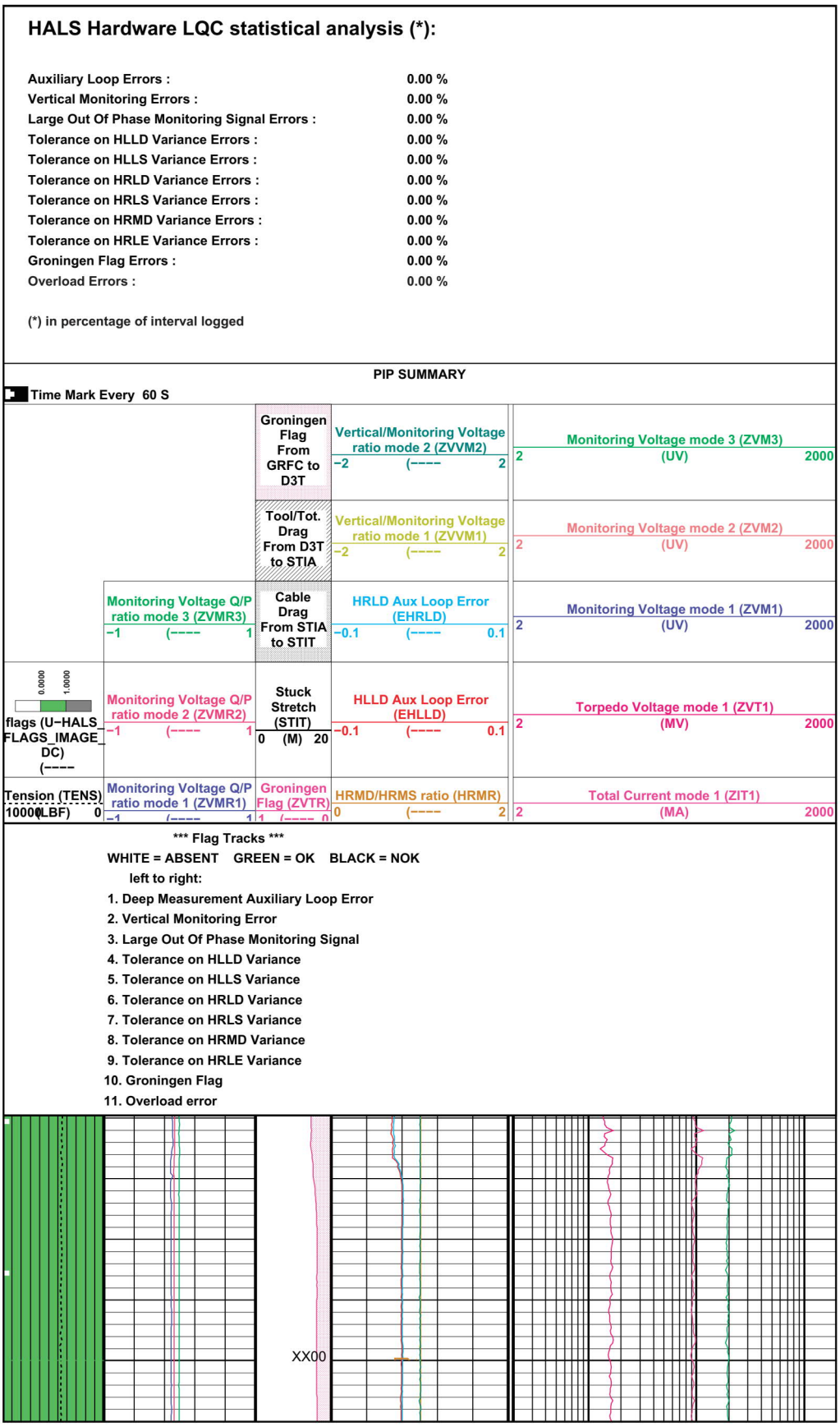

Figure 2. HALS standard format.

Response in known conditions

- In impermeable zones, the borehole-corrected HLLD and HLLS should overlay.
- In permeable zones, the relative position of the curves should show a coherent profile depending on the value of the resistivity of the mud filtrate (R_{mf}) and the resistivity of the water (R_w), the respective saturation, and the depth of invasion. In salt muds, generally, the invasion profile is such that deeper-reading curves read a value higher than shallower-reading curves, with HLLD approaching R_t and HLLS approaching the resistivity of the invaded zone (R_{xo}).

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MicroSFL

Overview

The MicroSFL* spherically focused resistivity tool (MSFL) achieves the very shallow depth of investigation necessary to measure formation resistivity close to the borehole wall through its electrode spacing arrangement in combination with control of the bucking current. The MicroSFL tool also provides an indication of the mudcake thickness (h_{mc}) and a real-time synthetic Microlog generated from the micro-normal (MNOR) and micro-inverse (MINV) measurements.

Specifications

Measurement Specifications	
Output	Invaded zone resistivity (R_{xo})
Logging speed	1,800 ft/h [549 m/h]
Range of measurement	0.2 to 1,000 ohm.m
Vertical resolution	2 to 3 in [5.08 to 7.67 cm]
Accuracy	±2 ohm.m
Depth of investigation	0.7 in [1.78 cm]
Mud type or weight limitations	Oil-base mud
Combinability	Combinable with most tools

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	5½ in [13.97 cm]
Borehole size—max.	17½ in [44.45 cm]
Outside diameter	Caliper closed: 4.77 in [12.11 cm]
Length	12.3 ft [3.75 m]
Weight	313 lbm [142 kg]
Tension	40,000 lbf [177,930 N]
Compression	5,000 lbf [22,240 N]

Calibration

At the wellsite, the before-survey calibration compares the sensor readings with a wellsite reference to ensure that no drift has occurred. At the end of the survey, sensor readings are verified again during the after-survey calibration.

If a caliper device is calibrated at surface, the caliper readings should not be adjusted in casing at the end of a logging run. Any drift observed is important information that can be used to correct for a drifting device. If a suspicious drift is observed, a post-survey verification should be performed.

It is authorized, however, to calibrate the caliper device in the casing after collecting accurate information on the casing inside diameter. The calibration in casing procedure should be documented in the Remarks section.

Caliper calibration frequency should be performed before each run in the hole and preferably at the wellsite. Calibration can be performed with the tools in horizontal or vertical position.

Caliper calibrations are performed with two jig measurements. The jigs are usually calibration rings with a specified diameter. A zero measurement is taken using the smaller of the two rings. A plus measurement is taken using the larger ring. The calibration rings must be continuous, without notched or removed sections, not have any visible damage, and not be ovalized.

Tool quality control

Standard curves

The MSFL standard curves are listed in Table 1.

Table 1. MSFL Standard Curves

Output Mnemonic	Output Name
CALS	Caliper
MSFC	Corrected microspherically focused resistivity
MSFL	Microspherically focused resistivity

Operation

MSFL tool orientation in the borehole is important because it can affect the repeatability of the tool. Good pad contact is critical.

It is recommended that zones of interest be relogged where pad contact is poor. They can be recognized by anomalously low resistivity readings.

Formats

The MSFL tool is commonly run in combination with a laterolog measurement. The format in Fig. 1 is used mainly as a quality control.

- Track 1
  - CALS is important for identifying borehole conditions such as washouts and undergauge hole sections that can be correlated to the log for interpretation.
- Track 2
  - MSFL provides a very shallow resistivity measurement. It helps in determining a complete formation resistivity profile in combination with a laterolog tool. The MSFL curve should correlate in profile with laterolog curves, keeping in mind that the vertical resolution of the MSFL measurement is higher than those of the laterolog measurements.

Response in known conditions

- In impermeable zones, the MSFL resistivity curve should equal the resistivity measurements for other depths of investigation from a laterolog tool.
- In permeable zones, the MSFL resistivity curve should show a coherent profile with the other laterolog tool resistivity curves as an indication of invasion.

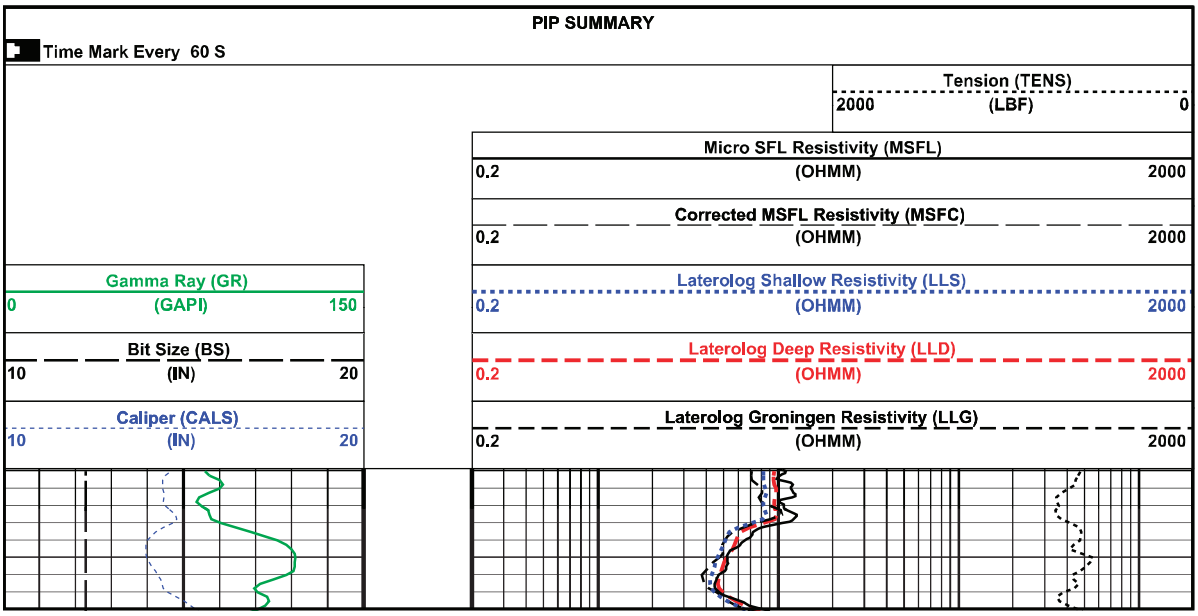

Figure 1. MSFL standard format.

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Microlog

Overview

The Microlog tool (MLT) provides the classic micro-inverse and micro-normal resistivity readings and hole diameter measurement from the caliper and pad assembly. The resistivity readings and caliper measurements can be used to indicate permeability through the presence of mudcake. Mudcake can be detected by a difference in the two resistivity readings, as well as through a measured decrease in hole diameter.

Specifications

Measurement Specifications	
Output	Micro-inverse resistivity, micro-normal resistivity, caliper
Logging speed	3,600 ft/h [1,097 m/h]
Vertical resolution	Micro-normal: 2 in [5.08 cm] Micro-inverse: 1 in [2.54 cm]
Accuracy	Caliper: ±0.2 in [±0.51 cm]
Depth of investigation	Micro-normal: ~1.5 in [~3.8 cm] Micro-inverse: ~0.5 in [~1.27 cm]
Mud type or weight limitations	Oil-base mud

Mechanical Specifications	
Temperature rating	350 degF [177 deg C]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	6.5 in [16.51 cm]
Borehole size—max.	20 in [50.8 cm]
Outside diameter	Pad: 5.875 in [14.92 cm] Cartridge: 3.375 in [8.57 cm]
Length	8.1 ft [2.5 m]
Weight	177 lbm [80 kg]
Tension	25,000 lbf [111,205 N]
Compression	6,000 lbf [26,690 N]

Calibration

At the wellsite, the before-survey calibration compares the sensor readings with a wellsite reference to ensure that no drift has occurred. At the end of the survey, sensor readings are verified again during the after-survey calibration.

If the caliper device is calibrated at surface, the caliper readings should not be adjusted in casing at the end of a logging run. Any drift observed is important information that can be used to correct for a drifting device. If a suspicious drift is observed, a post-survey verification should be performed.

It is authorized, however, to calibrate the caliper device in the casing after collecting accurate information on the casing inside diameter. The calibration in casing procedure should be documented in the Remarks section.

Caliper calibration should be performed before each run in the hole and preferably at the wellsite. Calibration can be performed with the tools in horizontal or vertical position.

Caliper calibrations are performed with two jig measurements. The jigs are usually calibration rings with a specified diameter. A zero measurement is taken using the smaller of the two rings. A plus measurement is taken using the larger ring. The calibration rings must be continuous, without notched or removed sections, not have any visible damage, and not be ovalized.

Tool quality control

Standard curves

The MLT standard curves are listed in Table 1.

Table 1. MLT Standard Curves

Output Mnemonic	Output Name
BMIN	Micro-inverse
BMNO	Micro-normal
MCAL	Caliper

Operation

The MLT is run eccentered with a caliper arm to push the pad to the borehole wall.

Formats

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

- Track 1

  MCAL is important for understanding the borehole conditions (e.g., washouts), which can affect the quality of the measurement.

- Track 2

  The BMIN and BMNO curves should be either separated, indicating a permeable zone, or overlaid, indicating an impermeable zone.

Response in known conditions

- In permeable zones, BMIN and BMNO should be separated.
- In impermeable zones, BMIN and BMNO should overlay.

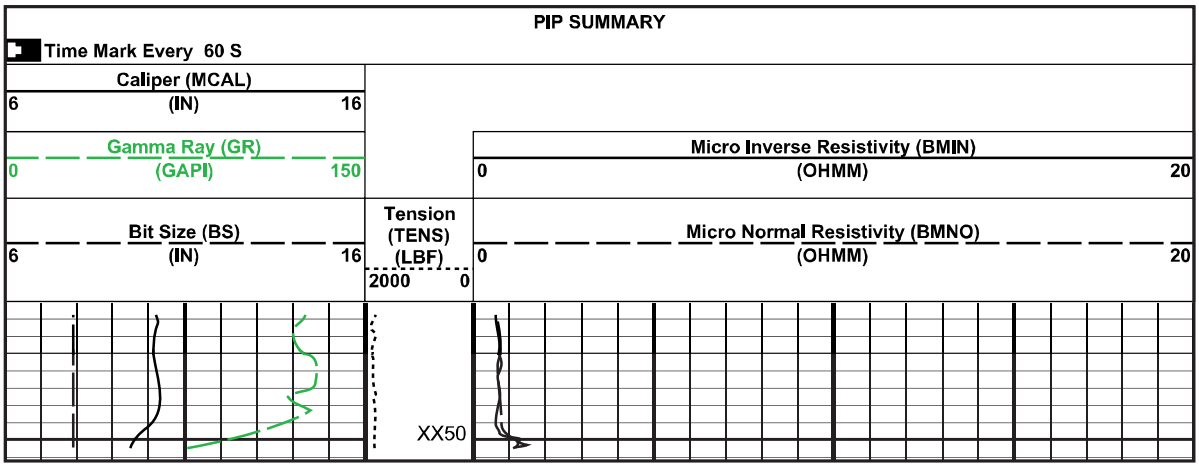

Figure 1. MLT standard format.

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CHFR-Plus and CHFR Slim

Overview

The CHFR-Plus* cased hole formation resistivity tool and CHFR-Slim* slim-hole version provide deep-reading resistivity measurements from behind steel casing. The tools induce a current that travels in the casing, where it flows both upward and downward before returning to the surface along a path similar to that employed by openhole latero-log tools. Most of the current remains in the casing, but a very small portion escapes to the formation. Electrodes on the tools measure the potential difference created by the leaked current, which is proportional to the formation conductivity.

Typical formation resistivity values are about 10^9 times the resistivity value of the steel casing. The measurement current escaping to the formation causes a voltage drop in the casing segment. Because the resistance of casing is a few tens of microohms and the leaked current is typically on the order of few milliamperes, the potential difference measured by the CHFR-Plus and CHFR-Slim tools is in nanovolts.

Measurement is performed while the CHFR-Plus and CHFR-Slim tools are stationary to avoid the noise introduced by tool movement. Contact between the electrodes and the casing is optimized by the design of the electrodes, which scrape through small amounts of casing scale and corrosion. Because the electrodes are in direct contact with the casing, the CHFR-Plus and CHFR-Slim tools are not limited to operations in conductive borehole fluids and operate in wells with oil, oil-base mud, or gas in the casing. The typical low-resistivity (1- to 5-ohm.m) cements used in well construction do not have a significant affect on cased hole resistivity measurement.

Specifications

Measurement Specifications

	CHFR-Plus and CHFR-Slim Tools
Output	Formation resistivity
Logging speed	Stationary: ~1 min/station†
Range of measurement	1 to 100 ohm.m‡
Vertical resolution	4 ft [1.2 m]
Accuracy	3% to 10%
Depth of investigation§	7 to 32 ft [2.1 to 9.75 m]
Mud type or weight limitations	None
Special applications	H_2S service

† Stations are recorded every 4 ft [1.22 m]. Two resistivity measurements, 2 ft [0.61 m] apart, are made simultaneously by redundant electrodes at each station. The resulting effective logging speed is 240 ft/h [73 m/h].
‡ Measurement of resistivities greater than 100 ohm.m may be possible based on the environment.
§ For an infinitely thick bed

Mechanical Specifications

	CHFR-Plus Tool	CHFR-Slim Tool
Temperature rating	302 degF [150 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa]	15,000 psi [103 MPa]
Casing size—min.	4½ in	2⅞ in (min. ID: 2.4 in [6.10 cm])
Casing size—max.	9⅝ in	7 in
Outside diameter	3.375 in [8.57 cm]	2.125 in [5.40 cm]
Length	48 ft [14.63 m]	37 ft [11.28 m]
Weight	683 lbm [310 kg]	253 lbm [115 kg]
Tension	20,000 lbf [88,960 N]	10,000 lbf [44,480 N]
Compression	2,400 lbf [10,675 N]	1,000 lbf [4,448 N]

Calibration

The CHFR-Plus and CHFR-Slim downhole sensor readings are periodically compared with a known reference as a master calibration. At the wellsite, sensor readings are again compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified in the after-survey calibration.

Tool quality control

Standard curves

The CHFR-Plus and CHFR-Slim standard curves are listed in Table 1.

Table 1. CHFR-Plus and CHFR-Slim Standard Curves

Output Mnemonic	Output Name
Cfrt LQC Bad Flag	Failure flag
Csre	Casing segment resistance
Ifor_Nois_F	CHFR* tool (CFRT) formation current (IFOR) noise flag
Ifor_Top	Top-step formation leakage current
Itot_Csg_F	CFRT flag for low total current (ITOT)
Itot_Top_F	CFRT top-step flag for low total current
Pif	Perforation zone
Ref1	External reference resistivity
Ref2	Openhole gamma ray
Res_Top_Estim	Top resistivity computed with estimated voltage
Res_Top_Meas	Top-step resistivity computed with DC voltage
Satu_Csg_F	Amplifier saturation flag for bad casing segment resistance
Zinj	Casing step injection impedance
Zinj_Csg_F	CFRT flag for bad impedance Zinj

Operation

The CHFR-Plus and CHFR-Slim tools require good contact with the casing to produce proper measurements; scale buildup and corrosion may be an issue, especially in old wells. A good scraper run is necessary to clean the casing. If the scraper run is insufficient, a casing wash (acid wash) may greatly improve conditions.

Formats

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

- Tracks 1 and 2
  - Under normal conditions, these tracks should be free of any tool QC flags. The problem-indicating flags are triggered by measurement conditions or if the tolerance for a curve is not set.
- Track 3
  - Res_Top_Meas formation resistivity is calculated using a measured value of the tool voltage. Res_Top_Est formation resistivity is derived with an empirical formula. Both curves should follow the shape trend.
- Track 4
  - The Zinj resistance seen by the current source during the first step of the measurement should be flat if the contact is good. An average value is from 0.5 to 0.7 ohm. A wildly varying Zinj is an indication of contact problems resulting from electrode wear, casing corrosion, or scale.
  - Ifor_Top shows the formation leakage current from the top step. It is a signal-to-noise ratio indicator and should follow the trend of the resistivity curves.
  - Csre is inversely proportional to the casing weight. It is used as a contact quality indicator and to detect bad data. It shows a kick on collars and goes to 0 when contact is bad.

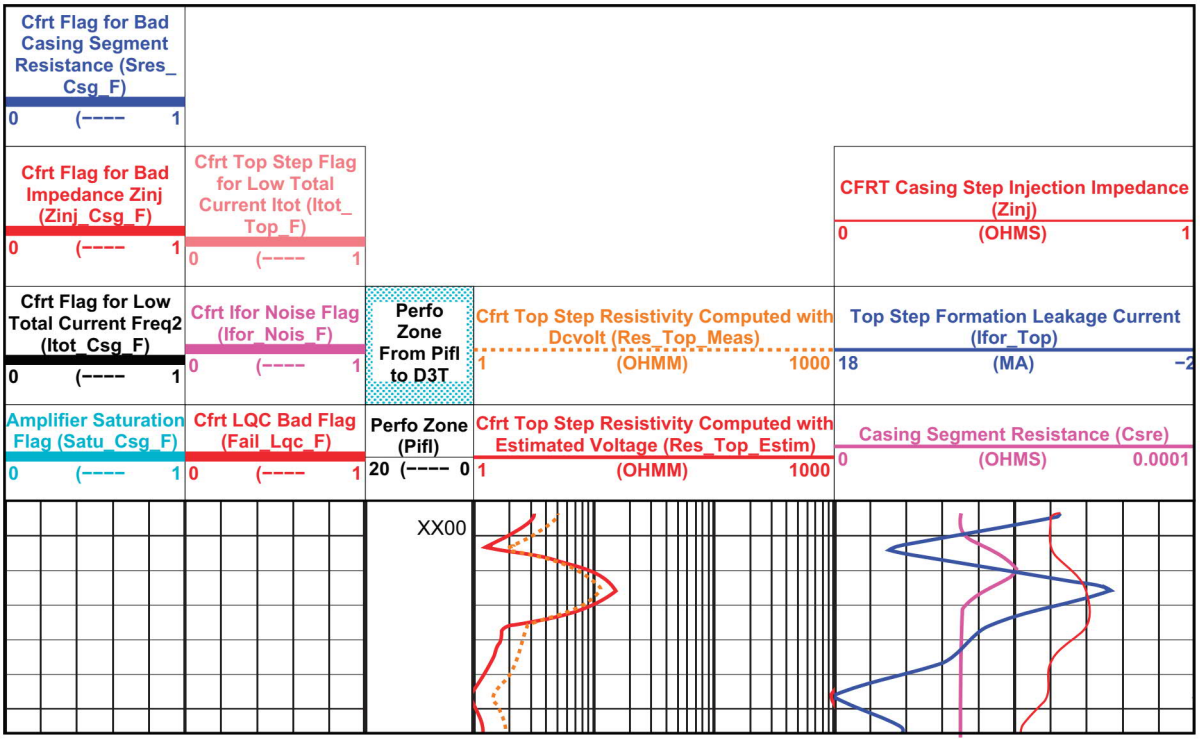

Figure 1. CHFR-Plus and CHFR-Slim standard format.

Response in known conditions

- CHFR tools are qualitative resistivity tools. A CHFR log should match the openhole resistivity log after calibration. The CHFR true resistivity measurement (R_t) should match the R_t of openhole logs for zones in which depletion is not present.
- In impermeable zones, all curves should overlay and match each other.
- In permeable zones, the relative position of the curves should show a coherent profile depending on the value of the resistivity of the mud filtrate (R_{mf}) and the resistivity of the water (R_w), the respective saturation, and the depth of invasion. In salt muds, usually the invasion profile is such that deeper-reading curves read higher than the shallower-reading curves.

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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 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.

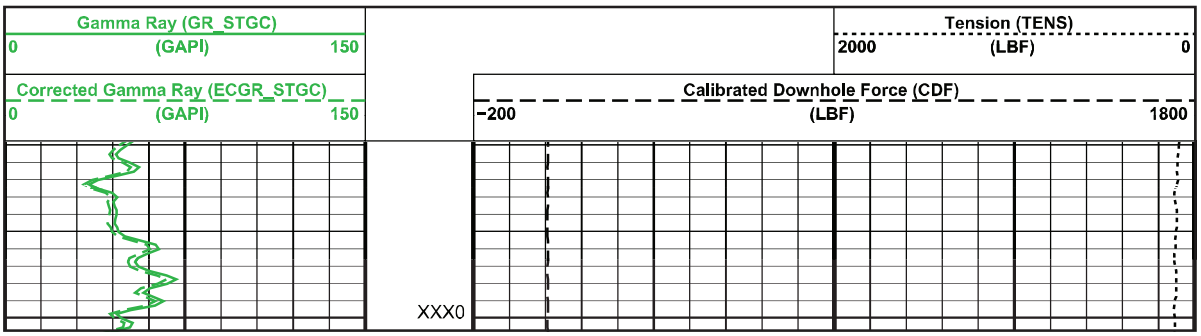

Figure 1. Gamma ray standard format.

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.

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NGS

Overview

The NGS* natural gamma ray spectrometry tool uses five-window spectroscopy to resolve the total gamma ray spectra into potassium, thorium, and uranium (K, Th, and U) curves to provide insight into the mineral composition of formations. These data are used to distinguish important features of the clay or sand around the wellbore. Clay type can be determined and radioactive sand identified. The standard gamma ray and the gamma ray minus the uranium component are also presented. The computed gamma ray can be used to evaluate the clay content where radioactive minerals are present.

Specifications

Measurement Specifications	
Output	Gamma ray; gamma ray contribution from thorium and potassium; potassium, thorium, and uranium concentrations
Logging speed	900 ft/h [274 m/h]
Range of measurement	0 to 2,000 gAPI
Vertical resolution	8 to 12 in [20.32 to 30.48 cm]
Accuracy	K: ±0.4% (accuracy), 0.25% (repeatability) Th: ±3.2 ppm (accuracy), 1.5 ppm (repeatability) U: ±2.3 ppm (accuracy), 0.9 ppm (repeatability)
Depth of investigation	9.5 in [24.13 cm]
Mud type or weight limitations	In potassium chloride (KCl) muds, KCl content must be known

Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	NGT-C: 4.5 in [11.43 cm] NGT-D: 5 in [12.70 cm]
Borehole size—max.	24 in [60.96 cm]
Outside diameter	NGT-C: 3.625 in [9.21 cm] NGT-D: 3.875 in [9.84 cm]
Length	NGT-C: 8.6 ft [2.62 m] NGT-D: 9.2 ft [2.80 m]
Weight	NGT-C: 165 lbm [75 kg] NGT-D: 189 lbm [86 kg]
Tension	50,000 lbf [222,410 N]
Compression	20,000 lbf [88,960 N]

Calibration

NGS tools should have a master calibration performed every month.

The calibration area for NGS tools must be free from outside nuclear interference. Background and plus calibrations are typically performed at the wellsite with the radioactive sources removed 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.

Tool quality control

Standard curves

The NGS standard curves are listed in Table 1.

Table 1. NGS Standard Curves

Output Mnemonic	Output Name
CGR	Computed gamma ray (Th + K)
LQCL	Log quality control upper window
LQCU	Log quality control lower window
POTA	Potassium (K)
SGR	Spectroscopy gamma ray (Th + U + K)
THOR	Thorium (Th)
URAN	Uranium (U)

Operation

The NGT is run eccentered.

Formats

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

- Track 1
  - SGR and CGR depend on formation and borehole conditions and differ from each other by the uranium content.
- Tracks 2 and 3
  - Because THOR, URAN, and POTA are all elements of the formation they depend on the type of formation and borehole conditions.
  - LQCL and LQCU are quality indicator curves that reflect the deviation of actual americium stabilization source window count rates from those measured in the shop. They should range from –1 to 1.

Response in known conditions

- SGR should match the gamma ray curve measured by a spectral gamma ray tool within ±17% after both curves are corrected for borehole effects.
- For mineral identification, Th, U, and K values must be compared with photoelectric effect (PEF) values from the Litho-Density* tool.

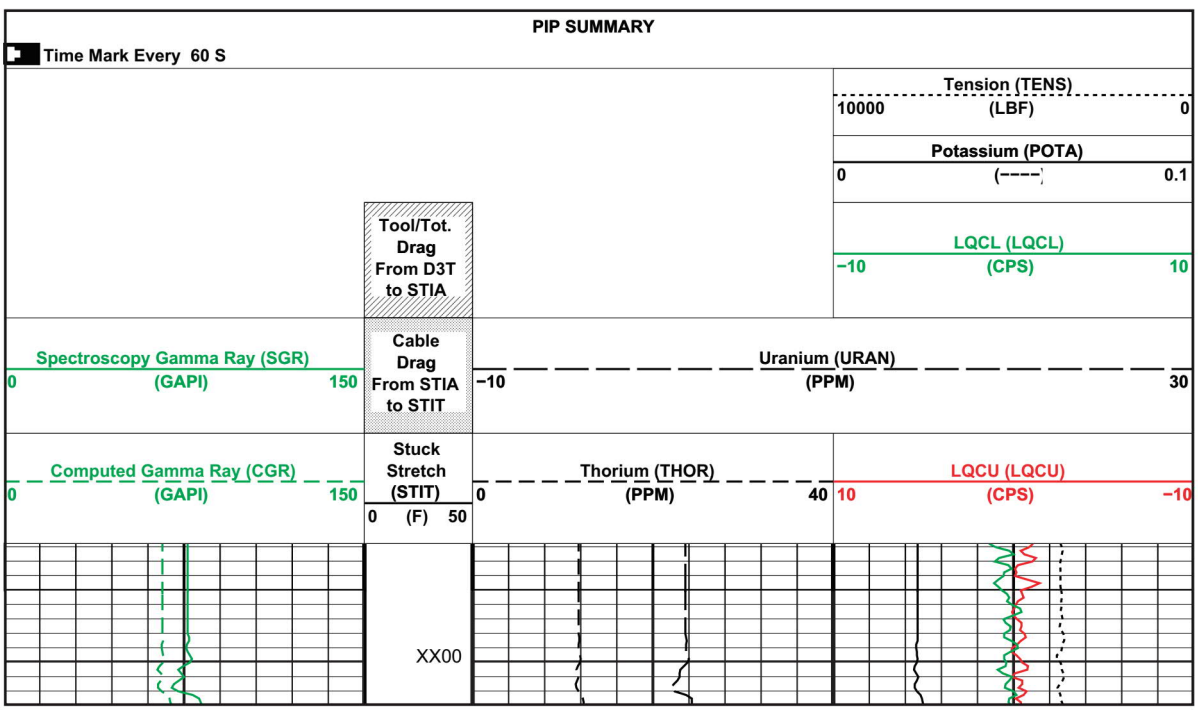

Figure 1. NGS standard format.

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Hostile Environment Natural Gamma Ray Sonde

Overview

The Hostile Environment Natural Gamma Ray Sonde (HNGS) measures the total gamma ray spectra from the formation and resolves it into the three most common components of naturally occurring radiation: potassium, thorium, and uranium (K, Th, and U, respectively). These data are used to distinguish important characteristics of the formation such as the clay type and presence of radioactive sands.

The increased detection efficiency of the detector set in the HNGS along with advanced spectral processing improves the tool's statistical response to formation gamma rays to produce a more accurate and precise spectral analysis. The improvement in the HNGS measurement is also aided by the use of two detectors instead of one, to reduce background contamination from the stabilization source. These improvements allow the HNGS to log at faster speeds than previous natural gamma ray tools. The 500 degF [260 degC] temperature rating of the HGNS makes it suitable for operations in extreme borehole environments.

Specifications

Measurement Specifications	
Output	Gamma ray; gamma ray corrected for uranium; potassium, thorium, and uranium yields
Logging speed	1,800 ft/h [549 m/h]
Range of measurement	0 to 2,000 gAPI
Vertical resolution	8 to 12 in [20.32 to 30.48 cm]
Accuracy	K: ±0.5% (accuracy), 0.14% (repeatability) Th: ±2% (accuracy), 0.9 ppm (repeatability) U: ±2% (accuracy), 0.4 ppm (repeatability)
Depth of investigation	9.5 in [24.13 cm]
Mud type or weight limitations	In potassium chloride (KCl) muds, the KCl content must be known

Mechanical Specifications	
Temperature rating	500 degF [260 degC]
Pressure rating	25,000 psi [172 MPa]
Borehole size—min.	4¾ in [12.07 cm]
Borehole size—max.	24 in [60.96 cm]
Outside diameter	3.75 in [9.53 cm]
Length	11.7 ft [3.57 m]
Weight	276 lbm [125 kg]
Tension	50,000 lbf [222,410 N]
Compression	37,000 lbf [164,580 N]

Calibration

Master calibration of an HNGS tool must be performed every 3 months.

The calibration area for HNGS tools must be free from outside nuclear interference from nonessential sources. The first step of the calibration ensures that the spectrum acquired by the tool is not shifted in frequency by using a thorium blanket reference to stabilize it. The second part of the calibration acquires the background spectra with no sources nearby, which is used to check the proper functioning of the tool and the resolution of the detectors.

Tool quality control

Standard curves

The HNGS standard curves are listed in Table 1.

Table 1. HNGS Standard Curves

Output Mnemonic	Output Name
CHI1	HNGS detector 1 chi-squared
CHI2	HNGS detector 2 chi-squared
D1PD	HNGS detector 1 pulse shape compensation
D2PD	HNGS detector 2 pulse shape compensation
GCF1	HNGS detector 1 gain correction factor
GCF2	HNGS detector 2 gain correction factor
HBHK	Borehole potassium concentration
HCGR	Computed gamma ray (Th + K)
HFK	Formation potassium concentration
HSGR	Standard gamma ray (Th + U + K)
HTHO	Formation thorium concentration
HTPR	Thorium/potassium ratio
HTUR	Thorium/uranium ratio
HURA	Formation uranium concentration
MBHK	HNGS borehole potassium minus error
MCGR	HNGS computed gamma ray minus error
MFK	HNGS potassium minus error
MSGR	HNGS spectroscopy gamma ray minus error
MTHO	HNGS thorium minus error
MURA	HNGS uranium minus error
PBHK	HNGS borehole potassium plus error
PCGR	HNGS computed gamma ray plus error
PFK	HNGS potassium plus error
PSGR	HNGS spectroscopy gamma ray plus error
PTHR	HNGS thorium plus error
PURA	HNGS uranium plus error
RDF1	HNGS detector 1 resolution degradation factor
RDF2	HNGS detector 2 resolution degradation factor
S1AT	HNGS detector 1 spectrum accumulation time
S1DT	HNGS detector 1 dead-time count rate
S1TM	HNGS detector 1 temperature value
S2AT	HNGS detector 2 spectrum accumulation time
S2DT	HNGS detector 2 dead-time count rate
S2TM	HNGS detector 2 temperature value

Operation

The HNGS is preferably run eccentered. In some situations it can be run centered through selection of one of the tool's field parameters.

Formats

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

- Track 1
  - HSGR is computed from the total gamma ray count rates starting at a low energy of 200 keV. Similar to the GR processing for a conventional gamma ray device, it is sensitive to the presence of barite in the mud.
  - HCGR is reconstructed from the thorium and potassium yields derived from spectral gamma ray data starting at 500 keV. It is insensitive to the mud barite content and is always corrected for hole size effect.
  - CHIx and GCFx are indicators of how well the measured spectrum fits to the standard values.
  - Average CHIx values should be less than 2.
  - GCFx should be between 0.95 and 1.05.
  - RDFx indicates the detector resolution degradation and should be less than 10 at a detector temperature of 140 degF [60 degC] and about 3 at room temperature. Deviations from the stated values may occur as a result of high temperature, a bad detector, or wrong parameter setting.
- Tracks 2 and 3
  - The different yields are displayed as formation concentrations HTHO for thorium, HURA for uranium, and HFK for potassium and HBHK for the borehole potassium concentration.

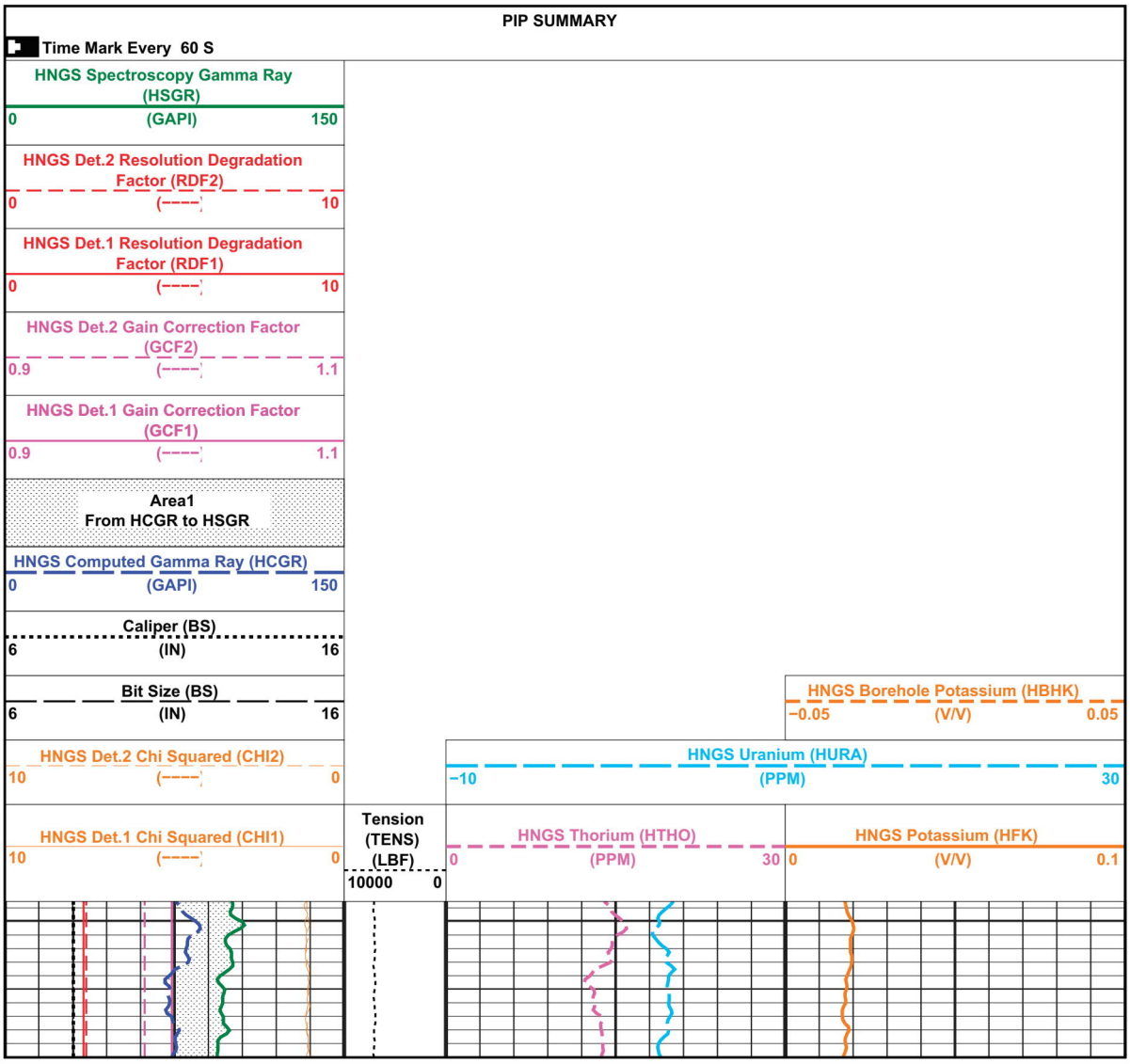

Figure 1. HNGS standard format.

Response in known conditions

- HSGR should match the gamma ray curve recorded by spectral gamma ray tools within ±17% after correction for borehole effects.
- For mineral identification, the Th, U, and K values must be compared with photoelectric effect (PEFL) values from the Litho-Density* sonde (LDS).
- In a nonbarite environment with default processing, HSGR and HCGR should compare well, with HSGR always larger or equal to HCGR because both are corrected for hole size.

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ECS

Overview

The ECS* elemental capture spectroscopy sonde uses a standard ^{16}Ci [59.2×10^{10}-Bq] americium beryllium (AmBe) neutron source and large bismuth germanate (BGO) detector to measure relative elemental yields based on neutron-induced capture gamma ray spectroscopy. The primary elements measured in both open holes and cased holes are the formation elements silicon (Si), iron (Fe), calcium (Ca), sulfur (S), titanium (Ti), gadolinium (Gd), chlorine (Cl), barium (Ba), and hydrogen (H).

Wellsite processing uses the 254-channel gamma ray energy spectrum to produce dry-weight elemental concentrations, lithology, and matrix properties. The first step involves spectral deconvolution of the composite gamma ray energy spectrum by using a set of elemental standards to produce relative elemental yields. The relative yields are then converted to dry-weight elemental concentration logs for the elements Si, Fe, Ca, S, Ti, and Gd using an oxide closure method. Matrix properties and quantitative dry-weight lithologies are then calculated from the dry-weight elemental fractions using SpectroLith* empirical relationships derived from an extensive core chemistry and mineralogy database.

Calibration

ECS sensor readings are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration. These reference calibration readings are extremely important for the accuracy and validity of the logs.

Specifications

Measurement Specifications	
Output	Elemental yields, dry-weight elemental fractions, dry-weight SpectroLith lithology, matrix properties
Logging speed	Open hole: 1,800 ft/h [549 m/h]† Cased hole: 900 ft/h [275 m/h]
Range of measurement	600 keV to 8 MeV
Vertical resolution	18 in [45.72 cm]
Accuracy‡	2% – coherence to standards computed
Depth of investigation	9 in [22.86 cm]
Mud type or weight limitations	None§
Combinability	Combinable with most tools
Special applications	Automatic wellsite petrophysical interpretation

† Speed reduction may be necessary with increasing borehole salinity and hole size.

‡ Elemental statistical uncertainty at nominal conditions (1,800-ft/h logging speed, resolution degradation factor of 5, 16,000-cps count rate, and closure normalization factor of 3): Si 2.16%, Ca 2.19%, Fe 0.36%, S 1.04%, Ti 0.10%, and Gd 3.48 ppm.

§ Statistical precision is adversely affected by high-salinity mud, particularly in large boreholes.

Mechanical Specifications	
Temperature rating	ECS-AA: 350 degF [177 degC] ECS-HP (high pressure): 500 degF [260 degC]
Pressure rating	ECS-AA : 20,000 psi [138 MPa] ECS-HP : 25,000 psi [172 MPa]
Borehole size—min.	6 in [15.24 cm]
Borehole size—max.	20 in [50.80 cm]
Outside diameter	ECS-AA: 5.0 in [12.70 cm] ECS-HP: 5.25 in [13.34 cm]
Length	10.15 ft [3.09 m]
Weight	305 lbm [138 kg]
Tension	50,000 lbf [222,410 N]
Compression	20,000 lbf [88, 960 N]

The ECS calibration is needed to reduce tool-to-tool variations in spectroscopy response caused by variations in the relative positions of the full energy and first escape peaks. The spectrum acquired during the calibration is compared with the reference spectrum using a spectral fitting procedure to determine the shift factor, which is an indication of the shift between the full energy and first escape peaks. The calibration is then used to compute a set of "shifted" tool-specific elemental standards, which are appropriate for the tool.

The shift factor is required for the DecisionXpress* petrophysical evaluation system. If the shop calibration was not conducted or the shift factor is not available at the wellsite, the shift factor can still be obtained by logging the ECS sonde in casing for a small section.

The ECS sonde with cartridge directly attached is inserted in a calibration tank. The calibration should be done at room temperature. If the outside temperature is high (detector temperature > 68 degF [20 degC]) the tool must be cooled with CO_2 before performing the calibration.

Tool quality control

Standard curves

The ECS standard curves are listed in Table 1.

Table 1. ECS Standard Curves

Output Mnemonic	Output Name
CCA_WALK2	Capture calcium relative yield (SpectroLith WALK2 model)
CCHL_WALK2	Capture chlorine relative yield (SpectroLith WALK2 model)
CFE_WALK2	Capture iron relative yield (corrected, SpectroLith WALK2 model)
CGD_WALK2	Capture gadolinium relative yield (SpectroLith WALK2 model)
CHY_WALK2	Capture hydrogen relative yield (SpectroLith WALK2 model)
CSI_WALK2	Capture silicon relative yield (20 elemental standards processing)
CSUL_WALK2	Capture sulfur relative yield (corrected, SpectroLith WALK2 model)
CTI_WALK2	Capture titanium relative yield (SpectroLith WALK2 model)
DWAL_WALK2	Dry-weight fraction pseudo-aluminum (SpectroLith WALK2 model)
DWCA_WALK2	Dry-weight fraction calcium (SpectroLith WALK2 model)
DWFE_WALK2	Dry-weight fraction iron + 0.14 aluminum (SpectroLith WALK2 model)
DWSI_WALK2	Dry-weight fraction silicon (SpectroLith WALK2 model)
DWSU_WALK2	Dry-weight fraction sulfur (SpectroLith WALK2 model)
DWTI_WALK2	Dry-weight fraction titanium (SpectroLith WALK2 model)
DXFE_WALK2	Dry-weight fraction excess iron (SpectroLith WALK2 model)
ECMG_20	ECS gain from frame by frame Marquardt solver (20 elemental standards processing)
ECST	ECS temperature
EGCF_20	Gain correction factor (20 elemental standards processing)
ENGE_WALK2	Epithermal neutron matrix from elemental concentrations (SpectroLith WALK2 model)
EOFC_20	Offset correction factor (20 elemental standards processing)
ERDF_20	Resolution degradation factor (20 elemental standards processing)
ESSR_20	ECS spectral count rate (channels 40–240) (20 elemental standards processing)
ESUF_WALK2	Elemental statistical uncertainty factor (SpectroLith WALK2 model)
FY2W_WALK2	Oxides closure normalization factor (SpectroLith WALK2 model)
IC_WALK2	Inelastic carbon relative yield (SpectroLith WALK2 model)
PEGE_WALK2	Matrix photoelectric factor from elemental concentrations (SpectroLith WALK2 model)
RHGE_Acq	Matrix density
RHGE_WALK2	Matrix density from elemental concentrations (SpectroLith WALK2 model)
TNGE_WALK2	Thermal neutron matrix from elemental concentrations (SpectroLith WALK2 model)
UGE_WALK2	Matrix volumetric photoelectric factor from elemental concentrations (SpectroLith WALK2 model)
WANH_WALK2	ECS anhydrite/gypsum fraction from SpectroLith processing
WASID_WALK2	ECS siderite fraction from SpectroLith processing
WCAR_WALK2	ECS carbonate fraction from SpectroLith processing
WCLA_WALK2	ECS clay fraction from SpectroLith processing
WCOA_WALK2	ECS coal fraction from SpectroLith processing
WEVA_WALK2	ECS salt fraction from SpectroLith processing (qualitative)
WPYR_WALK2	ECS pyrite fraction from SpectroLith processing
WQFM_WALK2	ECS quartz-feldspar-mica fraction from SpectroLith processin

Operation

The ECS sonde should be run eccentered using a bow spring to maximize the formation signal. In highly saline boreholes, bow springs should be placed above and below the ECS sonde. In large, saline boreholes, the ECS logging speed may need to be reduced (to 900 ft/h [274 m/h] or even less) to obtain measurements with adequate statistical precision.

It is strongly recommended that the tool always be chilled with CO_2 because the spectral energy resolution of the BGO detector degrades as its temperature increases. This is particularly essential before a long job (TLC* tough logging conditions operations) or in hot wells.

When the ECS sonde is logging in casing, the real-time casing correction must be enabled, and the speed should be 900 ft/h [274 m/h] or less.

The gamma ray tool should be positioned above the ECS tool. ECS operation affects gamma ray tools positioned below through formation activation.

ECS logs can be performed with a different source and a different cartridge than the ones used in the master calibration.

Formats

The formats in Figs. 1 and 2 are used for both log quality control and basic real-time SpectroLith outputs. A separate SpectroLith answer product format used in playback plots additional data after processing. The log in Fig. 1 is the ECS SpectroLith acquisition format.

- Track 1
  - RHGE_WALK2 is the matrix density computed from elemental concentrations. It should agree with the ECS predicted lithology.
  - The color map in this track shows the corresponding mineral elemental concentrations (e.g., clay is indicated by gray). Q-F-M stands for quartz-feldspar-mica. Additional lithology profiling is available in playback and from Data & Consulting Services.
- Track 2
  - The depth track plots gamma ray, cable speed, and cable tension.
- Tracks 3 through 8
  - These tracks include the dry-weight elemental fractions, along with their upper and lower error limits. As the uncertainty in the measurement increases, the error bands become wider.
- Flag track
  - The three flag tracks (I1 to I3) on the far-right side of the format provide log quality control for the detector performance and the ECS products. Ideally all flags are green for good data quality. A yellow stripe implies that data could be affected and action (such as reducing speed) should be taken. A red flag could suggest that the data quality is compromised. The flags are as follows.

    I1: This flag comes up when there is an electronics problem related to the detector or the count rate is too high (such as in an air-filled hole).

    I2: This flag comes up as the resolution of the detector crystal degrades (ERDF becomes high), which may occur when the detector temperature increases if the tool was not sufficiently cooled with CO_2 before logging. Yellow means ERDF is between 6 and 9, and a red flag means ERDF > 9.

    I3: This main data quality flag represents the statistical uncertainty in the mineralogy and lithology predicted by ECS logging. A yellow flag (ESUF between 1 and 2) indicates that the data quality is less than advertised but is usually very acceptable through most shale and nonreservoir intervals. The red flag (ESUF > 2) indicates poor data quality. It usually comes up in large holes and high-salinity muds. The logging speed should be continuously reduced till the flag becomes green or at least yellow. Insufficient eccentralization can also bring up this flag.

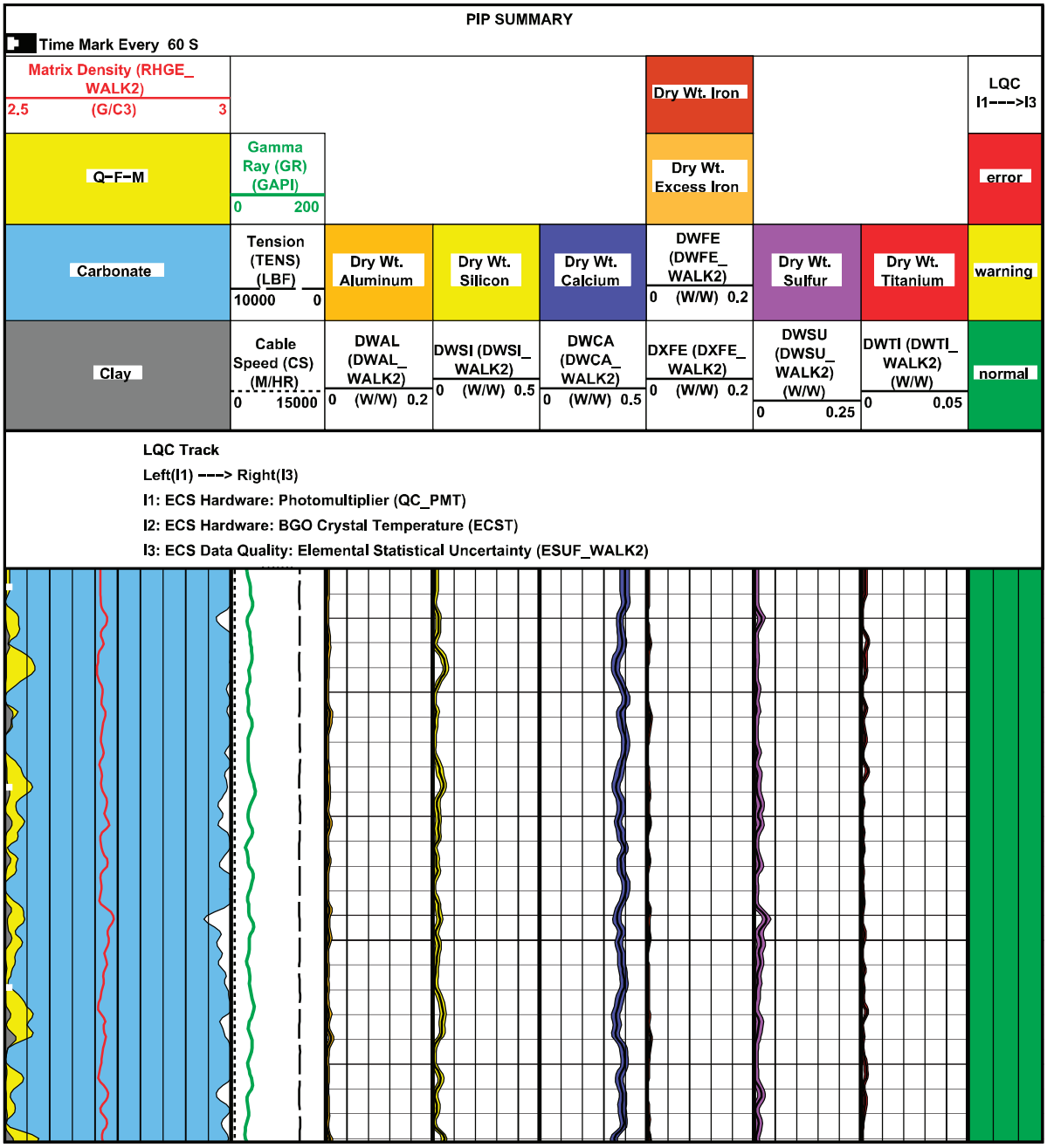

Figure 1. ECS SpectroLith acquisition format.

The log in Fig. 2 is for the ECS yields.

- Track 1
  - FY2W_WALK2 is based on the stability of the oxides closure model. In a good borehole environment (hole size 8 to 10 in, freshwater- or oil-base mud, total chlorides < 50,000 ug/g), this value is <3. A logging speed of 1,800 ft/h may be reasonable in this case. In more adverse or high-sigma borehole environments (>12-in borehole filled with salt-saturated mud) FY2W_WALK2 increases owing to increased statistical uncertainty in the formation signal (because the chlorine in the borehole accounts for 60% or more of the total measurement). It may also increase when the mineralogy is outside the scope of the SpectroLith model.
  - ESUF_WALK2 is a measure of the statistical uncertainty of the measurement. It comes up as the count rates decrease and the speed, oxides closure factor, and resolution degradation factor increase. For good data, it should be <1. When it is between 1 and 2, a yellow flag shows up in I4 flag track, and a red flag occurs when ESUF_WALK2 > 2. This curve is severely affected in large holes with high-salinity mud. To reduce ESUF_WALK2 by a factor of 2, the logging speed is reduced by a factor of 4.
  - ECMG_20 is an indicator of the performance of the Marquardt regulation, and is normally about 1. If the Marquardt fails to converge, it triggers a red flag in I5 of the flag track.
  - ESSR_20 is the spectral count rate between channels 40 and 240 of the ECS spectrum.
  - EOCF_20 is the offset correction factor and it should be stable, normally about 0.
  - ECST is the temperature of the detector, and it should be less than 122 degF [50 degC]. As it increases, the resolution of the detector degrades.
  - ERDF_20 is a measure of the degradation of the detector resolution, and it should be less than 8 for good data. It goes up as the detector temperature increases, and it can set off the I2 flag in the flag track.
  - HCAL and BS are to measure borehole diameter and indicate any washouts or gauge effects.
- Flag track
  - The five flag tracks (I1 to I5) on the far-right side of the format provide log quality control for the ECS hardware and data quality. The flags ideally should be green for good data quality. A yellow stripe implies that data could be affected and that action (such as reducing speed) should be taken. A red flag suggests that the data quality is compromised. The flags are as follows.

    I1: This flag comes up when there is an electronics problem related to the detector or the count rate is too high (such as in an air-filled hole).

    I2: This flag comes up as the resolution of the detector crystal degrades (ERDF becomes high), which may occur when the detector temperature increases if the tool was not sufficiently cooled with CO2 before logging. Yellow means ERDF is between 6 and 9, and a red flag means ERDF > 9.

    I3: This flag is triggered when the high-voltage controll loop is not regulating properly.

    I4: This main data quality flag represents the statistical uncertainty in the mineralogy and lithology predicted by ECS logging. A yellow flag (ESUF between 1 and 2) indicates that the data quality is less than advertised but is usually very acceptable through most shale and nonreservoir intervals. The red flag (ESUF > 2) indicates poor data quality. It usually comes up in large holes and high-salinity muds. The logging speed should be continuously reduced till the flag becomes green or at least yellow. Insufficient eccentralization can also bring up this flag.

    I5: This flag indicates the performance of the Marquardt fitting process, and it goes red if Marquardt does not converge (caused by the presence of gamma rays from the mud or formation, which are not included in the tool standard, or it could be caused by a malfunctioning detector).
- Tracks 3 through 10
  - The elemental yields are defined as the fraction of the observed signal resulting from each element. (The fraction of the spectral signal resulting from the gamma rays from a particular element is called the relative elemental yield.)

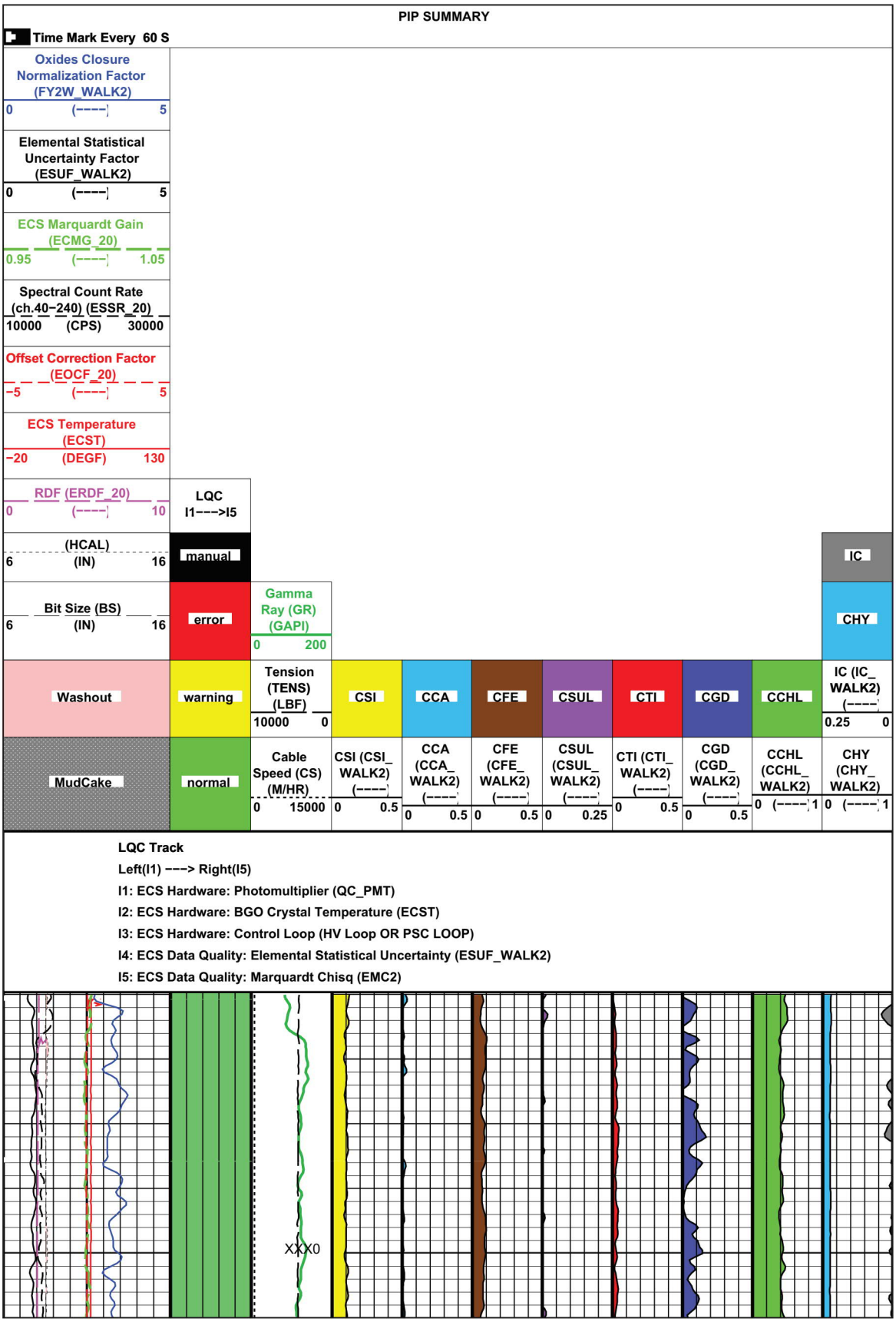

Figure 2. ECS yields quality control format.

Response in known conditions

- In oil-base mud, barite- or hematite-weighted mud, or potassium chloride mud, there can be significant contributions to the borehole signal from Ca, Ba, Fe, S, or K.
- In small (<8-in) oil- or freshwater-filled holes, the borehole signal is minimal (<20%) and comes from hydrogen and chlorine.
- In larger boreholes (>12 in) filled with salt-saturated brine, the chlorine signal from the borehole can easily account for more than 60% of the total capture energy spectrum.
- The elemental yields and estimated lithology should agree. For example, the Q-F-M of sands should correlate with an increase in Si content.
- The computed matrix density should agree with the bulk density measured by the density tool in the very low-porosity zones.

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CNL

Overview

CNL* compensated neutron log tools use a radioactive source that bombards the formation with fast neutrons. The neutrons are slowed, primarily by hydrogen atoms in the formation. Detectors count the slowed neutrons deflected back to the tool. Both epithermal (intermediate energy) neutrons and thermal (slow) neutrons can be measured depending on the detector design. The CNT-H and CNT-K tools use two thermal detectors to produce a borehole-compensated thermal neutron measurement. The neutron count rates measured at the two detectors are used to compute a ratio related to formation porosity that is much less affected by environmental factors than porosity obtained from a single-detector tool. The DNL* dual-energy neutron log (CNT-G) has two thermal and two epithermal detectors that make separate energy measurements for gas detection and improved reservoir description.

The Slim Compensated Neutron Tool (CNT-S and SCNT) and the SlimXtreme Compensated Neutron Tool (QCNT) use two thermal detectors to measure borehole-compensated thermal neutron porosity based on the same neutron interactions as the standard CNL tools.

Specifications

Measurement Specifications	
Output	CNT-H, CNT-K, CNT-S, SCNT, QCNT: Thermal neutron porosity (uncorrected, environmentally corrected, or alpha processed) CNT-G: Epithermal neutron porosity, thermal neutron porosity (uncorrected, environmentally corrected, or alpha processed)
Logging speed	Standard: 1,800 ft/h [549 m/h], high resolution: 900 ft/h [247 m/h]
Range of measurement	–2 to 100 V/V
Vertical resolution	24 in [60.96 cm] (standard 1,800 ft/h)
Precision	0 to 20 V/V: ±2 V/V 30 V/V: ±3 V/V 45 V/V: ±9 V/V
Accuracy and repeatability	0 to 20 V/V: ±1 V/V 30 V/V: ±2 V/V 45 V/V: ±6 V/V
Depth of investigation	6 to 10 in [15.24 to 25.4 cm][†]
Mud type or weight limitations	Thermal measurements not possible in air- or gas-filled wellbores
Combinability	Combinable with most tools

[†] Depth of investigation depends on porosity and salinity.

Mechanical Specifications	CNT-H	CNT-K	CNT-G	CNT-S	SCNT	QCNT
Temperature rating, degF [degC]	400 [204]	400 [204]	400 [204]	302 [150]	302 [150]	500 [260]
Pressure rating, psi [MPa]	20,000 [138]	20,000 [138]	20,000 [138]	14,000 [97]	14,000 [97]	30,000 [207]
Borehole size—min., in [cm]	4.375 [11.11] without bow spring, 6 [15.24] with bow spring	4.375 [11.11] without bow spring, 6 [15.24] with bow spring	4.375 [11.11] without bow spring, 6 [15.24] with bow spring	3.75 [9.53]	3.75 [9.53]	4 [10.16]
Borehole size—max., in [cm]	20 [50.8]	20 [50.8]	20 [50.8]	10 [25.4] for NPHI, TNPH, NPOR; 12 [30.48] for TNPH, NPOR	10 [25.4] for NPHI, TNPH, NPOR; 12 [30.48] for TNPH, NPOR	10 [25.4] for NPHI, TNPH, NPOR; 16 [40.64] for TNPH, NPOR
Outside diameter, in [cm]	3.375 [9.53] without bow spring	3.375 [9.53] without bow spring	3.375 [9.53] without bow spring	2.75 [6.99]	2.5 [6.35]	3 [7.62]
Length, ft [m]	7.25 [2.21]	7.25 [2.21]	7.25 [2.21]	18.4 [5.61]	7.67 [2.34]	11.92 [3.63]
Weight, lbm [kg]	203 [92]	203 [92]	203 [92]	254 [115]	90 [41]	191 [87]
Tension, lbf [N]	50,000 [222,410]	50,000 [222,410]	50,000 [222,410]	68,000 [302,480]	100,000 [444,820]	100,000 [444,820]
Compression, lbf [N]	23,000 [102,310]	23,000 [102,310]	23,000 [102,310]	9,600 [42,700]	20,000 [88,960]	14,100 [62,720]

Calibration

CNL tools should have a master calibration performed every 3 months. The tool is positioned vertically in a neutron calibration tank filled with fresh water. The tank must be at least 8 ft [2.4 m] from walls or stationary items, with the area also cleared of all equipment and personnel. The bottom edge of the tank is at least 33 in [84 cm] above the floor. An aluminum insert sleeve is seated in the tank, and the centering clamp is placed on the tool housing at the centering mark. The tool is lowered so that the taper on the centering clamp enters the tank, and only the centering clamp supports the weight of the tool. Centering disks are also mounted to the bottom portion of the tool because the calibration environment significantly affects the accuracy of CNL measurements.

Tool quality control

Standard curves

The CNL standard curves are listed in Table 1.

Table 1. CNL Standard Curves

Output Mnemonic	Output Name
CNFC	Far detector count rate
CNTC	Near detector count rate
NPHI	Neutron porosity (matrix and hole size corrections may be applied)
NPOR	Neutron porosity (equivalent to TNPH but with enhanced vertical resolution)
TALP	Thermal alpha factor
TNPH	Neutron porosity computed with a different algorithm (environmental corrections may be applied)
TNRA	Thermal neutron porosity ratio

Operation

The tool should always be run eccentered with a bow spring unless a very small hole is being logged. For holes larger than 12 in [30.48 cm], the large-hole kit should be used with the CNT-H, CNT-K, and CNT-G and a standard CNL bow spring is used above and below the QCNT.

The same source used for the master calibration has to be used for the logging run. If the same source is not used, the tool must be calibrated with the source used for logging and the log played back.

At a minimum, the hole size correction should be applied using caliper input. Other corrections (temperature, pressure, salinity, standoff, etc.) can be applied as necessary.

Formats

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

- Track 1
  - TNPH (environmentally corrected neutron porosity) and the dead-time-corrected, depth-matched, calibrated, and resolution-matched near counts (CNTC) are used to compute the factor TALP.
  - TALP is an indicator of the tool accuracy and environmental effects. The average value of the TALP output over the entire logging interval should be about 1.0 under ideal conditions. However, the TALP value can shift because of borehole conditions, formation matrix, and gas effects, but it should not drop lower than 0.8 if both detectors are working well.
- Depth track
  - This track includes the cable tension.
- Track 3
  - TALP and the dead-time-corrected, depth-matched, calibrated (but not resolution-matched) near counts are used to obtain the third thermal porosity output, NPOR (enhanced-resolution processed thermal porosity). NPOR has the better vertical resolution and statistical precision of the near detector while still maintaining the depth of investigation of the far detector. This is true only if the near-wellbore effects have less influence than the formation properties. Abrupt changes in borehole conditions and tool sticking are the main limitations for NPOR.
  - TNPH is computed from a ratio of the dead-time-corrected, depth-matched, calibrated, and resolution-matched count rates. It is corrected for any environmental corrections that were switched on. On average, TNPH and NPOR should be equivalent with some difference in resolution.

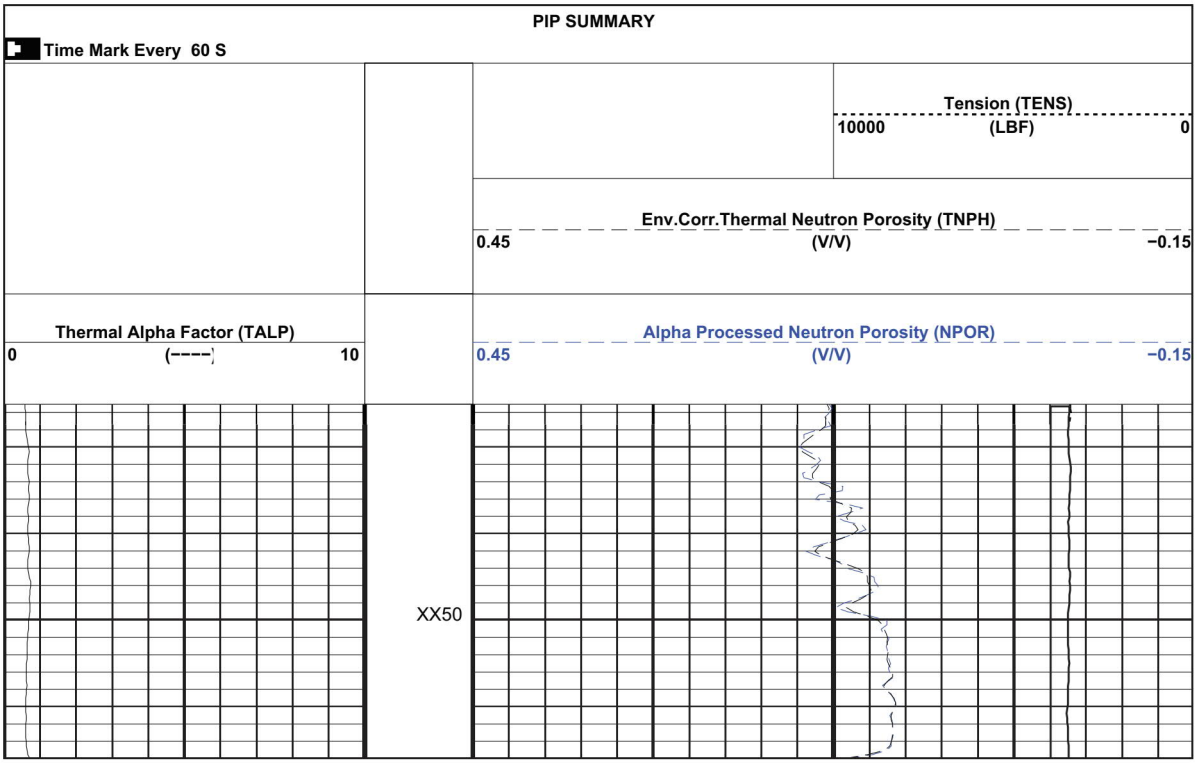

Figure 1. CNL standard format.

Response in known conditions

The values in Table 2 assume that the matrix parameter is set to limestone (MATR = LIME), hole is in gauge, and borehole corrections are applied.

- CNL porosity is poor in high porosity because count rates are very low (high hydrogen index = low count rates = statistical fluctuations).
- CNL porosity is significantly affected by standoff. Approximately 0.5 in [1.27 cm] of standoff in a 12.25-in [31.12-cm] hole causes NPHI to read 2 V/V too high.
- Neutron porosity reads abnormally low in gas zones owing to the excavation effect.
- Neutron porosity tends to read higher than density porosity in shales because of the shale effect.

Table 2. Typical CNL Response in Known Conditions

Formation	NPHI,† V/V	TNPH or NPOR,‡ V/V
Sandstone, 0% porosity	–1.7	–2.0
Limestone, 0% porosity	0	0
Dolomite, 0% porosity	2.4	0.7
Sandstone, 20% porosity§	15.8 if formation salinity = 0 ug/g	15.1 if formation salinity = 0 ug/g 14.4 if formation salinity = 250 ug/g
Limestone, 20% porosity	20.0	20.0
Dolomite, 20% porosity§	27.2 if formation salinity = 0 ug/g	22.6 if formation salinity = 0 ug/g 24.1 if formation salinity = 250 ug/g
Anhydrite	–0.2	–2.0
Salt	0	–3.0
Coal	38 to 70	38 to 70
Shale	30 to 60	30 to 60

† After borehole correction with MATR = LIME. Refer to Chart CP-1c in *Schlumberger Log Interpretation Charts*.

‡ After borehole correction with MATR = LIME. Refer to Charts CP-1e and -1f in *Schlumberger Log Interpretation Charts*.

§ Value differs with formation salinity. The correction depends on the matrix. Refer to Chart Por-13b in *Schlumberger Log Interpretation Charts*.

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APS

Overview

The APS* accelerator porosity sonde uses an electronic pulsed neutron generator instead of a conventional radioactive chemical source. The large yield of the neutron source enables the use of epithermal neutron detection and borehole shielding. As a result, the porosity measurements are affected only minimally by the borehole environment and formation characteristics, such as lithology and salinity. Five detectors provide information for porosity evaluation, gas detection, shale evaluation, improvement of the vertical resolution, and borehole correction. The measurements can be performed in open holes (air-filled or liquid-filled) and cased holes (only liquid-filled).

The Hostile Environment Accelerator Porosity Sonde (HAPS) is a component of the Xtreme* high-pressure, high-temperature (HPHT) well logging platform. It provides an APS measurement in HPHT environments. The installation of a conventional APS cartridge inside a thermal Dewar flask makes HAPS operations possible at bottomhole temperatures up to 500 degF [260 degC]. The HAPS cannot be used in cased holes or air-filled open holes.

Specifications

Measurement Specifications

	APS Sonde	HAPS
Output	Neutron porosity index, formation sigma	Neutron porosity index, formation sigma
Logging speed	Standard: 1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h]	Standard: 1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h]
Range of measurement	Porosity: –2 to 100 V/V (open hole) 0 to 50 V/V (cased hole) Sigma: 4 to 60 cu	Porosity: –2 to 100 V/V Sigma: 4 to 60 cu
Vertical resolution	14 in [35.56 cm]	14 in [35.56 cm]
Accuracy	<5 V/V: ±0.5 V/V 5 to 30 V/V: ±7% 30 to 60 V/V: ±10% Sigma: Greater of 5% or 1 cu [0.1/m]	<5 V/V: ±0.5 V/V 5 to 30 V/V: ±7% 30 to 60 V/V: ±10% Sigma: Greater of 5% or 1 cu [0.1/m]
Depth of investigation	7 in [17.78 cm]	7 in [17.78 cm]
Mud type or weight limitations	None	Cannot be used in air-filled holes
Combinability	Combinable with most services If combined with the ECS* elemental capture spectroscopy sonde, the APS sonde must be run below it	Combinable with most services If combined with the ECS sonde, the HAPS sonde must be run below it

Mechanical Specifications

	APS Sonde	HAPS
Temperature rating	350 degF [177 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	25,000 psi [172 MPa]
Borehole size—min.	4⅝ in [11.75 cm]	5⅞ in [14.92 cm]
Borehole size—max.	18 in [45.72 cm] Air-filled holes: 12 in [30.48 cm]	18 in [45.72 cm]
Casing OD range	4.5 to 9.625 in [11.43 to 24.45 cm]	na
Casing ID range	4.09 to 8.755 in [10.39 to 22.238 cm]	na
Casing thickness range	0.205 to 0.545 in [5.2 to 13.8 mm]	na
Maximum cement thickness	1.25 in [31.75 mm]	na
Outside diameter	3.625 in [9.21 cm]	Without bow spring: 4 in [10.16 cm]
Length	13 ft [3.96 m]	16 ft [4.88 m]
Weight	222 lbm [101 kg]	400 lbm [181 kg]
Tension	50,000 lbf [222,410 N]	50,000 lbf [222,410 N]
Compression	23,000 lbf [102,310 N]	23,000 lbf [102,310 N]

na = The HAPS is not characterized for cased holes and air-filled open holes.

Calibration

Master calibration of an APS sonde should be performed every 3 months.

The APS tool is positioned horizontally in an aluminum insert in a calibration tank filled with water free from chlorides. The housing diameter must be measured on both the wear axis and 90° perpendicular to the wear axis. The calibration is performed twice, with the tool rotated 180° for the second pass.

Tool quality control

Standard curves

The APS standard curves are listed in Table 1.

Table 1. APS Standard Curves

Output Mnemonic	Output Name
ADHV	APS array detectors measured high voltage
APDC	APS near/array corrected dolomite porosity
APLC	APS near/array corrected limestone porosity
APLU	APS near/array uncorrected limestone porosity
APSC	APS near/array corrected sandstone porosity
ENAR	APS dead-time-corrected near/array count rate ratio
ENFR	APS dead-time-corrected near/far count rate ratio
FDHV	APS far detector measured high voltage
NDHV	APS near detector measured high voltage
PHICOR_APLC	APS array total correction in APLC
QSDP	APS quality from slowing-down time
QSGF	APS quality of formation sigma
SDPB[†]	APS slowing-down porosity
SIGF	APS formation capture cross section
STOF	APS effective standoff in limestone
STPC	APS standoff porosity corrected
U-APS_ARRAY1_SPECTRUM_CPS_DC	APS array 1 spectrum

[†] SDPB is the porosity used for air-filled boreholes.

Operation

The APS tool is run eccentered using a bow spring. It is important to minimize the standoff as much as possible because the standoff correction is the heaviest correction. At more than 1 in [2.5 cm] of standoff, log quality begins to degrade.

It is highly recommended to run a caliper tool with the APS tool to provide a continuous borehole diameter input to the hole size correction.

Performing an APS down log with the Minitron* pulsed neutron generator device switched on is not recommended. This activates the formation and affects the measurements of other tools. Similarly, the repeatability of the gamma ray can be affected if formation activation is still present between the main and repeat passes.

Formats

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

- Track 1
  - APLC along with STPC is an indicator check for log quality control. The difference between STPC and APLC porosity should remain below 15%.
  - STOF provides only a qualitative, quick-look indication of data quality. It defines the ability of the tool to correct for tool standoff from the formation. A value less than 1 in indicates a good-quality log. If the values are between 1 in and 1.5 in [3.8 cm], the log must be correlated with offset wells and interpreted to determine if the data is usable. If it is greater than 1.5 in, the log is not interpretable and should not be used.
  - SIGF indicates the ability of an element to absorb thermal neutrons.
- Track 2
  - U-APS_ARRAY1_SPECTRUM_CPS_DC represents an image for the counts decay spectrum as received in the array 1 detector. The pattern shown in the track is ideal, with the counts high at the begining (colored orange) and decaying with time (colored blue).
- Tracks 3 and 4
  - Tracks 3 and 4 are the same as Track 2 for the array 2 detector and the thermal array detector, respectively.

For liquid-filled cased holes and air-filled open holes, two log quality control channels are available.

- QSDP in cased holes is a measure of the hydrogen volume in the annulus between the casing and the formation. A value between 0 and 2 indicates good cement bonding, whereas a value greater than 2 indicates poor or missing cement or a large washout behind the casing. QSDP in air-filled holes is a measure of consistency with other detector responses that are less sensitive to standoff. A value between 0 and 2 indicates small environmental corrections and a good log, whereas a value greater than 2 indicates large corrections and thus potentially inaccurate data.
- QSGF is calculated in the same manner as for liquid-filled open holes. It should be less than 2 for reliable sigma.

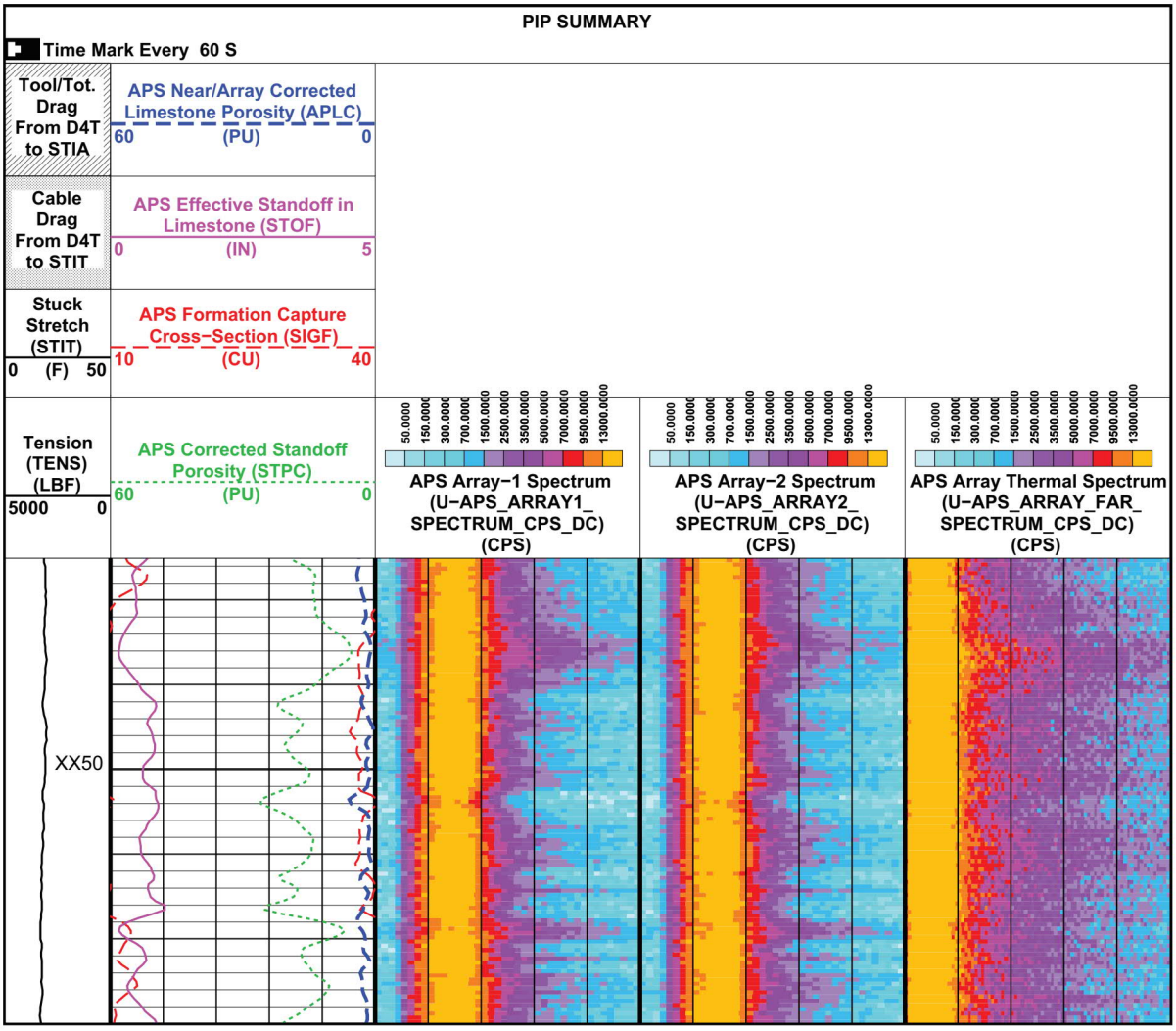

Figure 1. APS standard format.

Response in known conditions

Table 2 lists typical response values for the APS tool.

Table 2. Typical APS Response in Known Conditions

Formation	APLC, % porosity
Sandstone, 0% porosity	–0.8
Limestone, 0% porosity	0
Dolomite, 0% porosity	0
Sandstone, 20% porosity	16.5
Limestone, 20% porosity	20
Dolomite, 20% porosity	20.5
Anhydrite	1.5
Salt†	21 to 24

† The unusual response of APLC in salt is due to the very low atomic density and large slowing-down length, which exceeds the source-to-array detector spacing.

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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: 2 1/4 in [5.72 cm]	2 7/8 in [7.30 cm]
Borehole size—max.	9 5/8 in [24.45 cm] With flask: 9 5/8 in [24.45 cm]	9 5/8 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.

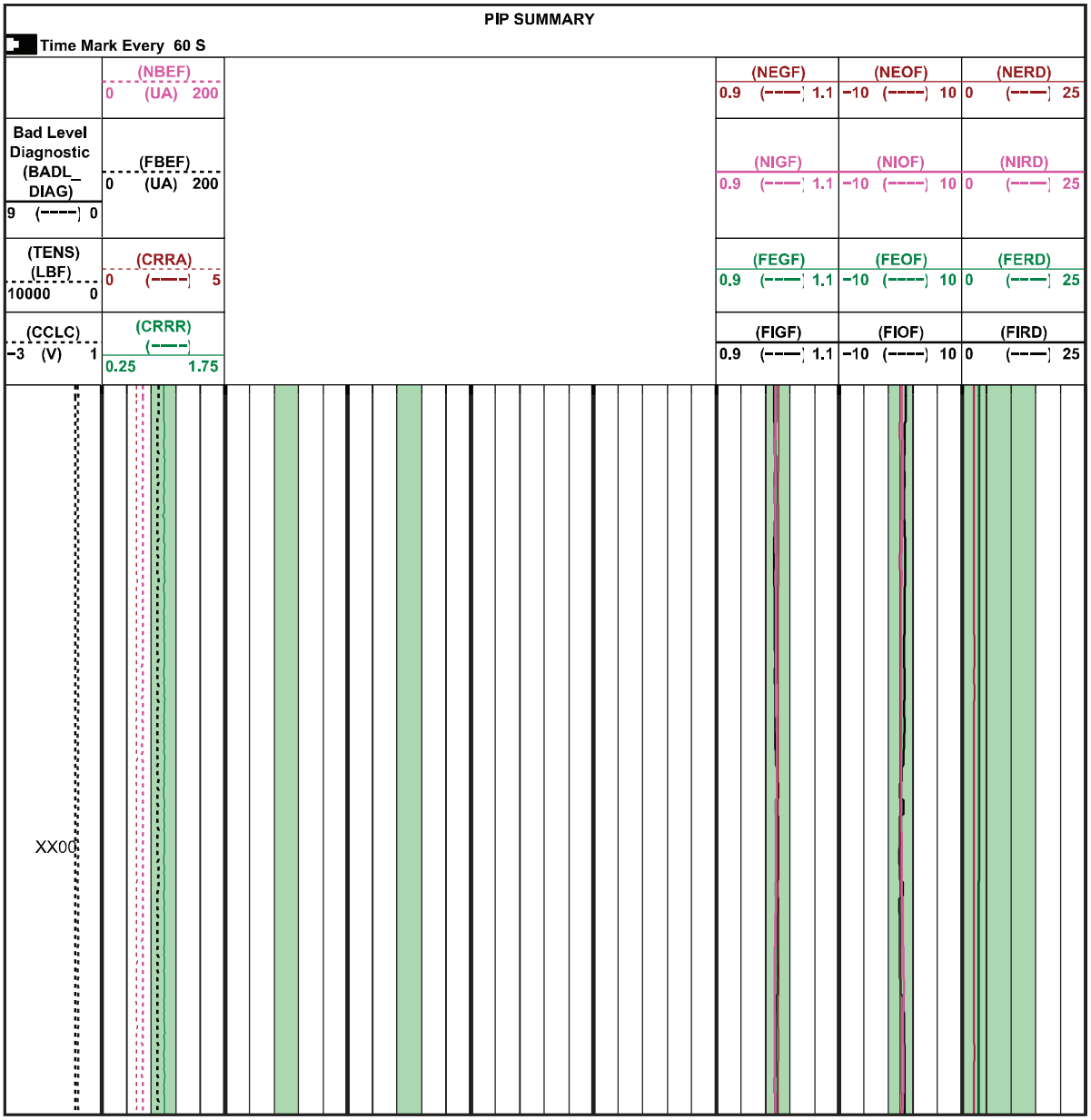

Figure 1. RST and RSTPro hardware format.

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.

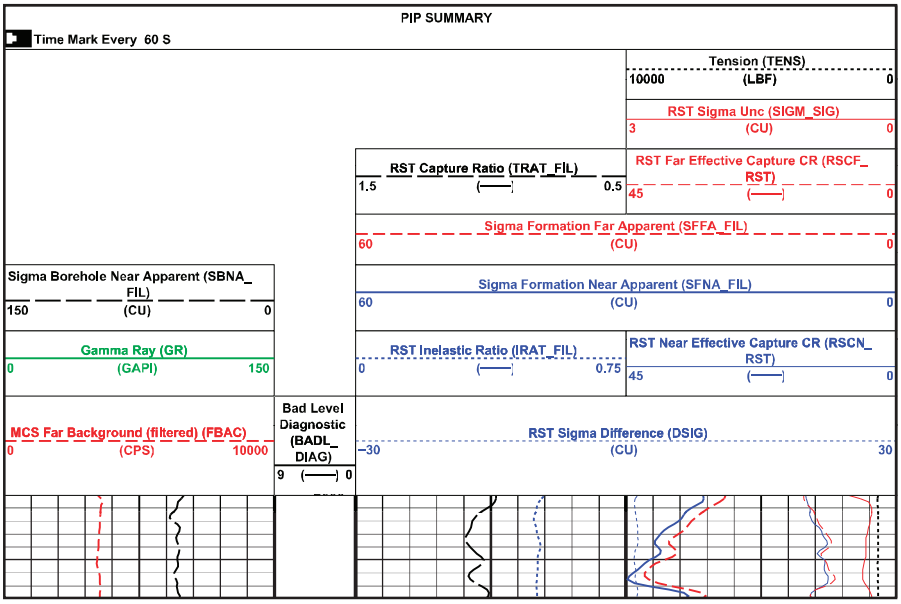

Figure 2. RST and RSTPro sigma standard format.

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

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Litho-Density

Overview

The Litho-Density* tool (LDT) makes direct measurements of formation lithology and density. Coupled with the CNL* compensated neutron log tool (CNT), it offers a good means of measuring porosity in a variety of environments. The contrasting response of the LDT and CNT is used to identify different rock matrices and differentiate between gas or liquid trapped in the rock pore spaces. The photoelectric absorption factor (PEF), along with the bulk density measurement, can be used to identify the lithology of the formation.

Specifications

Measurement Specifications	
Output	Bulk density, density, porosity, PEF, caliper
Logging speed	1,800 ft/h [549 m/h]
Vertical resolution	Density: 11 in [27.94 cm]
Accuracy	Bulk density: ±0.02 g/cm^3 from 1.6 to 3.0 g/cm^3, ±0.01 g/cm^3 from 1.0 to 1.6 g/cm^3 PEF: ±6% from 1.4 to 6.0
Depth of investigation	2 in [5.08 cm]
Mud type or weight limitations	Sensitive to barite
Combinability	Combinable with most tools

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	6 in
Borehole size—max.	Normal arm: 16 in Long arm: 22 in
Outside diameter	4.5 in [11.4 cm]
Length	17.3 ft [5.3 m]
Weight	311 lbm [141 kg]
Tension	40,000 lbf [177,930 N]
Compression	5,000 lbf [22,240 N]

Calibration

The master calibration for the Litho-Density tool should be performed every month. In cases of high usage in low-porosity formations (where pad wear is higher), a higher calibration frequency is recommended.

LDT calibration is performed in an aluminum block positioned off the ground at a minimum of 6 in [15 cm]. The area under the block must be free of objects and debris, and there must be no background radiation from other sources that could be sensed by the tool. An iron insert is used for the lithology calibration. The calibration is conducted by removing the density skid from LDT tool and placing it in the block. The skid is then connected to the tool using leads.

Tool quality control

Standard curves

The LDT standard curves are listed in Table 1.

Table 1. LDT Standard Curves

Output Mnemonic	Output Name
BDQC	Bulk density quality control
CALI	Caliper
DRHO	Bulk density correction
IHV	Integrated hole volume
PEF	Photoelectric factor
QR*x*S	Quality ratio for detector *x*
Q*x*S	Quality for detector *x*
RHOB	Bulk density
*x*FSS	Form factor detector
*x*SHV	High-voltage detector loop

Operation

The tool is run eccentered by a powered sonde.

Formats

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

- Track 1
  - QLS and QSS are quality indicators for the tool's detectors. Ideally, they should be zero, but they may vary ±0.025 g/cm^3 depending on PEF and hole rugosity.
- Tracks 2 and 3
  - xSHV high voltages slowly increase with temperature. No drift or sudden change should occur.
  - xSRH density for each sensor should follow the bulk density trend.
- Track 4
  - RHOB and density porosity (DPHI) should follow each other whereas DRHO should be close to zero, depending on the hole conditions. In undergauge or washout conditions, DRHO changes.

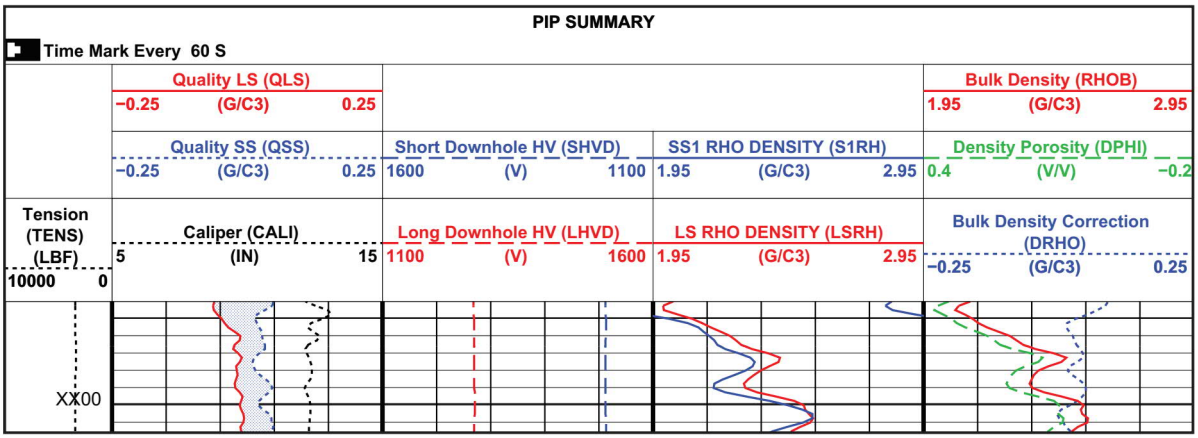

Figure 1. LDT standard format.

Response in known conditions

Table 2 lists typical LDT response values.

Table 2. Typical LDT Response in Known Conditions

Formation	RHOB, g/cm^3	PEF
Sandstone, 0% porosity	2.65 to 2.68	1.81
Limestone, 0% porosity	2.71	5.08
Anhydrite	2.98	5.05
Salt	2.04	4.65

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Litho-Density Sonde

Overview

The Litho-Density* Sonde (LDS) component of the IPL* integrated porosity logging toolstring (IPLT) measures the formation bulk density and photoelectric factor (PEF). It has a pad with a gamma ray source and two detectors. Magnetic shielding and high-speed electronics ensure excellent measurement stability. The LDS records the full-pulse-height gamma ray spectra from both detectors and processes them into windows. Bulk density and photoelectric cross section are derived conventionally from the windows counts with enhanced quality control.

Specifications

Measurement Specifications	
Output	Bulk density, porosity, PEF, caliper
Logging speed	Standard: 1,800 ft/h [549 m/h] High resolution: 900 ft/h [274 m/h] High speed: 3,600 ft/h [1,097 m/h]
Range of measurement	Bulk density: 1.3 to 3.05 g/cm^3 PEF: 1 to 6 Caliper: 16 in [40.64 cm]
Vertical resolution	Density: 15 in [38.10 cm]
Accuracy	Bulk density: ±0.01 g/cm^3 (accuracy), 0.014 g/cm^3 (repeatability) Caliper: 0.25 in [0.64 cm] (accuracy), 0.05 in [0.127 cm] (repeatability)
Depth of investigation†	4 in [10.16 cm]
Mud type or weight limitations	Sensitive to barite
Combinability	Combinable with most tools
Special applications	Spectral processing of formation gamma ray measurement

† Average values (depth of investigation depends on density)

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	5½ in [13.97 cm]
Borehole size—max.	21 in [53.34 cm]
Outside diameter	4.5 in [11.43 cm]
Length	11 ft [3.35 m]
Weight	292 lbm [132 kg]
Tension	30,000 lbf [133,450 N]
Compression	5,000 lbf [22,240 N]

Calibration

The master calibration for density tools should be performed every 3 months. In cases of high usage in low-porosity formations (where pad wear is higher), a higher calibration frequency is recommended.

The LDS is calibrated in an aluminum block positioned off the ground at a minimum of 6 in [15 cm]. The area under the block must be free of objects and debris, and there must be no background radiation from other sources that could be sensed by the tool. An iron insert is used for the lithology calibration. The calibration is conducted by positioning the tool in the block with the caliper open so that the skid lies flat. Calibration can be conducted in air or water.

Tool quality control

Standard curves

The LDS standard curves are listed in Table 1.

Table 1. LDS Standard Curves

Output Mnemonic	Output Name
DPO	LDS standard-resolution density porosity
DRH	LDS standard bulk density correction
HBDC	LDS high-resolution bulk density correction
HDEB	LDS high-resolution bulk density from alpha processing
HDPO	LDS high-resolution density porosity
HLEF	LDS long-spaced high-resolution photoelectric factor
HNDP	LDS high-resolution enhanced density porosity from alpha processing
HRHO	LDS high-resolution bulk density
HVML	Long-spacing measured high voltage
HVMS	Short-spacing measured high voltage
IHV	Integrated hole volume
LCAL	LDS caliper
LQDC	Density log quality
LQLS	Long-spacing log quality
LQSS	Short-spacing log quality
NDPH	LDS enhanced-resolution density porosity from alpha processing
NRHB	LDS standard-resolution bulk density from alpha processing
PEFL	LDS long-spaced standard-resolution photoelectric factor
RHL	Long-spacing density
RHOM	LDS standard-resolution bulk density
RHS*n*	Short-spacing detector *n* density

Operation

The LDS is run eccentered.

Formats

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

- Depth track
  - LQDC shows black shading where LQSS or LQLS is more than 0.2.
- Tracks 1 and 2
  - LCAL and BS are indicative of under- or overgauge holes.
  - RHOM in good hole conditions should show the same basic shape as the other density curves: RHL, RHS3, and RHS4.
  - DRH is the ability of the tool to correct for tool standoff from the formation. It should be about 0 in good hole conditions. Otherwise, it reads positive values, except when the material in front of the pad is denser than the formation (e.g., if there is barite in the mud system).
  - LQSS and LQLS should be less than 0.2 under standard conditions.
  - HVML and HVSS should not drift by more than 1 V/degC as the internal tool temperature changes.
- Tracks 3 and 4
  - The SS and LS spectra represent the decay of the counts with time. They should show high counts (red) toward the left of the track that decay with time (light blue).

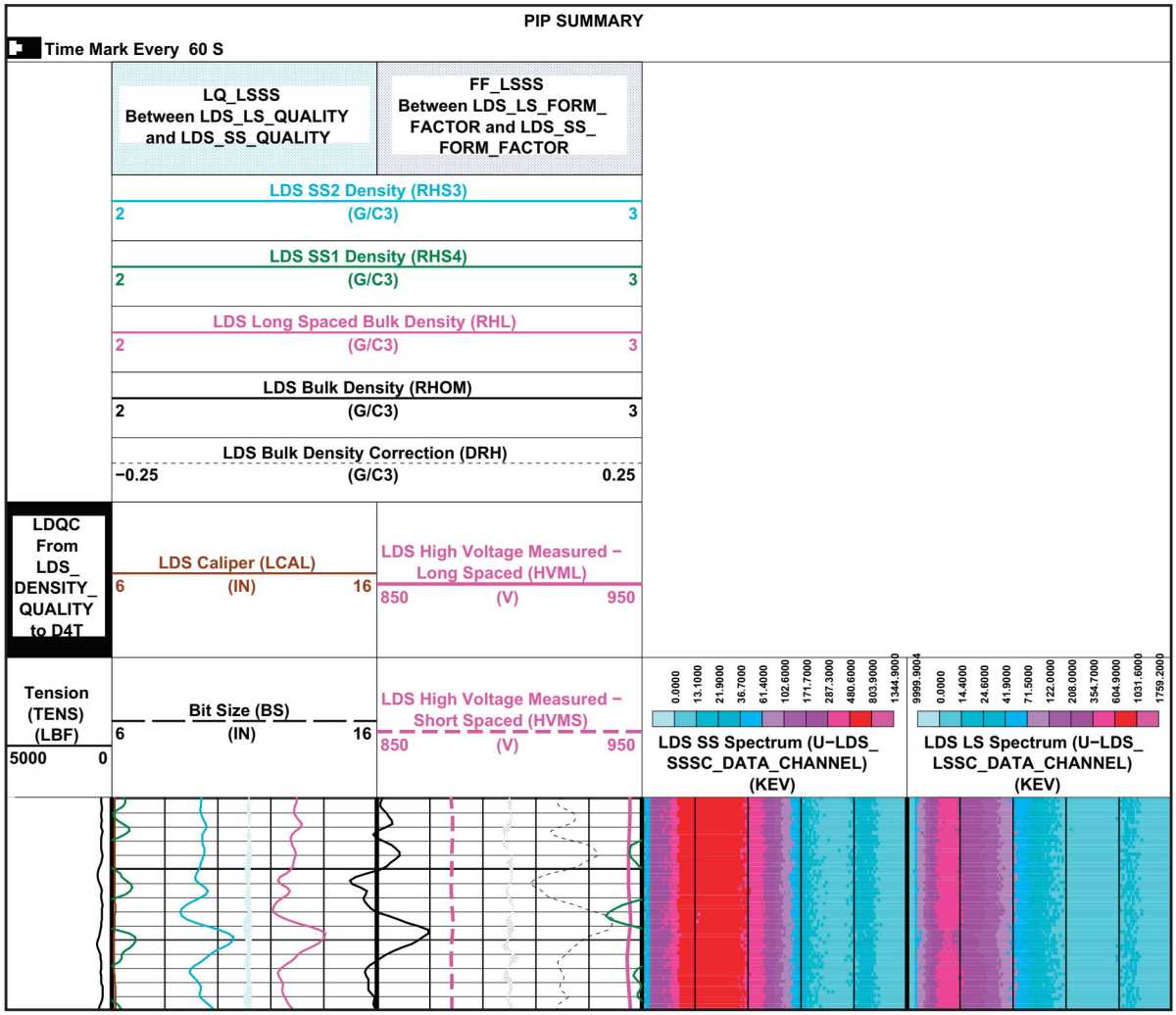

Figure 1. LDS standard format.

Response in known conditions

Table 2 lists typical response values, which should be observed after borehole corrections have been applied. Statistical variations are expected. For PEF, no mudcake is assumed.

Table 2. Typical LDS Response in Known Conditions

Formation	RHOM, g/cm^3	PEF
Sandstone, 0% porosity	2.65 to 2.68	1.81
Limestone, 0% porosity	2.71	5.08
Anhydrite	2.98	5.05
Salt	2.04	4.65

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HLDT

Overview

The HLDT* hostile environment Litho-Density* tool makes three primary measurements: formation density (RHOB), photoelectric factor (PEF) (long spacing [PEFL] and short spacing [PEFS]), and hole diameter (CALI). Density porosity (DPHI) is computed using the measured RHOB. The tool is rated for temperatures up to 500 degF [260 degC], pressures up to 25,000 psi [172 MPa], and borehole diameters down to 4.5 in [11.43 cm].

Specifications

Measurement Specifications	
Output	Bulk density, porosity, PEF, caliper
Logging speed	1,800 ft/h [549 m/h]
Range of measurement	Bulk density: 1.7 to 3.05 g/cm^3 up to 500 degF [260 degC] for 6 h PEF: 1.0 to 5.0
Vertical resolution	Density: 15 in [38.10 cm]
Accuracy	Bulk density: ±0.015 g/cm^3 PEF: ±5%
Depth of investigation	4 in [10.16 cm]

Mechanical Specifications	
Temperature rating	500 degF [260 degC] for 6 h
Pressure rating	25,000 psi [172.3 MPa]
Borehole size—min.	4½ in [11.43 cm]
Borehole size—max.	20 in [50.8 cm]
Outside diameter	3.5 in [8.9 cm]
Length	19.3 ft [5.88 m]
Weight	462 lbm [210 kg]
Tension	30,000 lbf [133,450 N]
Compression	5,000 lbf [222,410 N]

Calibration

The master calibration for density tools should be performed every 3 months. In cases of high usage in low-porosity formations (where pad wear is higher), a higher calibration frequency is recommended.

The HLDT tool is calibrated in an aluminum block positioned off the ground at a minimum of 6 in [15 cm]. The area under the block must be free of objects and debris, and there must be no background radiation from other sources that could be sensed by the tool. An iron insert is used for the lithology calibration. The calibration is conducted by positioning the tool in the block with the caliper opened so the tool lies flat. Calibration can be conducted in air or water.

Tool quality control

Standard curves

The HLDT standard curves are listed in Table 1.

Table 1. HLDT Standard Curves

Output Mnemonic	Output Name
BS	Bit size
CALI	Caliper
DPO	Density porosity
DRH	Bulk density correction
GR	Gamma ray
HVML	Long-spacing measured high voltage
HVMS	Short-spacing measured high voltage
IHV	Integrated hole volume
LCAL	Caliper
LQLS	Long-spacing log quality
LQSS	Short-spacing log quality
PEFL	Long-spacing corrected photoelectric factor
PEFS	Short-spacing corrected photoelectric factor
RHL	Long-spacing density
RHOM	Bulk density
RHS*n*	Short-spacing detector *n* density
*x*Q*x*S	Detector quality indicator

Operation

The tool is run eccentered using a powered sonde.

Formats

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

- Tracks 1 and 2
  - LQSS and LQLS should each be less than 0.2 under standard conditions.
  - HVML and HVSS should not drift by more than 1 V/degC as the tool's internal temperature changes.
  - LCAL is the caliper measurement of borehole diameter and gives an indication of washouts.
  - RHS3, RHS4, RHL, and RHOM should track each other in good hole conditions.
  - DRH should be about zero in good hole conditions. Negative values may suggest that the mud system has barite content.
- Tracks 3 and 4
  - The SS and LS spectra represent the decay of the counts with time. They should show high counts (purple) toward the left of the track that decay with time (light blue).

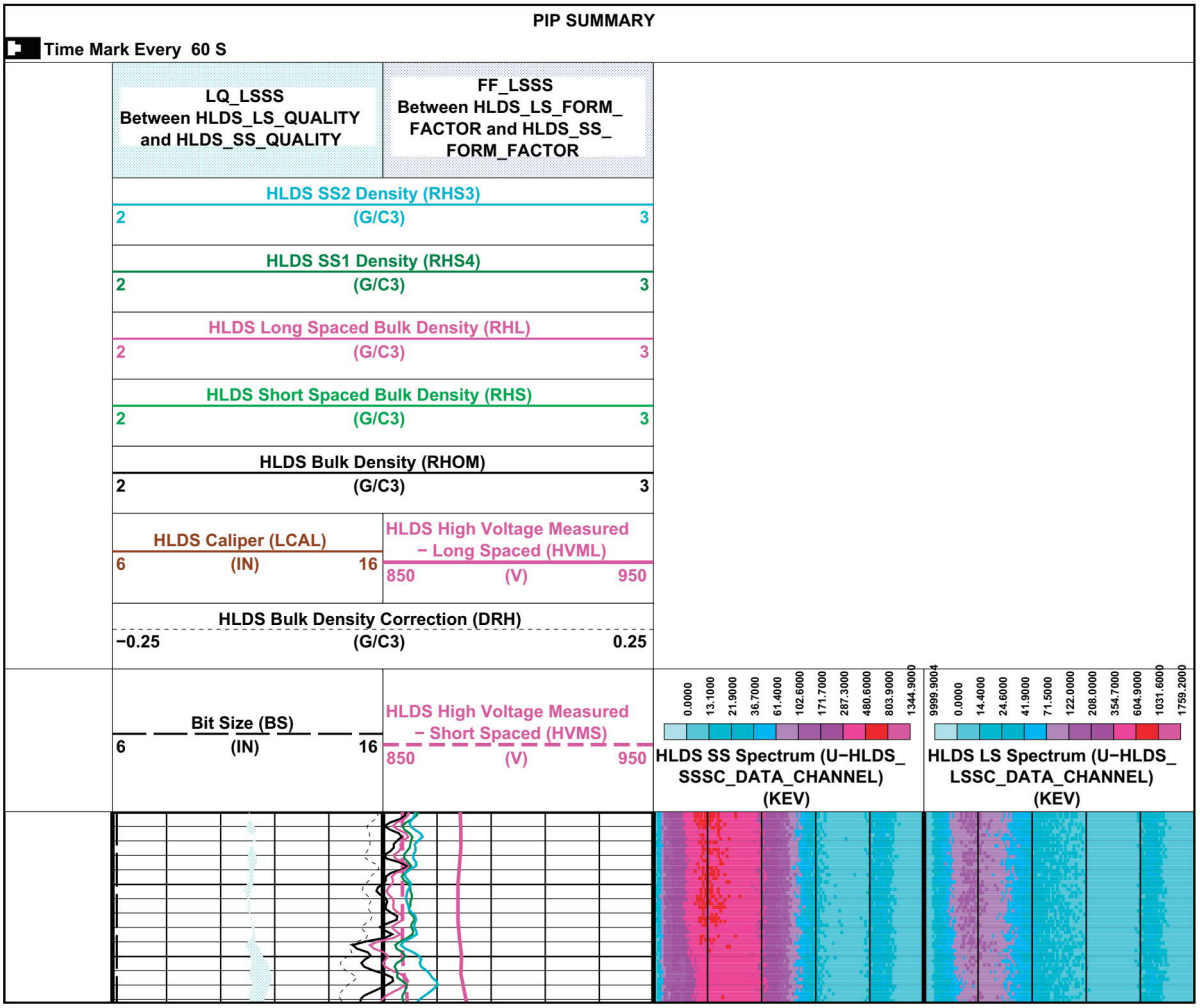

Figure 1. HLDT standard format.

Response in known conditions

Table 2 lists typical HLDT response values.

Table 2. Typical HLDT Response in Known Conditions

Formation	RHOM, g/cm^3	PEF
Sandstone, 0% porosity	2.65 to 2.68	1.8
Limestone, 0% porosity	2.71	5.1
Anhydrite	2.98	5.1
Salt	2.04	4.7

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SlimXtreme

Overview

The SlimXtreme* Litho-Density* tool (QLDT) is designed for operation in slim and hostile environments with temperature and pressure ratings of 500 degF [260 degC] and 30,000 psi [207 MPa], respectively. It measures density and the photoelectric factor (PEF) using full spectral data from a three-detector array.

Specifications

Measurement Specifications	
Output	Bulk density, porosity, PEF
Logging speed	1,800 ft/h [549 m/h]
Range of measurement	Bulk density: 1.3 to 3.05 g/cm^3 PEF: 1 to 6 Caliper: 9.5 in [24.13 cm]
Vertical resolution	Density: 15 in [38.10 cm]
Accuracy	Bulk density: ±0.015 g/cm^3 (accuracy), 0.014 g/cm^3 (repeatability) Caliper: ±0.1 in [0.25 cm] (accuracy), 0.05 in [0.127 cm] (repeatability)
Depth of investigation	4 in [10.16 cm]
Mud type or weight limitations	Sensitive to barite
Combinability	Part of the SlimXtreme system, combinable with most tools
Special applications	HPHT Slim wellbores Short-radius wells Tubing-conveyed logging On tractor

Mechanical Specifications	
Temperature rating	500 degF [260 degC]
Pressure rating	30,000 psi [207 MPa]
Borehole size—min.	3⅞ in [9.84 cm]
Borehole size—max.	9 in [22.86 cm]
Outside diameter	3 in [7.62 cm]
Length	14.7 ft [4.48 m]
Weight	253 lbm [115 kg]
Tension	50,000 lbm [222,410 N]
Compression	17,000 lbf [75,620 N]

Calibration

The master calibration for density tools should be performed every 2 month. In cases of high usage in low-porosity formations (where pad wear is higher), a higher calibration frequency is recommended.

The QLDT tool is calibrated in an aluminum block positioned off the ground at a minimum of 6 in [15 cm]. The area under the block must be free of objects and debris, and there must be no background radiation from other sources that could be sensed by the tool. An iron insert is used for the lithology calibration. The calibration is conducted by positioning the tool in the block with the caliper opened so the tool lies flat. Calibration can be conducted in air or water.

Tool quality control

Standard curves

The QLDT standard curves are listed in Table 1.

Table 1. QLDT Standard Curves

Output Mnemonic	Output Name
LHFF_SLDT	Slim Litho-Density tool (SLDT) long-spacing high-voltage form factor
LHSP_SLDT	SLDT long-spacing high-voltage set point
LPSP_SLDT	SLDT long-spacing pulse shape control (PSC) set point
LSTC_SLDT	SLDT long-spacing compensation/undercompensation
MHFF_SLDT	SLDT middle-spacing high-voltage form factor
MHSP_SLDT	SLDT middle-spacing high-voltage set point
MPSP_SLDT	SLDT middle-spacing PSC set point
MSRC_SLDT	SLDT middle-spacing compensation/undercompensation
PEFM_SLDT	SLDT middle-spacing photoelectric factor
PEFL_SLDT	SLDT long-spacing photoelectric factor
QHRO_SLDT	SLDT density quality factor
RHOB_SLDT	SLDT bulk density
RHOLS_SLDT	SLDT long-spacing density
RHOMS_SLDT	SLDT middle-spacing density
RHS24_SLDT	SLDT short-spacing 24 density
RHS56_SLDT	SLDT short-spacing 56 density
SHFF_SLDT	SLDT short-spacing high-voltage form factor
SHSP_SLDT	SLDT short-spacing high-voltage set point
SPSP_SLDT	SLDT short-spacing PSC set point
SSRC_SLDT	SLDT short-spacing compensation/undercompensation
TMPY_SLDT	SLDT temperature

Operation

The tool should be run eccentered using a powered sonde.

Formats

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

- Track 1
  - SSRC, TMPY, SHSP, and SHFF are all indicators of hardware problems with the tool's detector. Under normal conditions all form factors should be near 0. Some deviation may occur according to borehole conditions. Voltages and pulse compensation (SSRC_SLDT) should be stable values. Drift occurs over time as the temperature of the detectors changes.
- Tracks 2 and 3
  - These curves are the same as those in Track 1 but for the middle- and long-spacing detectors. The same log quality control also applies.

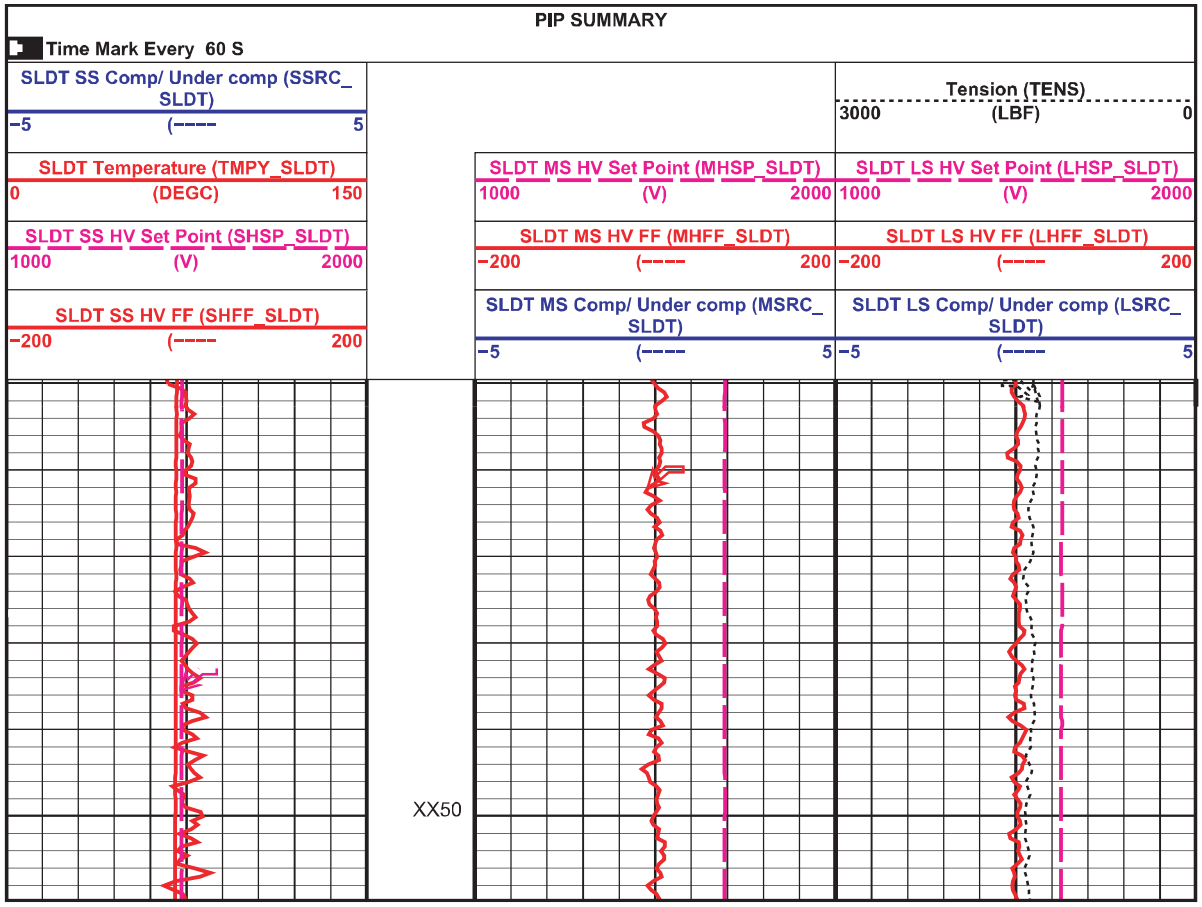

Figure 1. QLDT standard format.

Response in known conditions

Table 2 lists typical response values for the QLDT tool.

Table 2. Typical QLDT Response in Known Conditions

Formation	RHOB, g/cm^3	PEF
Sandstone, 0% porosity	2.65 to 2.68	1.81
Limestone, 0% porosity	2.71	5.08
Anhydrite	2.98	5.05
Salt	2.04	4.65

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MR Scanner

Overview

MR Scanner* expert magnetic resonance service uses multifrequency nuclear magnetic resonance (NMR) measurements in a gradient field design to investigate multiple depths of investigation (DOIs) in a single pass. The measurement depths of the main antenna, ranging from 1.5 to 4 in [3.81 to 10.16 cm], are maintained regardless of hole size, deviation, shape, or temperature. The deep DOIs—beyond the zone of formation damage—make it easy to identify and avoid data-quality problems associated with rugose boreholes, mudcake thickness, and fluids invasion. The MR Scanner measurement sequence produces a detailed evaluation of the near-wellbore region:

- oil and water saturation
- total and effective porosity for the determination of pore volume and storage capacity
- bulk volume irreducible water for the determination of water production rate
- transverse relaxation time (T_2) distribution of crude oil for the determination of oil viscosity and to assist in standard T_2 log interpretation
- brine T_2 distribution corrected for hydrocarbon effects to improve pore size analysis
- hydrocarbon-corrected Timur-Coates permeability for the determination of producibility
- longitudinal relaxation time (T_1) for use when T_2 is not available (e.g., logging vuggy porosity or light hydrocarbons).

This detailed profile view of the reservoir fluid contents is insensitive to borehole conditions and fluid salinity and independent of conventional formation evaluation measurements, such as resistivity and density logs. The combination of MR Scanner diffusion-editing acquisition methods and MRF* magnetic resonance fluid characterization produces robust, advanced fluid characterization, especially in the challenging environments of low-resistivity, low-contrast pay and hydrocarbon-bearing freshwater formations.

Specifications

Measurement Specifications	
Logging speed	3,600 ft/h [1,097 m/h]
	Basic NMR profiling: 1,800 ft/h [549 m/h]
	T_2 radial profiling: 900 ft/h [274 m/h]
	High-resolution logging: 400 ft/h [122 m/h]
	T_1 radial profiling: 300 ft/h [91 m/h]
	Saturation profiling: 250 ft/h [76 m/h]
Range of measurement	Porosity: 1 to 100 V/V
	T_2 distribution: 0.4 ms to 3.0 s
	T_1 distribution: 0.5 ms to 9.0 s
Vertical resolution†	Main antenna: 18 in [45.72 cm]
	High-resolution antenna: 7.5 in [19.05 cm]
Accuracy	Total NMR porosity: 1-V/V standard deviation, three-level averaging at 75 degF [24 degC]
	NMR free-fluid porosity: 0.5-V/V standard deviation, three-level averaging at 75 degF [24 degC]
Depth of investigation	Main antenna: 1.5, 1.9, 2.3, 2.7, and 4.0 in [3.81, 4.83, 5.84, 6.86, and 10.16 cm]
	High-resolution antenna: 1.25 in [3.18 cm]
Mud type or weight limitations	Mud resistivity: 0.05 ohm.m‡
Special applications	MRF depth and station logging
	Rugose boreholes and thick mudcake

† From measurement point 8.2 ft [2.5 m] above the bottom of the tool.
‡ Main antenna only; stacking may be required. MR Scanner logs have been acquired in 0.02-ohm.m environments with minor loss of precision.

Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	5.875 in [14.92 cm] in good borehole conditions
Borehole size—max.	No limit
Outside diameter	Sonde: 5 in [12.70 cm]
	Cartridge: 4.75 in [12.07 cm]
Length	32.7 ft [9.97 m]
Weight	1,200 lbm [544 kg]
Tension	50,000 lbf [222,410 N]
Compression	7,900 lbf [35,140 N]

Calibration

A master calibration should be performed once every 3 months. All measurements should be within the specified tolerance limits of the Calibration Summary Listing. To ensure measurement accuracy, the downhole sensor readings are compared with a known reference, compensating for any measurement drift.

At the wellsite, the before-survey calibration is performed. Sensor readings are compared with a wellsite reference to ensure that no drift has occurred since the last master calibration.

At the end of the survey, sensor readings may be verified again during the after-survey calibration.

Tool quality control

Standard curves

The MR Scanner standard curves are listed in Table 1.

Table 1. MR Scanner Standard Curves

Output Mnemonic	Output Name
AQF[*x*]	Antenna quality factor for shells S1, S2, S3, S4, S8
BADF_MRF[*x*]	Bad hole flag S1, S2, S3, S4, S8
FFV_MRF[*x*]	Free-fluid volume S1, S2, S3, S4, S8
FIRST_ECHO_RING[*x*]	First echo ringing S1, S2, S3, S4, S8
FREQ_OFFSET[*x*]	Frequency offset S1, S2, S3, S4, S8
FREQ_OFFSET_QC[*x*]	QC for frequency offset S1, S2, S3, S4, S8
GAIN_MR[0]	Total gain S1, S2, S3, S4, S8
KTIM_MRF[*x*]	Permeability S1, S2, S3, S4, S8
MRPP_MRF[*x*]	Total porosity S1, S2, S3, S4, S8
NOISE_ENV[*x*]	Environmental noise S1, S2, S3, S4, S8
NOISE_TOOL[*x*]	Tool noise S1, S2, S3, S4, S8
SECOND_ECHO_RING[*x*]	Second echo ringing S1, S2, S3, S4, S8
T2CUTOFF	T_2 cutoff
T2LM_MRF[*x*]	T_2 log mean S1, S2, S3, S4, S8

Operation

During logging, the following are checked:

- There are basically two classes of antenna quality factor (AQF) sequences, LOW_AQF and HIGH_AQF sequences. For $0 < \text{AQF} < 55$, LOW_AQF sequences should be used. For $55 \leq \text{AQF} < 100$, HIGH_AQF sequences should be used. If the log is recorded with the wrong sequence, the data is not recoverable.
- The correct MR Scanner sonde (MRXS) coefficient must be used.

The MR Scanner tool must be run eccentered. Skid contact with the formation is essential.

Precise repeatability specifications are not available because of the variety of possible logging speeds, pulse sequences, and environmental factors such as temperature, salinity, and rugosity.

Formats

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

- NOISE_TOOL represents the noise sensed by the tool, independent of any environmental corrections for temperature, frequency, or gain. Under normal circumstances, the tool noise should not fluctuate significantly during logging. Acceptable values for the tool noise for each MR Scanner shell are as follows:
  - S1 with 1.5-in DOI: 0.020 V/V
  - S2 with 1.9-in DOI: 0.026 V/V
  - S3 with 2.3-in DOI: 0.034 V/V
  - S4 with 2.7-in DOI: 0.040 V/V
  - S8 with 4.0-in DOI: 0.070 V/V
  - lower high-resolution (LHR) antenna with 1.25-in DOI: 0.021 V/V
  - upper high-resolution (UHR) antenna with 1.25-in DOI: 0.021 V/V.
- NOISE_ENV includes the effects of environmental conditions (e.g., temperature) as well as any extraneous noise. The environmental noise determines the precision of final answers. For most conditions, NOISE_ENV should be higher than the corresponding NOISE_TOOL curve. Acceptable values for the environmental noise for each MR Scanner shell are
  - S1 with 1.5-in DOI: 0.020 V/V in freshwater environment and 0.050 V/V in saline-mud environment
  - S2 with 1.9-in DOI: 0.026 V/V in freshwater environment and 0.065 V/V in saline-mud environment
  - S3 with 2.3-in DOI: 0.034 V/V in freshwater environment and 0.080 V/V in saline-mud environment
  - S4 with 2.7-in DOI: 0.040 V/V in freshwater environment and 0.100 V/V in saline-mud environment
  - S8 with 4.0-in DOI: 0.070 V/V in freshwater environment and 0.150 V/V in saline-mud environment
  - LHR antenna with 1.25-in DOI: 0.021 V/V in freshwater environment and 0.050 V/V in saline-mud environment
  - UHR antenna with 1.25-in DOI: 0.021 V/V in freshwater environment and 0.050 V/V in saline-mud environment.
- Under normal circumstances, all echoes in the measured echo trains are free from contamination by antenna ringdown (after radio frequency [RF] pulses). However, if the antenna degrades, is detuned, or becomes damaged, ringing artifacts may appear.

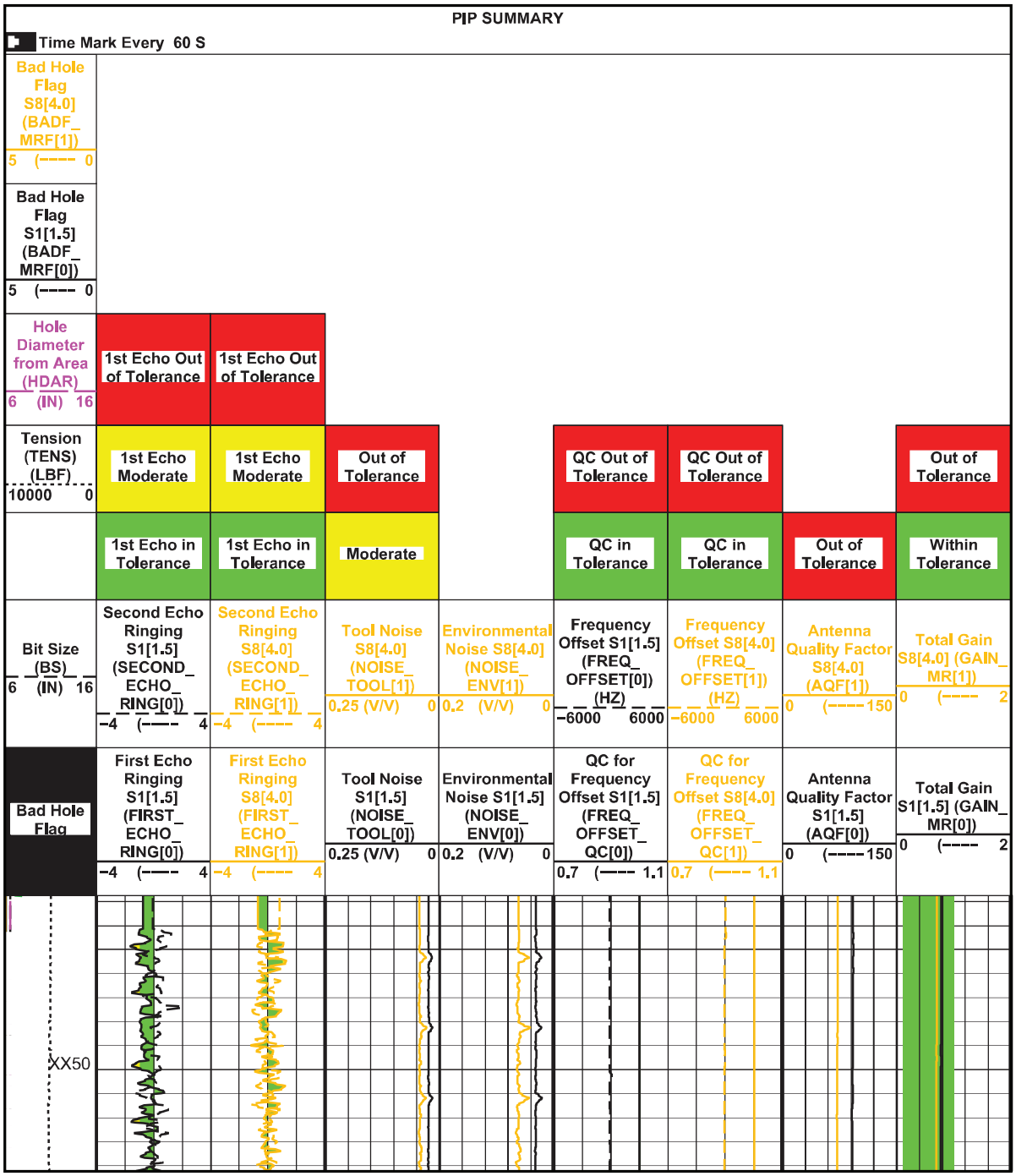

Figure 1. MR Scanner log format.

Response in known conditions

- Clean water-bearing formations: MR Scanner porosity is comparable with neutron and density porosities in clean water-bearing sandstones and carbonates.
- Shaly formations: MR Scanner porosity is a total porosity measurement and lower than neutron porosity and higher than density porosity in shaly formations (depends on quantity and type of clay). MR Scanner free-fluid porosity (FFV) is usually much lower than MR Scanner porosity (MRP) in shaly formations.
- Shale: MR Scanner porosity reads much lower than neutron porosity, but higher than density porosity (depends on type of clay in the shales). Free-fluid porosity is typically 0% porosity. MR Scanner porosity from S4 is often less than that from S1 in shales because of the echo spacing (TE) difference between the shells (0.450 s for S1; 0.600 s for S4). Also, the CMR* combinable magnetic resonance porosity may be higher than the MR Scanner porosity in shales because of the shorter CMR echo spacing (0.200 s).
- Gas zones: MR Scanner porosity is much lower than density porosity and usually slightly lower than neutron porosity (the MR Scanner response depends on invasion and the hydrogen index of the gas).
- Heavy oil zones: MR Scanner porosity does not include the volume of heavy oil (or bitumen); MR Scanner porosity is much lower than neutron and density porosities when heavy oil is present.
- Washouts: MR Scanner porosity spikes high in washouts and intervals where the tool loses contact with the formation. Shallow DOI modes (1.5 in and 1.25 in) are more affected by washouts. Deeper measurements (2.7 in and 4.0 in) are usually not affected in moderate washouts.

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CMR-Plus

Overview

The CMR-Plus* combinable magnetic resonance tool with high-logging-speed capability makes nuclear magnetic resonance (NMR) measurements of the buildup and decay of the polarization of hydrogen nuclei (protons) in the liquids contained in the pore space of rock formations.

One primary measurement of the CMR-Plus tool is the total formation porosity. Borehole NMR measurement is unaffected by solid nonmagnetic materials, so the measurement is not sensitive to matrix type and therefore lithology independent. The total porosity can be partitioned into the spectrum of pore sizes present, which provides information on the irreducible water saturation. Permeability can be estimated from the free-fluid to bound-fluid ratio and the shape of the pore-size distribution.

NMR measurement is also useful for fluid identification because it is a hydrogen index measurement, and various fluids have different hydrogen index values as well as polarization characteristics. NMR data can be processed to yield formation fluid properties such as gas and oil saturation and oil viscosity.

Specifications

Measurement Specifications	
Output	Transverse relaxation time (T_2) distribution, total porosity, free- and bound-fluid volumes, permeability determined with Schlumberger-Doll Research (SDR) and Timur-Coates equations, capillary bound porosity, small-pore bound porosity, quality control curves and flags
	MRF* magnetic resonance fluid station log: Saturation; oil, gas, and water volumes; oil viscosity; water and oil T_2 distributions; hydrocarbon-corrected permeability; oil and water log-mean T_2 distributions
Logging speed	Bound-fluid mode: 3,600 ft/h [1,097 m/h]
	Short time constant for the polarizing process (T_1) environment: 2,400 ft/h [731 m/h]
	Long T_1 environment: 800 ft/h [244 m/h]
Range of measurement	Porosity: 0 to 100 V/V
	Minimum echo spacing: 200 us
	T_2 distribution: 0.3 ms to 3.0 s
	Nominal raw signal-to-noise ratio: 32 dB
Vertical resolution	Stationary: 6-in [15.24-cm] measurement aperture
	Depth log (high-resolution mode): 7.5-in [19.05-cm] vertical resolution, three-level stacking
	Depth log (fast mode): 30-in [76.20-cm] vertical resolution, three-level stacking
Accuracy	Total CMR-Plus porosity standard deviation: ±1.0 V/V at 75 degF [24 degC], three-level stacking
	CMR-Plus free-fluid porosity standard deviation: ±0.5 V/V at 75 degF [24 degC], three-level averaging
Depth of investigation	Blind zone (2.5% point): 0.50 in [1.27 cm]
	Median (50% point): 1.12 in [2.84 cm]
	Maximum (95% point): 1.50 in [3.81 cm]

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
	High-pressure version: 25,000 psi [172 MPa]
Borehole size—min.	Without integral bow spring: 5.875 in [14.92 cm]
	With integral bow spring: 7.875 in [20 cm]
Borehole size—max.	No limit
Outside diameter	Without bow spring: 5.3 in [13.46 cm]
	With bow spring: 6.6 in [16.76 cm]
Length	15.6 ft [4.75 m]
Weight	Without bow spring: 374 lbm [170 kg]
	With bow spring: 413 lbm [187 kg]
Tension	50,000 lbf [222,410 N]
Compression	23,000 lbf [102,310 N]

Calibration

CMR-Plus tools are calibrated every month.

The calibration setup positions the CMR-Plus tool face up with a calibration bottle affixed containing nickel chloride mixed with water in a ratio of 11 g of NiCl to 1 L of water. A Faraday shield is placed over the magnetic section to reduce noise.

All metal objects, including other tools, hand tools, tool stands, and tool end caps, must be removed from the calibration area. The calibration area must be located so that interference from electrical noise (fluorescent lights, overhead cranes, and radio towers) is minimized. The CMR-Plus tool must not have tools connected below it or any jumper leads that may add noise. The tool should be positioned 3 ft [0.9 m] above the floor to eliminate noise.

Tool quality control

Standard curves

The standard curves of the CMR-Plus tool are listed in Table 1.

Table 1. CMR-Plus Standard Curves

Output Mnemonic	Output Name
BFV_SIG	Standard deviation of total bound-fluid porosity
CMFF_SIG	Standard deviation of free-fluid porosity
CMR_GAIN	CMR* system gain
CMR_TEMP	CMR temperature
CMRP_MAX	CMR porosity (CMRP) using T_1/T_2 ratio maximum
CMRP_MIN	CMRP using T_1/T_2 ratio minimum
DELTA_B0	Difference in the static magnetic field (ΔB_0)
FREQ_OP	CMR operating frequency
FREQ_WO_ALF	Frequency without auto Larmor frequency (ALF)
HV_LOADED	High voltage when loaded
HV_PEAK_CUR	High voltage peak current
NOISE_ENV	Noise per echo
NOISE_TOOL	Tool hardware noise
NOISE_TOOL_WSUM	Tool window-sums noise
SPHASE	Signal phase
TCMR	Total CMR porosity
TCMR_SIG	Standard deviation of total CMR porosity
WIN_POR_1	Windows porosity 1
WIN_POR_2	Windows porosity 2
WIN_POR_3	Windows porosity 3

Operation

CMR-Plus data can be acquired versus depth or versus time (stationary measurement).

The CMR-Plus tool is commonly run in autotuning mode, which allows the operating frequency to automatically adjust to changes in the static magnetic field B_0. When the CMR-Plus tool is run in manual mode, the tool must be retuned if one or both of the following conditions apply:

- the difference between the operating and central search frequencies exceeds 15 kHz
- ΔB_0 exceeds 0.1 mT [1 gauss] during logging.

Planning CMR-Plus jobs involves many variables depending on hole conditions, formation, and type of fluids, among other factors. To help job planning, it is recommended to run the CMR Advisor to select the best suitable pulse sequence.

The CMR-Plus tool must be run eccentered using a minimum of two bow springs, inline eccentralizers, or powered caliper devices above and below the sonde. Skid contact with the formation is essential.

Precise repeatability specifications are not available because of the variety of possible logging speeds, pulse sequences, and environmental factors such as temperature, salinity, and rugosity.

Format

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

- Depth track
  - If the Insufficient Wait-Time Flag is on, this may indicate that the polarization time is insufficient. This does not necessarily mean that the computed results are incorrect, but that the standard deviation is high. Consult your Schlumberger representative when this flag is displayed.
  - An increase in the No Update Count is caused by logging too fast or by telemetry problems.
- Track 1
  - The three window porosities should be similar and free of spikes.
  - The difference between Windows 2 and 3 should be less than 3 V/V.
- Track 2
  - CMR_GAIN should read close to 0.8–1.0 for low-temperature fresh-mud wells and close to 0.3–0.5 in hot wells with conductive mud. It may drop further in zones of washouts.
  - DELTA_B0 and CMR_TEMP should decrease slowly while logging up.
  - FREQ_OP should slightly increase while logging up (at about 0.8 kHz/degC).
  - With autotuning, the area indicated as ALF Frequency Correction should be small; the maximum acceptable difference between the FREQ_WO_ALF and FREQ_OP should not be more than 50–60 kHz.
  - SPHASE should remain relatively constant through porous regions.
- Track 3
  - ΔB_0 should be zero if a Larmor frequency search task (LFST) was conducted before the log is started. A rapidly varying ΔB_0 suggests the presence of debris, which may affect data quality.
  - Standard deviations of total porosity, free-fluid porosity, and bound-fluid porosity all vary proportionally with temperature and inversely with the amount of stacking, but should remain below 3 V/V.
  - If noise is a problem, the software flags the data yellow where the noise curve is above 3 V/V, and then red if it exceeds 6 V/V. Examine the echo to find out if the noise source is the tool configuration (indicated where noise pattern does not change with depth) or from the environment.
- Track 4
  - The CMRP_MAX and CMRP_MIN curves trigger the Insufficient Wait-Time Flag in the depth track.
  - If the regulated HV_LOADED curve drops below 240 V, data is flagged red to indicate that the transmitter is not receiving enough power.
  - The HV_PEAK_CUR increases when there is an increase in loading on the antenna (e.g., in zones of washouts).

CMR DEPTH LOG REPORT

PARAMETER SUMMARY

Tool Type: CMR−Plus	Cart. Number: X	Sonde Number: X	
Kit Number: X	DHC Version : 16.4	DSP Version : 13	SP Version : 2062001
Mode: Sandstone Depth Log − B Mode		LFST Freq(khz) : 2213	LFST Temp(degc) : 40.39
Log Direction: Up	Polarization Correction: On	EPM: No	
Despiking: Off	High Res: Off	KBFV: Off	DMRP: Off
Echo Spacing(us):	(200)		
Polarization Times(sec) for:	T1=1s: (2.X)	T1=3s: (2.X)	T1=5s: (2.X)
Number of Echoes:	(1200)		
Repetition:	(1)	Duty Cycle (highest): 0.0351	
Regularization:	Auto		
T2 Min(msec): 0.3	T2 Max(msec): 3000	T2 Cutoff(msec): 33	T1/T2: 2
Number of Components: 30	Downhole Stacking: 3	Uphole Stacking: 1	First Echo Used: No
Multiple T2 Cutoffs(msec):	(0.3 1 3 10 33 100 300 1000 3000)		
Sample Int.(in): 7.5	Req Log Speed (f/h): 2700		

PIP SUMMARY

Time Mark Every 60 S

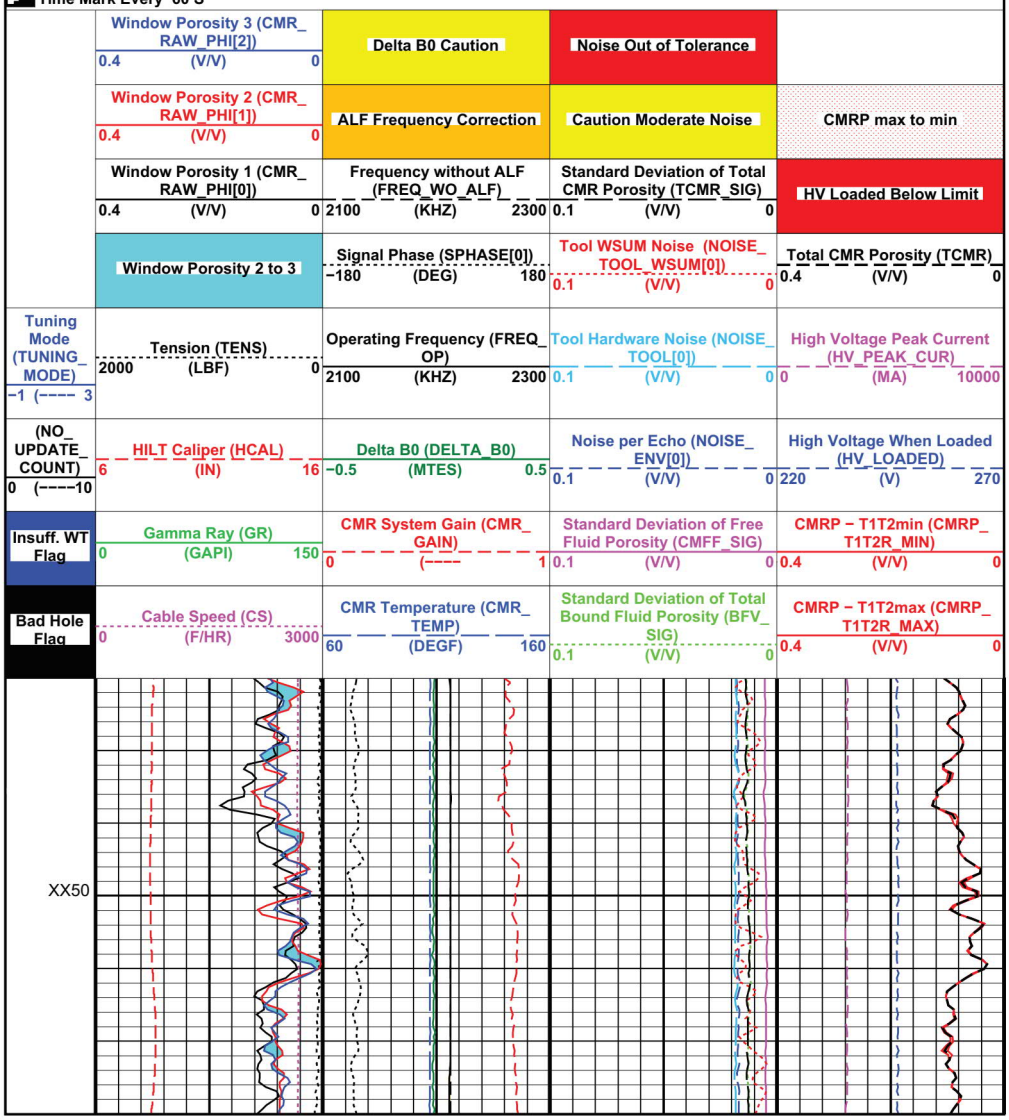

Figure 1. CMR-Plus standard format.

Response in known conditions

- Clean water-bearing formations: CMR-Plus porosity is comparable with neutron and density porosities in clean water-bearing sandstones and carbonates.
- Shaly formations: CMR-Plus porosity is a total porosity measurement and is lower than neutron porosity and slightly higher than density porosity in shaly formations (depending on the quantity and type of clay).
- Shale: CMR-Plus porosity reads much lower than neutron porosity but higher than density porosity (depending on the type of clay in the shales), and free-fluid porosity is typically 0% porosity.
- Gas zones: CMR-Plus porosity is much lower than density porosity and usually slightly lower than neutron porosity (the CMR-Plus response depends on invasion and the hydrogen index of the gas).
- Heavy oil zones: CMR-Plus porosity does not include the volume of very heavy oil (or bitumen), so it is much lower than neutron and density porosities when heavy oil is present.
- Washouts: CMR-Plus porosity spikes high in washouts and intervals where the skid is not in good contact with the formation.
- Mudcake: CMR-Plus readings are usually unreliable where mudcake thickness exceeds 0.5 in [1.3 cm].

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Sonic Scanner

Overview

The Sonic Scanner* acoustic scanning platform provides a 3D representation of the formations surrounding the borehole by scanning both orthogonally and radially. Acoustic technology is used to acquire borehole-compensated (BHC) monopole with long and short spacings, cross-dipole, and cement bond quality measurements. In addition to making axial and azimuthal measurements, the tool radially measures the formation for both near-wellbore and far-field slowness. The typical depths of investigation are 2 to 3 times the borehole diameter.

The wide frequency spectrum used by the Sonic Scanner tool captures data at a high signal-to-noise ratio, regardless of the formation slowness. The combination of a long axial array and multiple transmitter-receiver spacings enables the measurement of a radial monopole profile across the near-wellbore altered zone.

A 3D anisotropy algorithm is used to transform Sonic Scanner compressional, fast and slow shear, and Stoneley slowness measurements with respect to the borehole axes to referenced anisotropic moduli. The formation can then be classified as isotropic or anisotropic, along with determining the type and cause of the anisotropy—intrinsic or stress induced from the drilling process.

Specifications

Measurement Specifications	
Logging speed	Max.: 3,600 ft/h [1,097 m/h]†
Range of measurement	Advanced monopole configuration: 40 to 240 us/ft [131.2 to 787.2 us/m] Standard shear slowness: 75 to 1,500 us/ft [246 to 4,920 us/m] Stoneley mode: 180 to 1,500 us/ft [590 to 4,920 us/m]
Vertical resolution	<6-ft [<1.82-m] processing resolution for 6-in [15.24-cm] sampling rate 2-ft [0.6-m] or less processing resolution possible using multishot processing
Accuracy	Formation integral traveltime (Δt) for up to 14-in [35.56-cm] hole size: 2 us/ft [6.56 us/m] or 2% Δt for >14-in [>35.56-cm] hole size: 5 us/ft [16.40 us/m] or 5%
Depth of investigation	Typical presentation of up to 7 borehole radii

†Logging speed depends on the number of acquisition modes used and the data sampling rate.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]†
Borehole size	4.75 to 22 in [12.07 to 55.88 cm]
Outside diameter	3.625 in [9.21 cm]
Length	41.28 ft [12.58 m] (including isolation joint) Basic toolstring (near monopoles only): 22 ft [6.71 m]
Weight	844 lbm [383 kg] (including isolation joint) Basic toolstring: 413 lbm [187 kg]
Tension	35,000 lbf [155,690 N]
Compression	3,000 lbf [13,340 N]

†30,000-psi [207-MPa] version is available.

Tool quality control

Standard curves

The Sonic Scanner standard curves are listed in Table 1.

Table 1. Sonic Scanner Standard Curves

Output Mnemonic	Output Name
DCIS1	Data copy indicator status from upper monopole
DCIS2	Data copy indicator status from lower monopole
DCIS3	Data copy indicator status from far monopole
DCIS4	Data copy indicator status from far monopole low-frequency
DCIS5	Data copy indicator status from X dipole
DCIS6	Data copy indicator status from Y dipole
DT_ANISO	Anisotropy Δt
DTCO	Compressional Δt
DTCO1	Compressional Δt from upper monopole
DTCO2	Compressional Δt from lower monopole
DTCO3	Compressional Δt from far monopole
DTSH1	Shear Δt from upper monopole
DTSH2	Shear Δt from lower monopole
DTSH3	Shear Δt from far monopole
DTSH5	Shear Δt from X dipole
DTSH6	Shear Δt from Y dipole
DTSM	Shear Δt
DTST	Stoneley Δt
HAZIM	Hole azimuth
HDAR	Hole diameter from area
ITT	Integrated transit time
PR	Poisson's ratio
SPHI	Sonic porosity
SPJ1	Slowness projection from upper monopole
SPJ2	Slowness projection from lower monopole
SPJ3	Slowness projection from far monopole
SPJ4	Slowness projection from far monopole low-frequency
SPJ5	Slowness projection from X dipole
SPJ6	Slowness projection from Y dipole
SSVE	Shear velocity
SVEL	Compressional velocity
VDL	Variable density log
VPVS	Compressional to shear velocity ratio

Operation

The Sonic Scanner tool can be run in one or more of several modes.

- Standard: Data is acquired from all eight azimuths at dipole or four azimuths at monopole but modal decomposition is performed downhole and only the decomposed monopole and dipole components are transmitted to the surface.
- Record all data: Data is acquired from all eight azimuths at dipole or four azimuths at monopole. All waveforms are transmitted uphole, hence the logging speed is slower compared with standard mode.
- Cement evaluation: Waveforms are recorded every 2 in [5 cm] from the 3–5 ft [0.9–1.5 m] spacing. The discriminated cement bond log (DCBL) outputs are recorded every 6 in [15.2 cm]; Variable Density* log (VDL) waveforms are recorded every 2 in.
- Imaging: Waveforms are acquired from all three monopole firings using all 104 sensors (stations 1 to 13 and azimuths 1 to 8).
- BHC: Data from the 3–5 ft spacing is recorded from both near monopole receivers.

Acquiring accurate, good-quality dipole data requires correct tool setup. The following factors can hinder data quality:

- corkscrew hole
- highly laminated formations
- excessive washouts
- eccentered tool
- elongated borehole.

Centering the Sonic Scanner tool is of extreme importance for good-quality dipole data. Sonic Scanner data quality can also be affected by road noise caused by centralizers rubbing against formations that have a rugose surface.

In a high-porosity formation, the presence of gas in the pore space of rock increases the sonic transit time compared with that of the same rock saturated with water or oil. Gas is very compressible; when it replaces pore liquid, it lowers the rock rigidity more than its density and decreases sonic velocity.

In a deep, low-porosity formation, where the pore volume and gas content are both low and the compaction pressure is high, the pore fluid contributes little to the rock rigidity and therefore has little influence on the sonic velocity.

For anisotropy services, the Sonic Scanner tool must be combined with a directional survey measurement (for example, GPIT* general purpose inclinometry tool) to obtain the tool azimuth and deviation.

All depth copy status indicators ($DCSI_n$) should read zero. The acquisition system compares the measurement from the current depth frame with that of the previous one. If both datasets are identical, that indicates that the waveform data acquired in time was copied to two (or more) consecutive depth frames. The $DCSI_n$ flag is set when data is copied to multiple frames, which means that the logging speed is too fast.

The labeling of the compressional and shear traveltimes (Δt_c and Δt_s, respectively) should follow the highest coherence peaks on the underlying image.

Formats

The various formats in Figs. 1 through 3 are used as the main presentation for Sonic Scanner logs and for quality control.

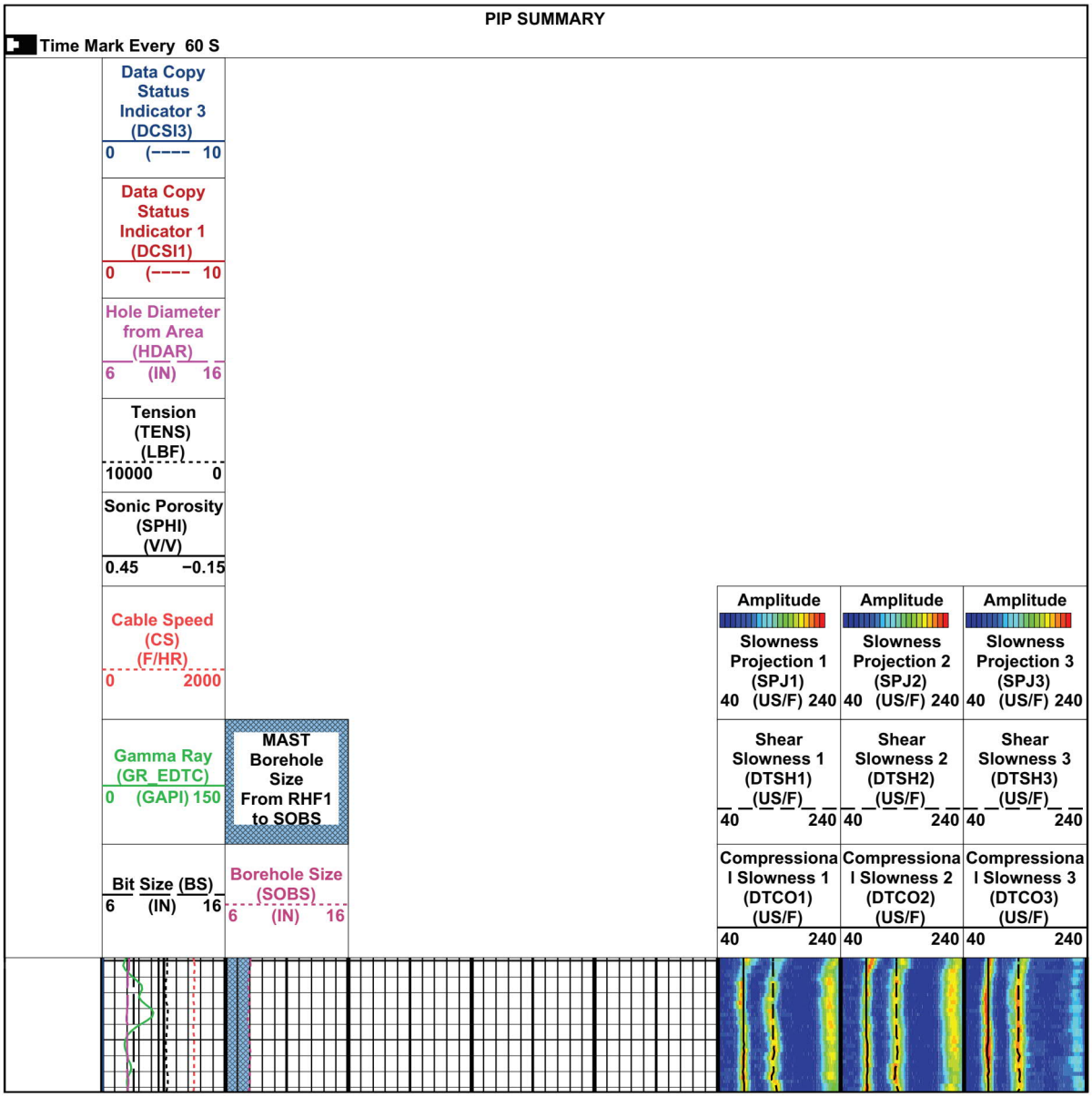

Figure 1. Sonic Scanner monopole measurement.

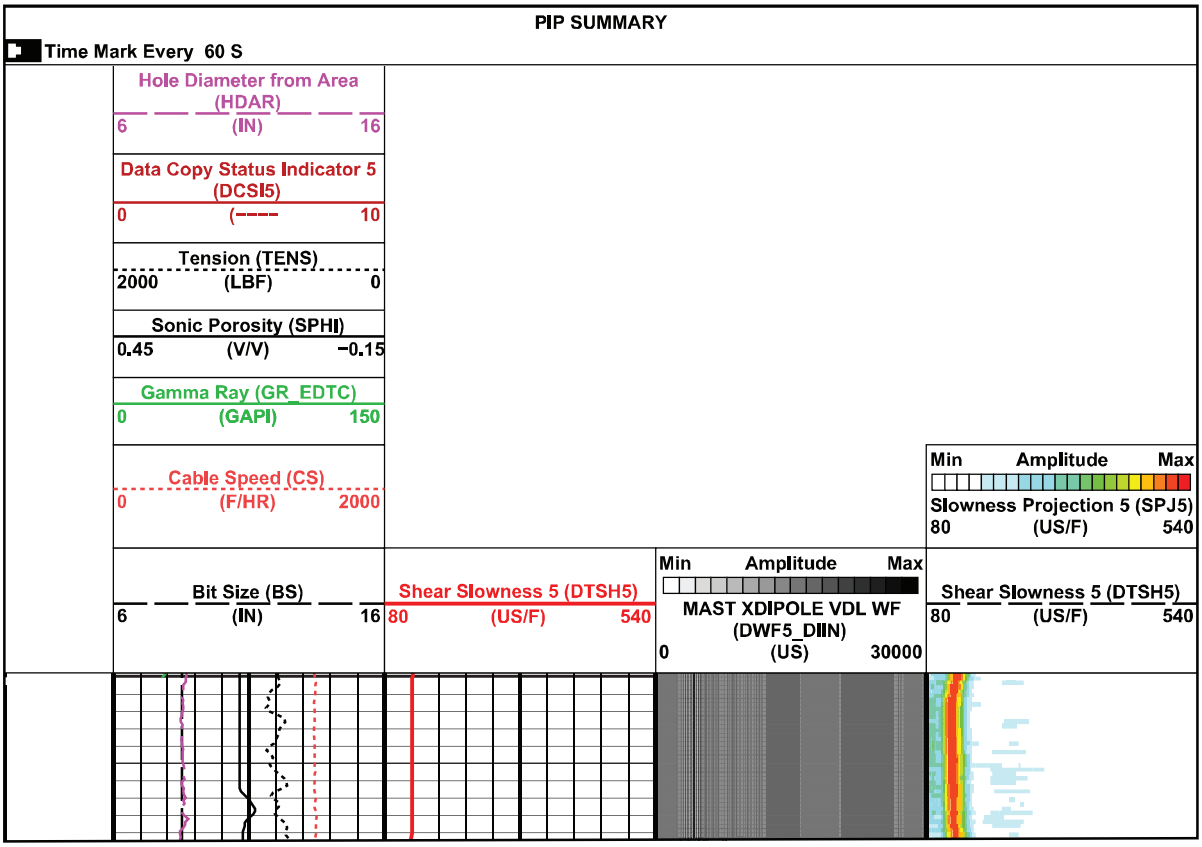

Figure 2. Sonic Scanner dipole measurement.

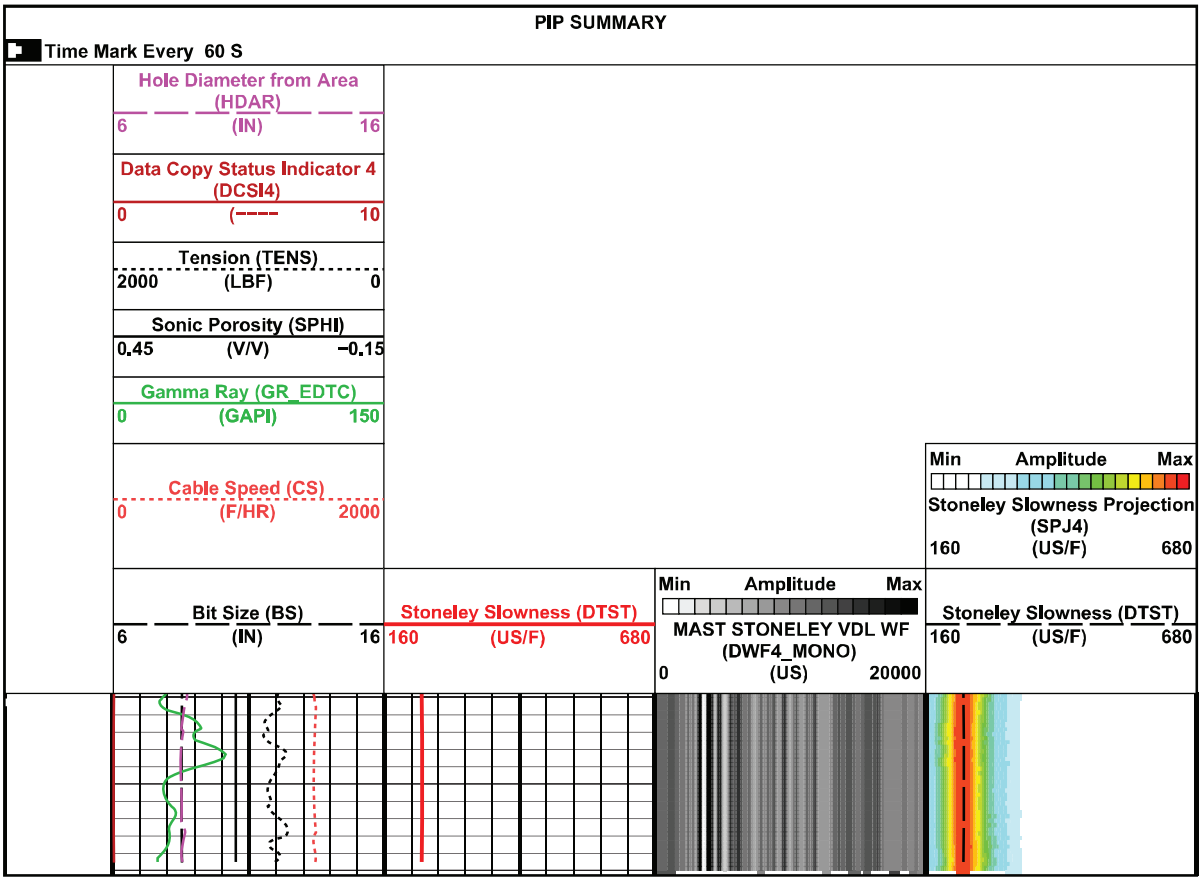

Figure 3. Sonic Scanner Stoneley measurement.

Response in known conditions

The typical values in Table 2 should be observed within the repeatability tolerance (±2 us/ft [±6.6 us/m]) on the measurement:

Table 2. Typical Sonic Scanner Response in Known Conditions

Formation	Δt_c, us/ft [us/m]	Δt_s, us/ft [us/m]
Quartz	56.0 [184]	88.0 [289]
Calcite	49.0 [161]	88.4 [290]
Anhydrite	50.0 [164]	
Salt	67.0 [220]	120.0 [394]

Sonic Scanner measurements are performed downhole in an environment that cannot be exhaustively described. Some factors can negatively affect Sonic Scanner measurements. For example, wells that are washed out, oval shaped, or spiral are not ideal logging conditions for Sonic Scanner measurement. Including a caliper measurement in the toolstring combination can help in evaluating the validity of the results.

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Borehole-Compensated Sonic

Overview

The borehole-compensated (BHC) sonic measurement is acquired using a BHC sonde. The BHC measurement uses two transmitters and four receivers, generating four transit times for computing the formation integral traveltime (Δt) and sonic porosity from compressional slowness. Acoustic logs recognize secondary, or vugular, porosity in lithified sediments.

Calibration

Sonic sonde calibration should be performed with every Q-check. Time between Q-checks varies for each tool. Normalization should be performed once every 12 months for a DSLT tool. In addition to timed calibrations, the Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The calibration checkout tube is supported with two stands, one on each end. A stand in the center of the tube distorts the waveform and can cause errors. One end of the tube should be elevated to remove all air in the system. Centralizer rings are used to position the tool in the checkout tube.

Specifications

Measurement Specifications

	Digital Sonic Logging Tool (DSLT)	Hostile Environment Sonic Logging Tool (HSLT)	Slim Array Sonic Tool (SSLT)	SlimXtreme* Sonic Logging Tool (QSLT)
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]	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 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]	40 to 400 us/ft [131 to 1,312 us/m]
Vertical resolution	2 ft [0.61 m]	2 ft [0.61 m]	Standard: 2 ft [0.61 m] High resolution: 6 in [15.24 cm]	Standard: 2 ft [0.61 m] High resolution: 6 in [15.24 cm]
Accuracy	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]
Repeatability	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]
Depth of investigation	3 in [7.62 cm]	3 in [7.62 cm]	3 in [7.62 cm]	3 in [7.62 cm]

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]
Borehole size	5 to 18 in [12.70 to 45.72 cm]	5 to 18 in [12.70 to 45.72 cm]	3.5 to 8 in [8.89 to 20.32 cm]	4 to 8 in [10.16 to 20.32 cm]
Outside diameter	3.625 in [9.21 cm]	3.875 in [9.84 cm]	2.5 in [6.35 cm]	3 in [7.62 cm]
Length	SLS-D: 18.73 ft [5.71 m] SLS-E: 20.6 ft [6.28 m] SLS-F: 23.81 ft [7.26 m]	25.5 ft [7.77 m]	23.1 ft [7.04 m]	23 ft [7.01 m]
Weight	SLS-D: 273 lbm [124 kg] SLS-E: 313 lbm [142 kg] SLS-F: 353 lbm [160 kg]	440 lbm [199 kg]	232 lbm [105 kg]	295 lbm [134 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-D: 1,700 lbf [7,560 N] SLS-E: 2,870 lbf [12,770 N] SLS-F: 1,650 lbf [7,340 N]	2,870 lbf [12,770 N]	4,400 lbf [19,570 N]	4,400 lbf [19,750 N]

Tool quality control

Standard curves

There are seven standard BHC curves (Table 1).

Table 1. Standard Curves of the BHC Sonic Sondes

Output Mnemonic	Output Name
DELTA-T	Formation integral traveltime (Δt)
SPHI	Sonic porosity
SVEL	Sonic velocity
TT1	Transit time 1
TT2	Transit time 2
TT3	Transit time 3
TT4	Transit time 4

Operation

A number of tools can acquire BHC sonic logs:

- Digital Sonic Logging Tool (DSLT)
- Hostile Environment Sonic Logging Tool (HSLT) for the Xtreme* platform
- Slim Array Sonic Logging Tool (SSLT) for the SlimAccess* platform
- SlimXtreme Sonic Logging Tool (QSLT).

Tool selection depends on the logging environment, but the final log product is essentially the same.

In zones of cycle skipping, repeat sections are run in an effort to improve the data using any or all of the following options:

- changing logging speed
- changing signal gain
- changing equipment setup (e.g., standoffs, centralizers).

In zones that are excessively washed out, it is possible that the compressional signal is attenuated and detection occurs on later Stoneley arrivals. This is characterized by a relatively flat response of the Δt curve.

Formats

The format in Fig. 1 is used as the main presentation for BHC sonic logs and for quality control.

- Track 1
  - The individual transit times are displayed for quality control. Each pair of transit times, with equal transmitter-receiver spacing, should overlay. Cycle skips are always evident on the transit times because a cycle skip shows a sharp increase in increments of 40 us. Road noise is also evident because it is represented by sharp, random drops in transit time.
- Tracks 2 and 3
  - DELTA-T is the integral traveltime in the formation. It is the main output computed from the individual transit times.
  - The SPHI sonic porosity is computed from the DELTA-T output for a defined formation.

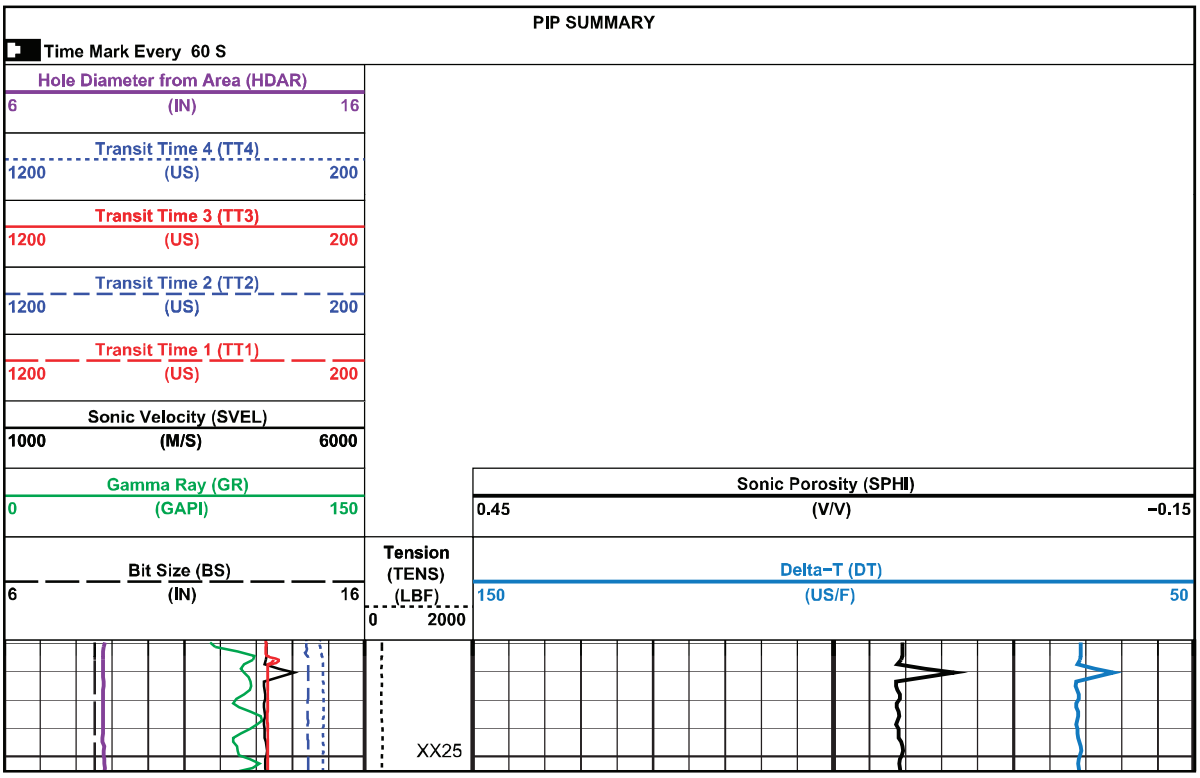

Figure 1. BHC sonic log format.

Response in known conditions

The typical values in Table 2 should be observed within the repeatability tolerance (±2 us/ft [±6.6 us/m]).

The casing check is compulsory.

Table 2. Typical BHC Response in Known Conditions

Formation	Δ*t*, us/ft [us/m]
0-pu sandstone	51.2–55.5 [168–182.1]
0-pu limestone	43.5–47.6 [142.7–156.2]
Anhydrite	50 [164]
Salt	67 [220]

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Sonic Long Spacing

Overview

The sonic long-spacing (SLS) measurement is acquired using a depth-derived borehole-compensated (DDBHC) sonde. The DDBHC measurement uses two transmitters and two receivers, generating four transit times for computing the formation near and far integral travel-times (Δt_n and Δt_f, respectively) and sonic porosity from compressional slowness. Acoustic logs recognize secondary, or vugular, porosity in lithified sediments.

Calibration

Sonic sonde calibration should be performed with every Q-check. Time between Q-checks varies for each tool. Normalization should be performed once every 12 months for a DSLT tool. In addition to timed calibrations, the Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The calibration checkout tube is supported with two stands, one on each end. A stand in the center of the tube distorts the waveform and can cause errors. One end of the tube should be elevated to remove all air in the system. Centralizer rings are used to position the tool in the checkout tube.

Specifications

Measurement Specifications

	Digital Sonic Logging Tool (DSLT)	Hostile Environment Sonic Logging Tool (HSLT)	Slim Array Sonic Tool (SSLT)	SlimXtreme* Sonic Logging Tool (QSLT)
Logging speed	3,600 ft/h [1,097 m/h] Recording waveforms: 1,800 ft/h [549 m/h]	3,600 ft/h [1,097 m/h] Recording waveforms: 1,800 ft/h [549 m/h]	3,600 ft/h [1,097 m/h] Recording waveforms: 1,800 ft/h [549 m/h]	3,600 ft/h [1,097 m/h] Recording waveforms: 1,800 ft/h [549 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 200 us/ft [131 to 656 us/m]	40 to 200 us/ft [131 to 656 us/m]	40 to 200 us/ft [131 to 656 us/m]
Vertical resolution	4 ft [1.22 m]	4 ft [1.22 m]	4 ft [1.22 m]	4 ft [1.22 m]
Accuracy	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]
Repeatability	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]	Δt: ±2 us/ft [±6.6 us/m]

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]
Borehole size	5 to 18 in [12.70 to 45.72 cm]	5 to 18 in [12.70 to 45.72 cm]	3.5 to 8 in [8.89 to 20.32 cm]	4 to 8 in [10.16 to 20.32 cm]
Outside diameter	3.625 in [9.21 cm]	3.875 in [9.84 cm]	2.5 in [6.35 cm]	3 in [7.62 cm]
Length	SLS-D: 18.73 ft [5.71 m] SLS-E: 20.6 ft [6.28 m] SLS-F: 23.81 ft [7.26 m]	28.4 ft [8.66 m]	23.1 ft [7.04 m]	23 ft [7.01 m]
Weight	SLS-D: 273 lbm [124 kg] SLS-E: 313 lbm [142 kg] SLS-F: 353 lbm [160 kg]	482 lbm [219 kg]	232 lbm [105 kg]	295 lbm [134 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-D: 1,700 lbf [7,560 N] SLS-E: 2,870 lbf [12,770 N] SLS-F: 1,650 lbf [7,340 N]	1,650 lbf [7,340 N]	4,400 lbf [19,570 N]	4,400 lbf [19,750 N]

Tool quality control

Standard curves

The standard SLS curves are listed in Table 1.

Table 1. Standard Curves for the SLS Measurement

Output Mnemonic	Output Name
DTLF	Far formation integral traveltime (Δt_f)
DTLN	Near formation integral traveltime (Δt_n)
SPHI	Sonic porosity
SVEL	Sonic velocity
LTT1	Long-spacing transit time 1
LTT2	Long-spacing transit time 2
LTT3	Long-spacing transit time 3
LTT4	Long-spacing transit time 4

Operation

A number of tools can acquire SLS logs:

- Digital Sonic Logging Tool (DSLT)
- Hostile Environment Sonic Logging Tool (HSLT) for the Xtreme* platform
- Slim Array Sonic Logging Tool (SSLT) for the SlimAccess* platform
- SlimXtreme Sonic Logging Tool (QSLT).

Tool selection depends on the logging environment, but the final product is essentially the same.

In zones of cycle skipping, repeat sections are run in an effort to improve the data using any or all of the following options:

- changing logging speed
- changing signal gain
- changing equipment setup (e.g., standoffs, centralizers).

In zones that are excessively washed out, it is possible that the compressional signal is attenuated and detection occurs on later Stoneley arrivals. This is characterized by a relatively flat response of the Δt curve.

Formats

The format in Fig. 1 is used as the main presentation for SLS logs and for quality control.

- Track 1
  - The individual transit times can be displayed for quality control, as is the case with BHC logs. Hole diameter (caliper) is displayed to show regions where the signal may be affected by borehole conditions.
- Tracks 2 and 3
  - DTLN and DTLF are the integral traveltimes in the formation. They are the main outputs computed from the individual transit times.
  - The sonic porosity (SPHI) is computed from the integral traveltime output for a defined formation.

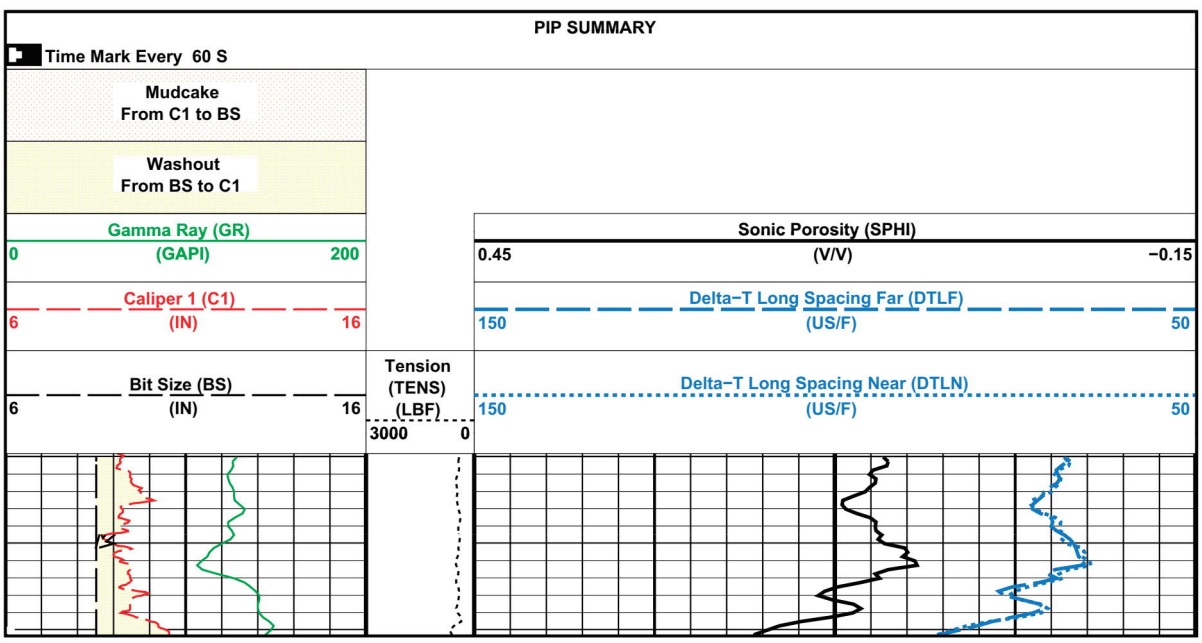

Figure 1. SLS log format.

Response in known conditions

In shale zones where the area around the borehole has been altered by the drilling process, the interval transit time from the longer spacing (10–12 ft [3–3.6 m]) reads the same or less than that from the shorter spacing (8–10 ft [2.4–3 m]). In other formations, these curves should overlie and the typical values in Table 2 should be observed within the repeatability tolerance (±2 us/ft [±6.6 us/m]).

The casing check is compulsory.

Table 2. Typical SLS Response in Known Conditions

Formation	Δ*t*, us/ft [us/m]
0-pu sandstone	51.2–55.5 [168–182.1]
0-pu limestone	43.5–47.6 [142.7–156.2]
Anhydrite	50 [164]
Salt	67 [220]
Casing	57 [187]

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DSI

Overview

The DSI* dipole shear sonic imager combines monopole and dipole sonic acquisition capabilities. The transmitter section contains a piezoelectric monopole transmitter and two electrodynamic dipole transmitters perpendicular to each other. An electric pulse at sonic frequencies is applied to the monopole transmitter to excite compressional and shear wave propagation in the formation. For Stoneley wave acquisition, a specific low-frequency pulse is used. The dipole transmitters are also driven at low frequency to excite the flexural wave around the borehole and obtain borehole shear measurements in both soft- and hard-rock formations. A special dipole mode enables recording both the inline and crossline (perpendicular) waveforms for each dipole mode. This mode, called both cross receivers (BCR), is used for anisotropy evaluation.

Specifications

Measurement Specifications	
Logging speed	Max.: 3,600 ft/h [1,097 m/h]†
Range of measurement	Standard shear slowness: 700 us/ft [2,297 us/m]
	S-DSI max. slowness: 1,200 us/ft [3,937 us/m]
	Max. slowness in casing: 250 to 350 us/ft [820 to 1,148 us/m]
Vertical resolution	3.5-ft [1.07-m] processing resolution for 6-in [15.24-cm] sampling rate
Accuracy	Transit time (Δt): 2 us/ft [6.56 us/m]

† Logging speed depends on the number of acquisition modes used and the data sampling rate.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size	4.75 to 21 in [12.07 to 53.34 cm]
Casing size	5½ to 20 in [13.97 to 50.80 cm]
Outside diameter	3.625 in [9.21 cm]
Length	51 ft [15.54 m] (including isolation joint)
Weight	900 lbm [408 kg]
Tension	Standard: 5,000 lbf [22,240 N]
	S-DSI: 3,500 lbf [15,570 N]
Compression	Standard: 1,550 lbf [6,890 N]
	S-DSI: 1,000 lbf [4,450 N]

Tool quality control

Standard curves

The DSI standard curves are listed in Table 1.

Table 1. DSI Standard Curves

Output Mnemonic	Output Name
AZTB	Azimuth at DSI tool depth
AZWD	Azimuth at waveform depth
CHR1	Peak coherence from SAM1 receiver array
CHR2	Peak coherence from SAM2 receiver array
CHR3	Peak coherence from SAM3 receiver array
CHRP	Compressional peak coherence from receiver array
CHRS	Shear peak coherence from receiver array
CHT1	Peak coherence from SAM1 transmitter array
CHT2	Peak coherence from SAM2 transmitter array
CHT3	Peak coherence from SAM3 transmitter array
CHTP	Compressional peak coherence from transmitter array
CHTS	Shear peak coherence from transmitter array
DT1	Shear transit time (Δt_s) from SAM1 dipole
DT1R	Δt_s receiver array from SAM1 dipole
DT1T	Δt_s transmitter array from SAM1 dipole
DT2	Δt_s from SAM2 dipole
DT2R	Δt_s receiver array from SAM2 dipole
DT2T	Δt_s transmitter array from SAM2 dipole
DT3R	Stoneley transit time ($\Delta t_{Stoneley}$) from receiver array
DT3T	$\Delta t_{Stoneley}$ from transmitter array
DT4P	Compressional transit time (Δt_c) from SAM4 monopole
DT4S	Δt_s from SAM4 monopole
DTRP	Δt_c from receiver array
DTRS	Δt_s receiver array
DTST	$\Delta t_{Stoneley}$
DTTP	Δt_c from transmitter array
DTTS	Δt_s transmitter array
DVTB	Deviation at DSI tool depth
DVWD	Deviation at waveform depth
HDAR	Hole diameter from area
PR	Poisson's ratio
RBTB	Relative bearing at DSI tool depth
RBWD	Relative bearing at waveform depth
SPHI	Sonic porosity
SSVE	Shear velocity
SVEL	Sonic compressional velocity
VPVS	Compressional-to-shear velocity ratio
WCI1	SAM1 waveform delay copy indicator
WCI2	SAM2 waveform delay copy indicator
WCI3	SAM3 waveform delay copy indicator
WCI4	SAM4 waveform delay copy indicator
WCIX	SAMX waveform delay copy indicator
WFG1	SAM1 waveform gain
WFG2	SAM2 waveform gain
WFG3	SAM3 waveform gain
WFG4	SAM4 waveform gain

Operation

The DSI tool can be run in several modes (Table 2).

Table 2. DSI Modes

SAM1 and SAM2	Dipole modes (upper and lower dipole transmitters), which can be run at standard frequency (1 to 2 kHz) or low frequency (0.25 to 1 kHz)
SAM3	Stoneley mode
SAM4	Monopole mode, which can be run at low frequency (5 kHz), medium frequency (7.5 kHz), or standard frequency (15 kHz)
SAMX	BCR mode, which can be run at standard frequency (1 to 2 kHz) or low frequency (0.25 to 1 kHz)

For all modes, slowness-time-coherence (STC) processing is performed and the slowness curve is labeled at the highest coherence point of the projection plot.

The chart in Fig. 1 is used to select the drive frequency of the dipole source (low frequency or standard frequency) on the basis of the hole size and expected formation slowness.

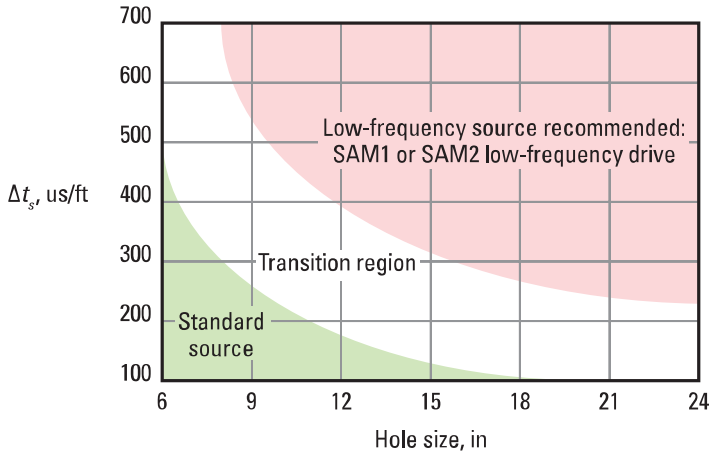

Figure 1. Dipole mode selection.

For SAMX mode, an azimuthal measurement must be run, either stand alone or in combination with a dipmeter tool. In addition, the tool must be run centralized. For SAM1 and SAM2 modes, running the DSI tool centralized and in combination with an azimuthal measurement is strongly recommended. Eccentering a dipole tool can result in mixed non-dipole-mode components in the received signal.

Waveforms should have a low noise baseline with no cyclic noise or waveform clipping.

DSI logs should not be spliced to avoid loss of data at the splice point.

Formats

The monopole measurement standard format (Fig. 2) is used mainly as a quality control.

- Track 1
  - WCI4 should be flat; if not, logging speed is too fast.
- Track 2
  - Coherence curves from the transmitter array and receiver array for a specific arrival should overlay.
  - DT1, DT1P, and DT1R should overlay.
- Track 3
  - Labeling of Δt_s should follow the track of highest coherence. The example shown in Fig. 2 represents a case of very weak coherence resulting from a low signal-to-noise ratio.

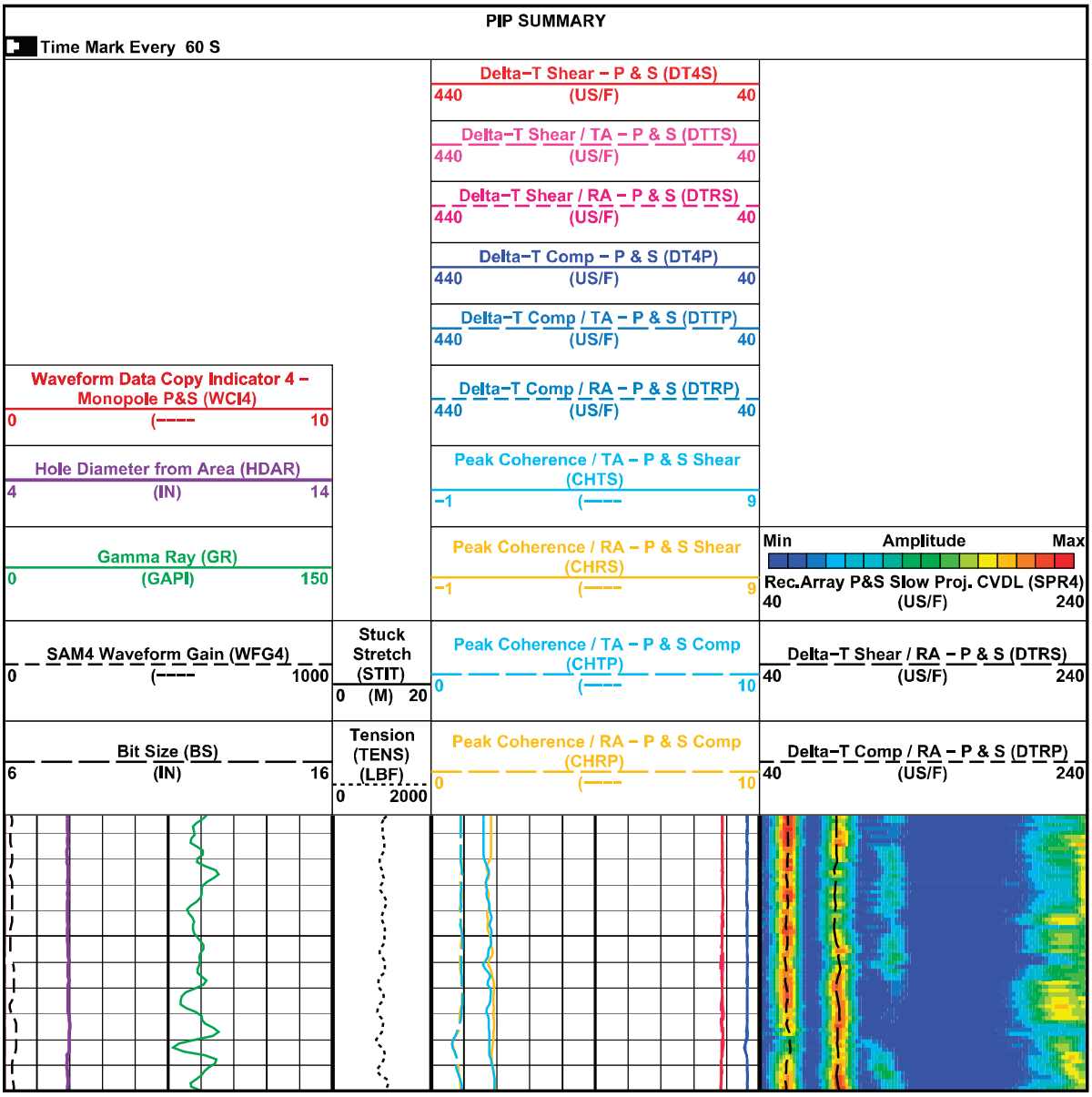

Figure 2. DSI monopole measurement standard format.

The dipole and Stoneley measurement standard format (Fig. 3) is used mainly as a quality control for SAM1, SAM2, and SAM3.

- WCI1, WCI2, and WCI3 should be flat; if not, logging speed is too fast.
- Coherence curves from the transmitter array and receiver array for a specific arrival should overlay.
- Labeling of Δt_s and $\Delta t_{\text{Stoneley}}$ should follow the track of highest coherence.

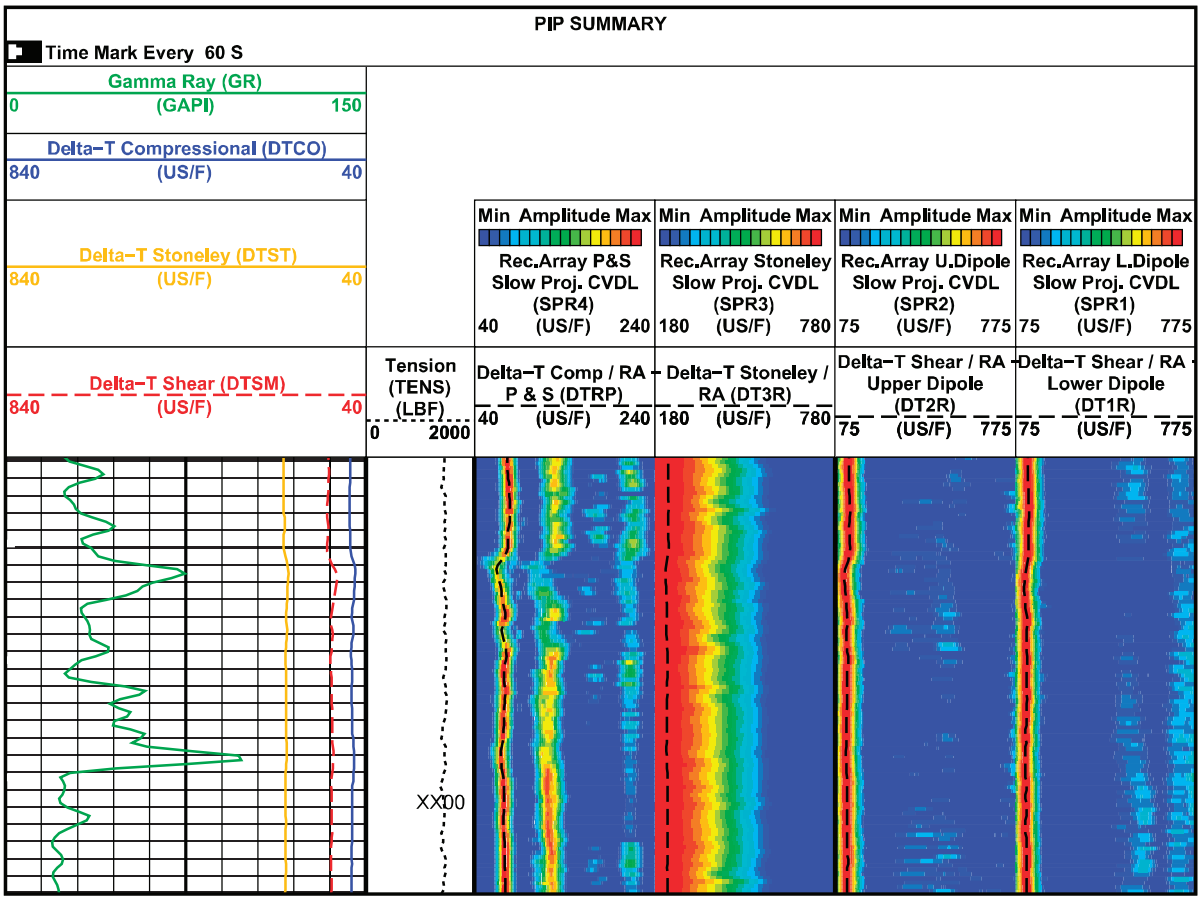

Figure 3. DSI dipole and Stoneley measurement standard format.

The anisotropy measurement standard format (Fig. 4) is used mainly as a quality control.

- SAMX is essentially firing both SAM1 and SAM2 modes together, coupled with directional measurement of the DSI tool and the waveforms.
- The quality control format for the dipole and Stoneley measurement (Fig. 3) can be used for this mode. It is recommended to record the Stoneley SAM3 mode to check the validity of the dipole arrivals from the SAM1 and SAM2 modes.
- WCIX should be flat; if not, logging speed is too fast.
- The tool should not rotate more than once every 30 ft [10 m].

Response in known conditions

The typical values in Table 3 should be observed within the repeatability tolerance (±2 us/ft [6.6 us/m]) of the measurement.

Table 3. Typical DSI Response in Known Conditions

Formation	Δt_c, us/ft [us/m]	Δt_s, us/ft [us/m]
Quartz	56.0 [183.7]	88.0 [288.7]
Calcite	49.0 [160.8]	88.4 [290.0]
Anhydrite	50.0 [164.0]	
Salt	67.0 [219.8]	120.0 [393.7]

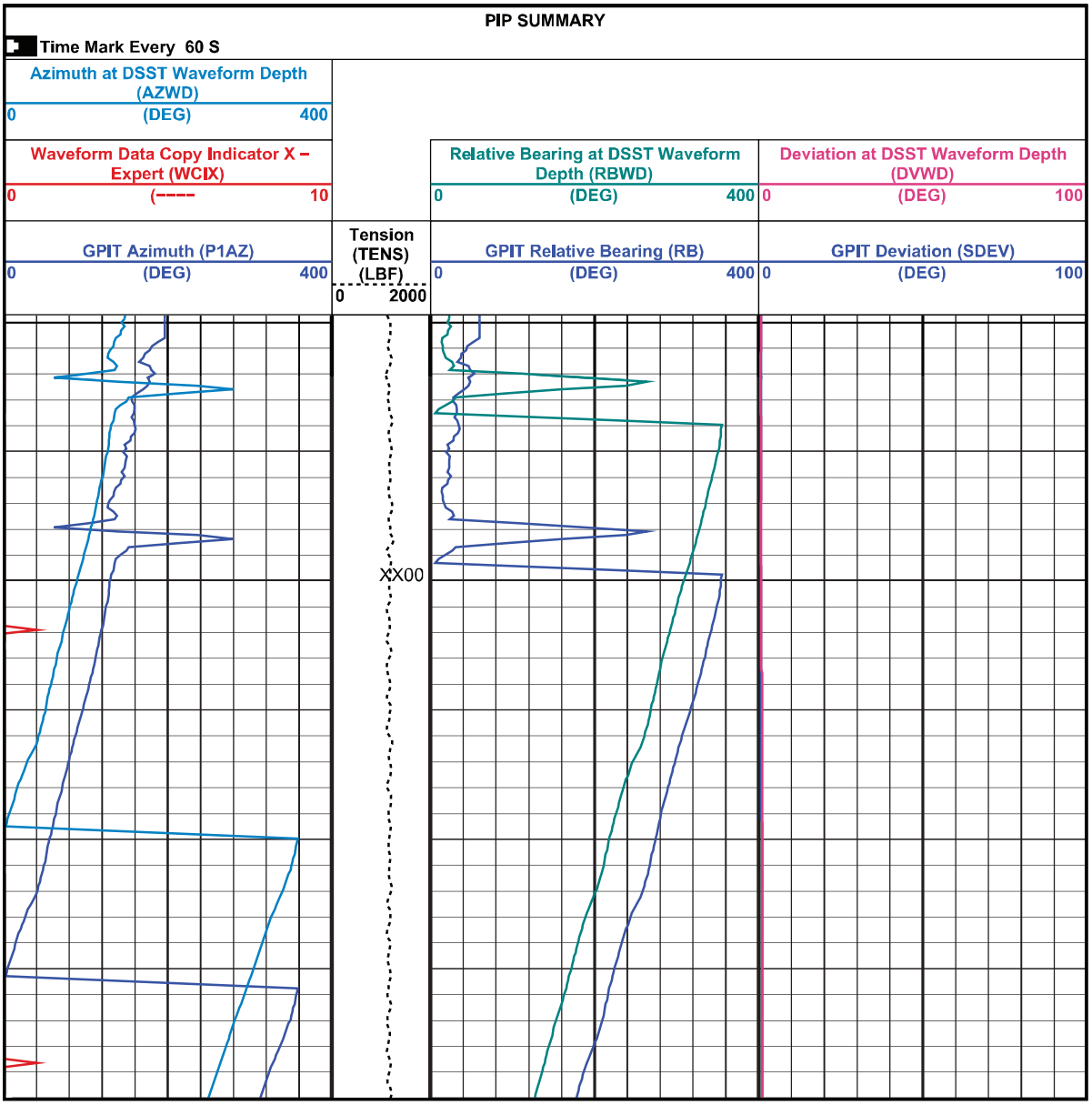

Figure 4. DSI anisotropy measurement standard format.

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FMI

Overview

The FMI* fullbore formation microimager provides an electrical borehole image generated from up to 192 microresistivity measurements. Special focusing circuitry ensures that the measuring currents are forced into the formation, where they modulate in amplitude with the formation conductivities to produce low-frequency signals rich in petrophysical and lithological information and a high-resolution component that provides the microscale information used for imaging and dip interpretation. Image calibration is achieved during postprocessing through calibration with low-frequency, deeper resistivity measurements input from other resistivity measurements, such as from the AIT* array induction imager tool or ARI* azimuthal resistivity imager. Image normalization further increases the completeness and reliability of this versatile tool for geological and reservoir characterization.

The combination of measuring button diameter, pad design, and high-speed telemetry system produces a vertical and azimuthal resolution of 0.2 in [0.51 cm] for the FMI tool. This means that the dimensions of a feature larger than 0.2 in can be estimated from the image. The size of features smaller than 0.2 in is estimated by quantifying the current flow to the electrode. Fine details such as 0.002-in- [0.051-mm-] wide fractures filled with conductive fluids are visible in FMI images.

Calibration

The downhole sensor readings of FMI tools are periodically compared with a known reference. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred. At the end of the survey, sensor readings are verified again in the after-survey calibration.

Caliper calibration for the FMI tool is performed with two jig measurements. The jigs are usually calibration rings with a specified diameter. A zero measurement is taken using the smaller of the two rings. A plus measurement is taken using the larger ring. The calibration rings must be continuous, without notched or removed sections, not have any visible damage, and not be ovalized.

Specifications

Measurement Specifications	
Output	Formation dip, borehole images
Logging speed	Image mode: 1,800 ft/h [549 m/h] Dipmeter mode: 3,600 ft/h [1,097 m/h]
Range of measurement	Sampling rate: 0.1 in [0.25 cm] Borehole coverage: 80% in 8-in [20.32-cm] borehole
Vertical resolution	Spatial resolution: 0.2 in [0.51 cm] Vertical resolution: 0.2 in [0.51 cm]
Accuracy	Caliper: ±0.2 in [±0.51 cm] Deviation: ±0.2° Azimuth: ±2°
Depth of investigation	1 in [2.54 cm]
Mud type or weight limitations	Water-base mud (maximum mud resistivity = 50 ohm.m)
Combinability	Bottom-only tool, combinable with most tools
Special	Horizontal wells

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	6¼ in [15.87 cm] 5⅞ in [14.92 cm] in good hole conditions using a kit
Borehole size—max.	21 in [53.34 cm]
Outside diameter	5 in [12.70 cm]
Length	24.42 ft [7.44 m]
Weight	433.7 lbm [197 kg]
Tension	12,000 lbf [53,380 N]
Compression	8,000 lbf [35,580 N]

Tool quality control

Standard curves

The FMI standard curves are listed in Table 1.

Table 1. Standard FMI Curves

Output Mnemonic	Output Name
C1	Caliper 1
C2	Caliper 2
DEVI	Deviation
EI	Emitter-exciter (EMEX) intensity
EV	EMEX voltage
FBCR	FMI correlation resistance
HAZI	Hole azimuth
P1AZ	Pad 1 azimuth
RB	Relative bearing
RBSV	FMI resistivity button set value

Operation

The FMI tool must be run centered.

It is very important that the tool moves smoothly in the borehole. This can be difficult to maintain in sticky hole conditions or when running the tool on drillpipe. Under these circumstances, a speed-corrected playback should be made to verify the data quality.

Formats

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

- Track 1
  - The calipers should be checked inside the casing and validated against the expected casing internal diameter. Calipers should repeat within ±0.25 in [±6.35 mm].
  - FBCR may be used to check the depth of the measurement.
- Tracks 1 and 2
  - Deviation and hole azimuth should be validated against the driller's directional data. The azimuth measurement should repeat within ±2° and deviation should repeat within ±0.2°.
- Track 2
  - EV and the current absolute value vary depending on the formation and mud properties, but should remain stable.
- Tracks 3 and 4
  - Microresistivity curves from each row of buttons on the pads and flaps should show reasonable activity. RBSV shows which resistivity button set is displayed on the log (Button 1 is the leftmost button and 12 is the rightmost button).

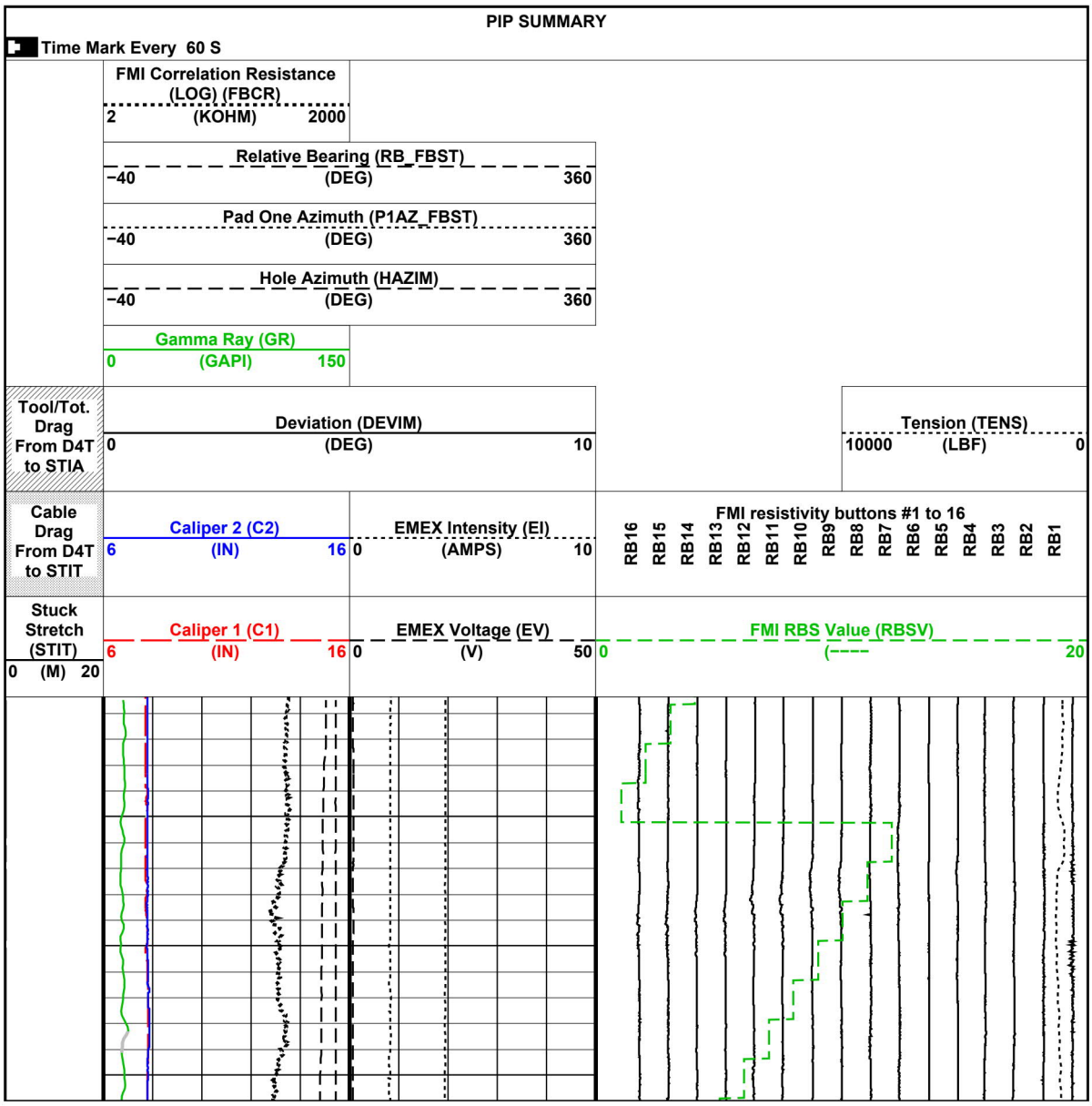

Figure 1. FMI standard format.

Response in known conditions

Caliper readings checked in casing should read the casing ID ± 0.25 in.

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FMI-HD

Overview

The FMI-HD* high-definition formation microimager delivers more-detailed microresistivity images than the original industry-standard FMI* fullbore formation microimager. Combining the field-proven FMI sonde with all-new electronics results in a step-improvement in operating range, reliability, and image quality.

Clearer images are now consistently possible in environments that were previously challenging, such as wells drilled with salt-saturated muds or reservoirs in excess of 1,000-ohm.m resistivity. Novel signal-processing methods ensure optimal measurement and increase the signal-to-noise ratio while reducing human dependencies. The new high-definition electronics reproduce the formation signal so faithfully that wells drilled with oil-base muds can be imaged under specific conditions.

As for the FMI tool, 192 measurement buttons produce a vertical and azimuthal resolution of 0.2 in [0.51 cm]. However, the visibility and interpretability of small features is improved under all conditions in the FMI-HD images. Much smaller features can be observed where there is resistivity contrast with the surrounding background. The high-definition FMI-HD electronics are more sensitive to fine contrasts than that of the original FMI tool and may image fluid-filled fractures less than 10 um in width. The size of features smaller than 0.2 in is estimated by quantifying the current flow to the electrode.

Calibration

The downhole sensor readings of FMI-HD tools are periodically compared with a known reference. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred. At the end of the survey, sensor readings are verified again in the after-survey calibration.

Caliper calibration for the FMI-HD tool is performed with two jig measurements. The jigs are usually calibration rings with a specified diameter. A zero measurement is taken using the smaller of the two rings. A plus measurement is taken using the larger ring. The calibration rings must be continuous, without notched or removed sections, not have any visible damage, and not be ovalized.

Specifications

Measurement Specifications	
Output	Formation images and dip
Logging speed	Image mode: 1,800 ft/h [549 m/h] Dipmeter mode: 3,600 ft/h [1,097 m/h]
Range of measurement	Sampling rate: 0.1 in [0.25 cm] Borehole coverage: 80% in 8-in [20.32-cm] borehole
Vertical resolution	Spatial resolution: 0.2 in [0.51 cm] Vertical resolution: 0.2 in [0.51 cm]
Accuracy	Caliper: ±0.2 in [±0.51 cm] Deviation: ±0.2° Azimuth: ±2°
Depth of investigation	1 in [2.54 cm]
Mud type or weight limitations	Water-base mud (maximum mud resistivity = 50 ohm.m) Oil-base mud under specific conditions†

†For oil-base mud applications, contact your Schlumberger representative.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	6.25 in [15.87 cm] 5.875 in [14.92 cm] in good hole conditions using a kit
Borehole size—max.	21 in [53.34 cm]
Outside diameter	5 in [12.70 cm]
Length	25.43 ft [7.75 m
Weight	443 lbm [201 kg]
Tension	12,000 lbf [53,380 N]
Compression	8,000 lbf [35,580 N

Tool quality control

Standard curves

The FMI-HD standard curves are listed in Table 1.

Table 1. FMI-HD Standard Curves

Output Mnemonic	Output Name
BCEG*xn*	Button resistivity profile corrected for gain and emitter-exciter (EMEX) intensity for a total of 16 arrays where *x* = *A* . . . *D* and *n* = 1 . . . 4
C1	Caliper 1
C2	Caliper 2
DEVI	Deviation
EI	EMEX intensity
EV	EMEX voltage
HAZI	Hole azimuth
P1NO	Pad 1 north
RB	Relative bearing
RBSV	FMI resistivity button set value

Operation

The FMI-HD tool is always run at the bottom of the toolstring and the sonde must be centered. In deviated wells, an AH-320 insulated flex joint should be run above the sonde to relieve eccentering forces caused by the weight of other tools above. A rubber-fin standoff is placed above the flex joint to control the amount of eccentering at the top of the tool. The standoff distance provided by the fins should be measured and is a required input parameter to derive the angular difference between the deviation of the borehole and the measured attitude of the sonde.

Smooth movement of the tool in the borehole is important but can be difficult to maintain in sticky hole conditions or when running the tool on drillpipe. Under these circumstances, a speed-corrected playback should be made to verify the data quality.

Formats

The format in Fig. 1 is used for quality control (QC).

- Track 1
  - The calipers should be checked inside the casing and validated against the expected casing ID. Calipers should repeat within ±0.25 in [±6.35 mm].
  - Pad pressure (PP) should be stable at the value set by the field engineer, except when crossing significant washouts or restrictions.
- Track 2
  - The log QC flags relate to the hardware status and should normally be all green, with the exception of the pad pressure, which may be yellow in a vertical well where the engineer has opted to run the log without pad pressure.
- Track 3
  - The first three flags provide a check of the normalized acceleration, magnetic field intensity, and magnetic field inclination computed from inclinometry compared with the expected values from the International Geomagnetic Reference Field. Red flags may indicate magnetization caused by proximity to the casing shoe or by the presence of excessive metal filings or debris in the well. Values entered for latitude and longitude should be verified as accurate to within 1 minute before suspecting a sensor failure.
  - The deviation heading reference unit (DHRU) temperatures flag should normally be green.
- Track 4
  - The button average (FBAVN) is unitless, representing the average current measured by all the buttons. The scale is normally set by the engineer based on local experience; values can range from –2,000 to 30,000 and should anticorrelate to the formation resistivity.
  - Direct current head voltage (DCHV) is the EMEX voltage delivered to the tool from surface. It should be nonzero when the tool is on and should vary slowly, increasing with formation resistivity when the tool is run in automatic EMEX regulation mode.
  - Regulated EMEX voltage (FCHV) should track DCHV but at a lower value.
  - EV and EI should be nonzero and should vary smoothly.
  - Computed phase compensation (PHICOMP) normally varies between 0 and –60° when logging in water-base mud. It correlates loosely with formation resistivity, with lower values of resistivity correlating to more negative values of PHICOMP. In very saline muds it is possible to have values of PHICOMP as low as –120°.
  - Acquisition phase shift (ACQPSHIFT) should normally follow PHICOMP with a depth delay of 16 ft [5 m].
  - Quality of phase compensation computation (QPCOCOMP) gives the number of arms for which the phase compensation is valid. The normal value is four.
- Track 5
  - The hardware flags identify potential pad and flap failures and should normally be all green.
- Track 6
  - The display of field-processed images may or may not be adequately color-scaled for viewing geologic features, depending on the environment. Preparation of the image for interpretation is normally done on a workstation after acquisition has finished.

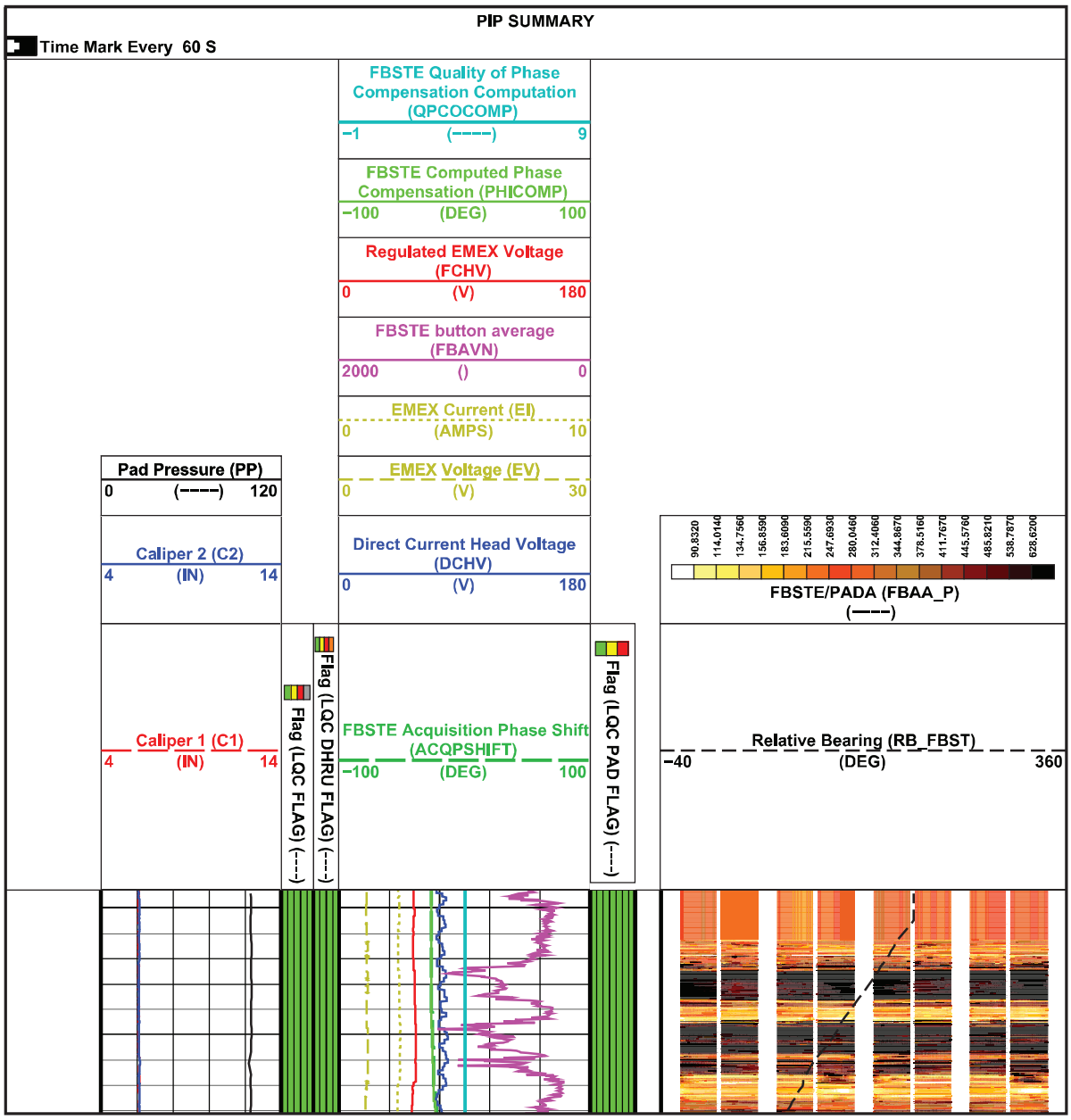

Figure 1. FMI-HD quality control format.

Response in known conditions

Caliper readings checked in casing should read the casing ID ± 0.25 in.

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UBI

Overview

The UBI* ultrasonic borehole imager produces high-resolution acoustic images of the wellbore in water-base or oil-base mud. The images are used to identify dipping beds, fractures, and other features intersecting the borehole. Critical information on borehole stability and breakouts can be derived from the accurate borehole cross section measured by the tool.

The UBI tool has a focused rotating transducer sensor subassembly—available in a variety of sizes—that emits ultrasonic pulses and measures the transit time and amplitude of the resulting echo. The subassembly size is selected to optimize the travel distance between the sensor and target borehole of the ultrasonic pulse in the borehole fluid. This keeps the target borehole within focus, reducing attenuation in heavy fluids and maintaining a good signal-to-noise ratio.

The UBI tool is relatively insensitive to eccentralization—up to 0.25 in [0.63 cm]—and provides clean images that are easy to interpret, even in highly deviated wells. Processing software further enhances UBI images by correcting amplitude and transit-time information for the effects of logging speed variations and tool eccentering and by applying noise filtering. The images are oriented with inclinometer data from the combinable GPIT* general purpose inclinometry tool and then enhanced by dynamic normalization for easy visual interpretation.

Specifications

Measurement Specifications	
Output	Borehole images, amplitude, and transit time in analog and digital imagery
Logging speed	425 to 2,125 ft/h [130 to 648 m/h] (depends on desired resolution)
Range of measurement	5.5 to 12.875 in [13.97 to 32.70 cm]
Vertical resolution	0.2 in [0.51 cm] at 500 kHz 0.4 in [1.02 cm] at 250 kHz 0.6 in [1.52 cm] at 250 kHz 1.0 in [2.54 cm] at 250 kHz Azimuthal sampling: 2.0° or 2.6°
Accuracy	Borehole radius: ±0.12 in [±3 mm] (absolute) Resolution†: 0.003 in [0.075 mm] at 500 kHz, 0.006 in [0.150 mm] at 250 kHz
Depth of investigation	Borehole wall
Mud type or weight limitations	High mud weights can cause significant signal attenuation Water-base mud weight: Above ~15.9 lbm/galUS [1.9 g/cm^3] Oil-base mud weight: Above ~11.6 lbm/galUS [1.4 g/cm^3]
Combinability	Bottom-only tool; combinable with most tools
Special applications	H_2S service

† In clear fluid

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	5⅞ in [13.97 cm]
Borehole size—max.	12⅞ in [32.70 cm]
Outside diameter	Without sub: 3.375 in [8.57 cm]
Length	19.75 ft [6.02 m]
Weight	377.6 lbm [171 kg] (with 7-in [17.78-cm] USRS-B sub)
Tension	40,000 lbf [177,930 N]
Compression	11,000 lbf [48,930 N]

Calibration

There is no calibration necessary for UBI service. Instead, a fluid properties log is recorded while running in the hole. This is used during logging up to convert measured transit times to radii.

Tool quality control

Standard curves

The UBI standard curves are listed in Table 1.

Table 1. UBI Standard Curves

Output Mnemonic	Output Name
AWAV	Average of amplitude
AWMN	Minimum of amplitude
AWMX	Maximum of amplitude
CALI	Caliper average
CS	Cable speed
ECCE	Eccentralization
GNMN	Minimum of UBI programmable gain amplitude (UPGA) in 6-in [15.24-cm] interval
GNMX	Maximum of UPGA in 6-in interval
HRTT	Transit-time index histogram
TTAV	Transit-time average
TTMN	Transit-time minimum
TTMX	Transit-time maximum
UFLG	UBI noise detection flags
UPGA	UBI programmable gain amplitude

Operation

The UBI tool must be run centered and combined with a GPIT tool for orienting the UBI log formation features.

The UBI tool can be run in one or more of several modes (Table 2).

Typically, a low-resolution-speed pass is recorded first, and then high-resolution passes are recorded over zones of interest.

The transducer requires about 4 MPa to start operating correctly but, once pressurized, it operates correctly down to about 1 MPa of pressure. As a result, it may be necessary in shallow wells to run in near the bottom of the well and then return to surface to repeat the fluid properties measurement (FPM).

Table 2. UBI Modes

Mode	Window	Points per Revolution	Frequency, kHz	Window Length, us	Window Control
OH1	Sliding	140	250	164	Manual or auto
OH3	Sliding	180	250	121	Manual or auto
OH5	Sliding	140	500	116	Manual or auto
OH7	Sliding	180	500	87	Manual or auto
OH9	Sliding	140 + raw waveform	250	121	Manual or auto
OHA	Sliding	140 + raw waveform	500	87	Manual or auto
OHB	Fixed	140 + raw waveform	250	Maximum 121	Window beginning for peak location (WINB) or window end for peak location (WINE)
OHC	Fixed	140 + raw waveform	500	Maximum 87	WINB or WINE
OHD	Fixed	180	250	Maximum 121	WINB or WINE
OHF	Fixed	180	500	Maximum 87	WINB or WINE

Notes:

Sliding window modes are recommended for open hole.

Fixed window modes are recommended for cased hole.

Lower frequency modes are recommended for more attenuative fluids.

Where significant breakouts or washed-out holes are expected, a mode with 140 points per revolution without raw waveforms should be used because these modes have the widest sliding detection windows.

Raw waveform modes are available for troubleshooting but should not be used generally because such modes limit the dynamic range for sliding window modes and create bigger DLIS files.

Formats

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

- Track 1
  - HRTT corresponds to the position of the peak detection window. Most echoes should be inside the window. Measured transit times should be well within the peak detection window in a good hole. The peak location window should not lock up on the second echo, which would give erroneously large transit time and radii measurements. In washed-out sections of the hole, some transit times may not be measurable because they are past the end of the peak location window.
- Track 2
  - TTMN, TTMX, and TTAV should not be artificially limited except in a bad hole. A typical problem is early-time noise, which causes low TTMN spikes in places where TTMX is limited by the peak location window.
- Track 3
  - AWMN, AWMX, and AWAV have no specific tolerances.
- Track 4
  - UFLG highlights problems with noise detection.
- Track 5
  - GNMN should be in the range of –6 dB to +10 dB. It may exceed 10 dB in attenuative fluids, rough borehole, or damaged casing. There is no specific tolerance for GNMX.

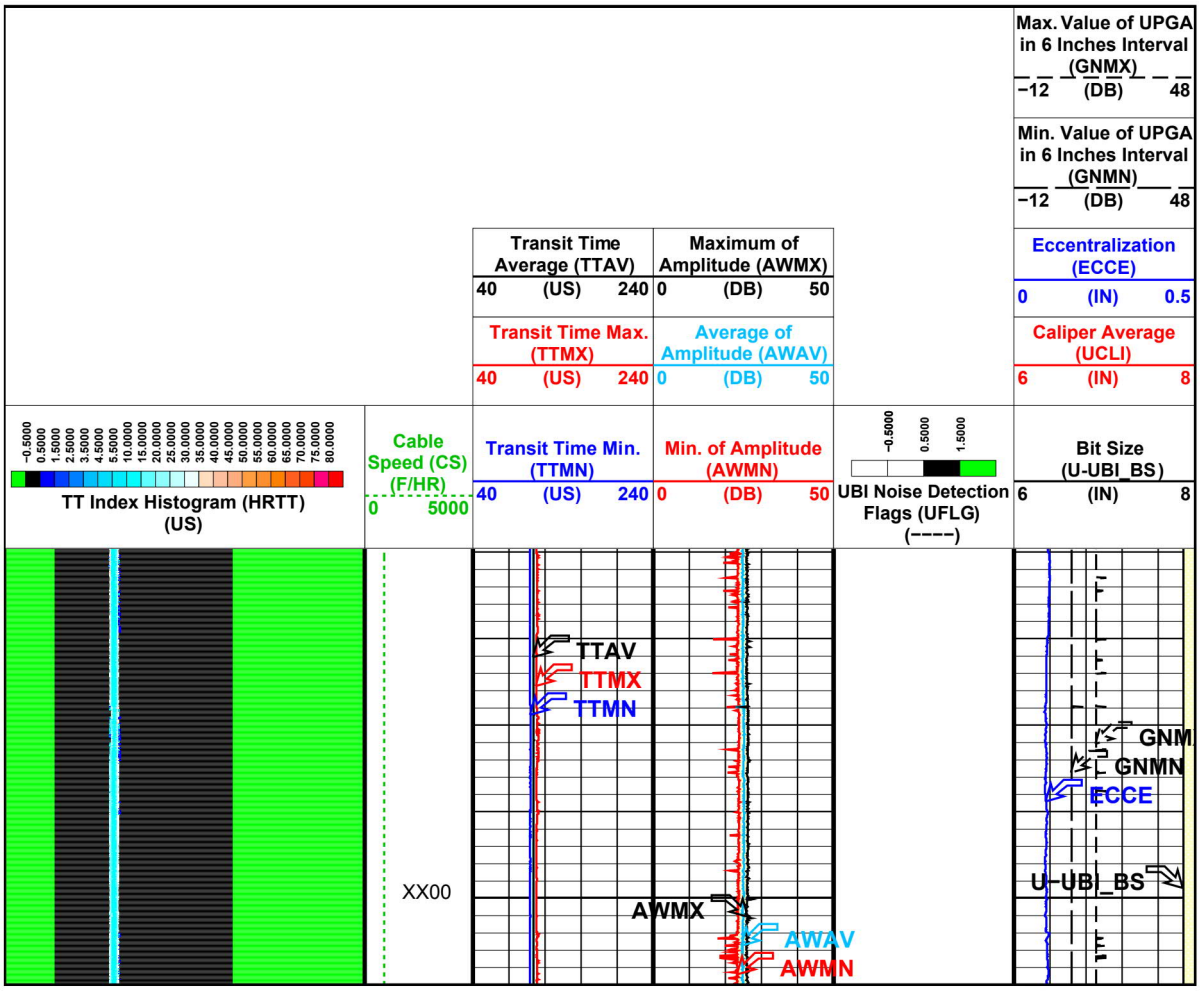

Figure 1. UBI quality control format.

Radial plots, showing all the radii measurements for a certain depth, can be computed from a list of required depths and included in the final log (Fig. 2).

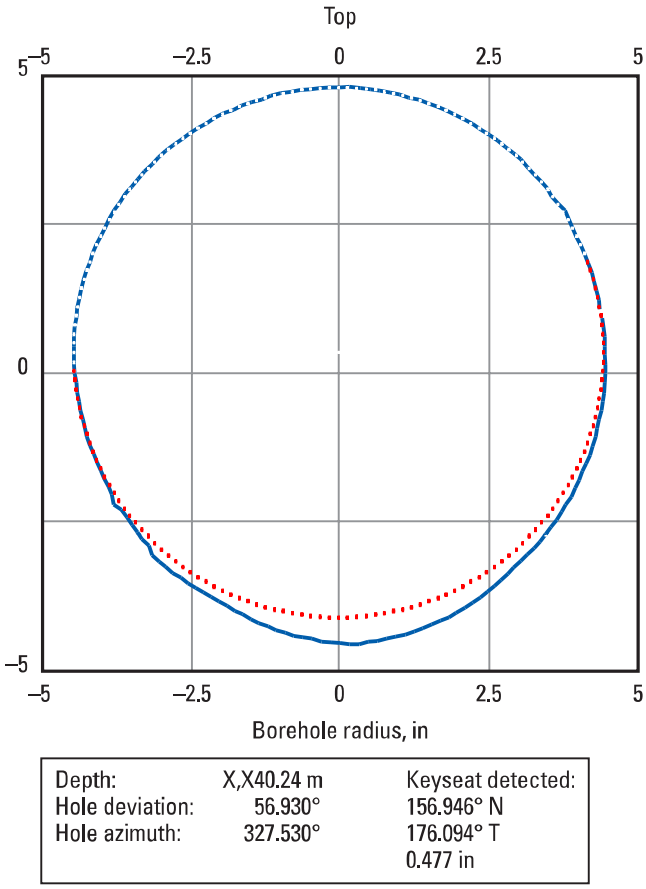

Figure 2. UBI hole shape view.

Response in known conditions

The FPM of fluid acoustic slowness (HFVL) should be consistent with the expected values based on the borehole fluid (Table 3).

Table 3. Typical HFVL Response in Known Conditions

Fluid	HFVL, 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 should be close to what is expected from caliper logs in open hole and very close (±0.07 in [±2 mm]) to the casing ID in noncorroded casing.

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OBMI

Overview

The OBMI* oil-base microimager tool extends microresistivity imaging to the environment of nonconductive, invert-emulsion mud systems. The increasing use of oil- and synthetic-base mud systems to limit drilling risks and improve efficiency poses many challenges for formation imaging. Even a thin film of nonconductive mud is essentially an opaque curtain, preventing conventional microresistivity imagers from measuring the formation. The presence of nonconductive mudcake or mud filtrate further complicates the situation. The OBMI tool meets these challenges by integrating unique technology with simple resistivity logging principles to produce an image that enables virtual visualization of the reservoir.

The OBMI tool provides direct, high-resolution measurement of the flushed zone resistivity R_{xo}. The short-normal resistivity principle employed is inherently quantitative and does not require calibration with another log. Petrophysicists frequently use the OBMI R_{xo} measurement to discriminate sand and shale beds as thin as 1.2 in [3.05 cm]. Geologists use OBMI images to recognize bedding and other sedimentary features as small as 0.4 in [1.02 cm], which is the tool's measurement aperture.

The OBMI2* integrated dual oil-base microimagers tool uses two OBMI sondes at a 45° offset to double the hole coverage.

Calibration

The downhole sensor readings of OBMI tools are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration.

Caliper calibration for an OBMI tool is performed with two jig measurements. The jigs are usually calibration rings with a specified diameter. A zero measurement is taken using the smaller of the two rings. A plus measurement is taken using the larger ring. The calibration rings must be continuous, without notched or removed sections, not have any visible damage, and not be ovalized.

Specifications

Measurement Specifications	
Output	High-resolution, oriented formation images, dual-axis caliper
Logging speed	3,600 ft/h [1,097 m/h]
Range of measurement	32% coverage in 8-in [20.32-cm] borehole Resistivity range: 0.2 to 10,000 ohm.m
Vertical resolution	0.4-in [1.02-cm] nominal image resolution 1.2-in [3.05-cm] petrophysical resolution
Accuracy	±20% R_{xo} measurement
Depth of investigation	3.5 in [8.89 cm]
Mud type or weight limitations	Operates in any oil-, diesel-, or synthetic-base mud
Combinability	Top and bottom combinable
Special applications	Wireline or TLC* tough logging conditions system

Mechanical Specifications	
Temperature rating	320 degF [160 degC] High-temperature, high-pressure (HPHT) version: 350 degF [177 degC]†
Pressure rating	20,000 psi [138 MPa] HPHT version: 25,000 psi [173 MPa]†
Borehole size—min.	Standard: 7.5 in [19.05 cm] Slim: 6 in [15.24 cm] Caliper: 6.5 in [16.51 cm]
Borehole size—max.	16 in [40.64 cm] Caliper: 17.5 in [44.45 cm]
Outside diameter	Standard: 5.75 in [14.60 cm] Slim: 5.25 in [13.33 cm]
Length	17 ft [5.18 m]
Weight	310 lbm [137 kg]
Tension	50,000 lbf [222,410 N]
Compression	Standard: 10,000 lbf [44,482 N] Slim: 8,000 lbf [35,590 N]

† Limited availability

Tool quality control

Standard curves

The OBMI standard curves are listed in Table 1.

Table 1. OBMI Standard Curves

Output Mnemonic	Output Name
C1_OBMT	Caliper 1
C2_OBMT	Caliper 2
DEVIM	Deviation
FCAZ	High-resolution z-axis accelerometer
IMP_IMG_OBMT	OBMI impedance image with one track per pad
LQC_IMB_OBMT	OBMI log quality control (LQC) image with one track per button (20 tracks total)
OBR*x*3	Pad *x* button 3 resistivity
ONA	Resistivity image
OZ*x*	Pad *x* impedance
PP_OBMT	Pad pressure
RB_OBMT	Relative bearing

Operation

The OBMI tool must be positioned such that the pad portion of the tool stays centered. The OBMI tool should be run on the bottom of the toolstring when possible.

Tool rotation must be kept below one turn per 30 ft [9.1 m].

The quality flags may trigger in washouts, fractures, rugose boreholes, and similar conditions. It is uncommon to have a totally green LQC image.

Formats

The six-track format in Fig. 1 is used mainly as a quality control.

- Depth track
  - Also displayed is the acceleration curve, which is the main curve for detecting sticking, as indicated by intermittent flatlining.
- Track 1
  - Pad pressure, calipers, deviation, gamma ray, and relative bearing are displayed.
- Track 2
  - The impedance image is shown with one track per pad in the following colors: green = okay, yellow = low pad impedance in the range of 10,000 to 50,000 ohm, orange = sharp impedance changes that may indicate high rugosity, blue = very low pad impedance in the range of 0 to 10,000 ohm, as in the case of conductive mud, and red = high standoff or high true resistivity R_t.
- Track 3
  - The impedance of each pad is shown. If pad contact is good, all impedances have a baseline value in the range of 5,000 to 50,000 ohm, depending on the mud composition and the presence or absence of mudcake. When there is undesirable standoff, the impedance for that pad tends to be greater than 200,000 ohm.
- Track 4
  - Each of the 20 buttons generates a colored stripe on the LQC image: green = okay, yellow = some pad liftoff, red = pad liftoff, and blue = saturation.
- Track 5
  - There should be a general correlation between the four resistivities measured by the center button of each pad. Because these resistivity values are quantitative, there should also be a reasonable correlation with other induction measurements, allowing for differences in the depth of investigation.
- Track 6
  - The four-pad image is not oriented.

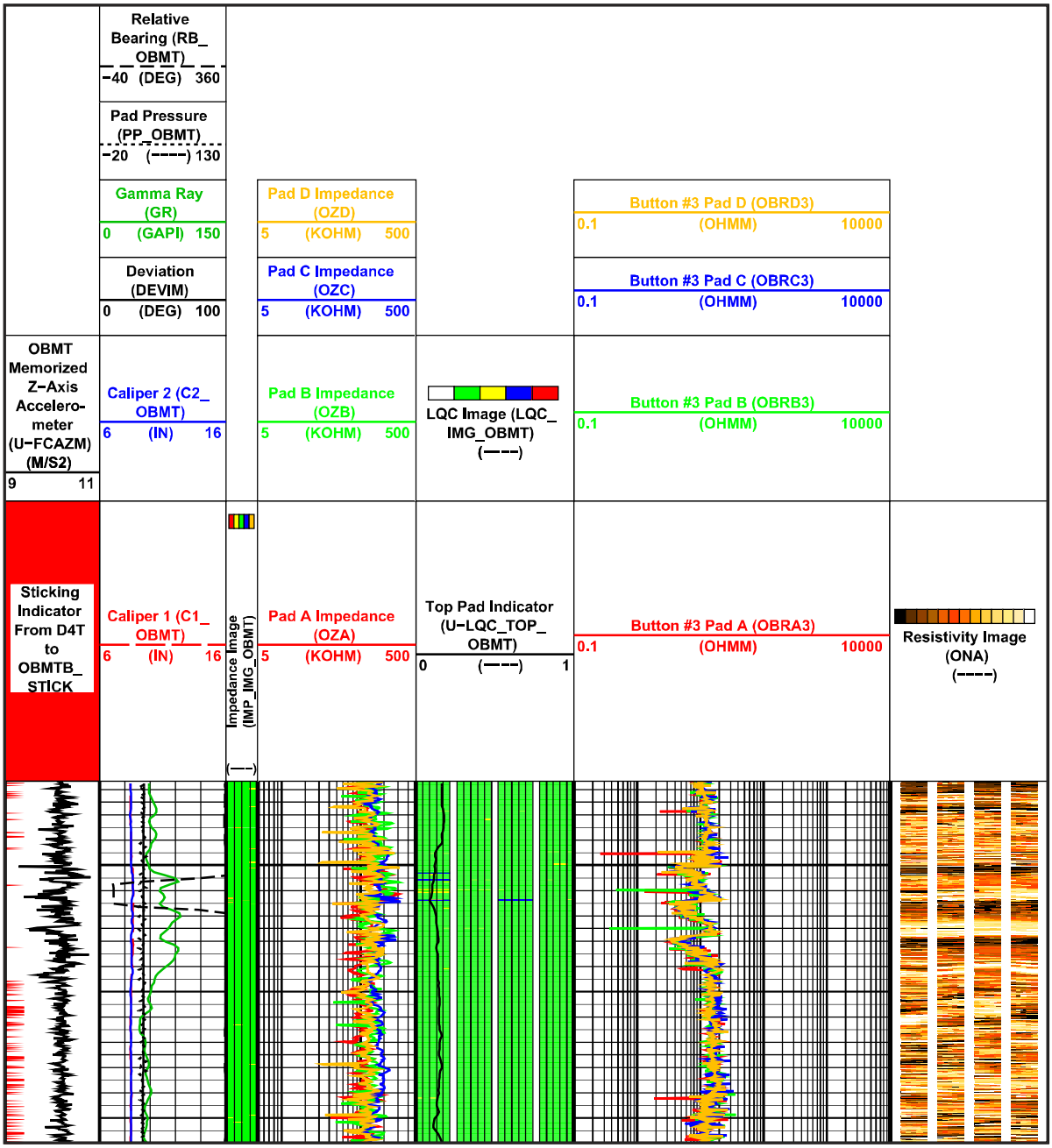

Figure 1. OBMI standard format.

Response in known conditions

Caliper readings checked in casing should read the casing ID ± 0.2 in [0.51 cm].

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GPIT

Overview

The GPIT* general purpose inclinometry tool provides inclinometer measurements. Tool orientation is defined by three parameters: tool deviation, tool azimuth, and relative bearing. The GPIT tool uses both a three-axis inclinometer and a three-axis magnetometer to make measurements for determining these parameters.

The basic principle of downhole inclinometer measurements is to accurately define the tool system axis with respect to the Earth's gravity (**G**) and magnetic field (**F**). Because both vectors are well defined within the Earth system, the relation of the tool to the Earth system can be established. The magnetometer determines $\mathbf{F_x}$, $\mathbf{F_y}$, and $\mathbf{F_z}$, and the inclinometer determines $\mathbf{A_x}$, $\mathbf{A_y}$, and $\mathbf{A_z}$ for the acceleration resulting from **G**. The acquisition system computes deviation, azimuth, and relative bearing from these values.

Specifications

Measurement Specifications	
Logging speed	3,600 ft/h [1,097 m/h]
Range of measurement	0 to 360°
Vertical resolution	6 in [15.24 cm]
Accuracy	Azimuth: ±2°†
	Deviation: ±0.2°
	Relative bearing: ±2°‡
	Pad 1 azimuth: ±2°§

†For deviation > 5° and magnetic inclination < 80°
‡For deviation > 5°
§For deviation < 80° and magnetic inclination < 80°

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	4⅝ in [11.75 cm]
Borehole size—max.	No limit
Outside diameter	3.375 in [8.57 cm]
Length	4 ft [1.22 m]
Weight	55 lbm [25 kg]
Tension	50,000 lbf [222,410 N]
Compression	16,700 lbf [74,280 N]

Calibration

The GPIT tool cannot be calibrated in the field; only a validation of the factory calibration can be done annually.

In the field, a postacquisition check and environmental correction is performed for each job. GPIT operation is verified by performing two roll tests while the tool is aligned to two positions that are approximately 90° apart. This quality check of the inclinometry data uses a combination of tool rotation and the International Geomagnetic Reference Field (IGRF). Before logging, the latitude and longitude of the well location (accurate to within ±0.01 deg) are entered into the acquisition system for determining expected values of the magnetic field normalized intensity and inclination from the IGRF.

The annual check of the validity of the factory calibration data is done only after demagnetizating the tool with a demagnetization coil and should be conducted in a magnetically quiet environment. Any shift in the factory calibration necessitates return to the manufacturer for recalibration.

The SE-92 equipment used for the annual check consists of a housing into which the GPIT tool is placed for positioning in different orientations by making three rotations around the "vertical," "horizontal," and tool axes. The equipment should rest on a firm, nonmagnetic surface (e.g., hard concrete that is not steel reinforced). The Earth's natural magnetic field around the stand must be constant and homogeneous so that the measurement changes reflect the orientation changes of the GPIT tool and not local and erratic magnetic disturbances. The magnetic field should be uniform to approximately ±50 nT within the 70 ft^3 [2 m^3] around the SE-92 equipment.

No metallic bodies, however small, should be present around the stand within a radius of at least 30 ft [9 m]. The acquisition unit for operating the GPIT tool should be kept 200 ft [60 m] away. Within that radius, metallic objects render any measurement valueless.

Tool quality control

Standard curves

Standard curves for the GPIT tool are listed in Table 1.

Table 1. GPIT Standard Curves

Output Mnemonic	Output Name
ANOR	Acceleration normalized
AX	X-axis accelerometer
AY	Y-axis accelerometer
AZ	Z-axis accelerometer
FINC	Magnetic field inclination
FNOR	Magnetic field normalized
FX	X-axis magnetometer
FY	Y-axis magnetometer
FZ	Z-axis magnetometer
HAZI	Hole azimuth nonmemorized
HAZIM	Hole azimuth memorized
P1AZ	Pad 1 azimuth
RB	Relative bearing
SDEV	Hole deviation nonmemorized
SDEVM	Hole deviation memorized

Operation

When the GPIT tool is used in an open wellbore, the tools above and below it must have nonmagnetic housings. In cased hole, the tool can be used only for deviation and relative-bearing measurements.

Formats

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

- Track 1
  - All the voltages should be stable.
- Track 2
  - None of the data from the accelerometers should be erratic.
  - In vertical wells, $\mathbf{A_x}$ and $\mathbf{A_y}$ are close to zero and $\mathbf{A_z}$ reads 9.81 m/s^2.
  - An erratic $\mathbf{A_z}$ measurement can indicate irregular tool motion.
- Track 3
  - None of the data from the magnetometers should be erratic.
- Track 4
  - FNOR should match the location's magnetic field inclination (MFIN, from chart) within ±10%.
  - ANOR should read 9.81 m/s^2 ± 0.1 m/s^2.

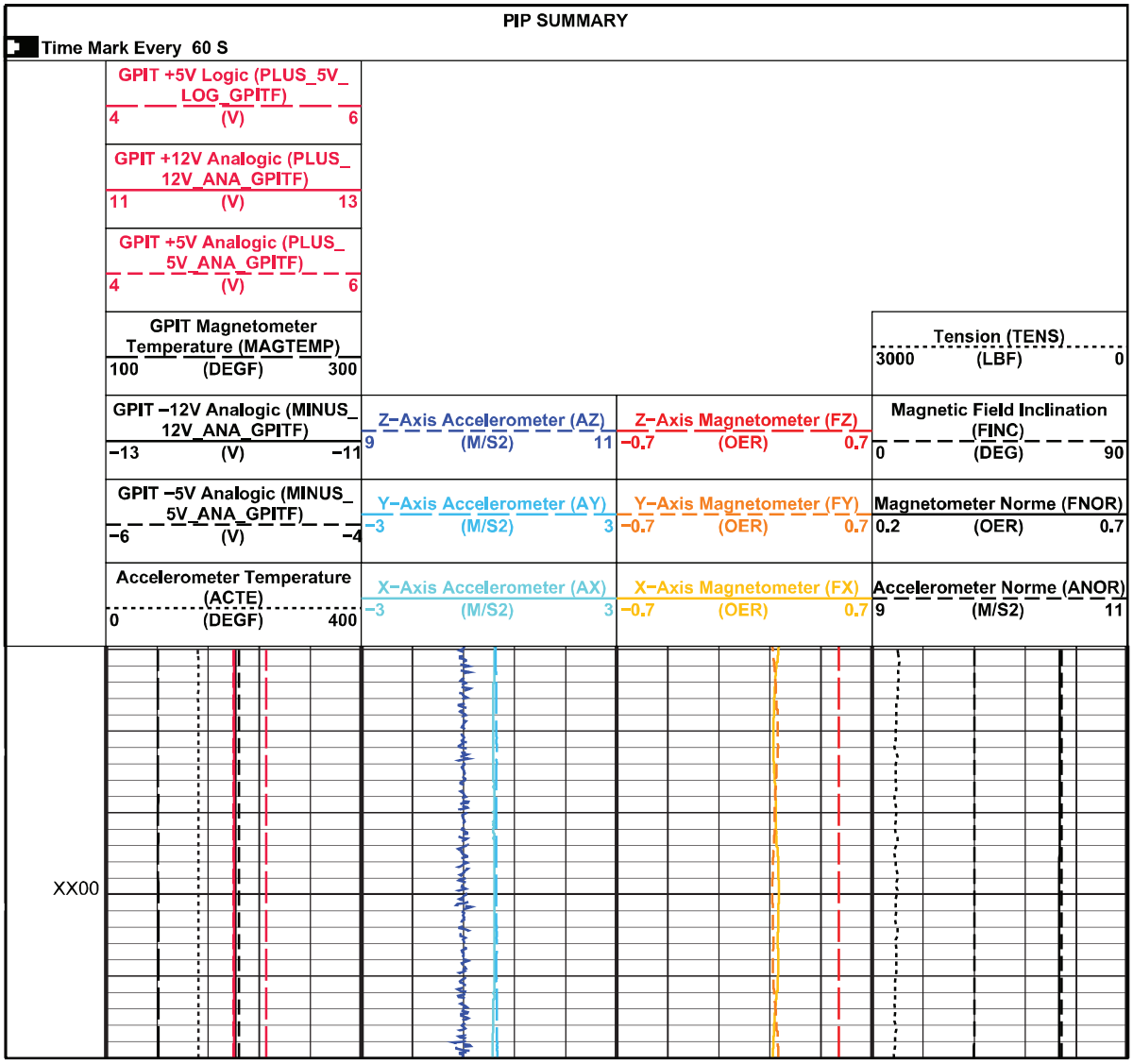

Figure 1. GPIT standard format.

Response in known conditions

The measurements should be consistent, as follows:

- SDEVM should match the excepted well deviation and should not be erratic.
- RB should not be erratic, except if the deviation is less than 2°.
- HAZIM should match the expected hole azimuth. This measurement may appear erratic if the deviation is less than 2°.
- SDEVM and HAZIM are used in making directional survey reports.
- Tool rotation should be less than one turn in 30 ft [9 m].

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CSI

Overview

The CSI* combinable seismic imager is a three-axis borehole seismic acquisition tool for both open- and cased hole applications. The design of the CSI tool physically isolates the sensor components from the heavy tool body during seismic acquisition. The small size and low mass of the sensor module and the strong anchoring force of the tool ensure optimum acoustic coupling, even in soft formations, which results in high-quality recorded seismic data. The CSI tool is self-combinable using stiff or flexible interconnects, and it is also fully combinable with other logging tools. Deployment can be on wireline, TLC* tough logging conditions system, or wireline tractor.

Calibration

Schlumberger locations that conduct borehole seismic operations use an airgun simulator to check downhole seismic tools. Use of the airgun simulator is mandatory for a complete system check of all borehole seismic equipment before every job.

Specifications

Measurement Specifications	
Output	Seismic waveform produced by acoustic reflections from bed boundaries
Logging speed	Stationary
	Seismic waveform recording: 1-, 2-, or 4-ms output sampling rate
Array capability	Up to four tools
Sensor package	
Length	24.4 in [61.98 cm]
Weight	19.9 lbm [9 kg]
Sensor	Geophone accelerometer (GAC-A)
Sensitivity	>0.5 V/g ± 5%
Sensor natural frequency	25 Hz
	Flat bandwidth in acceleration: 2 to 200 Hz
Dynamic range	90 dB
Distortion	<–60 dB
Digitization	16 bit
Combinability	Combinable with most tools†
Special applications	Conveyance on wireline, TLC system, or tractor

† Some tool connections require a switch. Contact your Schlumberger representative for more information.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	4.9 in [12.45 cm]
Borehole size—max.	19 in [48.26 cm]
	With extension: 22 in [55.88 cm]
Outside diameter	4.625 in [11.75 cm]
	Without standoff: 4 in [10.16 cm]
Length	17.8 ft [5.42 m]
Weight	271 lbm [123 kg]
Tension	50,000 lbf [222,240 N]
Compression	4,400 lbf [19,570 N]
Anchoring force	630 lbf [2,800 N] in 5-in [12.70-cm] hole
	719 lbf [3,200 N] in 10-in [25.40-cm] hole
	1,124 lbf [5,000 N] in 19-in [28.26-cm] hole
Sensor package coupling force	240 lbf [1,067 N]
Coupling force/sensor weight ratio	10:1

Tool quality control

Standard curves

The standard curves of the CSI tool are listed in Table 1.

Table 1. CSI Standard Curves

Output Mnemonic	Output Name
GR	Gamma ray
PLOT	Seismic plot
PP	Peak to peak
SRD	Seismic reference datum
SVAI	Shaker output for tool descent monitoring
TT	Transit time
VSP	Vertical seismic profile

Operation

The tool must be anchored when acquiring station seismic data. The anchoring force should be adjusted to borehole conditions.

Formats

The format in Fig. 1 is used mainly for both acquisition and quality control. Acquisition from the three-axis sensor in the tool is represented as DX1, DY1, and DZ1. The following points address several important attributes of the format for quality control.

- The number of shots per stack must be sufficient for the requested operation (checkshots: minimum three shots required; VSP: minimum five shots required).
- Clean breaks for the waves must be observed. A flat baseline before break shows that the waves are free of noise.
- No saturation should be observed on the PP values. Saturation usually occurs at about 60,000 bits.
- The repeatability of the waveform shapes must be confirmed with the previous shots. Waveforms should repeat with linearly decreasing transit times as depth gets shallower.
- Waveforms should be free of tube waves.
- The break times should be constant between shots.

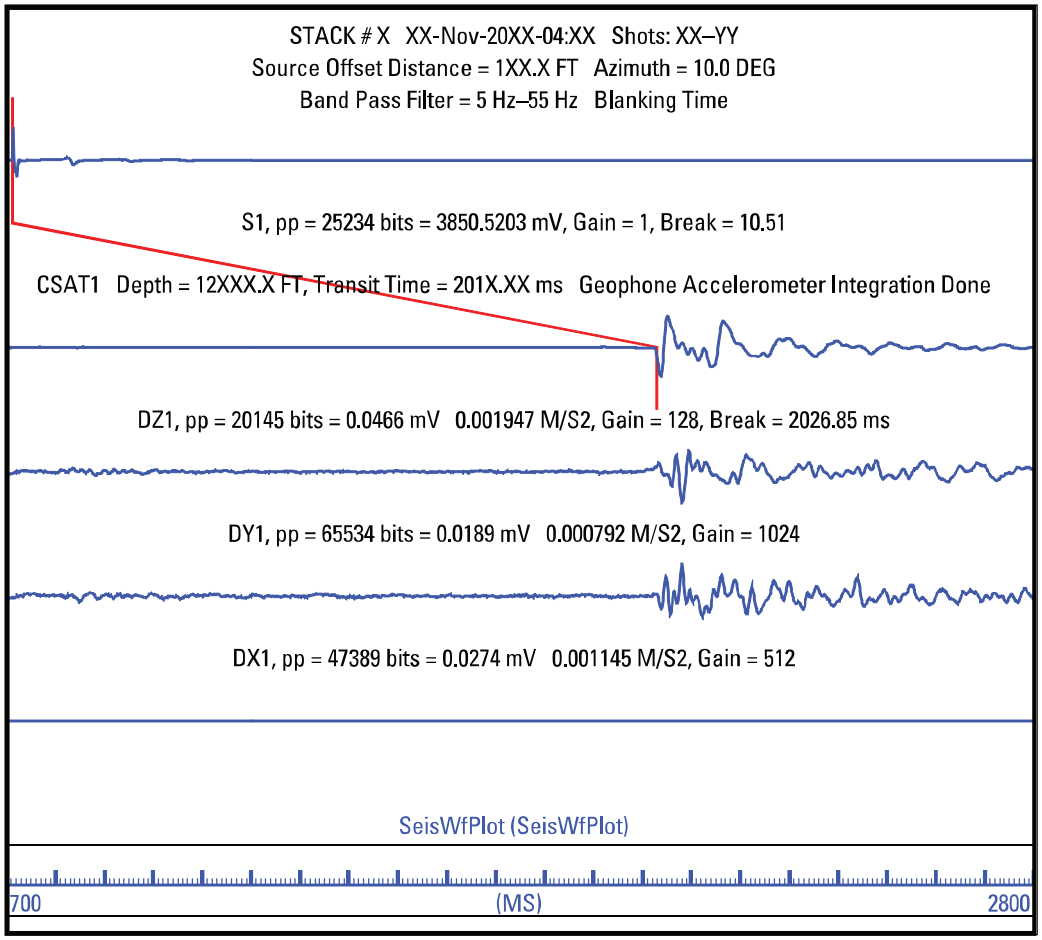

Figure 1. CSI seismic quality control log.

The crossplot format in Fig. 2 is used mainly for quality control of the transit times.

The transit times are shown in milliseconds per unit depth for the stacks acquired. In this important quality control crossplot, a smooth slope along the depth of the well is expected. Any discrepancy must be investigated.

Response in known conditions

- The transit times for levels recorded while running in the well must match the transit times for levels recorded while pulling out of the well. Three checkshots are recommended while descending, with the shots repeated at the same depths, adjusted for offset, when pulling out of the hole. The repeated records should agree within 2 ms.
- Integrated transit times should be correlative with those observed in sonic logs.

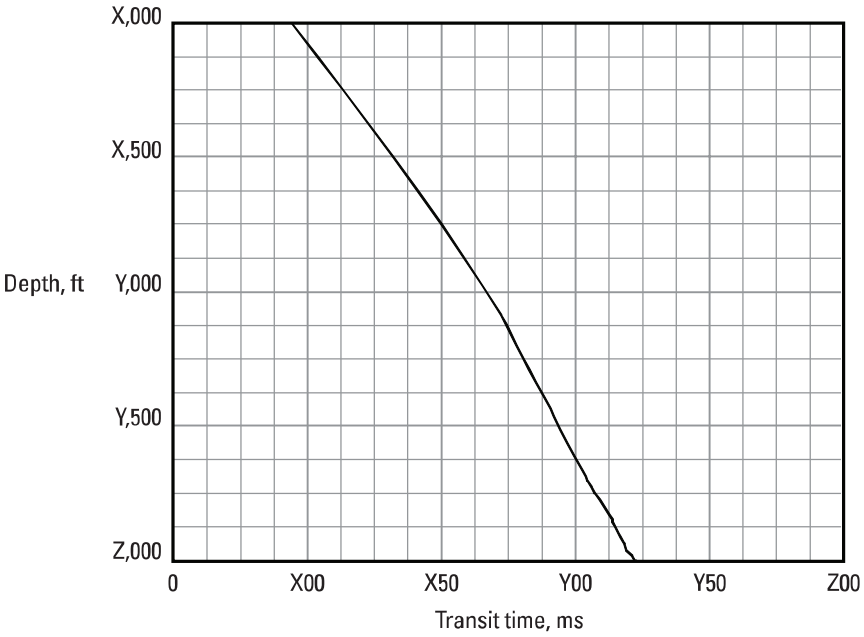

Figure 2. CSI seismic transit times quality control crossplot.

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VSI

Overview

The VSI* versatile seismic imager is a downhole component of the Q-Borehole* integrated system for optimized borehole seismic services during wireline operations and while drilling. It uses three-axis Q-Technology* broadband-sensor seismic hardware and software and wireline telemetry for efficient data delivery from the borehole to the surface. Each sensor package delivers high-fidelity wave fields through the use of three-axis geophone accelerometers, which are acoustically isolated from the main body of the tool. The number of sensors, intersensor spacing, connection type (either stiff or flexible), and tool diameter are field configurable to ensure the maximum array versatility. The VSI design focus on data fidelity and quick adaptation to changing survey needs avoids the compromise in data quality inherent to many borehole seismic array designs. The result is sharper, more accurate images and reduced operating logistics, which are fundamental elements for achieving complex surveys in a cost-effective manner and with timely delivery of the answer products.

Calibration

Schlumberger locations that conduct borehole seismic operations use an airgun simulator to check downhole seismic tools. Use of the airgun simulator is mandatory for a complete system check of all borehole seismic equipment before every job.

Specifications

Measurement Specifications	
Output	Seismic waveform produced by acoustic reflections from bed boundaries
Logging speed	Stationary Seismic waveform recording: 1-, 2-, or 4-ms output sampling rate Optional: Continuous data acquisition with 0.50-ms sampling interval
Array capability	VSIT-C and VSIT-P: 20 shuttles VSIT-G: 40 shuttles
Sensor package	
Length	11.4 in [28.96 cm]
Weight	6.4 lbm [2.9 kg]
Sensor	Geophone accelerometer (GAC-D)
Sensitivity	>0.5 V/g ± 5%
Sensor natural frequency	25 Hz Flat bandwidth in acceleration: 2 to 200 Hz
Dynamic range	>105 dB at 36-dB gain
Distortion	<–90 dB
Digitization	24-bit analog-to-digital converter
Combinability	Bottom-only combinable
Special applications	Conveyance on wireline, TLC* tough logging conditions system, pulled by tractor, or through drillpipe

Mechanical Specifications	
Temperature rating	347 degF [175 degC]
Pressure rating	VSIT-C: 20,000 psi [138 MPa] VSIT-P: 25,000 psi [172 MPa] VSIT-G: 25,000 psi [172 MPa]
Borehole size—min.	3 in [7.62 cm]
Borehole size—max.	22 in [55.88 cm]
Outside diameter	VSIT-C and VSIT-P: 2.5 in [6.25 cm] VSIT-G: 2.6 in [6.42 cm]
Length	VSIT-C and VSIT-P: Max. 20 shuttles at 66-ft [20-m] sensor spacing VSIT-G: Max. 36 shuttles at 100-ft [30-m] sensor spacing above 302 degF [150 degC] Max. 40 shuttles at 100-ft sensor spacing below 302 degF Max. 40 shuttles at 50-ft [15-m] sensor spacing to 347 degF [175 degC]
Weight	VSIT-G (40 shuttles at 100-ft sensor spacing): Weight in air: 5,013 lbm [2,274 kg] Weight in freshwater: 4,076 lbm [1,849 kg]
Tension	18,000 lbf [80,070 N]
Compression	Standard: 5,000 lbf [22,240 N] With stiffener: 10,000 lbf [44,480 N]
Anchoring force	246 lbf [1,094 N] in 3-in [7.62-cm] hole 214 lbf [952 N] in 6-in [15.24-cm] hole 255 lbf [1,134 N] in 12¼-in [31.75-cm] hole 160 lbf [711 N] in 17-in [43.18-cm] hole
Sensor package coupling force	64 lbf [285 N]
Coupling force/ sensor weight ratio	10:1

Tool quality control

Standard curves

The standard curves of the VSI tool are listed in Table 1.

Table 1. VSI Standard Curves

Output Mnemonic	Output Name
GR	Gamma ray
PP	Peak-to-peak amplitude
TT	Transit time

Operation

The optimum arm type must be selected prior to the survey, taking into account the borehole size range. VSI anchoring force is dependent on arm type and borehole diameter and cannot be changed when the VSI tool is downhole.

Formats

The VSI plots are used mainly as a quality control.

- Peak-to-peak amplitude plot

  The peak-to-peak amplitude plot (Fig. 1) for each of the three axes of each of the shuttles show the PP amplitudes in millivolts (mV) for all shots. A consistent low value of PP could indicate a weak source if all shuttles show the same behavior.

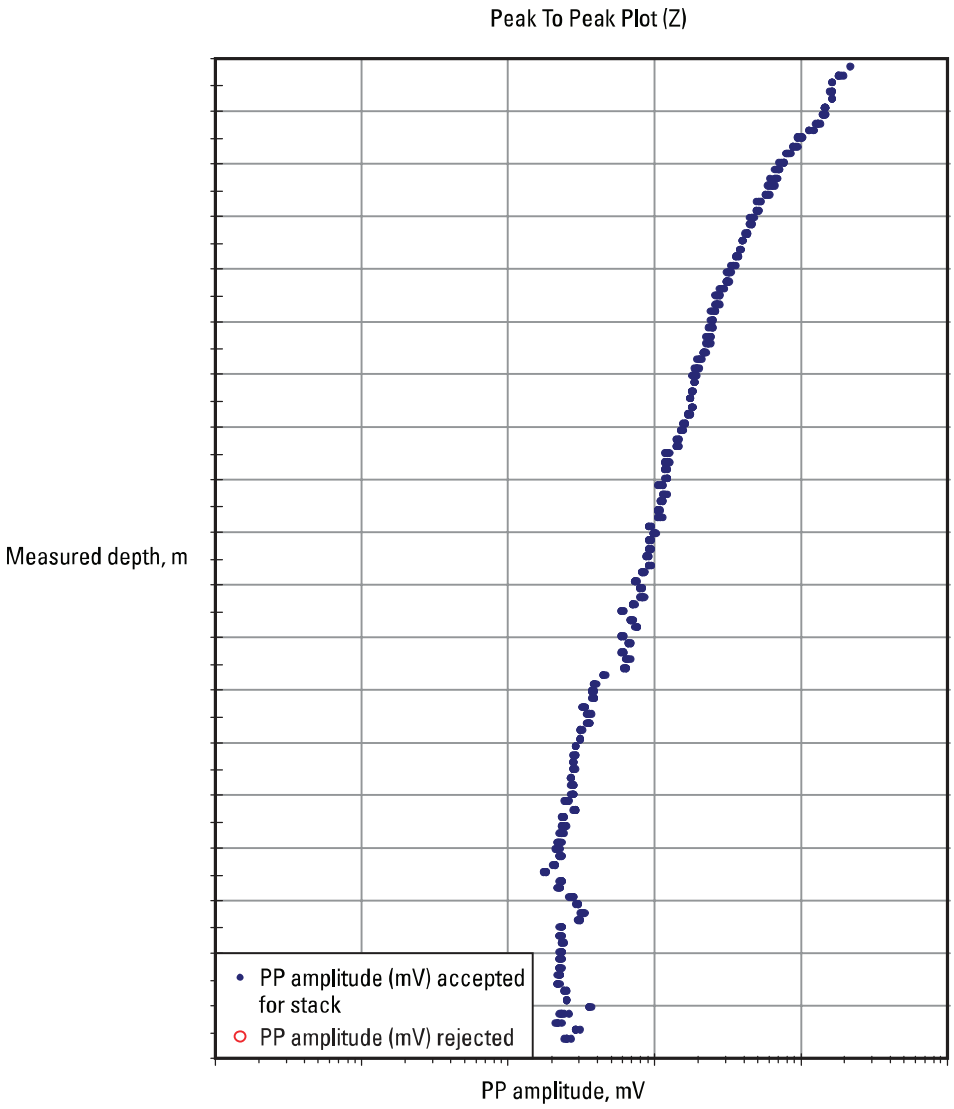

Figure 1. VSI peak-to-peak QC plot.

- Amplitude QC

The amplitude QC plot (Fig. 2) shows the peak-to-peak amplitudes of the raw shots in bits and the gain used for each shot. The bit ranges are shown as exponents of 2, with a range of 0 to 24 (i.e., 2^1 to 2^{24}). The amplitudes should be shown for each axis and for each shuttle separately.

The values should be between 18 and 22, depending on the offset and source strength. A value of 24 shows data saturation and a value less than 19 means that the dynamic range of the tool is not used. The acquisition gains are changed regularly from the software parameters to keep the range between 18 and 22.

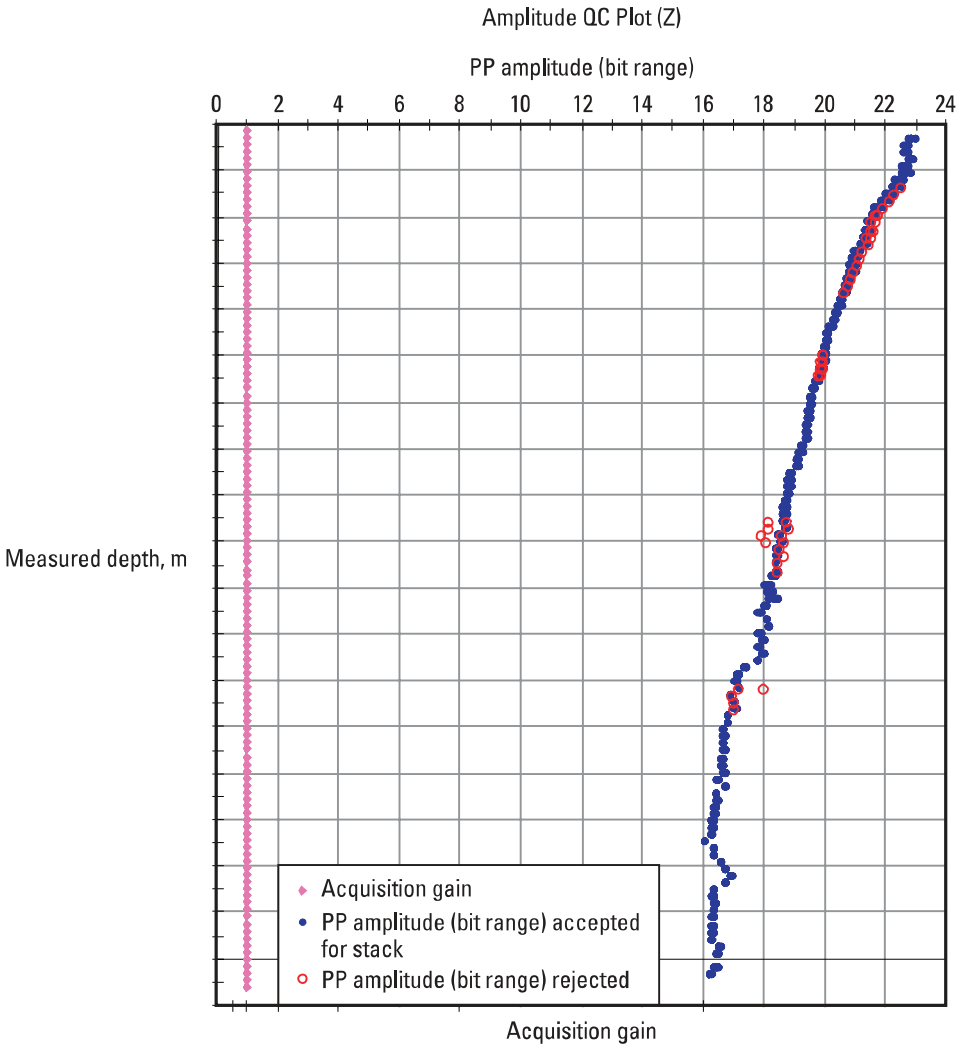

Figure 2. VSI amplitude QC plot.

- Surface sensor QC

  The surface sensor QC plot (Fig. 3) shows the shot number versus surface sensor break times for all recorded shots. Break times should be equal. In addition to break time, the near-field hydrophone (NFH) signature should be monitored for pressure and depth consistency.

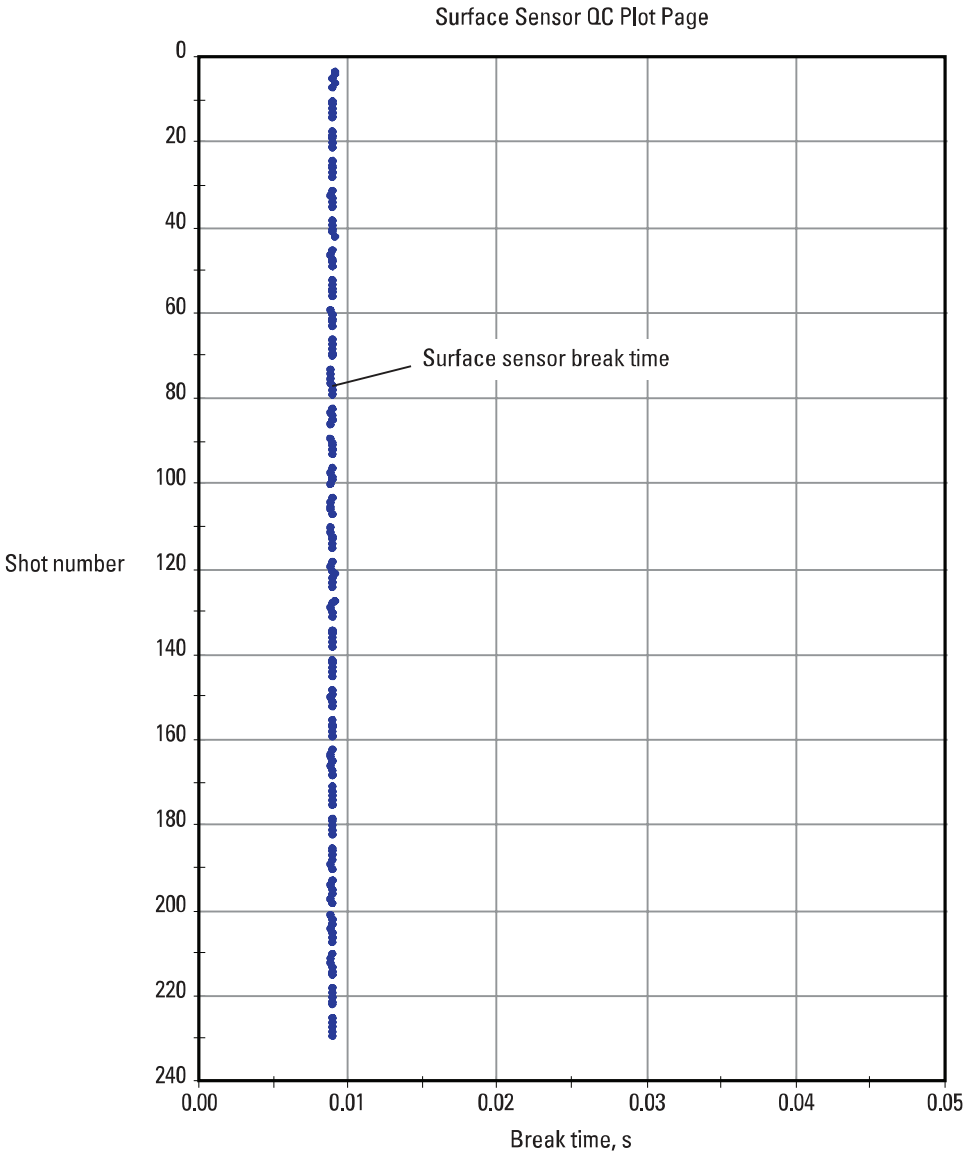

Figure 3. VSI surface sensor QC plot.

- Surface amplitude QC

  The amplitude QC plot (Fig. 4) shows the peak-to-peak amplitudes and gain used for each shot along with the acquisition gain for the surface sensor. The PP amplitude should have a stable value during operation.

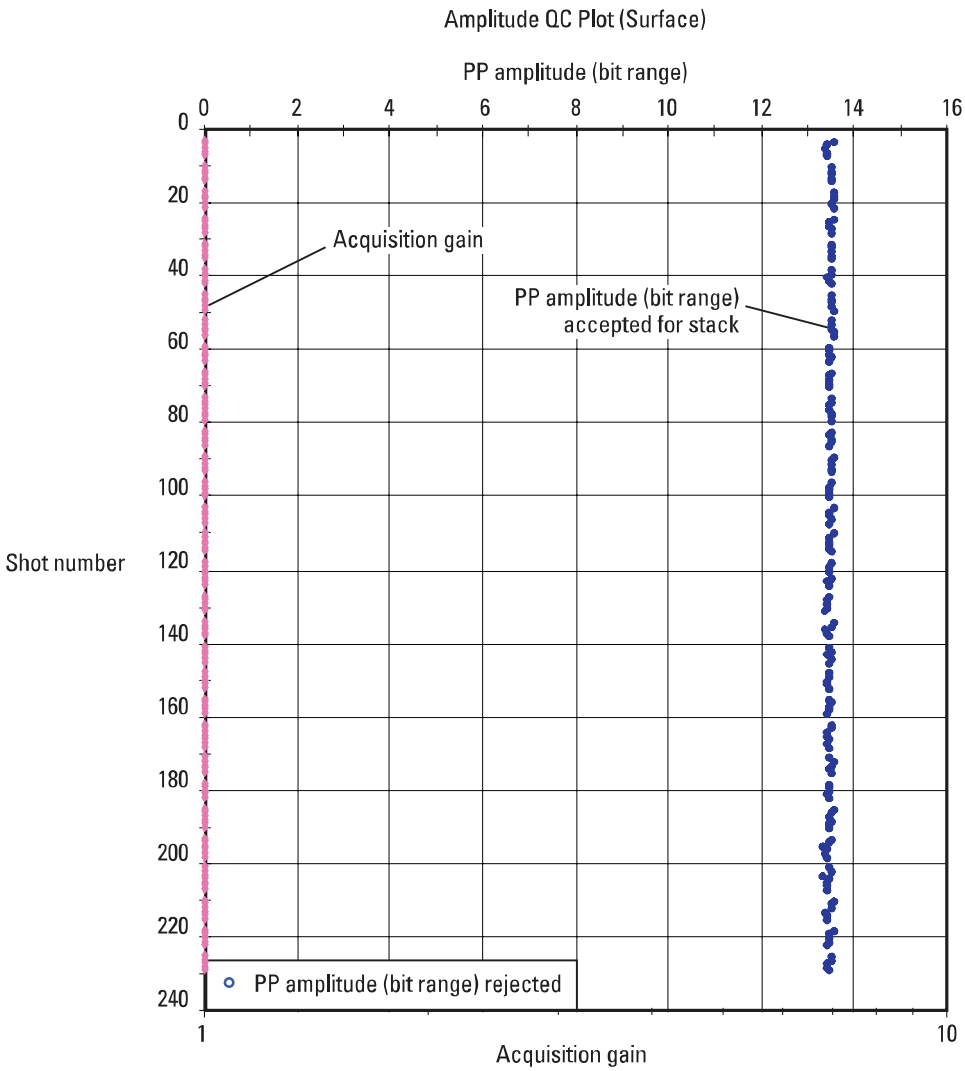

Figure 4. VSI surface amplitude QC plot.

- Time versus depth plot
  - The time versus depth plot (Fig. 5) shows the transit times in milliseconds per unit depth for the stacks acquired. This crossplot is very important for quality control. A smooth slope along the depth of the well is expected. Any discrepancy must be investigated.

Response in known conditions

- The VSI transit time should be correlative with sonic integrated transit times.
- Three checkshots are recommended while descending, with the shots repeated at the same depths, adjusted for offset, when pulling out of the hole. The repeated records should agree within 2 ms.

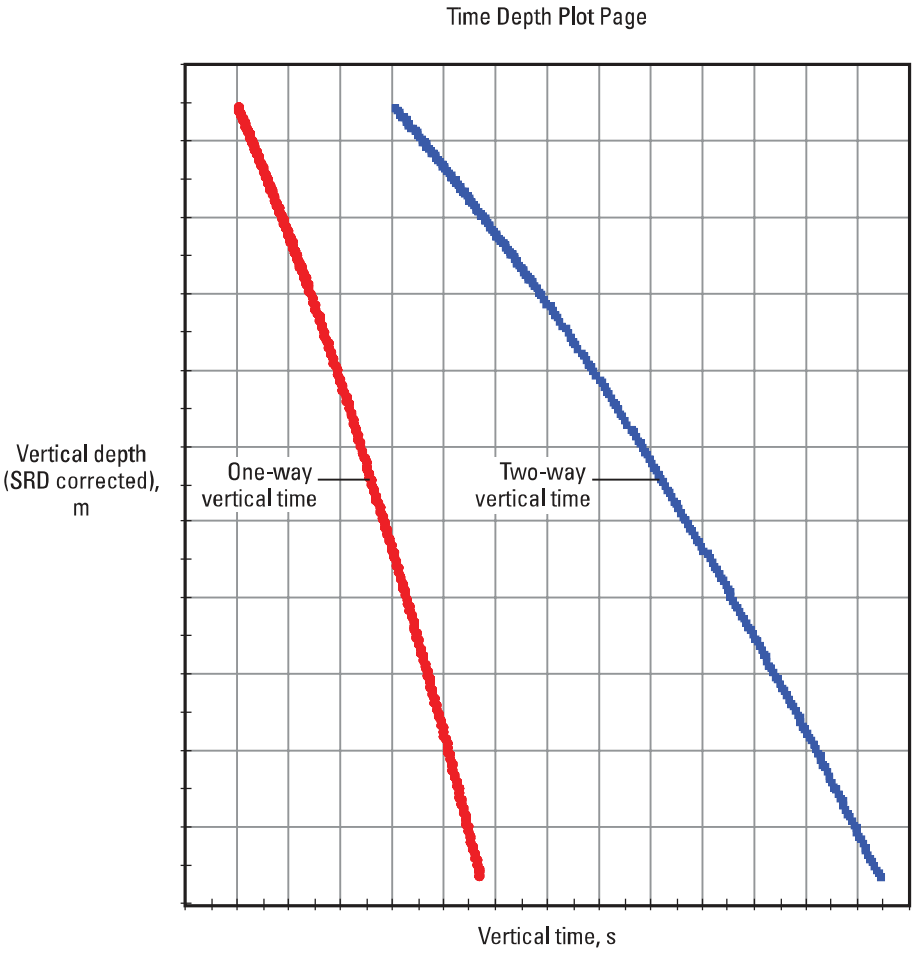

Figure 5. VSI time versus depth plot. SRD = seismic reference datum.

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MDT

The MDT* modular formation dynamics tester uses hydraulic pressure to force a probe into the formation for pressure measurement and fluid sampling. A variable-volume pretest chamber draws down the formation fluid to measure pressure for calculation of the near-wellbore permeability. Formation fluid can be diverted to one of several sample chambers. The MDT tool can also be used to conduct a mini-frac test to obtain the minimum in situ horizontal stress in several layers. The tool's modular design makes it readily customizable to meet specific objectives.

The basic MDT modules are as follows:

- Electronic Power Module (MRPC) converts power from the surface to power for the tool modules.
- Hydraulic Power Module (MRHY) contains an electric motor and pump to provide hydraulic power for setting and retracting the single- and dual-probe modules. The MRHY has an accumulator that enables automatic retraction of the probes if electric power fails, which prevents potential stuck tool situations.
- Single-Probe Module (MRPS) consists of the probe assembly (i.e., packer and telescoping backup pistons), pressure gauges, fluid resistivity and temperature sensors, and 20-cm^3 [0.005-galUS] pretest chamber. The MRPS contains both a strain gauge and the accurate, high-resolution, quick response CQG* crystal quartz gauge. The volume, rate, and drawdown of the pretest chamber can be controlled from the surface and adjusted depending on the formation characteristics.
- Modular Sample Chambers (MRSC) module is available in three sizes: 1, 2.75, and 6 galUS [3.8, 10.4, and 22.7 L]. The 1- and 2.75-galUS chambers are available in H_2S and standard service versions. Large stock-tank oil samples can be acquired by extending the 6-galUS chamber in 6-galUS increments up to 18 galUS.

Typical applications for the MDT tool are formation pressure measurements and fluid gradient identification, formation fluid sampling and downhole fluid analysis, pretest drawdown mobility calculation, permeability and permeability anisotropy determination away from the well, and in situ stress determination.

Specifications

Standard MDT Measurement Specifications

	Accuracy	Resolution	Range
Logging speed	Stationary	Stationary	Stationary
Strain gauge†	±10 psi [±68,947 Pa] ±20 psi [±137,895 Pa]	0.1 psi [689 Pa] 0.2 psi [1,379 Pa]	0 to 10,000 psi [0 to 69 MPa] 0 to 20,000 psi [0 to 138 MPa]
CQG gauge‡	±(2 psi [13,789 Pa] + 0.01% of reading)§ ±(4.0 psi [27,579 Pa] + 0.012% of reading)§	0.01 psi [69 Pa] 0.01 psi [69 Pa]	750 to 15,000 psi [5 to 103 MPa] 0 to 25,000 psi [0 to 172 MPa]
Resistivity	±5% of reading	0.001 ohm.m	0.01 to 20 ohm.m
Flowline temperature	±1.0 degF [±0.5 degC]	1.0 degF [0.5 degC]	–67 to 392 degF [–55 to 200 degC]

† 30,000-psi [207-MPa] strain gauge available on request.

‡ There are several versions of the CQG gauge. The CQG-C and CQG-G gauges are rated to 15,000 psi [103 MPa] and 350 degF [177 degC]. The HCQG-A gauge is rated to 25,000 psi [172 MPa] and 350 degF. A 30,000-psi [207-MPa] quartz gauge is available on request.

§ The 2- and 4-psi accuracy claims include calibration fitting error, hysteresis, repeatability, and some allowance for sensor aging; the corresponding percentages of the pressure readings account for the incertitude of the calibration equipment.

Basic MDT Modules Mechanical Specifications				
	MRPC	**MRHY**	**MRSC**	**MRPS**
Temperature rating	392 degF [200 degC]	392 degF [200 degC]	392 degF [200 degC]	392 degF [200 degC][†]
Pressure rating	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa][†]
Borehole size—min.	5⅝ in [14.29 cm]	5⅝ in [14.29 cm]	5⅝ in [14.29 cm]	Standard: 5⅝ in [14.29 cm] Large-hole kit: 8½ in [21.59 cm] Super-large-hole kit: 11½ in [29.21 cm]
Borehole size—max.	No limit	No limit	No limit	Standard: 14 in [35.56 cm] Large-hole kit: 19 in [48.26 cm] Super-large-hole kit: 22 in [55.88 cm]
Outside diameter	4.75 in [12.07 cm]	4.75 in [12.07 cm]	4.75 in [12.07 cm]	Standard: 4.75 in [12.07 cm] Large-hole kit: 7.5 in [19.05 cm] Super-large-hole kit: 10.5 in [26.67 cm]
Length	4.98 ft [1.52 m]	8.42 ft [2.57 m]	8.04 ft [2.45 m]	6.25 ft [1.91 m]
Weight	160 lbm [73 kg]	275 lbm [125 kg]	225 lbm [102 kg]	200 lbm [91 kg]
Tension[‡]	160,000 lbf [711,710 N]	160,000 lbf [711,710 N]	160,000 lbf [711,710 N]	160,000 lbf [711,710 N]
Compression[‡]	85,000 lbf [378,100 N]	85,000 lbf [378,100 N]	85,000 lbf [378,100 N]	85,000 lbf [378,100 N]
H_2S service	Yes	Yes	Yes	Yes

[†] Excluding the quartz gauge, the pressure and temperature ratings of the MRPS are 20,000 psi [138 MPa] and 293 degF [200 degC], respectively. These ratings can reduce the dependence on using a quartz gauge, of which there are several versions with various pressure and temperature ratings.

[‡] At 15,000 psi [103 MPa] and 320 degF [160 degC]. These ratings apply to all MDT modules except the Dual-Packer Module (MPRA). The compressive load is a function of temperature and pressure.

High-Pressure MDT Modules Mechanical Specifications				
	MRPC	**MRHY**	**MRSC**	**MRPS**
Temperature rating	350 degF [177 degC]	350 degF [177 degC]	350 degF [177 degC]	350 degF [177 degC][†]
Pressure rating[‡]	25,000 psi [172 MPa]	25,000 psi [172 MPa]	25,000 psi [172 MPa]	25,000 psi [172 MPa][†]
Borehole size—min.	5⅝ in [14.29 cm]	5⅝ in [14.29 cm]	5⅝ in [14.29 cm]	Standard: 5⅝ in [14.29 cm] Large-hole kit: 8½ in [21.59 cm] Super-large-hole kit: 11½ in [29.21 cm]
Borehole size—max.	No limit	No limit	No limit	Standard: 14 in [35.56 cm] Large-hole kit: 19 in [48.26 cm] Super-large-hole kit: 22 in [55.88 cm]
Outside diameter	5 in [12.70 cm]	5 in [12.70 cm]	5 in [12.70 cm]	Standard: 4.75 in [12.07 cm] Large-hole kit: 7.5 in [19.05 cm] Super-large-hole kit: 10.5 in [26.67 cm]
Length	4.98 ft [1.52 m]	8.42 ft [2.57 m]	8.04 ft [2.45 m]	6.25 ft [1.91 m]
Weight	160 lbm [73 kg]	275 lbm [125 kg]	225 lbm [102 kg]	200 lbm [91 kg]
Tension[§]	160,000 lbf [711,710 N]	160,000 lbf [711,710 N]	160,000 lbf [711,710 N]	160,000 lbf [711,710 N]
Compression[§]	85,000 lbf [378,100 N]	85,000 lbf [378,100 N]	85,000 lbf [378,100 N]	85,000 lbf [378,100 N]
H_2S service	Yes	Yes	Yes	Yes

[†] Using the HCQG-A gauge, rated to 25,000 psi [172 MPa] and 350 degF [177 degC].

[‡] 30,000-psi [207-MPa] versions of the MRPC, MRHY, and MRPS are available on request.

[§] At 15,000 psi [103 MPa] and 320 degF [160 degC]. These ratings apply to all MDT modules except the MRPA. The compressive load is a function of temperature and pressure.

Calibration

The downhole sensor readings of the MDT tool are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration.

The fluid resistivity measurement is calibrated to produce two straight-line transforms. One line covers the range 0.03 ohm.m to 0.33 ohm.m and the other is for 0.33 ohm.m to 3.30 ohm.m.

The CQG crystal quartz gauge used in the MDT tool should be recalibrated when the gauge has been used in the field for 12 months or when the shift of the atmospheric pressure reading at 95 degF [35 degC] exceeds 2 psi. The time between master calibrations should not exceed 18 months.

The strain gauge should be recalibrated after it has been used in the field for 6 months or when the shift in the atmospheric pressure at 95 degF [35 degC] exceeds 0.05% full scale (e.g., 5 psi for a 10,000-psi gauge). The dead-weight tester used to calibrate strain gauges should be calibrated once every 2 years.

The strain gauge temperature calibration is a two-point linear calibration using precision resistors with reference values equivalent to 32 degF and 350 degF [0 degC and 177 degC].

Tool quality control

Standard curves

The MDT standard curves are listed in Table 1.

Table 1. MDT Standard Curves†

Output Mnemonic	Output Name
BFR*i*	Flowline fluid resistivity for single probe *i*
B*i*TR	Flowline fluid temperature for single probe *i*
BQP*i*	CQG quartz gauge pressure for single probe *i*
BSG*i*	Strain gauge pressure for single probe *i*
BSL11	Solenoid echo
HMS*i*	Motor speed for hydraulic module *i*
PPUC	MDT power panel (MRPP) uphole current
VP*i*	Throttle valve position (sample chamber valve) for MRSC_*i*

† Variable *i* is the module number (1 to 3).

Operation

The MDT basic string consists of MRPS, MRHY, and MRPC modules. The tool is anchored to the formation during pressure measurements or sampling.

Standoffs should be used to minimize sticking.

Formats

The format in Fig. 1 for the pretest stations is used for monitoring the gauges and stabilization.

- Track 1
  - The gauge pressures BQP*i* and BSG*i* and the temperature BQT*i* show when the pretest was taken and the volume collected. This track is also labeled for the different tool operations (e.g., pretest, retract). BFR*i* is from the resistivity cell in the MRPS.
- Time track
  - ETIM is the elapsed time on station. HMS*i* shows when the hydraulic motor is running to conduct a pretest or to set or retract the tool.
- Tracks 3–6
  - The gauge pressures BSG*i* and BQP*i* are presented alphanumerically as well as a curve presentation. The curves are important for monitoring stabilization, which is one of the main attributes for pretest quality control.

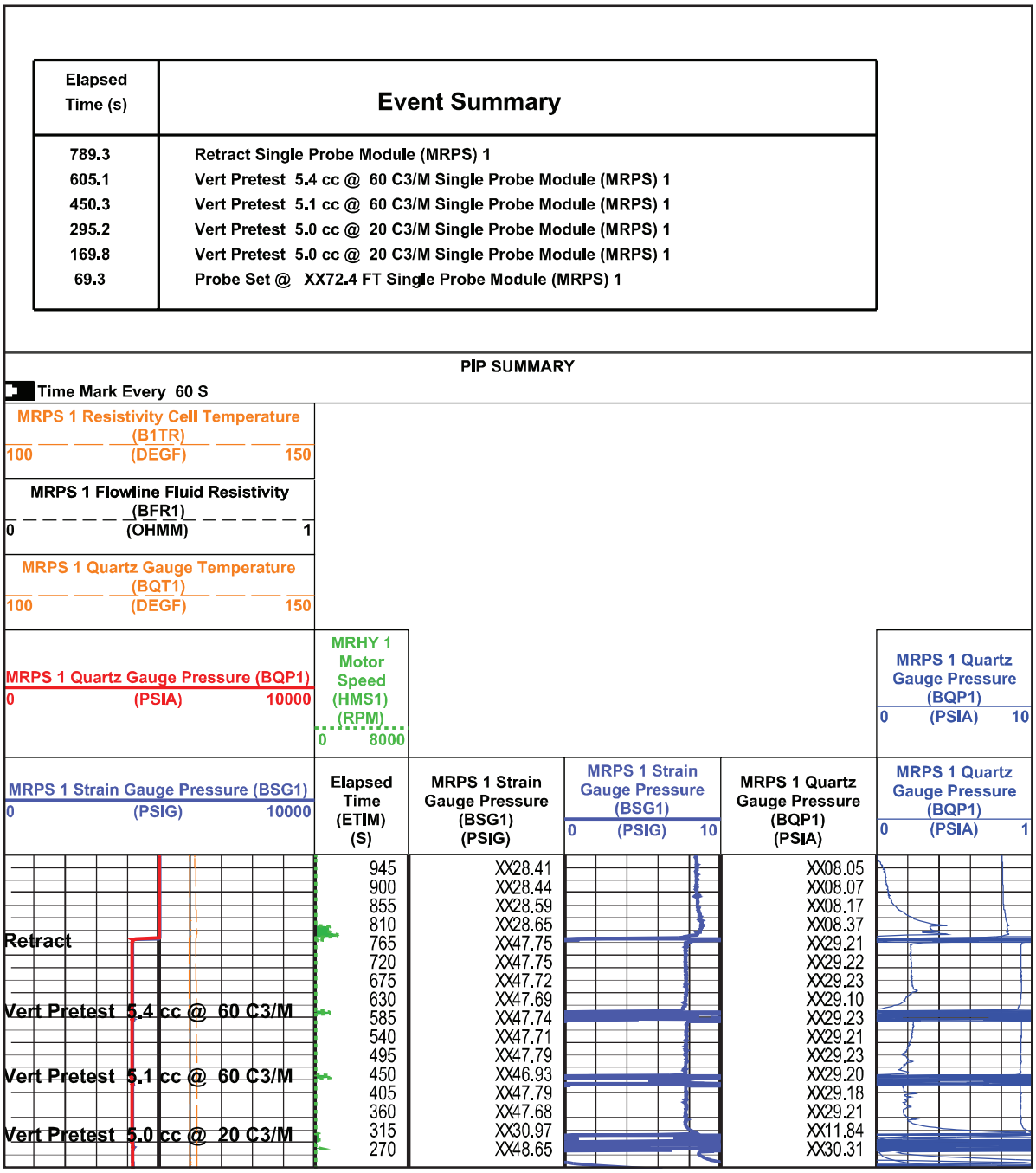

Figure 1. MDT pretest station format.

The pressure versus time (PTIM) plot in Fig. 2 is generated after the station log is finished. Hydrostatic pressure, flowline pressure, and motor speed are displayed as a function of time to provide a good overview of the pretest. Also included are the important values of mud pressure before and after the pretest, the last buildup pressure, and mobility.

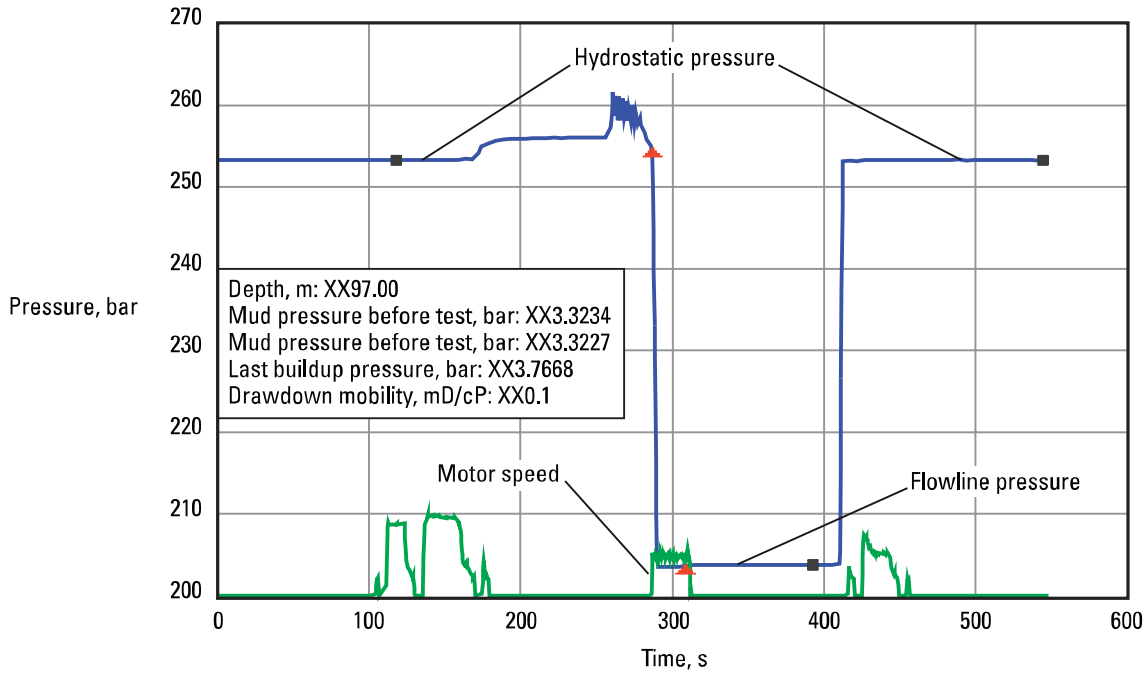

Figure 2. MDT pressure versus time plot.

Response in known conditions

- The hydrostatic pressure should be stable and the resulting mud pressure gradient should plot close to the actual well mud gradient. The mud system should be stable for close agreement.
- The well fluid level should be known and taken into account along with the deviation in comparing the measured hydrostatic pressure with the anticipated mud pressure.
- Formation pressure is normally recorded until the measured pressure is changing by less than 1 psi/min for strain gauges or less than 0.1 psi/min for quartz gauges. Pressure stabilization is critical for accurately measuring formation pressure.
- Typically there are three types of pretests:
  - Normal pretest: The last-read buildup is a stabilized value that equals the formation pressure.
  - Dry test: The fluid mobility is very low and there is not enough contribution from the formation to transmit the formation pressure to the flowline and pressure gauges.
  - Lost seal: The pressure at the end of the set cycle is higher than the pressure at the beginning of the set cycle.

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Quicksilver Probe

Overview

Quicksilver Probe* focused extraction of pure reservoir fluid is a sampling probe module for the MDT* modular formation dynamics tester that uses a focused probe assembly to perform fluid extraction and pressure measurements. The heart of the Quicksilver Probe tool is a dual-probe design featuring guard and sample flowlines, each with its own pump. With this design, the downhole tool can efficiently separate drilling mud filtrate contamination from virgin reservoir fluid during extraction. A clean reservoir fluid sample can be acquired much faster than with conventional sampling technology.

Quicksilver Probe focused fluid extraction technology acquires reservoir fluids that, in many cases, have levels of filtrate contamination below measurable limits. In addition, the time required on station is significantly reduced compared with conventional openhole sampling operations. Fluid properties can be accurately measured at reservoir conditions without contamination effects. Comparison between reservoir layers yields information concerning zonal connectivity and fluid compartmentalization that cannot be measured by other logs.

Specifications

Measurement Specifications	
Output	Extracted ultralow-contamination formation fluids; flowline pressure, resistivity, and temperature
Logging speed	Stationary
Range of measurement	CQG* crystal quartz gauge: 750 to 15,000 psi [5 to 103 MPa] 25,000-psi high-pressure Quartzdyne® gauge: 0 to 25,000 psi [0 to 172 MPa] Resistivity: 0.01 to 20 ohm.m Temperature: –67 to 350 degF [–55 to 177 degC]
Resolution	CQG gauge: 0.008 psi [55 Pa] at 1.3-s gate time 25,000-psi high-pressure Quartzdyne gauge: 0.01 psi/s [69 Pa/s] Resistivity: 0.001 ohm.m Temperature: 0.1 degF [0.05 degC]
Accuracy	CQG gauge: ±(2 psi [13,789 Pa] + 0.01% of reading)† 25,000-psi high-pressure Quartzdyne gauge: ±0.02% of full scale Resistivity: ±5% of reading Temperature: ±1.0 degF [±0.5 degC]
Mud type or weight limitations	None
Combinability	Fully integrates with MDT modular formation dynamics tester system and InSitu Family* sensors
Special applications	Downhole fluid analysis at reservoir conditions Reservoir fluid profiling

† Includes fitting error, hysteresis, repeatability, and some allowance for sensor aging; the corresponding percentages of the pressure reading account for the incertitude of the calibration equipment.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa] High-pressure version: 30,000 psi [207 MPa]
Borehole size—min.	6 in [15.24 cm]
Borehole size—max.	14 in [35.56 cm]
Outside diameter	4.75 in [12.07 cm] While sampling: 5 in [12.70 cm] High-pressure version: 5.25 in [13.34 cm] High-pressure version while sampling: 5.25 in [13.34 cm]
Length	Probe module: 8.48 ft [2.58 m]
Weight†	308 lbm [140 kg] High-pressure version: 351 lbm [159 kg]
Tension	160,000 lbf [711,710 N]
Compression†	85,000 lbf [378,100 N]

† At 15,000 psi [103 MPa] and 320 degF [160 degC]. The compressive load is a function of temperature and pressure.

Calibration

The downhole sensor readings of Quicksilver Probe tools are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration.

The fluid resistivity measurement is calibrated to produce two straight-line transforms. One line covers the range 0.03 ohm.m to 0.33 ohm.m and the other is for 0.33 ohm.m to 3.30 ohm.m.

The CQG crystal quartz gauge used in the Quicksilver Probe tool should be recalibrated when the gauge has been used in the field for 12 months or when the shift of the atmospheric pressure reading at 95 degF [35 degC] exceeds 2 psi. The time between master calibrations should not exceed 18 months.

The strain gauges should be recalibrated after they have been used in the field for 6 months or when the shift in the atmospheric pressure at 95 degF [35 degC] exceeds 0.05% full scale (e.g., 5 psi for a 10,000-psi gauge). The dead-weight tester used to calibrate strain gauges should be calibrated once every 2 years.

The strain gauge temperature calibration is a two-point linear calibration using precision resistors with reference values equivalent to 32 degF and 350 degF [0 degC and 177 degC].

Tool quality control

Standard curves

The Quicksilver Probe standard curves are listed in Table 1.

Table 1. Quicksilver Probe Standard Curves†

Output Mnemonic	Output Name
ETIM	Elapsed time in station
HMS*i*	Motor speed from hydraulic module *i*
POHP or POUDHP	Hydraulic pressure from pumpout module
POMS or POUDMS	Motor speed from pumpout module
POPV or POUDPV	Pumped volume from pumpout module
POS3 or POUDS3	Solenoid 3 status from pumpout module
PQFR*i*	Flowline fluid resistivity from probe *i*
PQ*i*TR	Flowline fluid temperature from probe *i*
PQQP*i*	CQG quartz gauge pressure from probe *i*
PQQT*i*	CQG quartz gauge temperature from probe *i*
PQSG*i*	Strain gauge pressure from probe *i*

Note: Standard curves for the MDT Pumpout Module are included because the Quicksilver Probe application mostly involves fluid extraction for sampling and a Pumpout Module is always required. The Pumpout Module curves could have several naming conventions, depending on which declaration was done in the software. For example, POMS, POMS2, POUDMS, and POUDMS2 all reference the same motor speed curve, but the mnemonic used depends on the declaration of the tool in the software. For more information refer to the Pumpout Module in the Log Quality Control Reference Manual.

† Variable *i* is the module number (1 to 3).

Operation

The tool is anchored to the formation during pressure measurements or fluid extraction.

Standoffs should be used to minimize sticking.

In Quicksilver Probe operation, two pumps are used simultaneously, one for the guard probe, the other one for the fluid extraction probe.

Formats

The format in Fig. 1 is used mainly for acquisition.

- Track 1
  - PQSG*i* and PQQP*i* are presented in wide scale for an overview.
  - PQFR*i* from the tool's resistivity cell is used for fluid interpretation.
  - PQ*i*TR, PQQT*i*, and PQSG*i* should closely match per unit depth.
- Time track
  - In addition to ETIM, HMS*i* on the time track shows when the hydraulic motor is running for taking a pretest or setting or retracting the tool.
- Tracks 3–6
  - PQSG*i* and PQQP*i* are shown as alphanumerical values and as curves at a reduced scale to help look for stabilization. Stabilization monitoring is one of key factors in good pretests.

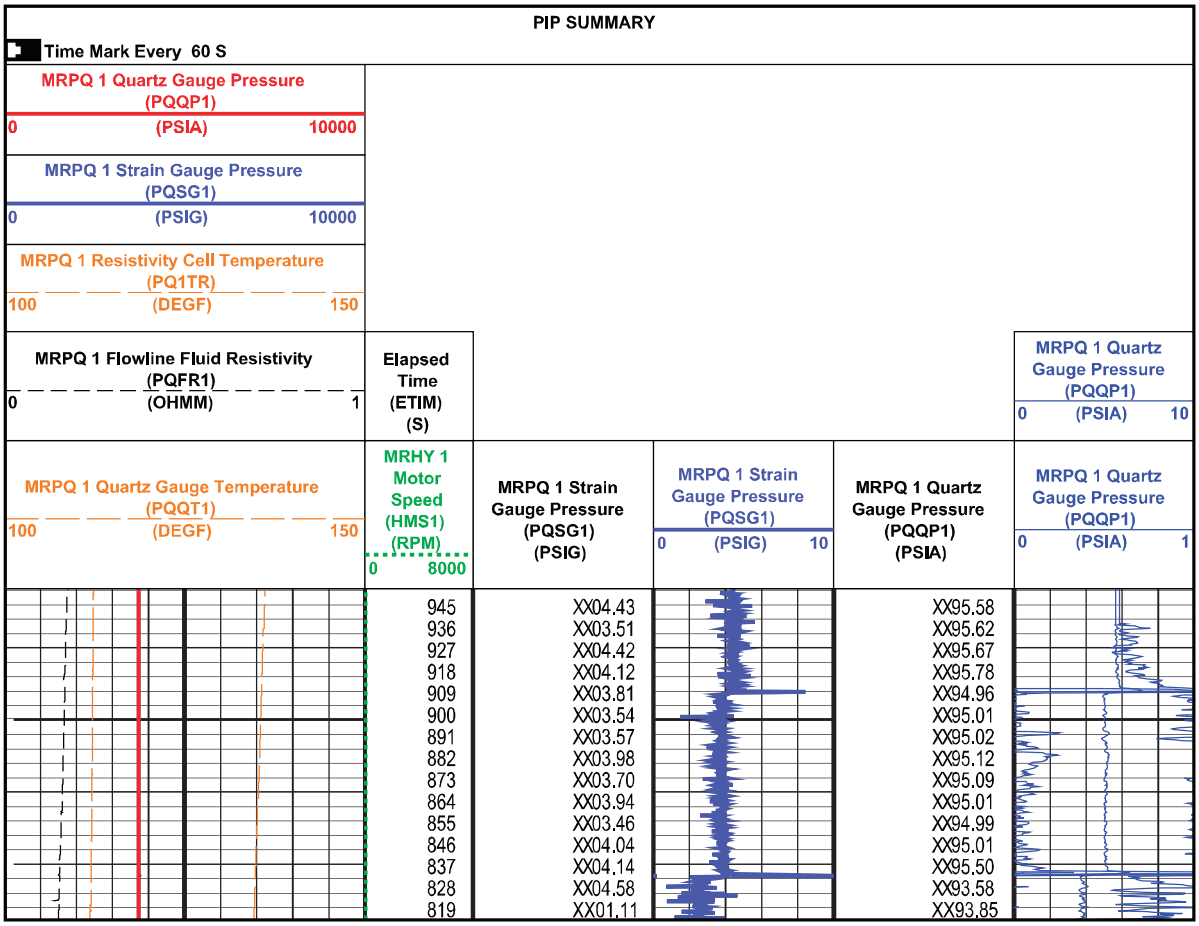

Figure 1. Quicksilver Probe station format.

The pressure versus time plot (PTIM, Fig. 2) is generated after the station log is finished. Hydrostatic pressure, flowline pressure, and motor speed are displayed as a function of time to provide a good overview of the pretest. Also listed are the important values of mud pressure before and after the pretest, the last buildup pressure, and mobility.

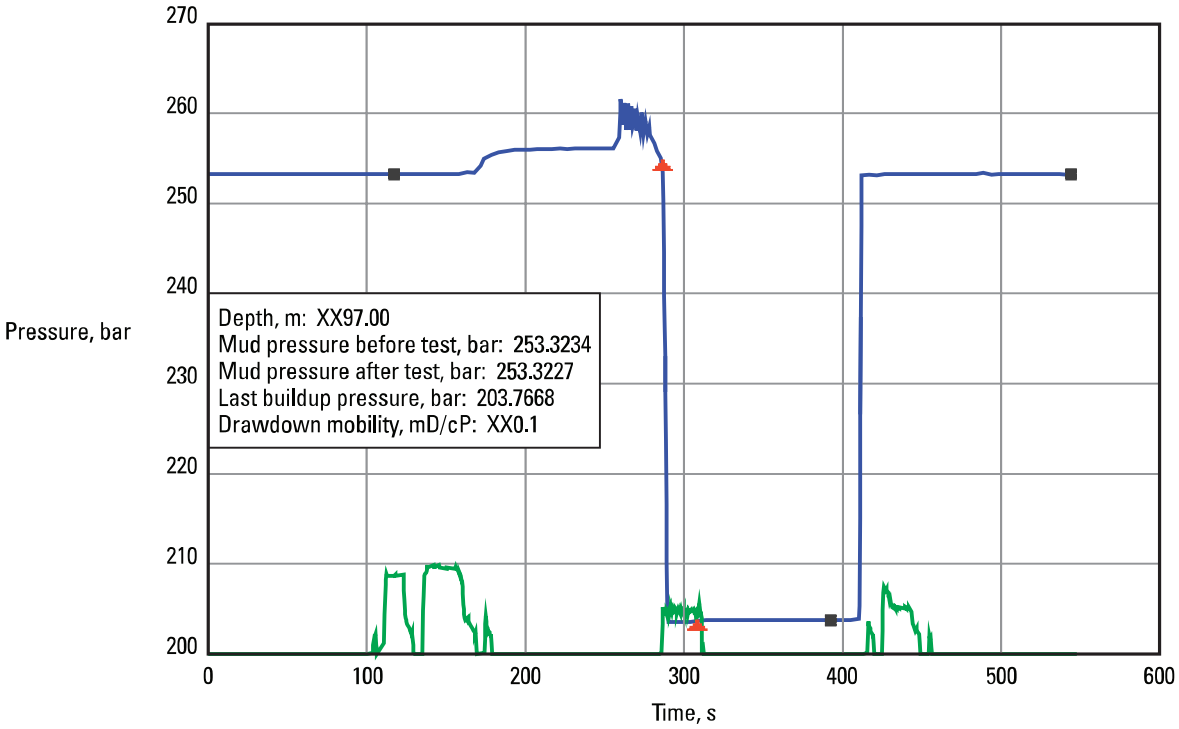

Figure 2. Quicksilver Probe pressure versus time plot.

Response in known conditions

- The hydrostatic pressures should be stable and plot a mud pressure gradient close to the actual well mud gradient. A stable mud system supports close agreement.
- The well fluid level should be known and taken into account along with deviation in comparing the measured hydrostatic pressure with the anticipated mud pressure.
- Formation pressure is recorded until the measured pressure is changing by less than 1 psi/min for strain gauges or less than 0.1 psi/min for quartz gauges. Pressure stabilization is an important attribute for accurately determining formation pressure.
- Typically there are three types of pretests:
  - Normal pretest: The last-read buildup is a stabilized value that equals the formation pressure.
  - Dry test: Fluid mobility is very low and there is not enough contribution from the formation to transmit the formation pressure to the flowline and pressure gauges.
  - Lost seal: Pressure at the end of the set cycle is higher than the pressure at the beginning of the set cycle.

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InSitu Fluid Analyzer

Overview

The InSitu Fluid Analyzer* new-generation platform integrates InSitu Family* sensors and measurements for downhole fluid analysis (DFA) of all types of reservoir fluids. Deployed on the MDT* modular formation dynamics tester toolstring, the InSitu Fluid Analyzer system provides quantified fluid measurements that were previously unachievable from wireline logs or laboratory analysis but are now possible downhole and in real time. Investigating fluids at their source delivers deeper insight to fluid composition and distribution, improving understanding of the reservoir.

The InSitu Family sensors include two optical spectrometers, fluorescence and gas detector, and fluid density, pressure, temperature, and resistivity sensors. The pH is also measured downhole. The filter array spectrometer measures wavelengths in the visible to near-infrared (Vis-NIR) range from 400 to 2,100 nm across 20 channels that indicate the color and molecular vibration absorptions of reservoir fluids and also show the absorption peaks of water and CO_2. The InSitu Composition* hydrocarbon fluid composition measurement is made with a laboratory-grade grating spectrometer, which has 16 channels focused on the 1,600- to 1,800-nm range. The dual-spectrometer measurements together with real-time calibration (performed downhole every 1 s) and improved compositional algorithms significantly improve the accuracy and repeatability of quantitative reservoir fluid analysis. It is this improved accuracy that enables Fluid Profiling* comparison of fluid properties between wells, making field-wide DFA characterization a new critical tool for reservoir studies.

The InSitu Family measurements are as follows.

- InSitu Composition measurement

  The Vis-NIR spectrum measured by the two InSitu Composition spectrometers is used for the analysis of fluid hydrocarbon composition, gas/oil ratio (GOR), CO_2, water content, and mud filtrate contamination. The analysis is reported in weight percentages of C_1, C_2, $C_{3–5}$, C_{6+}, and CO_2 in real time.
- InSitu GOR determination

  From the enhanced composition measurement, the GOR and condensate/gas ratio (CGR) are determined from the vaporizations of the hydrocarbon and CO_2 components at standard conditions for flashing a live fluid.
- InSitu CO_2 measurement

  The CO_2 content is measured with the filter array spectrometer. A dedicated channel for the CO_2 absorption peak is complemented with dual baseline channels above and below that subtract out the overlapping spectrum of hydrocarbon and small amounts of water. The new channels and enhanced algorithm make it possible to plot CO_2 content in real time.
- InSitu Color measurement

  The InSitu Color* reservoir fluid color measurement uses the extended measurement range of the 20-channel filter array spectrometer. The measurement is supported by continuous real-time autocalibration, application of a contamination algorithm that uses all the spectrometer channels, and a coated-window detection flag for enhanced quality control (QC). The color measurement supports fluid identification, determination of asphaltene gradients, and pH measurement.
- InSitu Density measurement

  This real-time measurement directly yields the slope of the pressure gradient for the identification of fluid contacts and helps establish gradients in thin beds. The InSitu Density* reservoir fluid density measurement is based on the resonance characteristics of a vibrating sensor that oscillates in two perpendicular modes within the fluid.
- InSitu Fluorescence measurement

  The InSitu Fluorescence* fluid fluorescence measurement detects free gas bubbles and retrograde condensate liquid dropout for single-phase assurance while conducting DFA and sampling. Fluid type is also identified. The resulting fluid phase information is especially useful for defining the difference between retrograde condensates and volatile oils.
- InSitu pH measurement

  Obtaining high-quality results from DFA and collecting representative samples of formation water relies on tracking mud filtrate contamination in real time. Water pH is measured with the InSitu pH* reservoir fluid pH measurement by injecting dye into the formation fluid being pumped through the InSitu Fluid Analyzer flowline. The pH is calculated with 0.1-unit accuracy from the relevant visible wavelengths of the dye signal measured by an optical fluid analyzer.

- Flowline resistivity measurement

  The flowline resistivity sensor uses the same proven technology employed in Schlumberger formation testing tools. With the resistivity sensor included in the DFA assembly, it is possible to monitor resistivity during dual-packer sampling operations in water-base mud.

- Flowline pressure and temperature measurements

  The high-resolution pressure and temperature sensors used in Schlumberger formation testing tools are also incorporated in the InSitu Fluid Analyzer service. The DFA measurements within the flowline can then be accurately translated back to virginal reservoir conditions by employing well-known equation-of-state (EOS) algorithms.

- Sampling quality control

  With InSitu Family measurements, the reservoir fluid is analyzed before samples are collected, which substantially improves the quality of the fluid samples. The sampling process is optimized in terms of where and when to sample and how many samples to collect.

Fluid Profiling analysis

The quantified accuracy of the InSitu Family measurements expands the application of DFA from a single well to multiple-well analysis, defining reservoir architecture across the entire field. Fluid Profiling quantification of the variation of fluid properties is at higher resolution than conventional sampling and analysis and identifies and differentiates compositional grading, fluid contacts, and reservoir compartments.

Calibration

Two calibrations are required for the InSitu Fluid Analyzer system.

The master calibration establishes the optical density baseline for the spectrometer under dry, empty flowline conditions. Before this dry master calibration is conducted, the tool flowline is cleaned and the optical windows are disassembled and physically cleaned. The master calibration also calibrates the fluorescence detector under dry conditions and with the standard fluorescence fluid (Rhodamine 6G water solution) and checks the functionality of the spectrometers and fluorescence detector with defined fluids (J26 and water).

The master calibration is performed every 3 months, every three jobs, or if the tool was exposed to temperatures above 300 degF [150 degC], whichever occurs first.

Temperature compensation calibration is required for the spectrometers to compensate for drift of the baseline (i.e., optical density [OD] = 0 level established by the master calibration) at elevated temperatures.

Temperature compensation calibration is performed every 6 months, every six jobs, or if the tool was exposed to temperatures above 300 degF, whichever occurs first.

Specifications

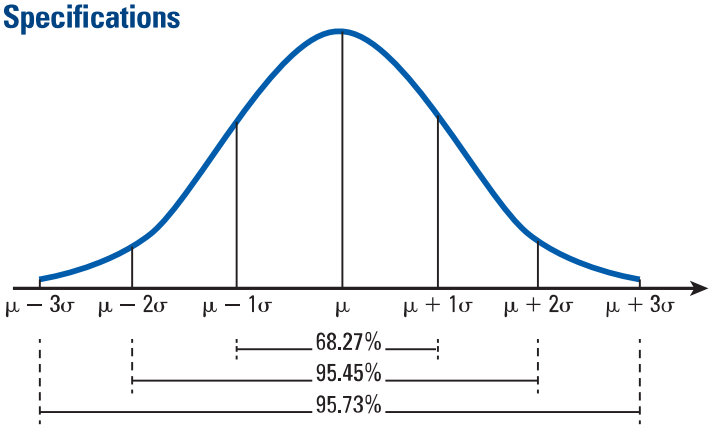

Figure 1. InSitu Fluid Analyzer specified accuracy (to 1 sigma).

Measurement Specifications

	Accuracy† (to 1 sigma, Fig. 1)						
	C_1, wt%	**C_2, wt%**	**C_{3-5}, wt%**	**C_{6+}, wt%**	**CO_2, wt%**	**GOR, scf/stb**	**GOR, %**
Medium to heavy oil	1.7	1.1	4.5	4.4	2.5	185	16
Volatile oil	2.7	2.6	6.7	4.5	2.8	726	19
Condensate gas	2.9	3.7	4.1	6.8	3.1	–	–
Dry gas	5.3	1.4	2.1	3.5	4.3	–	–
	pH	**Resistivity**	**Density**	**Pressure**	**Temperature**		
Range of measurement	3 to 9	0.01 to 20 ohm.m	0.05 to 1.2 g/cm^3	Max.: 25,000 psi	Max: 350 degF [175 degC]		
Accuracy	±0.1 pH unit	±0.01 ohm.m	±0.012 g/cm^3	±10^{-4} full scale Max.: ±2.5×10^{-4} full scale	±10^{-4} full scale Max.: ±2.5×10^{-4} full scale		
	Resolution						
	C_1, wt%	**C_2, wt%**	**C_{3-5}, wt%**	**C_{6+}, wt%**	**CO_2, wt%**	**GOR, scf/stb**	**GOR, %**
Oil	0.4	0.4	1.0	0.6	0.3	47	1
Gas	0.5	0.4	0.6	0.6	0.4	–	5

† Accuracy listed is for typical fluid in each fluid group; actual measurement accuracy may differ.

Mechanical Specifications	
Temperature rating	350 degF [175 degC]
Pressure rating	25,000 psi [172 MPa]
Borehole size—min.	6 in (5.75 in possible depending on hole conditions)
Borehole size—max.	No limit
Outside diameter	5 in [12.72 cm]
Weight	368 lbm [167 kg]

Tool quality control

Standard curves

Standard curves for the InSitu Fluid Analyzer system are listed in Table 1.

Table 1. InSitu Fluid Analyzer Standard Curves

Output Mnemonic	Output Name
CHCR_IFA(0)	InSitu Fluid Analyzer cumulative hydrocarbon composition ratio, methane
CHCR_IFA(1)	InSitu Fluid Analyzer cumulative hydrocarbon composition ratio, ethane
CHCR_IFA(2)	InSitu Fluid Analyzer cumulative hydrocarbon composition ratio, C_3-C_4-C_5
CHCR_IFA(3)	InSitu Fluid Analyzer cumulative hydrocarbon composition ratio, C_{6+}
CHCR_IFA(4)	InSitu Fluid Analyzer cumulative hydrocarbon composition ratio, CO_2
CO2QI_IFA1	InSitu Fluid Analyzer CO_2 ratio quality indicator
FFRES_IFA1	InSitu Fluid Analyzer flowline fluid resistivity
FL0_IFA1	InSitu Fluid Analyzer fluorescence channel 0
FL0IMG_IFA1	InSitu Fluid Analyzer fluorescence channel 0 image
FL1_IFA1	InSitu Fluid Analyzer fluorescence channel 1
FL1IMG_IFA1	InSitu Fluid Analyzer fluorescence channel 1 image
FLR_IFA1	InSitu Fluid Analyzer fluorescence reflection
FRAT_IFA1	InSitu Fluid Analyzer fluorescence ratio
FSODIMG_IFA1	Filter spectrometer OD image
GASFLG_IFA1	InSitu Fluid Analyzer gas flag
GOR_IFA1	InSitu Fluid Analyzer gas/oil ratio
GORQ1_IFA1	InSitu Fluid Analyzer gas/oil ratio quality indicator
GSODIMG_IFA1	Grating spectrometer OD image
HAFF_IFA1	InSitu Fluid Analyzer highly absorbing fluid flag
HCQI_IFA1	InSitu Fluid Analyzer hydrocarbon composition quality indicator
LEGS_IFA1	InSitu Fluid Analyzer live-fluid analyzer equivalent green shade
OPTCWF_IFA1	InSitu Fluid Analyzer coated window flag
PHDI_IFA1	pH from dye indicator
RCTEMP_IFA1	InSitu Fluid Analyzer resistivity cell temperature
RODDQUAL_IFA1	Density-viscosity (DV) rod density quality flag
RODRHO_IFA1	DV rod fluid density
RODVIS_IFA1	DV rod fluid viscosity
RODVQUAL_IFA1	DV rod viscosity quality flag
SOIPRES_IFA1	InSitu Fluid Analyzer pressure and temperature (SOI) gauge pressure
SOIPRESS_IFA1	InSitu Fluid Analyzer SOI gauge pressure
SOITEMP_IFA1	InSitu Fluid Analyzer SOI gauge temperature
WATF_IFA1	InSitu Fluid Analyzer water fraction

Operation

The InSitu Fluid Analyzer tool is placed below the power cartridge and can be run below or above the Pumpout Module. If pH measurement is required, the InSitu Fluid Analyzer tool is placed on the high-pressure end of the Pumpout Module.

Formats

The typical format in Fig. 2 includes QC outputs. More options are available if pH measurement is required. It is also possible to change the default formats with the dedicated InSituPro* software according to local needs.

- Track 1
  - The Pumpout Module speed (POUDMS) and cumulative volume pumped (POUDRV) are shown with the InSitu Fluid Analyzer RODVIS_IFA1, RODRHO-IFA1, RCTEMP_IFA1, and FFRES_IFA1 curves. Density and viscosity QC flags are also included.
- Track 2
  - The elapsed time (ETIM) is shown with the Pumpout solenoid status (POUDS3) and status indicators for the sample chamber valves (MUP1, MLP1, VP2, and VP1).
- Track 3
  - Fluorescence images FL1IMG_IFA1 and FL0IMG_IFA1 from both channels are shown with the gas detector output GASFLG_IFA1.
- Track 4
  - The flags are for the presence of oil, water, and highly absorbing fluid. Overlap of the oil and water tracks is also indicated in this track.
- Track 5
  - GOR_IFA1 and the CO_2 ratio (CO2R_IFA1) along with its high and low values (HLCO2R_IFA1 and LLCO2R_IFA1, respectively) are used for QC and may not be shown in some log formats.
- Track 6
  - QC flags in this track are OPTCWF_IFA1, HCQI_IFA1, GORQI_IFA1, and CO2QI_IFA1.
- Track 7
  - Composition data is presented in this track.

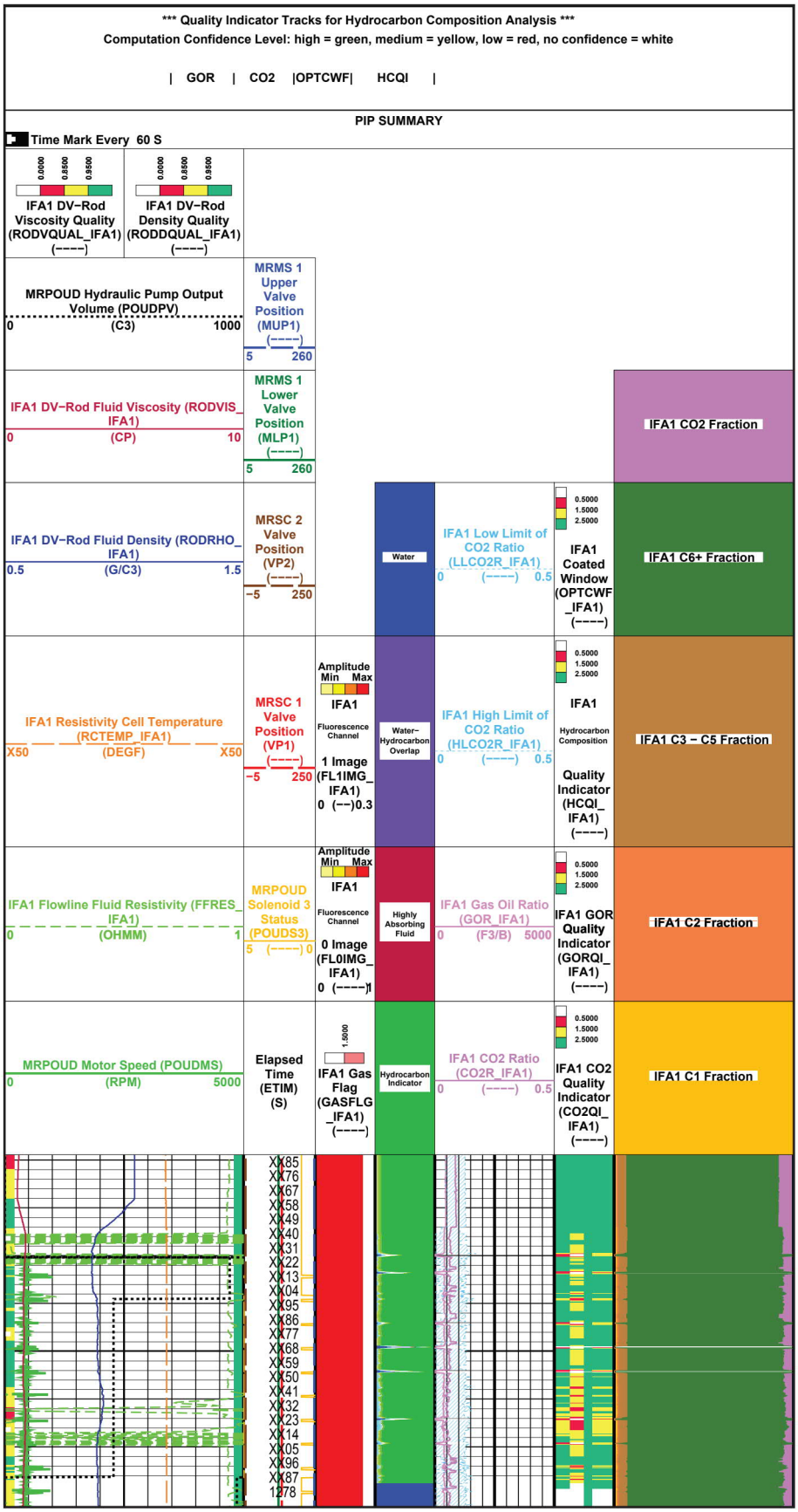

Figure 2. InSitu Fluid Analyzer quality control format.

Response in known conditions

- In mud and possibly in emulsions, HAFF_IFA1 is on and all the optical channels become saturated. There are no outputs for composition, GOR, and the QC flags.
- In water, the water fraction track indicates blue shading. The CO_2, GOR, and composition QC flags can indicate a lower quality depending on the amount of water present if oil is also observed. Above a certain water threshold, composition, CO_2, and GOR are not computed.
- In oil, green shading is shown. The spectrometer tracks display coloration and composition and GOR is also computed. The fluorescence channels display a higher value when oil is flowing in front of the sensor.
- In oil, the filter array spectrometer color optical densities define the exponential decrease with wavelength, making possible asphaltene gradient analysis based on fluid color.
- In gas, fluorescence reflection is dominant and gas composition is computed. Fluorescence is negligible.
- If oil-water emulsions are pumped, optical densities are high. With HAFF_IFA1 on, however, fluorescence still responds to the hydrocarbon presence.
- If the phase separation envelope is crossed downhole, gas flags are displayed if oil is pumped or fluorescence increases if retrograde gas is pumped, indicating that liquid dew is forming.
- OPTCWF_IFA1 alerts interpreters if an InSitu Fluid Analyzer window has stagnant liquids affecting the results while pumping. Corrective action then can be taken to clean the windows downhole during the survey.
- The flowline pressure gauge helps define sampling pressure, and flowline resistivity is instrumental while sampling with dual packers.

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MDT Dual-Packer Module

Overview

The Dual-Packer Module (MRPA) of the MDT* modular formation dynamics tester consists of two inflatable packer elements that seal against the borehole wall to isolate an interval of the borehole. The Pumpout Module (MRPO) is required to inflate the packers with wellbore fluid. The length of the test interval (i.e., the distance between the packers) is 3.2 ft [0.98 m] and can be extended by 2, 5, or 8 ft [0.61, 1.52, or 2.44 m]. For the 3.2-ft interval, the area of the isolated interval of the borehole is about 3,000 times larger than the area of the borehole wall isolated by an MDT probe. For fluid sampling, the large area results in flowing pressure that is only slightly below the reservoir pressure, which avoids phase separation even for pressure-sensitive fluids such as gas condensates or volatile oils. In low-permeability formations, high drawdown usually occurs with the probe, whereas the fluid can be withdrawn from the formation using the MRPA with minimum pressure drop through the larger flowing area. In finely laminated formations, the MRPA can be used to straddle permeable streaks that would be difficult to locate with a probe. In fractured formations, the MRPA can usually seal the interval whereas a probe could not.

For pressure transient testing, following a large-volume flow from the formation, the resulting pressure buildup has a radius of investigation of 50 to 80 ft [15 to 24 m]. Similar to a small-scale drillstem test (DST), this type of testing offers advantages over conventional DST tests. It is environmentally friendly because no fluids flow to the surface, and it is cost effective because many zones can be tested in a short time.

The MRPA can be used to create a micro-hydraulic fracture (i.e., stress testing) that can be pressure tested to determine the minimum in situ stress magnitude. The fracture is created by pumping wellbore fluid into the interval between the inflatable packer elements.

The MRPA can be used in cased hole for the same purposes; this is done by perforating a 3-ft [1-m] interval and setting the packers across the perforations. This kind of job must be extensively planned in coordination with the reservoir engineer at the location. A cement evaluation log is required to ensure that the zone to be tested is isolated and it is also recommended to conduct a scraper run to clean the perforations to avoid damaging the elements. A casing collar locator (CCL) tool should be used for correlation to avoid setting the elements on the perforations, which increases the chance of bursting the elements.

Calibration

The CQG* crystal quartz gauge should be recalibrated when the gauge has been used in the field for 12 months or when the shift of the atmospheric pressure reading at 95 degF [35 degC] exceeds 2 psi. The time between master calibrations should not exceed 18 months.

The strain gauge should be recalibrated after it has been used in the field for 6 months or when the shift in the atmospheric pressure at 95 degF [35 degC] exceeds 0.05% full scale (e.g., 5 psi for a 10,000-psi gauge). The dead-weight tester used to calibrate strain gauges should be calibrated once every 2 years.

The strain gauge temperature calibration is a two-point linear calibration using precision resistors with reference values equivalent to 32 degF and 350 degF [0 degC and 177 degC].

Specifications

Mechanical Specifications

Packer	SIP-A3A-5in	IPCF-BA-500	IPCF-PA-700	IPCF-BA-700	IPCF-PC-700	IPCF-H2S-700	SIP-A3A-6.75	SIP-A3A-8.5
Temperature rating, degF [degC]	350 [177]	410 [210]	350 [177]	410 [210]	350 [177]	350 [177]	350 [177]	350 [177]
Pressure rating, psi [MPa]	20,000 [138]	14,000 [97]	20,000 [138]	14,000 [97]	20,000 [138]	20,000 [138]	20,000 [138]	20,000 [138]
Hole size, in [cm]	6 [15.24]	6 [15.24]	8.5 [21.59]	8.5 [21.59]	8.5 [21.59]	8.5 [21.59]	8.5 [21.59]	12.25 [31.12]
Recommended max. differential pressure, psi [MPa]	3,000 [21]	3,000 [21]	3,000 [21]	3,000 [21]	4,500 [31]	3,000 [21]	3,000 [21]	3,000 [21]

Tool quality control

Standard curves

The MRPA standard curves are listed in Table 1.

Table 1. MRPA Standard Curves

Output Mnemonic	Output Name
PAAD	Packer autodeflate valve status
PAEM	MRPA element minimum pressure
PAEX	MRPA element maximum pressure
PAFP	Packer inflate valve position
PAHP	MRPA inflate pressure
PAMH	MRPA memorized hydraulic pressure
PAML	MRPA minimum interval pressure
PAQP	MRPA quartz gauge pressure
PAQT	MRPA quartz gauge temperature
PASG	MRPA strain gauge pressure
PATV	MRPA strain gauge temperature
PAVP	Packer internal valve position
PAXL	MRPA maximum interval pressure
POHP	MRPO hydraulic pressure (from Pumpout Module)
POMS	MRPO motor speed (from Pumpout Module)
POPV	MRPO pump volume (from Pumpout Module)
POS3	MRPO solenoid 3 status (from Pumpout Module)

Operation

The MRPA packer elements are inflated during pressure measurements or sampling.

The mud type and hole size guide packer element selection. Packer element performance is highly dependent upon hole conditions. Breakouts and washouts can cause sealing difficulties and could lead to element rupture.

If a fluid sample is to be collected, the best placement of the sample chambers is between the MRPA and the MRPO.

Inflating the packers in a hole with high ovality or bad hole conditions usually causes difficulties in sealing and increases the likelihood of rupturing an element.

The recommended inflation pressure is 1,000 psi [7 MPa]. Depending on the hole conditions, it may take from 2 to 16 galUS of fluid to inflate both packers.

Formats

The format in Fig. 1 is the standard MRPA format generated during a job involving the MRPA.

- Time track
  - The elapsed time on station is shown with the 50-V power supply.
- Track 1
  - 5V, 15V, U15V, and M15V are the internal low-voltage power supplies and they should be stable.
  - PASG is the strain gauge pressure displayed in alphanumerical values.
  - PAQP is the quartz gauge pressure, also in alphanumerical values.
- Track 2
  - The PASG and PAQP gauge pressures are presented in a wide overview scale.
  - The PAMH hydraulic pressure is memorized.
  - PAML and PAXL are calculated on the basis of the packer type used and the memorized hydraulic pressure. These should be monitored closely when pumping in or out of the interval.
  - PAEM and PAEX are calculated on the basis of the packer type used and the hole size.
- Track 3
  - PAHP presents the gauge values. It should be stable whenever the interval pressure is stable. Both the inflation and interval pressure lines control the flow of borehole fluids to and from the flowline.
  - PAVP and PAFP are the interval and inflate valve positions, for which a position of 0 indicates closed and 130 is open.
  - The MRPA autodeflate status shown by the PAAD curve is useful if power is lost and an autodeflate is necessarily by releasing the inflation line pressure.
- Track 4
  - PATV is presented as a curve and in alphanumerical values. It is considered the best estimation of flowline temperature because the MRPA does not have a resistivity cell such as the MDT Single-Probe Module (MRPS).
  - PAQP and PASG are shown at a reduced scale for identifying stabilization.
  - PAQT should be stable.

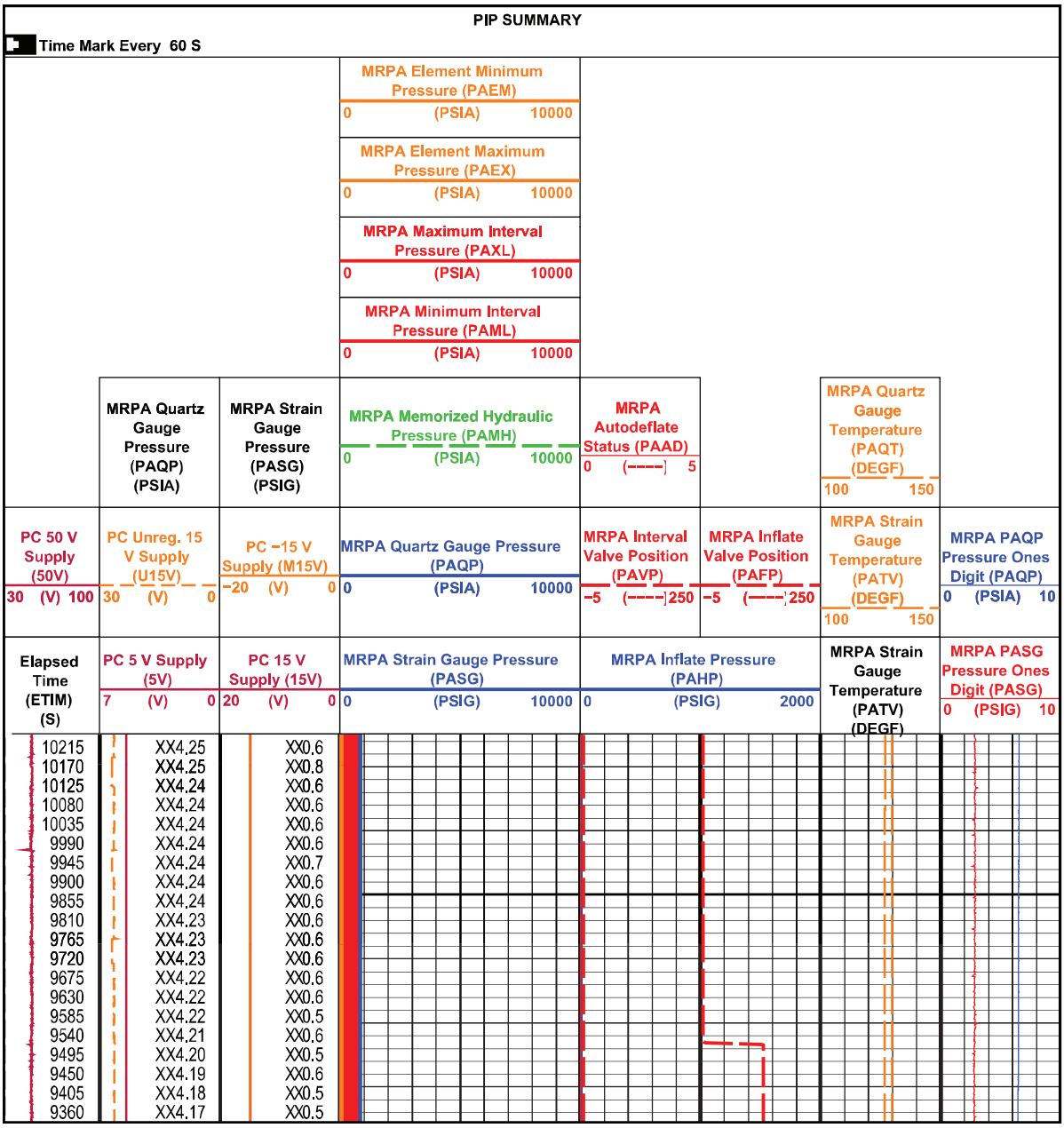

Figure 1. MRPA station format.

Response in known conditions

- The increase in CQG and strain gauge pressures as the elements make a seal with the formation is the best indication of the elements touching the borehole wall.

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MDT Dual-Probe Module

Overview

The Dual-Probe Module (MRDP) of the MDT* modular formation dynamics tester is used to establish pressure and fluid communication between different points in the test formation. It is used in combination with the Single-Probe Module (MRPS) to insert three sample probes into the formation. The sink probe of the MRDP is below and in line with the probe of the MRPS. The horizontal probe is diametrically opposite the sink probe.

The MRDP incorporates pretest chambers and gauges to measure pressure and temperature at both probes and also has a resistivity cell to measure fluid resistivity inline between the sink probe and the flowline. Strain gauge pressure is measured at the sink probe and the horizontal probe. Depending on the version of the MRDP, quartz gauge pressure measurements at the horizontal probe may also be available.

The usual test procedure is to set the tool and then take pretests at all three probes to verify the hydraulic seals and to obtain a stable formation pressure measurement at each probe. Both the MRDP and MRPS are set in a single hydraulic sequence. The sink probe is then pulsed using the 1,000-cm^3 chamber of the Flow-Control Module (MRFC) or using the Pumpout Module (MRPO), and the resulting pressure disturbance is observed on the horizontal and vertical probes.

Specifications

Mechanical Specifications	
Temperature rating	392 degF [200 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	7⅝ in [19.37 cm]
Borehole size—max.	13¼ in [33.65 cm]
Outside diameter	6 in [15.24 cm]
Length	6.75 ft [2.06 m] MRDP-BA, MRDP-BB, MRDP-BC, and MRDP-BX: 8.6 ft [2.62 m]
Weight	298 lbm [135 kg]
Tension†	160,000 lbf [711,710 N]
Compression†	85,000 lbf [378,100 N]
H_2S service	Yes

† At 15,000 psi [103 MPa] and 320 degF [160 degC]. These ratings apply to all MDT modules except the Dual-Packer Module (MRPA). The compressive load is a function of temperature and pressure.

Calibration

The downhole sensor readings of the MRDP are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration.

The fluid resistivity measurement is calibrated to produce two straight-line transforms. One line covers the range 0.03 ohm.m to 0.33 ohm.m and the other is for 0.33 ohm.m to 3.30 ohm.m.

The CQG* crystal quartz gauge used some MRDP versions should be recalibrated when the gauge has been used in the field for 12 months or when the shift of the atmospheric pressure reading at 95 degF [35 degC] exceeds 2 psi. The time between master calibrations should not exceed 18 months.

The strain gauge should be recalibrated after it has been used in the field for 6 months or when the shift in the atmospheric pressure at 95 degF [35 degC] exceeds 0.05% full scale (e.g., 5 psi for a 10,000-psi gauge). The dead-weight tester used to calibrate strain gauges should be calibrated once every 2 years.

The strain gauge temperature calibration is a two-point linear calibration using precision resistors with reference values equivalent to 32 degF and 350 degF [0 degC and 177 degC].

Tool quality control

Standard curves

The MRDP standard curves are listed in Table 1.

Table 1. MRDP Standard Curves†

Output Mnemonic	Output Name
DFR*i*	Dual-probe *i* flowline resistivity at sink probe
DHP*i*	Dual-probe *i* strain gauge pressure at horizontal probe
D*i*TH	Dual-probe *i* strain gauge temperature at horizontal probe
D*i*TR	Dual-probe *i* flowline resistivity temperature at sink probe
D*i*TS	Dual-probe *i* strain gauge temperature at sink probe
DQP*i*	Dual-probe *i* quartz gauge pressure at horizontal probe
DQT*i*	Dual-probe *i* quartz gauge temperature
DSP*i*	Dual-probe *i* strain gauge pressure at sink probe

† Variable *i* is the module number (1 to 3).

Operation

The MRPS is always run with the MRDP. The MDT tool is anchored to the formation during pressure measurements or sampling.

Standoffs should be used to minimize sticking.

Formats

The format in Fig. 1 includes all the pressures and temperatures from the different gauges. It also includes data from the MRPS.

- Track 1
  - BFR1 is the fluid resistivity measured in the flowline.
  - The B1TR and B1TV temperatures are measured at the resistivity cell and strain gauge, respectively.
  - BSG1 from the MRPS is presented on an expanded scale as a curve and in alphanumerical values.
- Time track
  - ETIM is the elapsed time at the station.
  - HMS1 is the motor speed, which shows when the hydraulic motor is running to take a pretest or to set or retract the tool.
- Track 2
  - DSP1 is presented as alphanumerical values and at reduced scale to help look for stabilization.
  - DFR1 is shown as alphanumerical values.
  - D1TR and D1TS are used for fluid interpretation.
- Track 3
  - DHP1 is presented in alphanumerical values and at reduced scale. D1TH is a curve. Both are observed for stabilization.

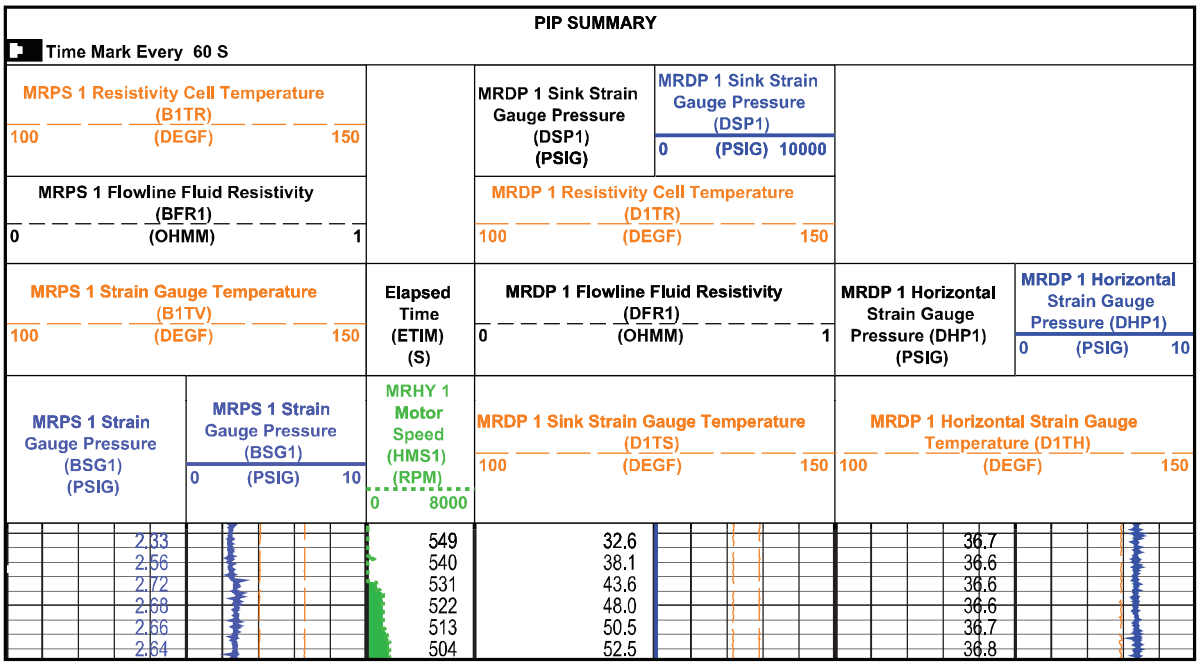

Figure 1. MRDP station format.

Response in known conditions

- The MRDP is used specifically to test for communication of different points of the formation with real-time acquisition. Quality control is limited to the acquired data with no noise and by ensuring that communication is noted on the observation probes, as evidenced by pressure disturbance.
- The hydrostatic pressures should be stable and plot a mud gradient close to the actual well mud gradient. The mud system should be stable for close agreement.
- The well fluid level should be known and taken into account along with deviation for comparing the measured hydrostatic pressure with the anticipated mud pressure.
- Formation pressures are usually recorded until the measured pressure is changing by less than 1 psi/min for strain gauges or less than 0.1 psi/min for quartz gauges. Pressure stabilization is critical for accurately measuring formation pressure.
- Typically there are three types of pretests:
  - Normal pretest: The last-read buildup is a stabilized value that equals the formation pressure.
  - Dry test: The fluid mobility is very low and there is not enough contribution from the formation to transmit the formation pressure to the flowline and pressure gauges.
  - Lost seal: The pressure at the end of the set cycle is higher than the pressure at the beginning of the set cycle.

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MDT Pumpout Module

Overview

The Pumpout Module (MRPO) of the MDT* modular formation dynamics tester is used to flow fluids from the reservoir at a controlled flowing pressure. Pressure control is required to avoid the separation of phases (i.e., gas or solids separating from oil, or liquid condensing from gas). Representative fluid samples require a "single-phase" fluid. The LFA* Live Fluid Analyzer, CFA* Composition Fluid Analyzer, or both modules can be used in combination with the MRPO to detect phase separation. The LFA module also measures the level of filtrate contamination. The fluid is then diverted to a sample chamber, where it is preserved for later analysis.

The Pumpout Module is used for the following applications:

- to pump formation fluids from the inlet port, probe, or dual packers out to the borehole before sampling
- to conduct low-shock sampling, in which fluids flow from the flowline into sample chambers set up with hydrostatic pressure on the back side of the sample piston
- to inflate dual-packer elements with borehole fluid
- to pump fluid from the flowline into the formation (e.g., stress test, injection test).

Specifications

Mechanical Specifications

	MRPO
Temperature rating	392 degF [200 degC]
Pressure rating†	20,000 psi [138 MPa]
Borehole size—min.	5⅝ in [14.29 cm]
Borehole size—max.	22 in [55.88 cm]
Outside diameter	4.75 in [12.07 cm]
Length	10.63 ft [3.24 m]
Weight	340 lbm [154 kg]
Tension‡	160,000 lbf [711,710 N]
Compression‡	85,000 lbf [378,100 N]
H_2S Service	Yes

† 25,000-psi [172-MPa] and 30,000-psi [207-MPa] versions are available upon request.
‡ At 15,000 psi [103 MPa] and 320 degF [160 degC]. These ratings apply to all MDT modules except the Dual-Packer Module (MPRA). The compressive load is a function of temperature and pressure.

Tool quality control

Standard curves

The MRPO has four standard curves (Table 1).

Table 1. Standard Curves of the MDT Pumpout Module

Output Mnemonic	Output Name
POS3	MRPO solenoid 3 status
POMS	MRPO motor speed
POHP	MRPO hydraulic pressure
POPV	MRPO pump volume

Pump operation

The MRPO pump can be operated in two modes:

- Constant power: This mode is recommended for sampling gas. A duty cycle drives the hydraulic pump at varying speeds while maintaining a constant power load.
- Constant speed: This mode is recommended for sampling liquids. A constant motor speed is maintained while varying the power load.

Formats

The format in Fig. 1 is used mainly as a quality control to monitor the pump behavior.

- Track 1
  - Voltages and currents are displayed from the Power Cartridge (MRPC) module.
  - MRPO hydraulic pressure (POHP) is used to pump fluids.
  - Time track
  - Solenoid 3 status (POS3) shows the MRPO strokes.
- Track 2
  - Duty cycle (PODC) should be stable while pumping when the MRPO is run in constant-power mode.
  - Motor current (POMC) should be stable while pumping when the MRPO is run in constant-speed mode.
- Track 3
  - Motor speed (POMS) should be stable while pumping when the MRPO is run in constant-speed mode under constant load.

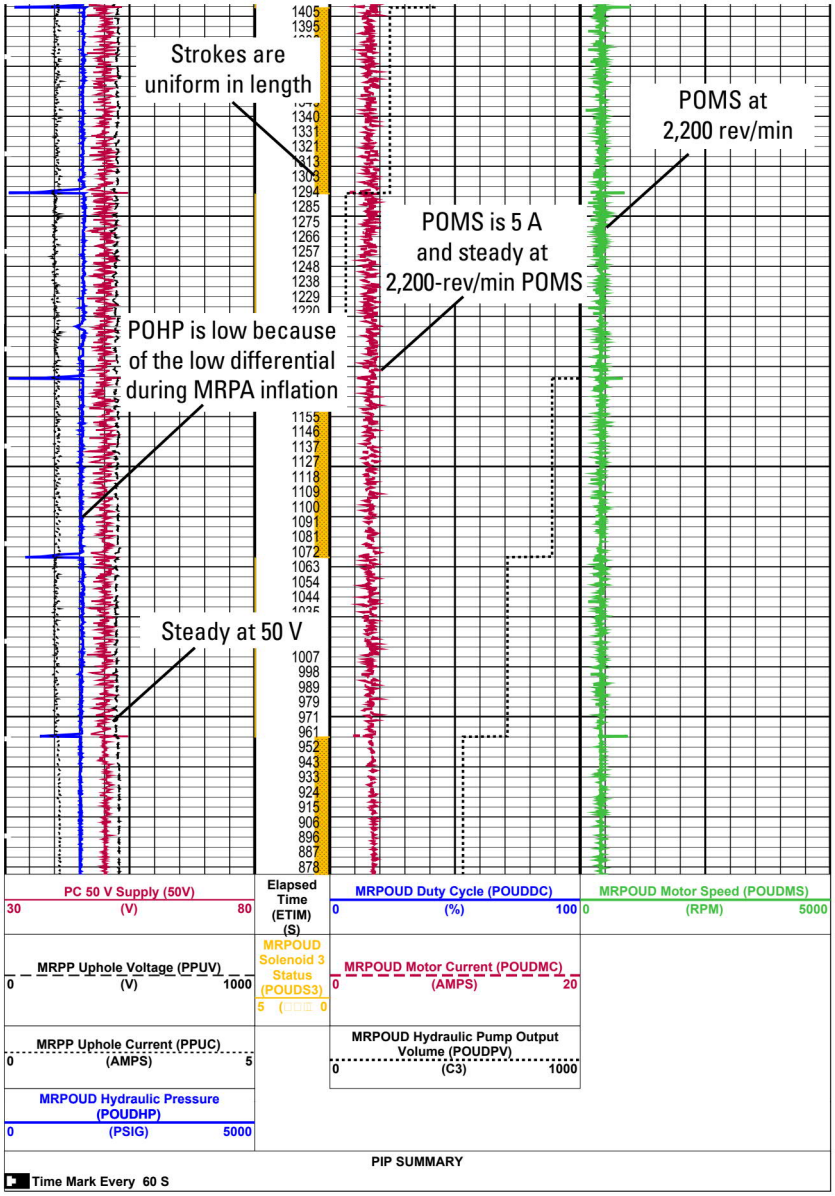

Figure 1. MRPO station format.

Response in known conditions

Figure 1 shows normal operation of an MRPO. During normal operation, the pumpout hydraulic pressure (POHP) should be approximately

$$\frac{\textit{displacement unit output pressure} - \textit{displacement unit input pressure}}{n} \quad (1)$$

where n is a constant that depends on the type of displacement unit used:

- 1.15 for standard displacement unit
- 1.52 for high-pressure displacement unit
- 2.09 for extra-high-pressure displacement unit
- 2.94 for XX high-pressure displacement unit.

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LFA

Overview

The LFA* live fluid analyzer for the modular formation dynamics tester is typically placed in the MDT* modular formation dynamics tester toolstring between the probe and the sample chambers or Pumpout Module (MRPO). It monitors the fluid flow using two sensor systems closely spaced along the flowline. The LFA module measures the percentage of drilling fluid filtrate mixed with the formation fluid as a function of time. This measurement is the basis for making real-time decisions on when to stop discarding the fluid to the wellbore and capture the sample in a chamber. The filtrate percentage is determined with a 10-channel optical spectrometer. Specific near-infrared wavelengths are used to determine the percentage of water-base filtrate in oil or of oil-base filtrate in water. A range of visible and near-infrared wavelengths is used to determine the percentage of oil-base mud filtrate in oil.

The LFA module also measures methane content and hydrocarbon content. From the ratio of the two, the gas/oil ratio (GOR) is calculated using a measurement made on oil above the bubblepoint. In addition to measuring contamination, the LFA module detects the presence of gas if the flowing pressure is below the bubblepoint. The engineer is alerted to slow the pumping rate to raise the pressure above the bubblepoint to avoid phase separation. The presence of a distinct gas phase is detected with an optical refractometer.

Specifications

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating†	20,000 psi [138 MPa]
Borehole size—min.	5⅝ in [14.29 cm]
Borehole size—max.	No limit
Outside diameter	4.75 in [12.07 cm]
Length	5.08 ft [1.55 m]
Weight	161 lbm [73 kg]
Tension	50,000 lbf [222,411 N]
Compression‡	85,000 lbf [378,100 N]

† 25,000-psi [172-MPa] and 30,000-psi [207-MPa] versions are available upon request.

‡ At 15,000 psi [103 MPa] and 320 degF [160 degC]. These ratings apply to all MDT modules except the Dual-Packer Module (MRPA). The compressive load is a function of temperature and pressure.

Calibration

The master calibration of the LFA tool determines the 0 and 100% points of the water/oil ratio (WOR) for the spectrometer. The gas detector is also calibrated for the 0 and 100% gas points to provide a rough estimate of low, medium, and high gas in the flowline. The spectrometer and gas detector master calibration should be performed once per month during the Tool Review and Inspection Monthly (TRIM) or when there is a change in the optical and electronic system.

A temperature calibration helps maintain accuracy for the optical densities within the range of ±0.01 optical density (OD). This calibration is required for the GOR output of the LFA tool. Temperature coefficients should be acquired once per year during the quality check.

Tool quality control

Standard curves

The LFA standard curves are listed in Table 1.

Table 1. LFA Standard Curves

Output Mnemonic	Output Name
FAOD_LFA[*n*]	LFA optical fluid density data
FAT	LFA temperature
FCOL_LFA	LFA fluid color
GASI	LFA gas indicator
GOR_UNCOR	LFA gas/oil ratio
OILF	LFA oil fraction
WATF	LFA water fraction

Operation

The LFA analyzer must be placed below the power cartridge. Normally, it is placed between the probe and the sample chamber modules.

It is highly recommended to run the LFA analyzer above the MRPO to take advantage of the segregation effect that occurs in the MRPO.

Formats

The format in Fig. 1 is most commonly used to monitor cleanup while sampling or scanning.

- Track 1
  - The gauge pressures BQP1 and BSG1 are from the inlet port (in this case the Single-Probe Module [MRPS]). It is important to monitor the pressure on the inlet port to detect plugging early.
- Time track
  - Where the GOR quality flag is green indicates high confidence, but where it is red indicates low confidence.
- Track 2
  - Normalized gas detector data is color coded to indicate low, medium, or high gas in the gas detector.
- Track 3
  - Oil and water fractions resulting from the spectrometer interpretation are presented as an image. A highly absorbing fluid such as mud also triggers this track. The coloration is based on the fluid's transmission and absorption properties. A low-absorption fluid is indicated by a light color, whereas a high-absorption fluid is a dark color.
- Track 4
  - FCOL_LFA is presented on a logarithmic scale. Because of the large dynamic range of the coloration, two curves with compatible scales are defined. FCOL_LFA is high in highly absorbing fluids and low in low-absorbing fluids.
- Track 5
  - The Flowline Fluid Resistivity (BFR1) from a resistivity cell in the MRPS is useful in fluid interpretation.
  - FAOD_LFA[n] presents individual optical densities for the 10 channels of the spectrometer.

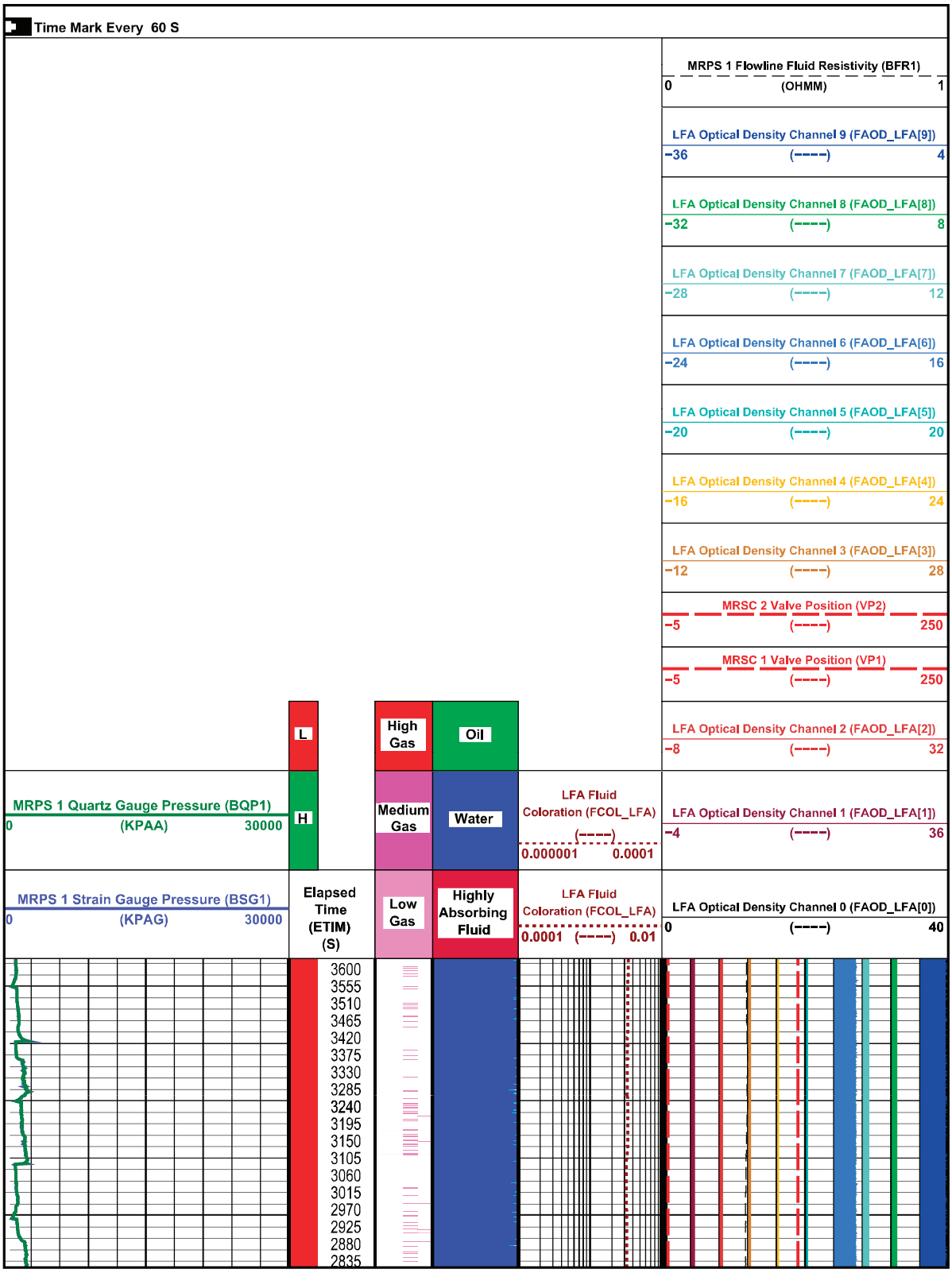

Figure 1. LFA station format.

Response in known conditions

- In mud, the highly absorbing fluid flag is triggered and the optical density channels are saturated. The FCOL_LFA value is also high.
- In water, a deep blue color appears in the fluid track. Water peaks appear on FAOD_LFA[6] and FAOD_LFA[9], which are the water peak channels
- In oil, the oil peak channel FAOD_LFA[8] has a peak. A green color is displayed. Also, FAOD_LFA[1] and FAOD_LFA[2] are slightly higher than the other FAOD_LFA[*n*] curves and FCOL_LFA has a high value, indicating fluid color.
- In gas, shades of red are shown in the log color track. Light pink is for low gas, darker pink for medium gas, and red for high gas concentrations.

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CFA

Overview

The CFA* composition fluid analyzer performs real-time compositional analysis of retrograde gases, condensates, and volatile oils. This module of the MDT* modular formation dynamics tester system has two detectors, a fluorescence device and an optical spectrometer. If liquids drop out from the gas phase, the dew that forms can be detected by an increase in the fluorescence level. The fluorescence detector ensures that the sample is above the dewpoint and in single-phase condition for gas sampling. The optical spectrometer is based on principles similar to those of the LFA* live fluid analyzer. However, the spread of the optical density channels enables the tool to measure the optical density at the peaks corresponding to methane (C_1), ethane to pentane group (C_2 to C_5), heavier hydrocarbon molecules (C_{6+}), carbon dioxide, and water to quantitatively measure their downhole concentrations.

Computation of the gas/oil ratio (GOR) or its inverse, the condensate/gas ratio (CGR), of the flowline fluid extends the range of GOR measurement to about 30,000 ft^3/bbl from the LFA maximum GOR of 2,500. In a hydrocarbon-bearing formation the CFA analyzer is used to characterize the fluid with respect to depth. The CFA compositional analysis at various depths provides compositional grading within the oil column below the gas zone. This information is valuable for reservoir engineers but was previously difficult to obtain. The CFA analyzer can be used in combination with the LFA analyzer to provide a total of 20 optical channels downhole for real-time assurance of single-phase conditions, detection of contamination, and measurement of composition.

Specifications

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating†	20,000 psi [138 MPa]
Borehole size—min.	5⅝ in [14.29 cm]
Borehole size—max.	No limit
Outside diameter	4.75 in [12.07 cm]
Length	5.1 ft [1.55 m] With handling caps: 6.6 ft [2.01 m]
Weight	161 lbm [73 kg]
Tension	50,000 lbf [222,411 N]
Compression‡	85,000 lbf [378,100 N]

† 25,000-psi [172-MPa] and 30,000-psi [207-MPa] versions are available upon request.

‡ At 15,000 psi [103 MPa] and 320 degF [160 degC]. These ratings apply to all MDT modules except the Dual-Packer Module (MRPA). The compressive load is a function of temperature and pressure.

Calibration

The master calibration of the CFA tool determines the 0 and 100% points of the water/oil ratio (WOR) for the spectrometer. The gas detector is also calibrated for the 0 and 100% gas points to provide a rough estimate of low, medium, and high gas in the flowline. The spectrometer and gas detector master calibration should be performed once per month during the Tool Review and Inspection Monthly (TRIM) or when there is a change in the optical and electronic system.

A temperature calibration helps maintain accuracy for the optical densities within the range of ±0.01 optical density (OD). This calibration is required for the GOR output of the CFA tool. Temperature coefficients should be acquired once per year during the quality check.

Tool quality control

Standard curves

The CFA standard curves are listed in Table 1.

Table 1. CFA Standard Curves

Output Mnemonic†	Output Name
AHYD_CFA	Apparent hydrocarbon density
CGR_CFA	Condensate gas ratio
CO2_CFA	CO_2 partial density
ETH_CFA	C_2–C_5 partial density
FAOD0_CFA	Optical density channel 0
FAOD1_CFA	Optical density channel 1
FLD0_CFA	Fluorescence channel 0
FLD1_CFA	Fluorescence channel 1
FLRA_CFA	Fluorescence ratio
GOR_CFA	Gas/oil ratio
HEX_CFA	C_{6+} partial density
METH_CFA	Methane partial density
WATF_CFA	Water volume fraction

† CFA mnemonics with the suffix CGA are identical outputs.

Operation

The CFA module must be placed below the power cartridge in the MDT toolstring. Normally, it is placed between the probe and the sample chamber modules.

It is highly recommended to run the CFA analyzer above the Pumpout Module (MRPO) to take advantage of the segregation effect that occurs in the MRPO.

Formats

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

- Track 1
  - The partial densities AHYD_CGA, METH_CGA, CO2_CGA, HEX_CGA, and ETH_CGA of the different hydrocarbon components are for C_1, CH_4, CO_2, C_{6+}, and C_2–C_5, respectively.
- Track 2
  - The CGAR_CGA ratio is in bbl/MMcf whereas the GOR_CGA ratio is in cf/bbl.
- Time, flag, and image tracks
  - ETIM is the elapsed time at a station.
  - The CO_2 analysis flag indicates if the CO_2 analysis is on (= 1) or off (= 0). Only when the CO_2 allow or disallow mode is set for allow and no water is detected is CO_2 analysis enabled. Otherwise, the flag indicates off.
  - The data quality flag is an indicator of the CFA compositional analysis data quality. Green indicates high confidence, yellow indicates medium confidence, and red indicates low confidence. Once hydrocarbons start pumping in large quantities, their signature is presented in the log according to their densities in the flowline. As mud is removed, the confidence flag changes to yellow and then to green, depending on the confidence level.
  - The Highly Scattering Fluid flag is displayed whenever all the optical channels, FAOD_CFA[0 through 9], become saturated. It is generally associated with mud, which has strong light-scattering properties.
- Track 3
  - In addition to FLD0_CGA and FLRA_CGA, monitoring channels FAOD1_CGA and FAOD0_CGA indicate the fluid coloration. In the presence of mud they are saturated.

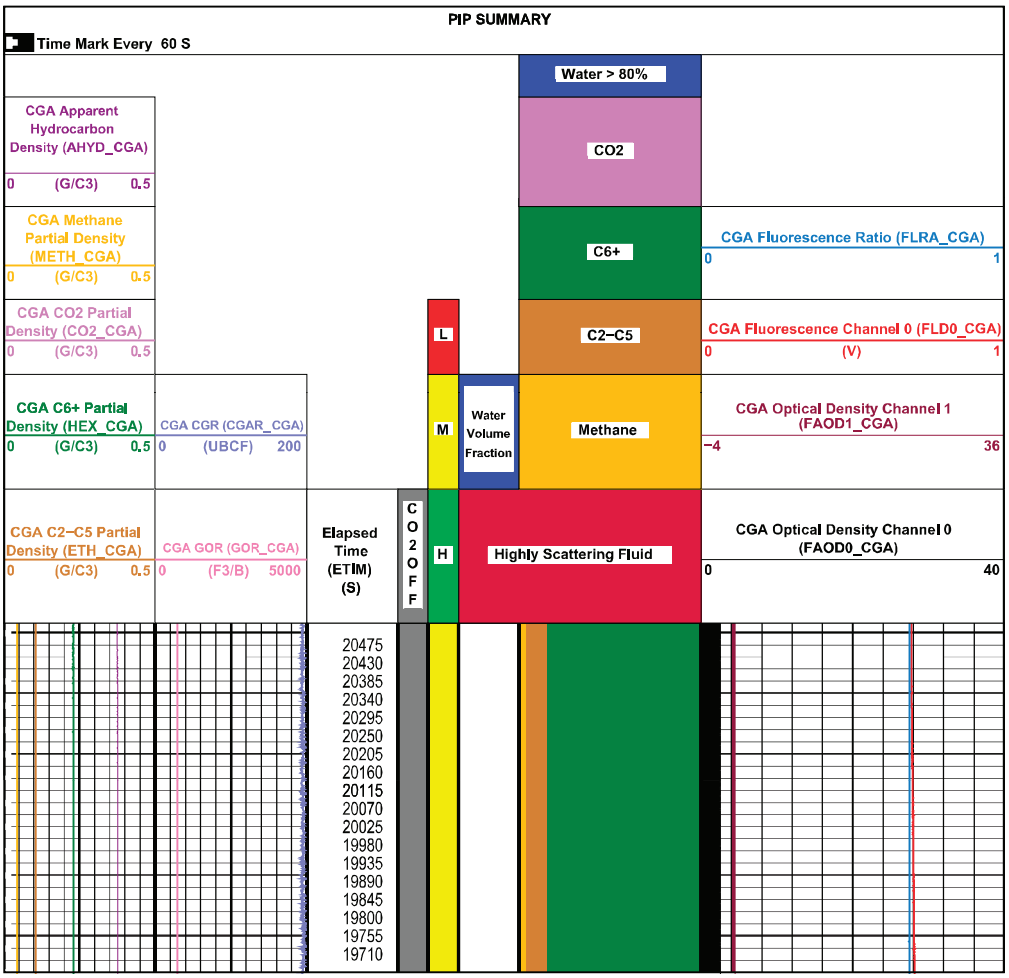

Figure 1. CFA station format.

Response in known conditions

- In mud, the Highly Scattering Fluid flag is on and all the optical channels FAOD_CFA[x] become saturated.
- In water, the color flag (water > 80%) is on, as well as the water fraction track indicates water. The fluorescence ratio remains high when water is present.
- In gas, the image track gives a clear color indication of the fraction of gas present. The fluid densities of C_1, C_2–C_5, and C_{6+} are graphically represented as color areas and also as output channels on Track 1.
- In oil, a high optical absorption is indicated on all optical channels. The florescence channel [0] displays a high value when oil is flowing in front of the sensor.

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MDT Multisample Module

Overview

The Multisample Module (MRMS) of the MDT* modular formation dynamics tester can retrieve six representative formation fluid samples on a single trip into the well. Two types of sample bottles are used in the MRMS: Multisample Production Sample Receptacle (MPSR) and the Single-Phase Multisample Module (SPMC).

The MRMS can be fitted with any combination of MPSR and SPMC bottles. A maximum of five MRMS modules (i.e., a total of 30 bottles) can be combined in one toolstring. The MPSR bottle has a 450-cm^3 [0.12-galUS] volume and is approved for transport by the US Department of Transportation (DOT). It can be heated to 200 degF [93 degC] for recombining the sample but is not suitable for long-term storage. The SPMC has a 250-cm^3 [0.07-galUS] volume and can be heated to 400 degF [204 degC]. It is not DOT transportable and therefore must be transferred at the wellsite. Heating to the reservoir temperature is required for revaporizing condensed liquids in gas condensate samples, and heating to 180 degF [82 degC] is required for recombining wax precipitants.

The SPMC maintains the sample pressure at or above the reservoir pressure despite the reduction in temperature at the surface. The SPMC must be used to prevent asphaltene solids from precipitating in oil samples because the precipitation of asphaltenes can be irreversible. The opening pressure on MPSR samples is much lower than the reservoir pressure because of the reduction in temperature at the surface. Gas, liquid, and solid phases separate within the MPSR bottle, and the sample cannot be validated, transferred, or analyzed until it has been recombined.

Specifications

Mechanical Specifications	
Temperature rating	392 degF [200 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	5⅝ in [14.29 cm]
Borehole size—max.	22 in [55.88 cm]
Outside diameter	5 in [12.70 cm] (max.)
Length	13.19 ft [4.02 m]
Weight	465 lbm [211 kg] (max.)
Tension†	160,000 lbf [711,710 N]
Compression†	85,000 lbf [378,100 N]

† At 15,000 psi [103 MPa] and 320 degF [160 degC]. These ratings apply to all MDT modules except the Dual-Packer Module (MRPA). The compressive load is a function of temperature and pressure.

Tool quality control

Standard curves

The MRMS standard curves are listed in Table 1.

Table 1. MRMS Standard Curves†

Output Mnemonic	Output Name
MEB*i*	MRMS *i* error band
MLP*i*	MRMS *i* lower valve position
MSL*i*	MRMS *i* slew rate
MST*i*	MRMS *i* set point
MUP*i*	MRMS *i* upper valve position

† Variable *i* is the module number (1 to 8).

Operation

The MRMS can be placed anywhere in the MDT toolstring below the power cartridge.

Formats

The format in Fig. 1 is used mainly to monitor the MRMS valves.

- Track 1
  - MUP*i* and MLP*i* are important for monitoring the closing and opening of the MRMS valves.
  - MEB*i* is for monitoring throttling, which is a means of regulating the flowing pressure differential by adjusting the valve opening. The error band shows how much error is accepted before a regulation correction for the throttling is done.
  - MSL*i* is also used when throttling. It is the speed at which the valve motor reacts to commands and is useful for valve position movement.
  - MST*i* is the pressure at which throttling is regulated.
- Time track
  - ETIM is the elapsed time on station.

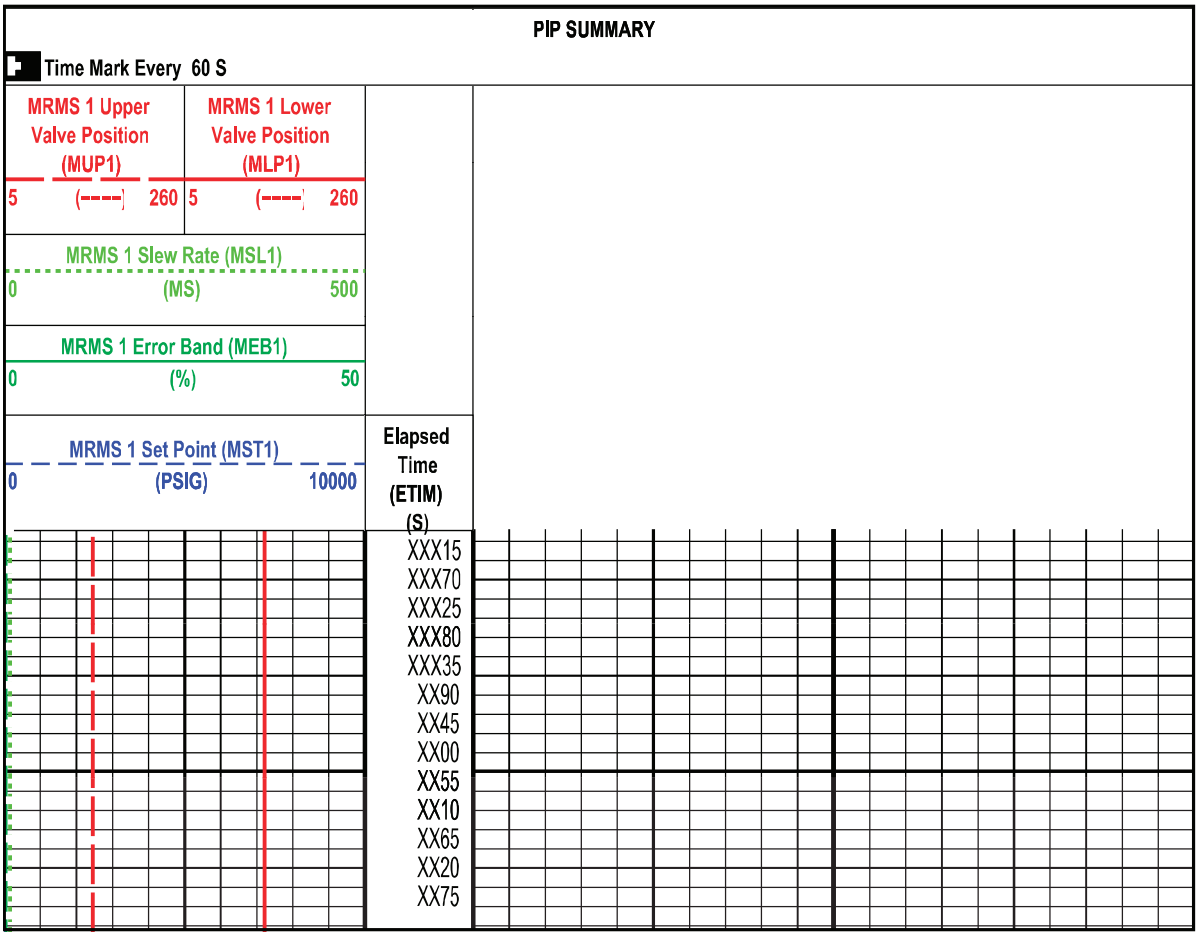

Figure 1. MRMS station format.

Response in known conditions

- The closed MRMS valve position reads 0 on the log, whereas when fully open it reads 130.

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PressureXpress

Overview

PressureXpress* reservoir pressure while logging service delivers a pressure survey with three primary answers: reservoir pressure for connectivity analysis, pressure gradient for fluid density and oil/water/gas contacts, and fluid mobility to aid in the selection of sampling points. The PressureXpress tool features high-accuracy pressure gauges, a precisely controlled, wide pretest range, and full combinability to run as a standard addition to the Platform Express* integrated toolstring.

The PressureXpress tool provides an efficient pressure solution in low-permeability applications with its high-precision pretest system that allows for ultra-small pretest volumes, minimized flowline storage volume, and real-time downhole control. Also incorporated is a dedicated wellbore pressure gauge that may be necessary for developing procedures and algorithms to overcome the supercharging effect that is commonly seen in many low-permeability applications.

Specifications

Measurement Specifications	
Output	Formation pressure, fluid mobility (permeability/viscosity), fluid density
Logging speed	Stationary
Range of measurement	Max. measured overbalance: XPT-B: 6,500 psi [44.8 MPa] XPT-C: 8,000 psi [55 MPa] XPT-H: 8,000 psi [55 MPa]
Resolution	Sapphire* gauge: 0.04 psi [276 Pa] at 1 Hz CQG* gauge: 0.005 psi [34 Pa] at 1 Hz XPT-H Quartzdyne® gauge: 0.01 psi/s [29 Pa/s] Temperature: 0.01 degF [0.05 degC]
Accuracy	Sapphire gauge: ±(5 psi [34 kPa] + 0.01% of reading) CQG gauge: ±(2 psi [14 kPa] + 0.01% of reading) XPT-H Quartzdyne gauge: ±0.02% of full scale + 0.01% of reading Temperature: ±1.0 degF [±0.05 degC]
Depth of investigation	Probe extension beyond packer surface: 0.45 in [1.14 cm]
Mud type or weight limitations	None
Combinability	Combinable with Platform Express* system and most tools

Mechanical Specifications				
	XPT-B	**XPT-C**	**XPT-H**	**HPXT**
Temperature rating	302 degF [150 degC]	320 degF [160 degC]	400 degF [204 degC]	400 degF [204 degC]
Pressure rating	20,000 psi [138 MPa] With CQG gauge: 15,000 psi [103 MPa]	20,000 psi [138 MPa] With CQG gauge: 15,000 psi [103 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]
Borehole size—min.	4¾ in [12.07 cm]	4¾ in [12.07 cm]	5⅞ in [14.92 cm]	4¾ in [12.07 cm]
Borehole size—max.	14.90 in [37.85 cm]	14.90 in [37.85 cm]	14.90 in [37.85 cm]	14.90 in [37.85 cm]
Outside diameter	Tool: 3.375 in [8.57 cm] Probe section: 3.875 in [9.84 cm]	Tool: 3.375 in [8.57 cm] Probe section: 3.875 in [9.84 cm]	Tool: 3.875 in [9.84 cm] Tool with bumpers or probe section with bumpers: 4.1375 in [10.51 cm]	Tool: 3.75 in [9.53 cm] Tool with bumpers or probe section without bumpers: 4.063 in [10.32 cm]
Length	21.31 ft [6.49 m]	21.55 ft [6.57 m]	30 ft [9.14 m]	30.2 ft [9.20 m]
Weight	450 lbm [204 kg]	451 lbm [204.5 kg]	483 lbm [219 kg]	730 lbm [31 kg]
Tension	50,000 lbf [222,410 N]	50,000 lbf [222,410 N]	50,000 lbf [222,410 N]	50,000 lbf [222,410 N]
Compression	22,000 lbf [97,860 N]	22,000 lbf [97,860 N]	22,000 lbf [97,860 N]	22,000 lbf [97,860 N]

Calibration

Master calibration of the pressure gauges is conducted on a yearly basis.

The CQG crystal quartz gauge should be recalibrated when the gauge has been used in the field for 12 months or when the shift of the atmospheric pressure reading at 95 degF [35 degC] exceeds 2 psi. The time between master calibrations should not exceed 18 months.

The Sapphire gauge should be recalibrated when the gauge has been used in the field for 12 months.

Tool quality control

Standard curves

The PressureXpress standard curves are listed in Table 1.

Table 1. PressureXpress Standard Curves

Output Mnemonic	Output Name
CP_CQG	Flowline CQG pressure
CP_HYD	Hydrostatic Sapphire pressure
CP_SAP	Flowline Sapphire pressure
MSPE_XPT	PressureXpress motor speed
MTEP_CQG	Flowline CQG temperature
MTEP_SAP	Flowline Sapphire temperature
PTV_XPT	Pretest volume
QCP	CQG zoomed pressure

Operation

The tool body is designed to minimize the tool area in contact with the formation and therefore minimize the sticking risk. Standoffs should also be used to minimize sticking.

The probe is located at 75.6 in [1.92 m] above the tool bottom (the PressureXpress tool bottom is the tool zero when it is run stand alone). Stations and measurements must be done in agreement with this offset.

Run in combination with Platform Express system, the PressureXpress probe is 180° opposite the density pad.

Formats

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

- Depth and station track
  - This track is useful for identifying which operation is under way through the displayed colors: red for setting, green for pretest, blue for retract, orange for initializing the position of the pistons, and purple for automatic compensation (ACOM), which is a task performed downhole to compensate for any drift in strain gauge measurement circuits.
  - MSPE_XPT is for monitoring tool motor operation in rpm.
- Track 1
  - The curves in this track (MTEP_QG , QCP , CP_SAP, MTEP_SAP, and CP_HYD) are the pressures and temperatures from the tool gauges.
- Track 2
  - QCP is displayed in alphanumerical values.
- Track 3
  - CP_SAP is displayed in alphanumerical values.
- Tracks 4, 5, and 6
  - The gauge pressures are presented for formation evaluation with three different scales for a ready overview for stabilization monitoring. These data are used to plot the pressure versus time (PITM) plot (Fig. 2).

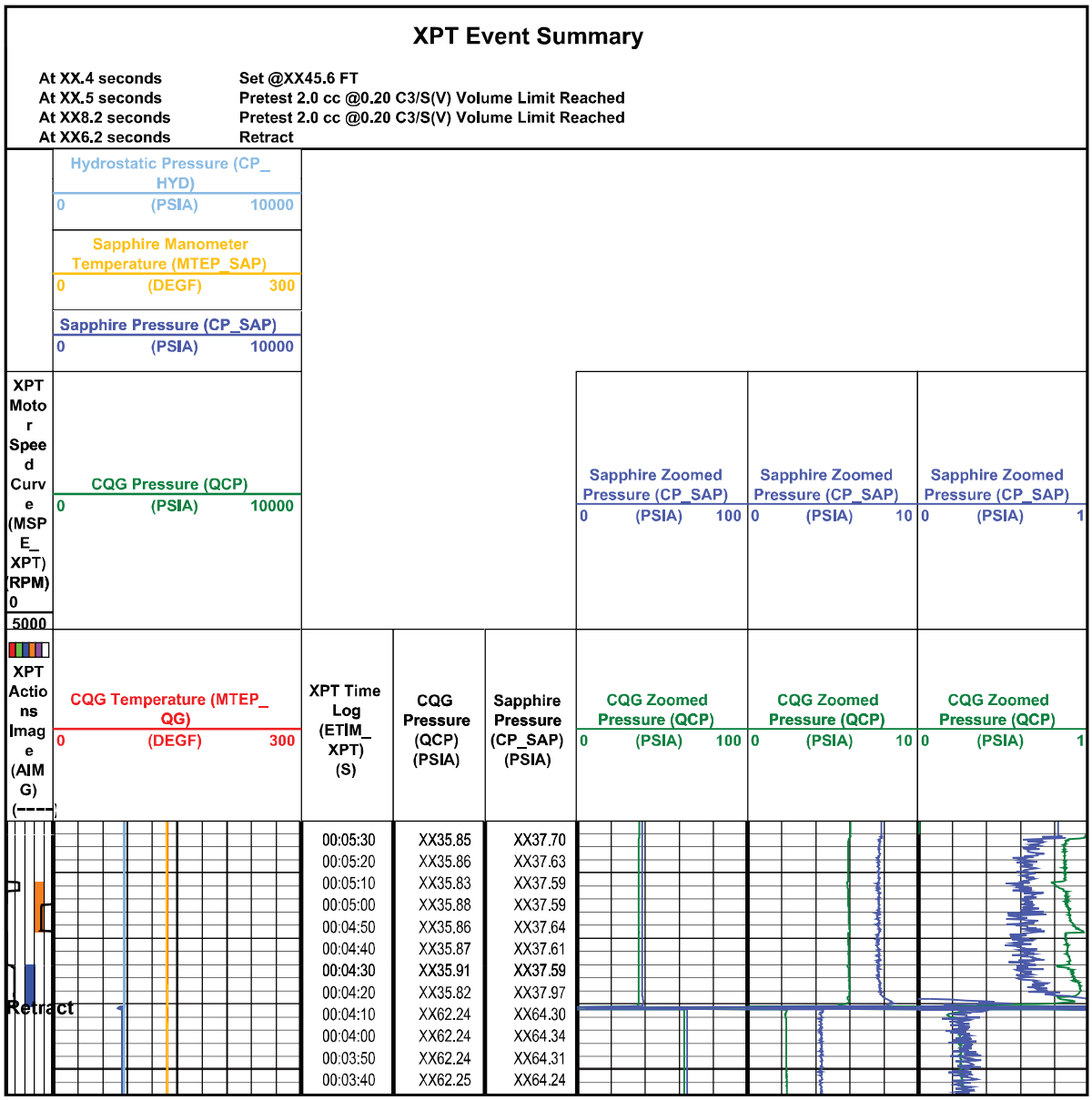

Figure 1. PressureXpress station format.

The PTIM plot (Fig. 2) displays the hydrostatic pressure, flowline pressure, and motor speed as a function of time. This overview of the pretest includes the important values of mud pressure before and after the pretest, the last buildup pressure, and mobility.

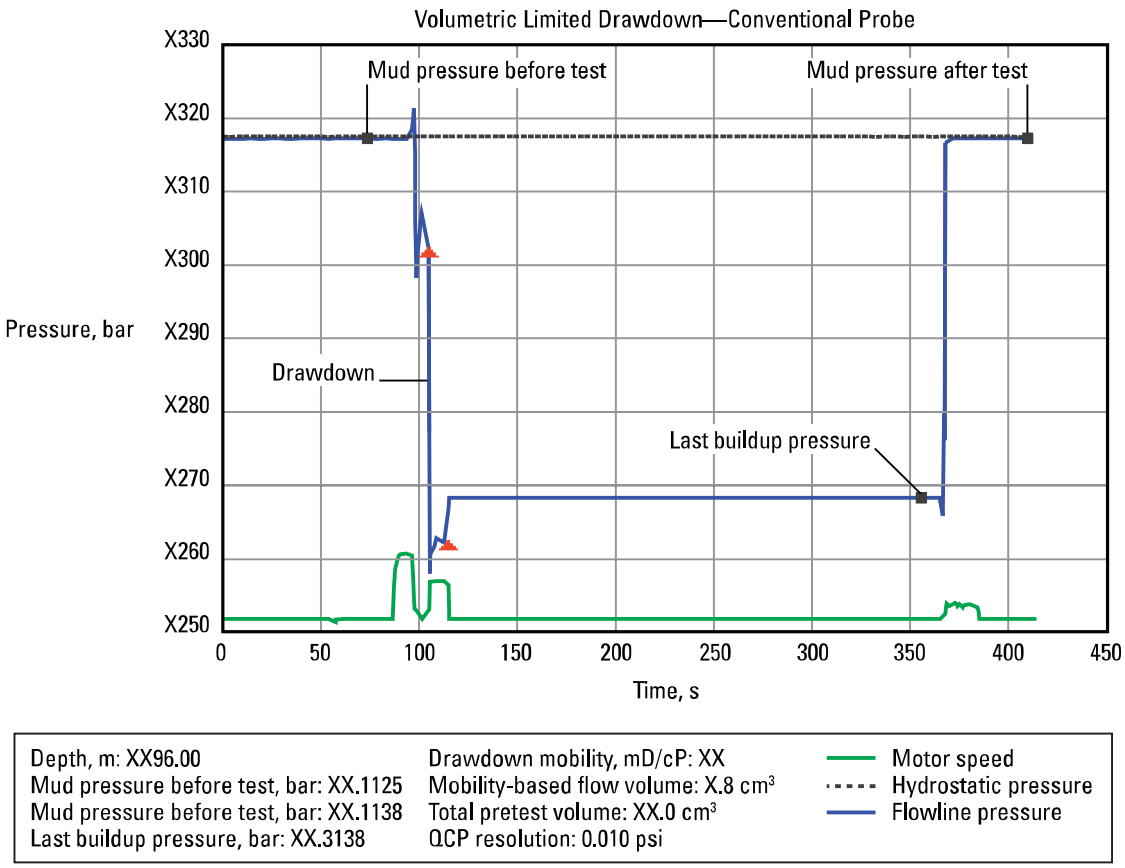

Figure 2. PressureXpress PTIM plot.

Response in known conditions

- The hydrostatic pressure should be stable and the resulting mud gradient should plot close to the actual well mud gradient. The mud system should be stable to achieve close agreement.
- The well fluid level should be known and taken into account along with the deviation in comparing the measured hydrostatic pressure with the anticipated mud pressure.
- Formation pressure is normally recorded until the measured pressure is changing by less than 1 psi/min for strain gauges or less than 0.1 psi/min for quartz gauges. Pressure stabilization is critical for accurately measuring formation pressure.
- Typically there are three types of pretests:
  - Normal pretest: The last-read buildup is a stabilized value that equals the formation pressure.
  - Dry test: The fluid mobility is very low and there is not enough contribution from the formation to transmit the formation pressure to the flowline and pressure gauges.
  - Lost seal: The pressure at the end of the set cycle is higher than the pressure at the beginning of the set cycle.

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SRFT

Overview

The SRFT* slimhole repeat formation tester—with a 3.375-in [8.57-cm] OD—brings wireline formation tester services to small-diameter boreholes. It can also be run in wells where conventional tools cannot operate because of abrupt changes in angle, swelling formations, hole restrictions, and other drilling problems. The SRFT tool can be repeatedly set and retracted during a single trip in the well. The CQG* crystal quartz gauge is used to provide quick, accurate pressure measurements. One segregated sample can be recovered in a sample bottle that is approved by the US Department of Transportation (DOT) for transport. Alternatively, two fluid samples can be recovered from two different depths. Sample chambers are available in two sizes: 450 cm^3 [0.12 galUS] and 2⅜ galUS [9 L]. An optional water cushion is used to reduce the shock resulting from pressure drawdown when a sample chamber is opened for sampling. Typical applications include formation pressure measurements and fluid sampling in slim holes, short-radius horizontal wells, and unstable or restricted wells.

Specifications

Measurement Specifications	
Output	Pressure measurement, fluid samples
Logging speed	Stationary measurements
Range of measurement	0 to 20,000 psi [0 to 138 MPa] at up to 350 degF [177 degC]
Accuracy	CQG gauge: Accuracy: ±(2 psi [13,789 Pa] + 0.01% of reading) Strain gauge: 5,000-, 10,000-, and 20,000-psi [34-, 69-, and 138-MPa] ranges Accuracy: ±0.1% of full scale Resolution: 0.001% of full scale
Special applications	Slim or restricted holes

Mechanical Specifications			
	Standard Probe and Piston	**Telescoping Piston (SRTP)**	**Large-Hole Kit (SRLH)**
Temperature rating	350 degF [177 degC]	350 degF [177 degC]	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]
Borehole size—min.†	4.125 in [10.48 cm]	4.8 in [12.19 cm]‡	6.5 in [16.51 cm]‡
Borehole size—max.	6.3 in [16.00 cm]	7.8 in [19.81 cm]	9.8 in [24.89 cm]
Outside diameter	Fully retracted: 3.375 in [8.57 cm] Fully extended: 6.5 in [16.51 cm]	Fully retracted: 3.375 in [8.57 cm] Fully extended: 8.0 in [20.32 cm]	Fully retracted: 4.5 in [11.43 cm] Fully extended: 10.0 in [25.40 cm]
Length	22.23 ft [6.77 m]	22.23 ft [6.77 m]	22.23 ft [6.77 m]
Weight	455 lbm [206 kg]	455 lbm [206 kg]	455 lbm [206 kg]
Tension	35,000 lbf [155,690 N]	35,000 lbf [155,690 N]	35,000 lbf [155,690 N]
Compression	3,900 lbf [17,350 N]	3,900 lbf [17,350 N]	3,900 lbf [17,350 N]

† Minimum borehole size is dependent on the borehole conditions and whether the SRFT tool is run on cable or pipe.

‡ If an SRFT tool with telescoping pistons is set in a hole smaller than recommended, the larger section of the telescoping pistons will touch the borehole. Standoffs should be used in this case.

Sample Chamber Specifications			
	SRSU-AA with MPSR-BA[†]	**SRSC-AA**	**Water Cushion (SRSW-AA)**
Capacity	450 cm^3 [0.12 galUS]	2.375 galUS [9.0 L]	2.375 galUS [9.0 L]
Temperature rating	350 degF [177 degC]	350 degF [177 degC]	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa][‡]	20,000 psi [138 MPa][‡]	20,000 psi [138 MPa][‡]
Outside diameter	3.375 in [8.57 cm]	3.375 in [8.57 cm]	3.375 in [8.57 cm]
Length	4.45 ft [1.36 m]	9.31 ft [2.84 m]	9.11 ft [2.78 m]
Weight	106 lbm [48 kg]	97 lbm [44 kg]	91 lbm [41 kg][§]
Special applications	DOT-approved Multisample Production Sample Receptable (MPSR) H_2S service Pressure-volume-temperature (PVT) samples	H_2S service	H_2S service Optional water cushion for SRSC-AA

[†] The SRSU is only the carrier and also provides the water cushion for the MPSR.
[‡] Rated to 20,000 psi [138 MPa] for both internal and external pressure.
[§] The SRSW filled with water weighs 111 lbm [50 kg].

Calibration

The CQG crystal quartz gauge used in the SRFT tool should be recalibrated when the gauge has been used in the field for 12 months or when the shift of the atmospheric pressure reading at 95 degF [35 degC] exceeds 2 psi. The time between master calibrations should not exceed 18 months.

The strain gauge should be recalibrated after it has been used in the field for 6 months or when the shift in the atmospheric pressure at 95 degF [35 degC] exceeds 0.05% full scale (e.g., 5 psi for a 10,000-psi gauge). The dead-weight tester used to calibrate strain gauges should be calibrated once every 2 years.

The strain gauge temperature calibration is a two-point linear calibration using precision resistors with reference values equivalent to 32 degF and 350 degF [0 degC and 177 degC].

Tool quality control

Standard curves

The SRFT standard curves are listed in Table 1.

Table 1. SRFT Standard Curves

Output Mnemonic	Output Name
MSPE	Motor speed
RPQP	CQG quartz gauge pressure
SGP	Strain gauge pressure
TEMS	Strain gauge temperature

Operation

The SRFT tool is set against the formation during pressure measurements or sampling. The tool is run with standoffs to minimize sticking.

Formats

The format in Fig. 1 is used mainly for acquisition monitoring of the gauges and stabilization periods during pretests.

- Track 1
  - MSPE shows when the hydraulic motor is running for taking a pretest or setting or retracting the tool.
  - RPQP and SGP are presented on a wide scale for an overview.
  - TEMS is shown in numerical values.
  - The track also has a visual plot showing green during operation of the tool (set and retract), indicating how much time was taken to complete the operation and which operation is occurring.
- Time track
  - ETIM is the elapsed time on station.
- Tracks 2 and 3
  - SGP is presented again in alphanumerical values and on a small-scale curve for identifying stabilization.
- Tracks 4 and 5
  - RPQP is presented in alphanumerical values and on a small-scale curve for identifying stabilization. Stabilization monitoring is critical to ensure a good pretest.

Elapsed Time (s)	Event Summary
XX3.2	Retracting
XX3.7	Packer SET at XX408.5 FT
0.0	Automatic Compensation
	Strain Gauge Pressure Coefficients:
	a: 1.69e−008 b: 0.992 c: 4.1
	Strain Gauge Temperature Coefficients:
	Gain: 1.01 Offset: −1.58

PIP SUMMARY

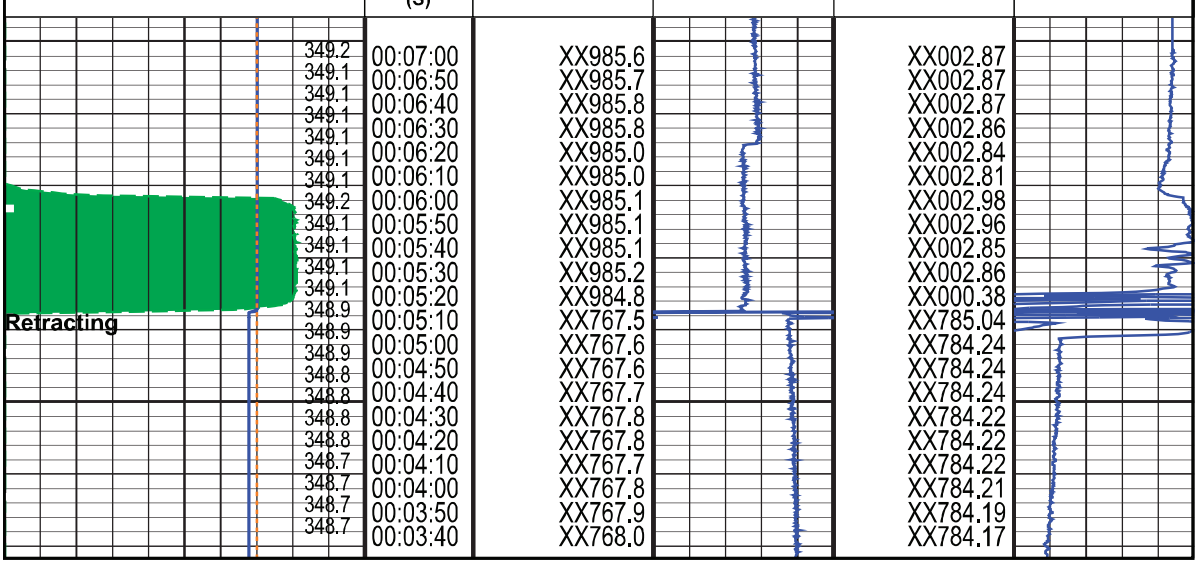
Time Mark Every 60 S

Strain Gauge Temp (TEMS) 0 (DEGF) 500

Strain Gauge Pressure (SGP) 0 (PSIA) 10000

CQG Gauge Pressure (RPQP) 0 (PSIA) 10000

Motor Speed (MSPE) 0 (RPM) 4000



Strain Gauge Temperature (TEMS) (DEGF)	Elapsed Time (ETIM) (S)	Strain Gauge Pressure (SGP) (PSIA)	CQG Gauge Pressure (RPQP) (PSIA)
349.2	00:07:00	XX985.6	XX002.87
349.1	00:06:50	XX985.7	XX002.87
349.1	00:06:40	XX985.8	XX002.87
349.1	00:06:30	XX985.8	XX002.86
349.1	00:06:20	XX985.0	XX002.84
349.1	00:06:10	XX985.0	XX002.81
349.2	00:06:00	XX985.1	XX002.98
349.1	00:05:50	XX985.1	XX002.96
349.1	00:05:40	XX985.1	XX002.85
349.1	00:05:30	XX985.2	XX002.86
349.1	00:05:20	XX984.8	XX000.38
348.9	00:05:10	XX767.5	XX785.04
348.9	00:05:00	XX767.6	XX784.24
348.9	00:04:50	XX767.6	XX784.24
348.8	00:04:40	XX767.7	XX784.24
348.8	00:04:30	XX767.8	XX784.22
348.8	00:04:20	XX767.8	XX784.22
348.8	00:04:10	XX767.7	XX784.22
348.7	00:04:00	XX767.8	XX784.21
348.7	00:03:50	XX767.9	XX784.19
348.7	00:03:40	XX768.0	XX784.17

Expanded SGP units decade (SGP) 0 (PSIA) 10

Fractional CQG Gauge Pressure (RPQP) 0 (PSIA) 1

Figure 1. SRFT station format.

The SRFT pressure versus time (PTIM) plot (Fig. 2) is generated immediately after the station log is completed. This provides a good overview of the pretest and includes the important values of mud pressure before and after the test, the last buildup pressure, and mobility.

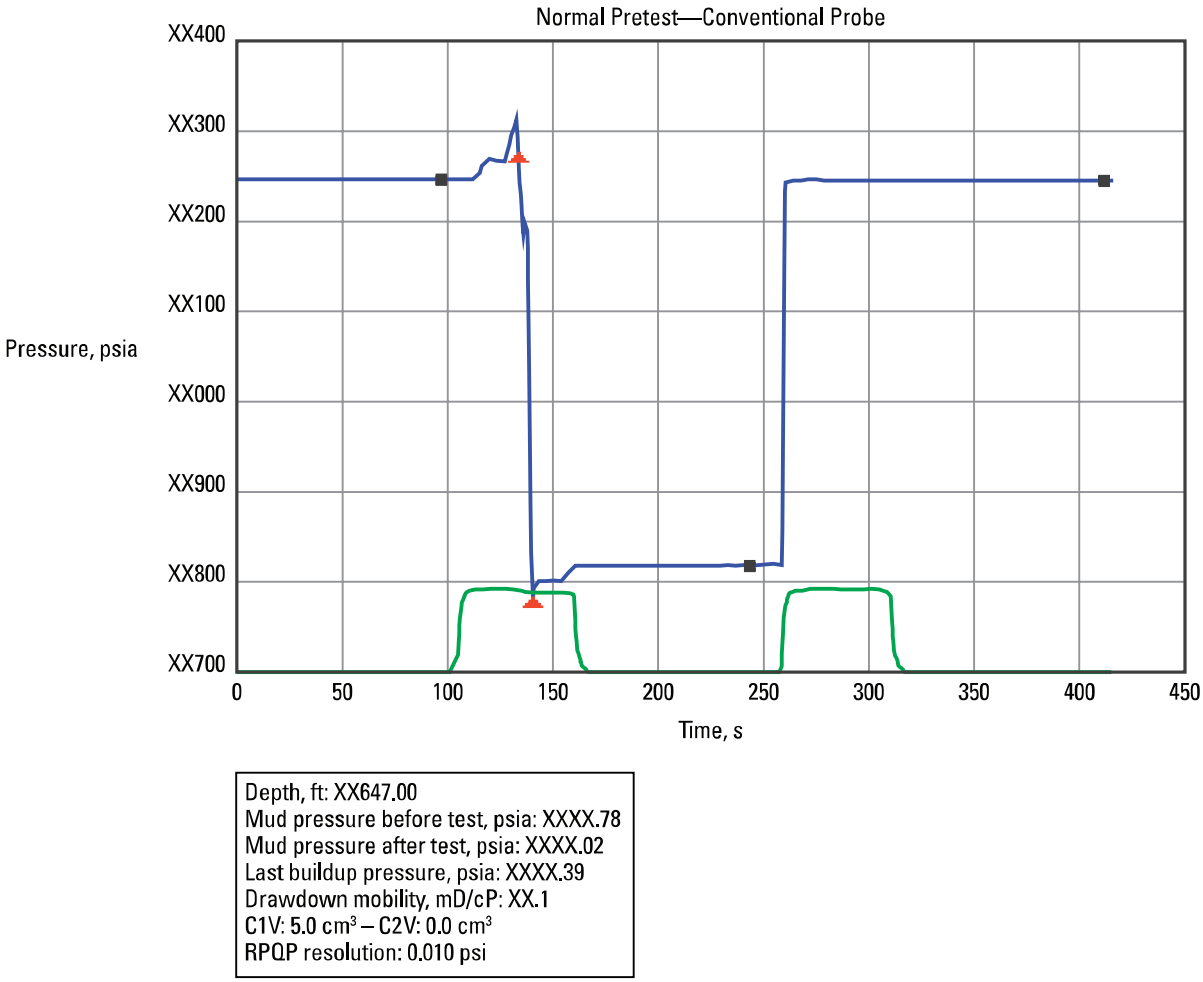


Figure 2. SRFT pressure versus time plot.

Response in known conditions

- The mud pressure log versus the true vertical depth should be a close match to the mud weight. A stable mud system is necessary for achieving close agreement.
- The well fluid level should be known and taken into account along with the deviation in comparing the measured hydrostatic pressure with the anticipated mud pressure.
- Formation pressure is normally recorded until the measured pressure is changing by less than 1 psi/min for strain gauges or less than 0.1 psi/min for quartz gauges. Pressure stabilization is critical for accurately measuring formation pressure.
- Typically there are three types of pretests:
  - Normal pretest: The last-read buildup is a stabilized value that equals the formation pressure.
  - Dry test: The fluid mobility is very low and there is not enough contribution from the formation to transmit the formation pressure to the flowline and pressure gauges.
  - Lost seal: The pressure at the end of the set cycle is higher than the pressure at the beginning of the set cycle.

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CHDT

Overview

The CHDT* cased hole dynamics tester, a component of the ABC* analysis behind casing suite of services, makes multiple pressure measurements and collects fluid samples from behind a cased wellbore. Developed with support from the Gas Technology Institute (GTI), the CHDT tool has the unique ability to drill through a cased borehole and into the formation, acquire multiple pressure measurements, recover high-quality fluid samples, and then plug the hole made in the casing to restore pressure integrity—in a single trip. The tool seals against the casing and uses a flexible drill shaft to penetrate both the casing and cement and into the formation. As the drill penetrates the target, the integrated instrument package simultaneously monitors pressure, fluid resistivity, and drilling parameters. This additional information about the casing/cement/formation interfaces enables real-time quality control of the operation.

The CHDT tool is combinable with MDT* modular formation dynamics tester modules in 6⅝-in and larger casing. The module combinations are used to perform high-quality single-phase sampling, enhanced fluid identification, and contamination monitoring, which are applications that were previously possible only for openhole applications. In combination with the other through-casing formation evaluation tools in the ABC services suite—CHFR-Plus* cased hole formation resistivity tool, RSTPro* reservoir saturation tool, CHFD* cased hole formation density service, CHFP* cased hole formation porosity service, Sonic Scanner* acoustic scanning platform, and DSI* dipole shear sonic imager—the CHDT tool delivers comprehensive reservoir analysis behind casing.

Specifications

Measurement Specifications	
Output	Behind-casing pressure measurement, PVT and conventional fluid samples, fluid mobility
Logging speed	Stationary
Accuracy	CQG gauge: ±(2 psi [13,789 Pa] + 0.01% of reading) (accuracy), 0.008 psi [55 Pa] at 1.3-s gate time (resolution)
Depth of drillhole	6 in [152 mm] (max. from casing)
Drillhole diameter	0.281 in [7.137 mm]
Pretest volume	6.1 in^3 [100 cm^3]
Limitations	Max. casing thickness: 0.625 in [1.59 cm] in 13⅜-in casing
Combinability	MDT modules,† another CHDT tool, most other tools
Special applications	Up to six holes drilled and plugged per run‡ H_2S service Fluid identification (resistivity and LFA* live fluid analyzer)

† Combinable with MDT modules in 6⅝-in and larger casing
‡ Formation and casing dependent

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa] Max. underbalanced: 4,000 psi [27 MPa] Plug rating: 10,000 psi [69 MPa] (bidirectional)
Casing size—min.	5½ in
Casing size—max.	9⅝ in
Outside diameter	4.25 in [10.79 cm]
Length	Pressure measurement only: 34.1 ft [10.4 m] Optional sample chamber: 9.7 ft [2.96 m]
Weight	Depends on configuration
Tension	Depends on configuration
Compression	Depends on configuration

Calibration

The downhole sensor readings of CHDT tools are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration.

The fluid resistivity measurement is calibrated to produce two straight-line transforms. One line covers the range 0.03 ohm.m to 0.33 ohm.m and the other is for 0.33 ohm.m to 3.30 ohm.m.

The CQG* crystal quartz gauge used in the CHDT tool should be recalibrated when the gauge has been used in the field for 12 months or when the shift of the atmospheric pressure reading at 95 degF [35 degC] exceeds 2 psi. The time between master calibrations should not exceed 18 months.

The strain gauges should be recalibrated after they have been used in the field for 6 months or when the shift in the atmospheric pressure at 95 degF [35 degC] exceeds 0.05% full scale (e.g., 5 psi for a 10,000-psi gauge). The dead-weight tester used to calibrate strain gauges should be calibrated once every 2 years. The strain gauge temperature calibration is a two-point linear calibration using precision resistors with reference values equivalent to 32 degF and 350 degF [0 degC and 177 degC].

Tool quality control

Standard curves

The CHDT standard curves are listed in Table 1.

Table 1. CHDT Standard Curves†

Output Mnemonic	Output Name
50V	Power cartridge 50-V power supply
CCBP*i*	CHDT casing drilling control (MDCC)*i* drillbit depth of penetration
CCHMS*i*	MDCC*i* hydraulic motor speed
CPFR*i*	CHDT probe module (MDCP)*i* flowline fluid resistivity
CPPV*i*	MDCP*i* pretest volume
CPPVSQ*i*	MSCP*i* current sequence pretest volume
CPQP*i*	MDCP*i* quartz gauge pressure
CPRT*i*	MDCP*i* resistivity cell temperature
CPSG*i*	MDCP*i* strain gauge pressure

† Variable *i* is the module number (1 to 3).

Operation

The CHDT tool is anchored to the casing during pressure measurements or sampling. No standoffs should be installed on the tool because standoffs may prevent the tool from properly sealing on the casing.

The internal casing ID should be smooth, uniform, and free of debris for a good-quality seal. Running a cement bond log before CHDT operations is recommended. The better the bond log, the better the formation pressure information. The data might be hard to interpret if the zone is not perfectly isolated by cement in the annulus.

Formats

The format in Fig. 1 is used mainly in station logs.

- Track 1
  - 50V should be a stable power voltage with minimal fluctuations throughout the operation.
  - CPFR*i* and CPRT*i* indicate the resistivity of the fluid used for interpretation of fluid type.
  - CCHMS*i* is for the hydraulic motor speed.
  - CPSG*i* and CPQP*i* are used to monitor formation and hydrostatic pressures. Stabilization is an important attribute in formation pretests.
- Time track
  - ETIM is the elapsed time on station.
- Track 2
  - CPPV*i* is shown as an alphanumerical value as well as a bar image on the left-hand side.
  - CPSG*i* is also shown as an alphanumerical value along with CPPVSQ*i* and a curve presentation.
- Track 3
  - The CCBP*i* depth of penetration of the drill in casing is presented in inches along with CPQP*i*. Numerical values are available for a stabilization look.

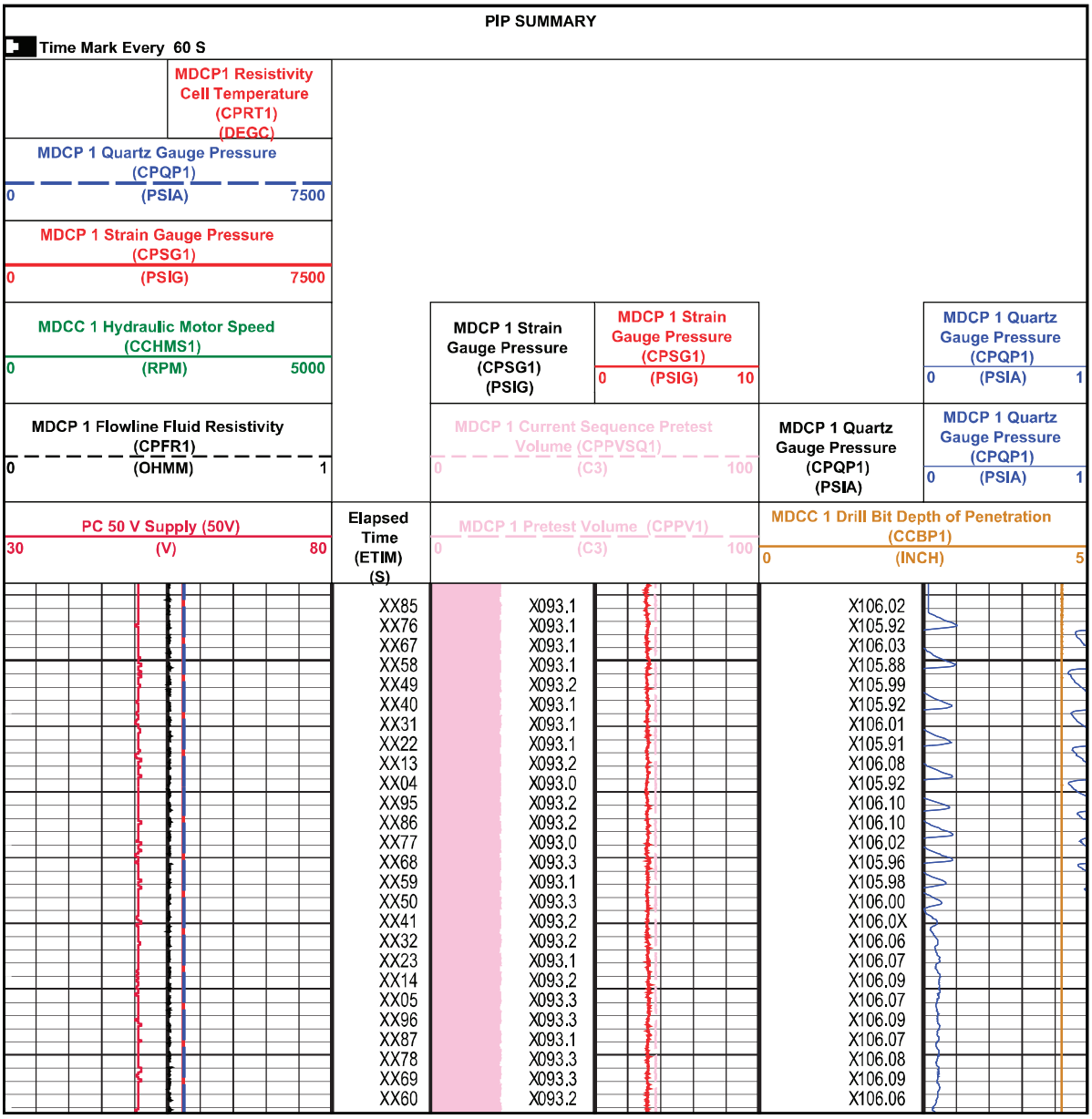

Figure 1. CHDT station format.

The pressure versus time plot (Fig. 2) displays the hydrostatic flowline pressure as a function of time. This overview includes a summary of the CHDT operation:

- Casing seal verification: A check of the tool sealing on casing is made to ensure that the pressure measurements are relevant and not influenced by the borehole. A leaking casing seal can yield erroneous formation pressures and temperatures.
- Drilling process: During the drilling process, monitoring the gauge pressures is important because the response in the annulus may be ambiguous.
- Pretest: A pretest shows a distinct drawdown and buildup. Refer to the following "Response in known conditions" for more information on pretests.
- Recycle pretest: In this stage the volume collected in the pretest piston is emptied from the pretest operation.
- Plug off: This is the insertion of a metal plug into the drilled hole. After plugging, the pressure should stabilize at a pressure different from both the wellbore and formation pressures.

Response in known conditions

- The hydrostatic pressure should be stable and close to the anticipated mud gradient for the well.
- The mud system should be stable. The well fluid level should be known and taken into account along with deviation before comparing the hydrostatic pressure with the anticipated mud pressure.
- Normally, there are three types of pretest responses:
  - Normal pretest: The last-read buildup is a stabilized value that equals formation pressure.
  - Dry test: Fluid mobility is very low and there is not enough contribution from the formation to transmit the formation pressure to the flowline and pressure gauges.
  - Lost seal: The pressure at the end of the set cycle is higher than the pressure at the beginning of the set cycle.
- Poor zonal isolation in the casing annulus results in questionable pressure measurement and an invalid mobility computation.

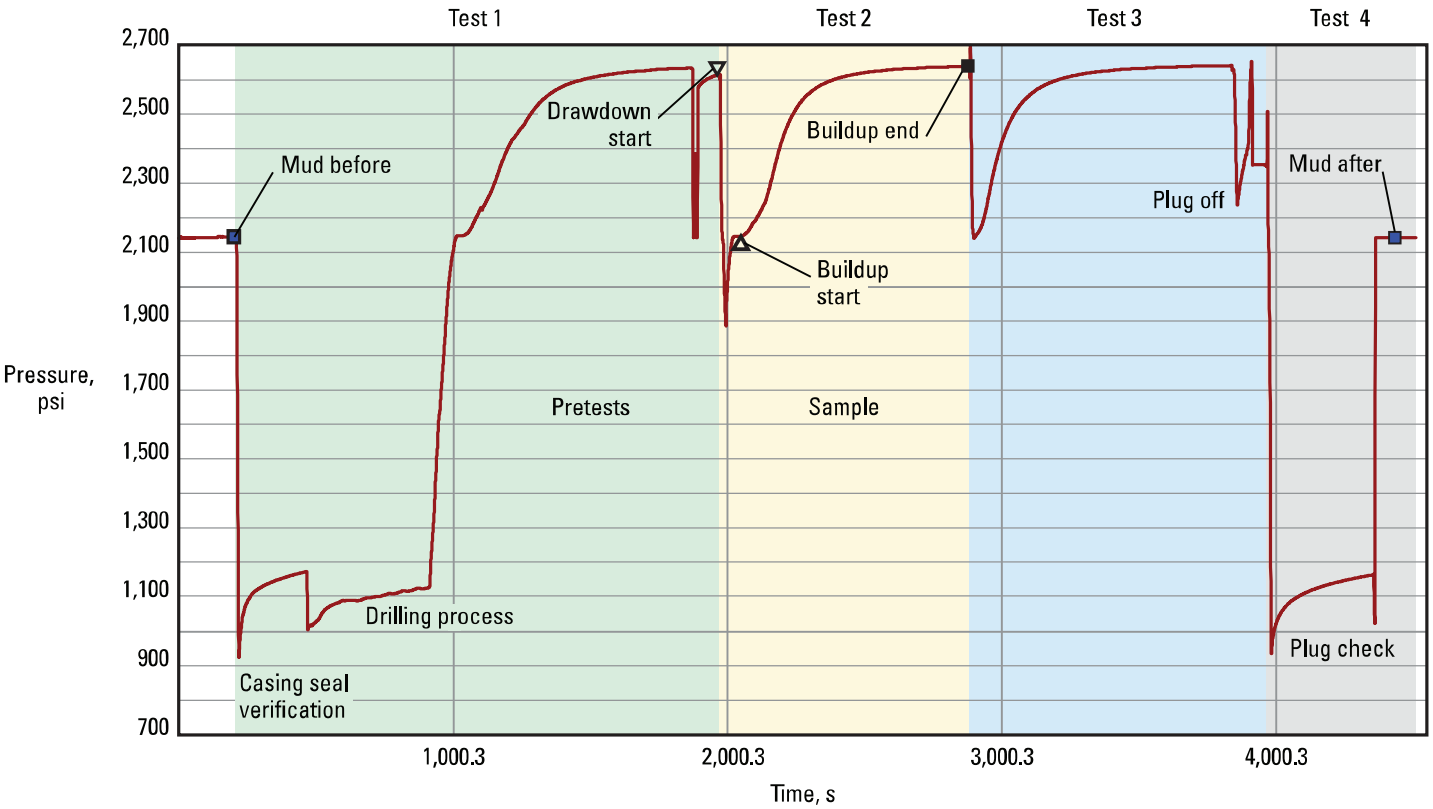

Figure 2. CHDT pressure versus time plot.

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MSCT

Overview

The MSCT* mechanical sidewall coring tool cuts cylindrical cores from the formation wall, stores them sequentially, and returns them to the surface for analysis. It can retrieve multiple cores, each with a diameter of 0.92 in by 2.0 in long [23.4 mm by 50.8 mm]. The information acquired from the retrieved cores provides the following answers: type of matrix material, formation fluid sample, porosity, and permeability estimates. The standard configuration of the rotary MSCT tool recovers 50 core samples. Optional configurations for recovering 75 core samples (dictated by core-catcher capacity) are available. Each sample is isolated for positive identification, and a summary output at surface lists all samples with the exact depth and time that each was taken. The real-time display at the logging unit confirms proper tool operation and sample acquisition.

Specifications

Measurement Specifications	
Output	Sidewall core samples†
Logging speed	Stationary Coring time (avg): 3 to 5 min per core
Range of measurement	Core size: 2 in [50.8 mm] long 0.92 in [23.4 mm] diameter
Depth of core sample	Core length: 1.5 or 1.75 in [38.1 or 44.4 mm]
Mud type or weight limitations	None
Combinability	With gamma ray tools only

† The MCFU-AA is used for 50 cores per descent and the MCCU is used for 20 cores per descent.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]†
Pressure rating	Standard: 20,000 psi [138 MPa] High pressure: 25,000 psi [172 MPa]
Borehole size—min.	6¼ in [15.87 cm]
Borehole size—max.	19 in [48.26 cm]
Outside diameter	5.375 in [13.65 cm]‡
Length	31.29 ft [9.54 m]
Weight	750 lbm [340 kg]§
Tension	22,900 lbf [101,860 N]
Compression	12,500 lbf [55,600 N]

† The MSCT-A can be run at 400 degF [204 degC] with a Dewar flask (UDFH-KF). Successful jobs have also been performed at 425 degF [218 degC].
‡ With the standoffs removed, the MSCT can be stripped down to 5 in [12.70 cm] and run in 5⅞-in [14.92-cm] holes.
§ The sonde weighs 580 lbm [263 kg].

The MSCT tool is run in combination with a gamma ray tool to correlate with openhole logs for accurate, real-time depth control of the coring points. Typical applications include lithology and secondary porosity analysis, porosity and permeability determination, confirmation of hydrocarbon shows, determination of clay content and grain density, and detection of fracture occurrence.

Calibration

Calibration for MSCT operations also involves calibration of the gamma ray tool, as separately described in this Log Quality Control Reference Manual.

The MSCT calibration task is run as automatic sequences to compute the piston position from zero and plus measurements of the piston position.

Tool quality control

Standard curves

The MSCT standard curves are listed in Table 1.

Table 1. MSCT Standard Curves

Output Mnemonic	Output Name
CMDV	Coring motor downhole voltage
CMLP	Coring motor linear position
ETIM	Elapsed time
GR	Gamma ray
HMCU	Hydraulic motor current
HMDV	Hydraulic motor downhole voltage
HPPR	Hydraulic pump pressure
MSCT_LMVL	Lower voltage limit
MSCT_LSWI	Limit switch
MSCT_UMVL	Upper voltage limit
RPPV	Kinematics pressure
SSTA	Solenoid status

Operation

The tool is anchored to the formation during coring. Standoffs should be used on the logging head and gamma ray tool to minimize sticking.

Formats

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

- Track 1
  - HMDV is greater than 50 V when the hydraulic motor is off. CMDV is greater than 400 V if the coring motor is on.
  - HMCU is about 3 A when the coring motor is turned on, with the lower and upper voltage limits shown by MSCT_LMVL and MSCT_UMVL, representatively.
- Time track
  - Shown along with ETIM, MSCT_LSWI is green when the tool is anchored.
- Track 2
  - RPPV is the pressure pushing on the bit. HPPR is the hydraulic pump pressure in the initial state, and when the hydraulic motor is on, the hydraulic and kinematics pressures read about 4,000 psi. The pressures drop as the open command is given. The coring pressure reaches up to 400 psi when the coring motor is turned on. The hydraulic and kinematics pressure usually range between 2,000 and 2,500 psi during coring.
- Track 3
  - CMLP tracks area to simulate taking cores. The core breaking point can be identified from the piston stopping point.

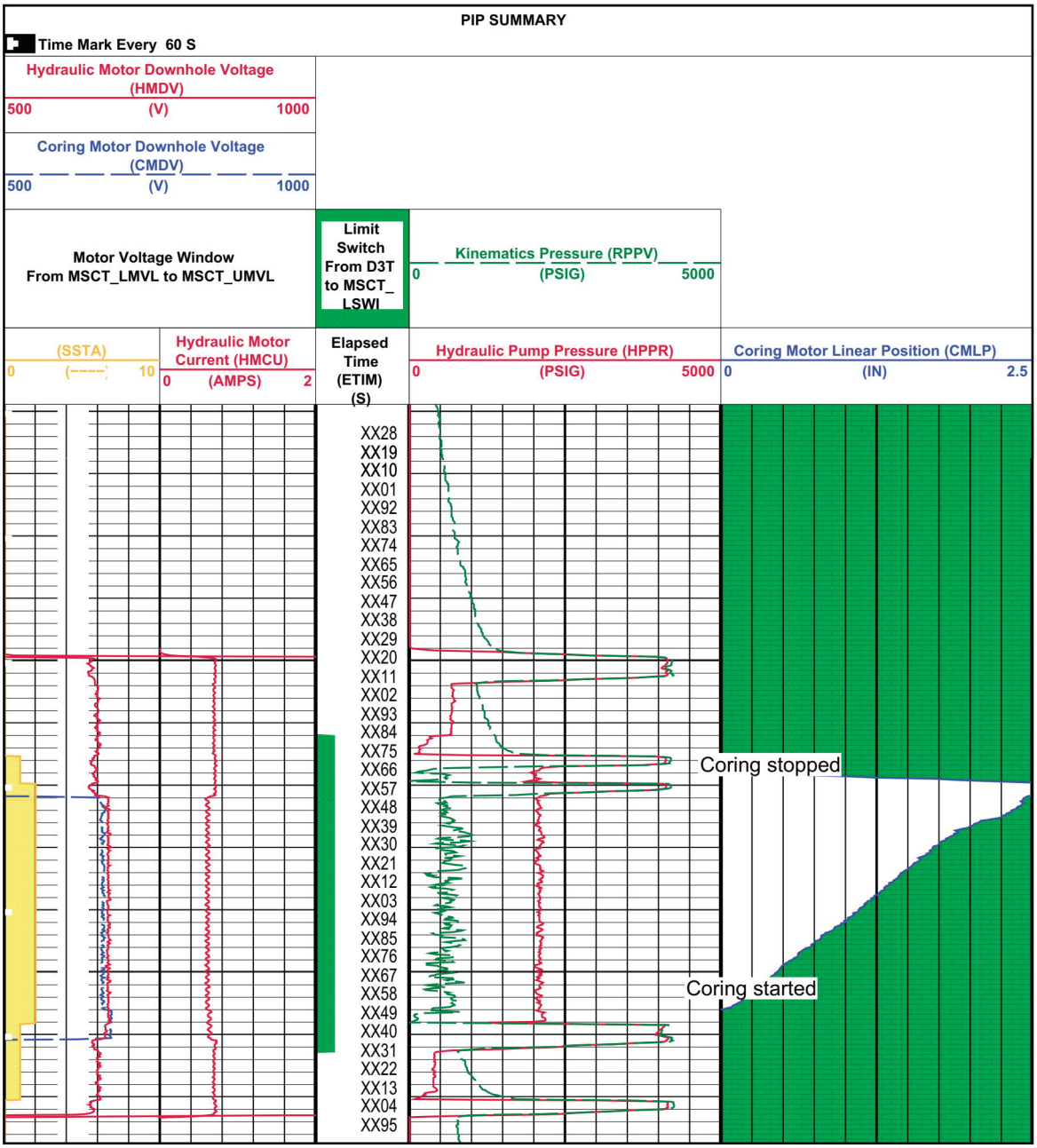

Figure 1. MSCT station format.

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CST

Overview

The CST* chronological sample taker can collect up to 90 core samples in one trip using a series of core recovery bullets. This percussion-type gun is accurately depth positioned by using a spontaneous potential (SP) or gamma ray log. A surface controlled, electrically ignited powder charge fires a hollow cylindrical bullet into the formation at each sample depth. Each bullet is attached by two retaining wires to the gun; these are used to retrieve the bullet and core. The wires have a breaking strength of approximately 1,800 lbf [8,000 N] to release the gun from the core bullet, which prevents a stuck core resulting in a stuck CST tool.

The CST guns vary in the number of bullets per gun. Bullet designs are available for optimum core recovery in various ranges of formation consolidation. The recovered samples are usually large enough for conducting core analysis.

The CST sample gun specifications are listed in Table 1.

Specifications

Measurement Specifications	
Output	Sidewall cores
Logging speed	Stationary when firing the bullets 3,600 ft/h [1,097 m/h] during gamma ray correlation
Mud type or weight limitations	Hydrostatic pressure and formation characteristics determine charge selection
Combinability	Usually run with the PGGT* powered gun gamma ray tool for correlation Up to three guns can be used to collect a maximum of 90 core samples
Special applications	H_2S service

Mechanical Specifications	
Temperature rating	Explosive charges: 280 degF [138 degC] for 1 h or 450 degF [232 degC] for 1 h
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.†	4⅛ in [10.48 cm]
Borehole size—max.†	25 in [63.50 cm]
Outside diameter†	3.375 to 5.25 in [8.57 to 13.33 cm]
Length†	6.83 to 17.08 ft [2.08 to 5.21 m]
Weight†	125 to 406 lbm [57 to 184 kg]
Tension	50,000 lbf [222,410 N]
Compression	23,000 lbf [102,310 N]

† Depends on the gun, see "CST Sample Gun Specifications"

Table 1. CST Sample Gun Specifications

	CST-AA	CST-BA	CST-C	CST-DA	CST-G	CST-G60N	CST-G60P	CST-G60Y
Core samples	30	30	30	30	30	60	60	60
Temperature rating	450 degF [232 degC]	450 degF [232 degC]	450 degF [232 degC]	450 degF [232 degC]	280 degF [138 degC]	280 degF [138 degC]	280 degF [138 degC]	280 degF [138 degC]
Pressure rating	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]
Borehole size—min.	8½ in [21.59 cm]	8½ in [21.59 cm]	8½ in [21.59 cm]	8½ in [21.59 cm]	5½ in [13.97 cm]	5½ in [13.97 cm]	5½ in [13.97 cm]	6⅛ in [15.55 cm]
Borehole size—max.	25 in [63.50 cm]	25 in [63.50 cm]	25 in [63.50 cm]	25 in [63.50 cm]	12½ in [31.75 cm]	12½ in [31.75 cm]	12½ in [31.75 cm]	12½ in [31.75 cm]
Outside diameter	5¼ in [13.33 cm]	4½ in [11.43 cm]	5¼ in [13.33 cm]	4½ in [11.43 cm]	4 in [10.16 cm]	4 in [10.16 cm]	4 in [10.16 cm]	4⅜ in [11.11 cm]
Length	9.08 ft [2.77 m]	7.92 ft [2.41 m]	7.86 ft [2.39 m]	11.42 ft [3.48 m]	9.50 ft [2.89 m]	17.08 ft [5.21 m]	17.08 ft [5.21 m]	16.71 ft [5.09 m]
Weight	262 lbm [119 kg]	229 lbm [104 kg]	200 lbm [91 kg]	326 lbm [148 kg]	175 lbm [79 kg]	308 lbm [140 kg]	308 lbm [140 kg]	308 lbm [140 kg]

	CST-GY	CST-J	CST-U	CST-V	CST-W	CST-Y	CST-Z
Core samples	30	25	24	21	12	21	30
Temperature rating	280 degF [138 degC]	450 degF [232 degC]	450 degF [232 degC]	450 degF [232 degC]	450 degF [232 degC]	450 degF [232 degC]	450 degF [232 degC]
Pressure rating	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]
Borehole size—min.	6⅛ in [15.56 cm]	4⅛ in [10.46 cm]	5½ in [13.97 cm]	5½ in [13.97 cm]	4¾ in [12.07 cm]	5½ in [13.97 cm]	8½ in [21.59 cm]
Borehole size—max.	12½ in [31.75 cm]	10 in [25.40 cm]	12½ in [31.75 cm]	12½ in [31.75 cm]	12½ in [31.75 cm]	12½ in [31.75 cm]	25 in [63.50 cm]
Outside diameter	4⅜ in [11.11 cm]	3⅜ in [8.57 cm]	4⅜ in [11.11 cm]	4⅜ in [11.11 cm]	4⅜ in [11.11 cm]	4⅜ in [11.11 cm]	5¼ in [13.33 cm]
Length	9.50 ft [2.89 m]	12.92 ft [3.93 m]	6.83 ft [2.08 m]	7.60 ft [2.32 m]	8.08 ft [2.46 m]	7.60 ft [2.32 m]	11.42 ft [3.48 m]
Weight	175 lbm [79 kg]	187 lbm [85 kg]	125 lbm [57 kg]	168 lbm [76 kg]	148 lbm [67 kg]	168 lbm [76 kg]	406 lbm [184 kg]

Tool quality control

Standard curves

The CST standard curves are listed in Table 2.

Table 2. CST Standard Curves

Output Mnemonic	Output Name
GR	Gamma ray from the PGGT tool
TENS	Cable tension

Operation

CST guns must be run with the correct standoffs and bottom nose centralizers so that the bullets have time to develop sufficient velocity before impact.

The correct gun type, bullet type, retaining wire, and centralizer configuration must be chosen according to the hole size. The combination of explosives and bullet configuration is chosen according to logs and hole information.

Formats

The format in Fig. 1 is used as the main presentation for CST logs and for quality control.

- Track 1
  - GR is used for correlation purposes and should be on depth with openhole reference logs.
- Track 3
  - TENS shows the tension, which is important for station monitoring of CST bullet firing.

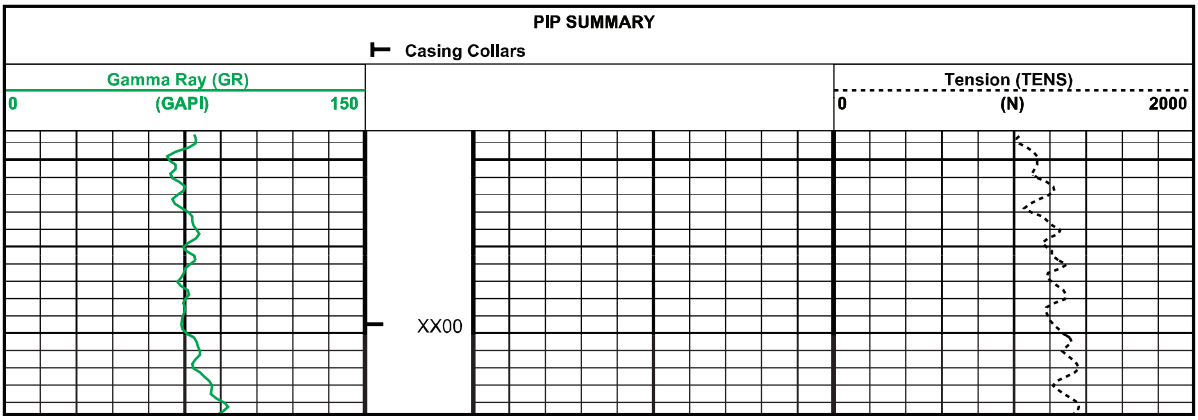

Figure 1. CST standard correlation format.

Reports

The software-generated CST client summary report can include the data listed in Table 3.

Table 3. CST Data Summary

Bullet Information	Well Data	Bullet Data	Summary Data	Header Data
Bullet type	Formation name	Depth	% recovered	Date as mm-dd-yy
Ring type	Lithology	Requested depth	Number recovered	Engineer's name
Charge type	Transit time (us)	Status and recovery	Number empty	Company name
Powder load (g)	Porosity	Core length (in)	Number lost	Field name
Fastener length (in)	Porosity source	Tension or pull	Number misfired	Well name
	Permeability (mD)	Odor	Number attempted	Logging unit number
	Density (g/cm^3)	Fluorescence		Logging unit location
	Caliper value (in)	Description		County or rig name
	Bit size (in)	Remarks		Run number
	Well deviation (deg)			Maximum recorded temperature
				Correlation tools used
				Bottom nose type
				Gun types
				Gun serial numbers

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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.

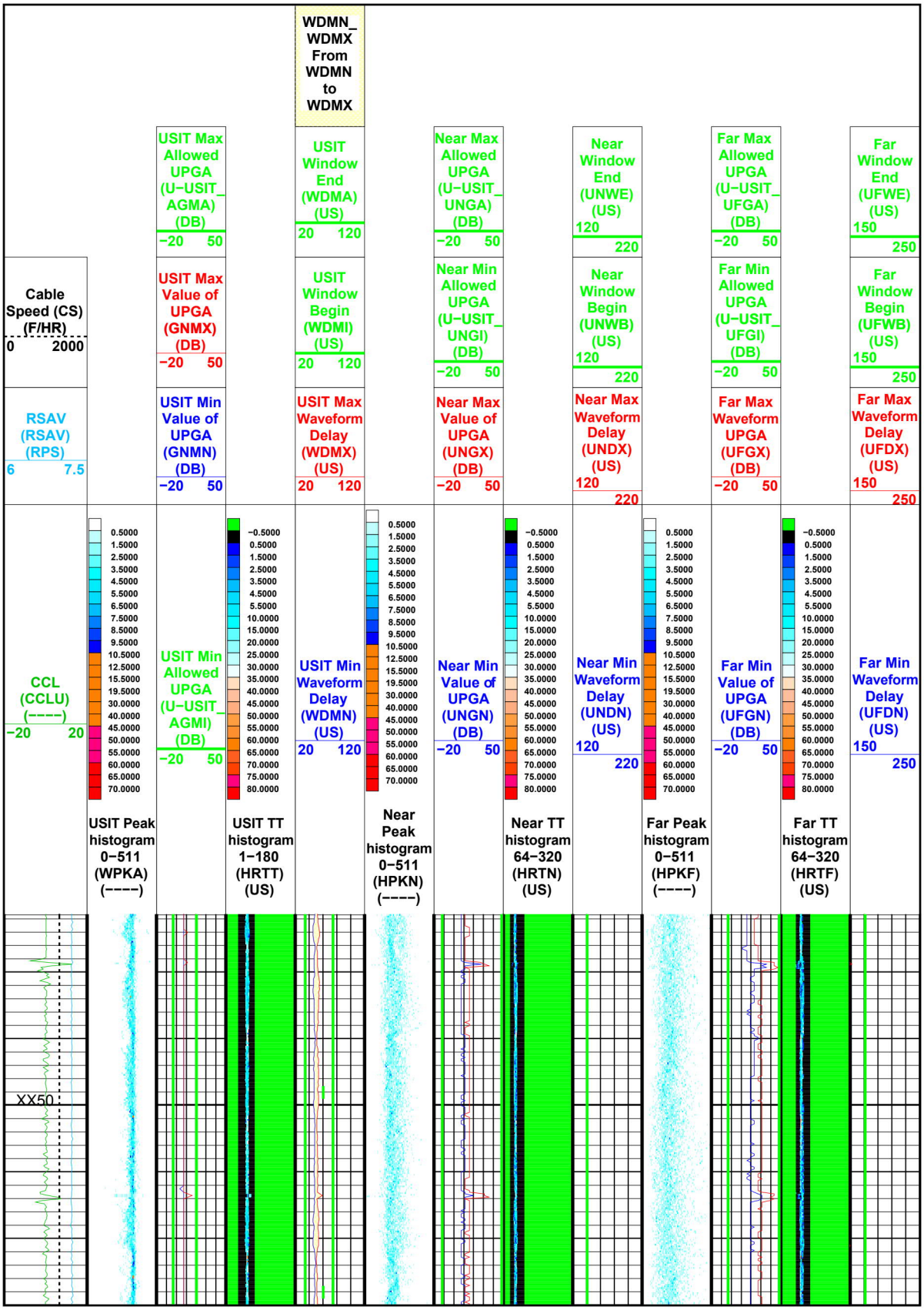

Figure 1. Isolation Scanner signal and waveforms quality control format.

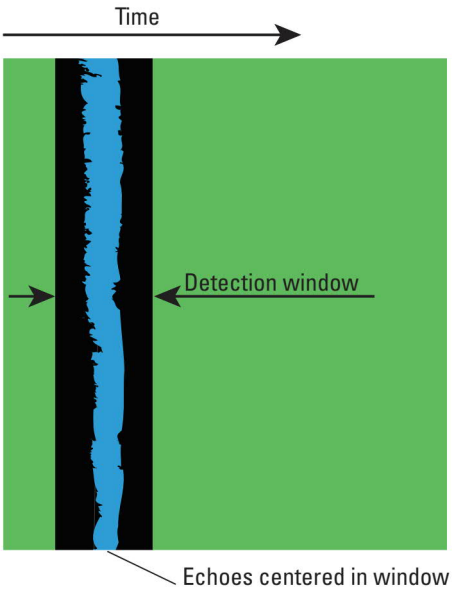

Figure 2. The USI transit-time histogram should be centered in the detection window.

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.

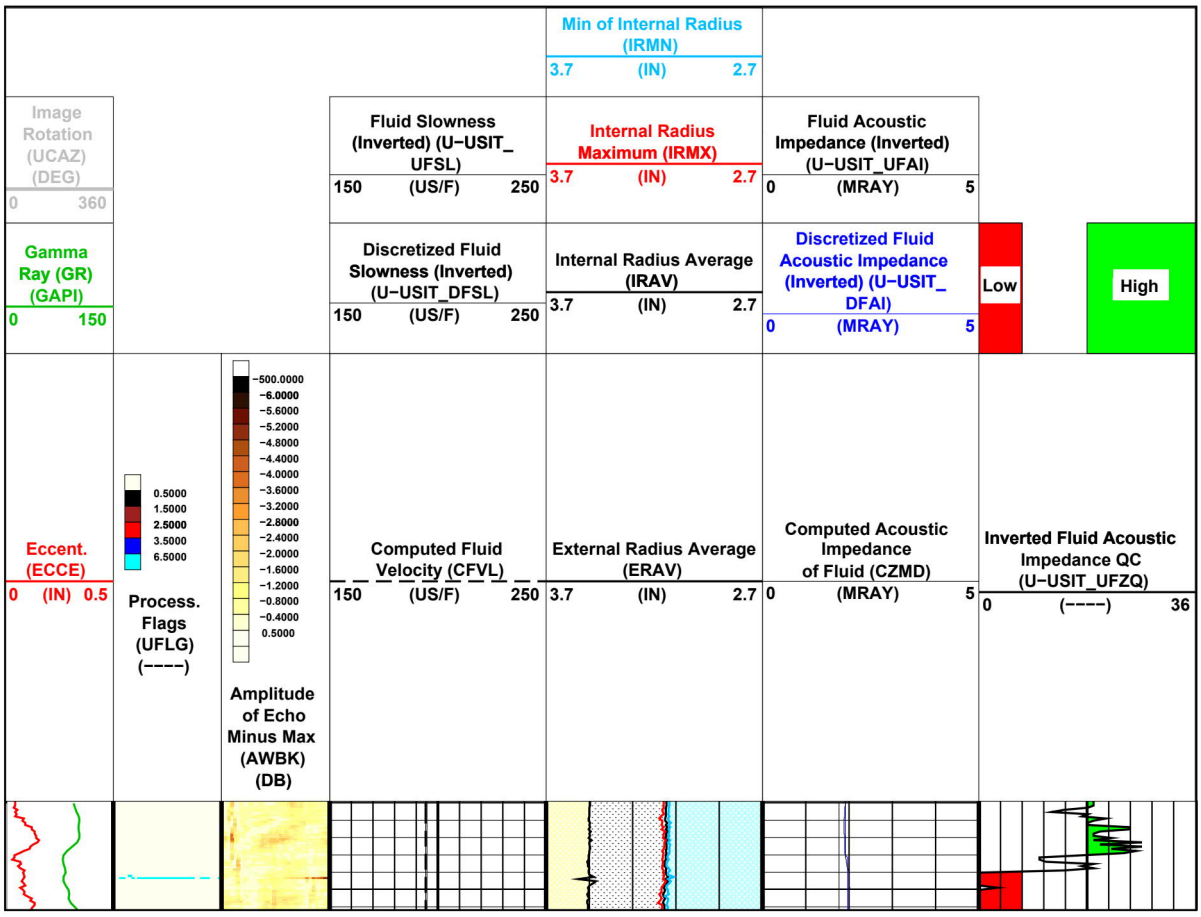

Figure 3. Isolation Scanner fluid property measurement quality control format.

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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†
SB1	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.

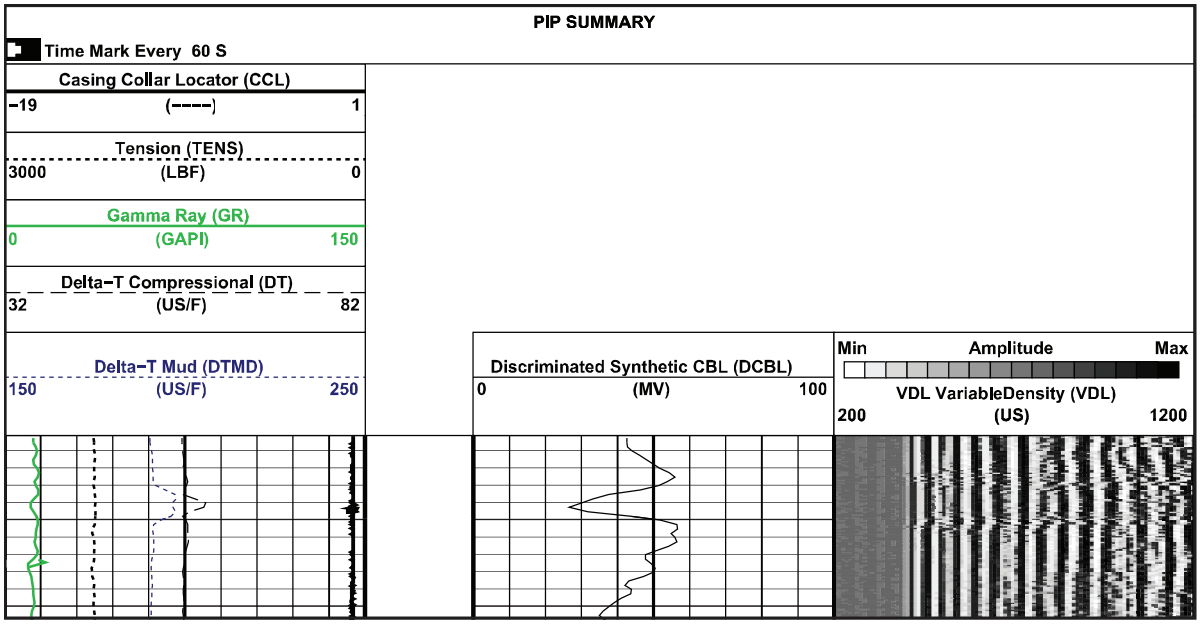

Figure 1. CBT standard format for CBL and VDL.

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.

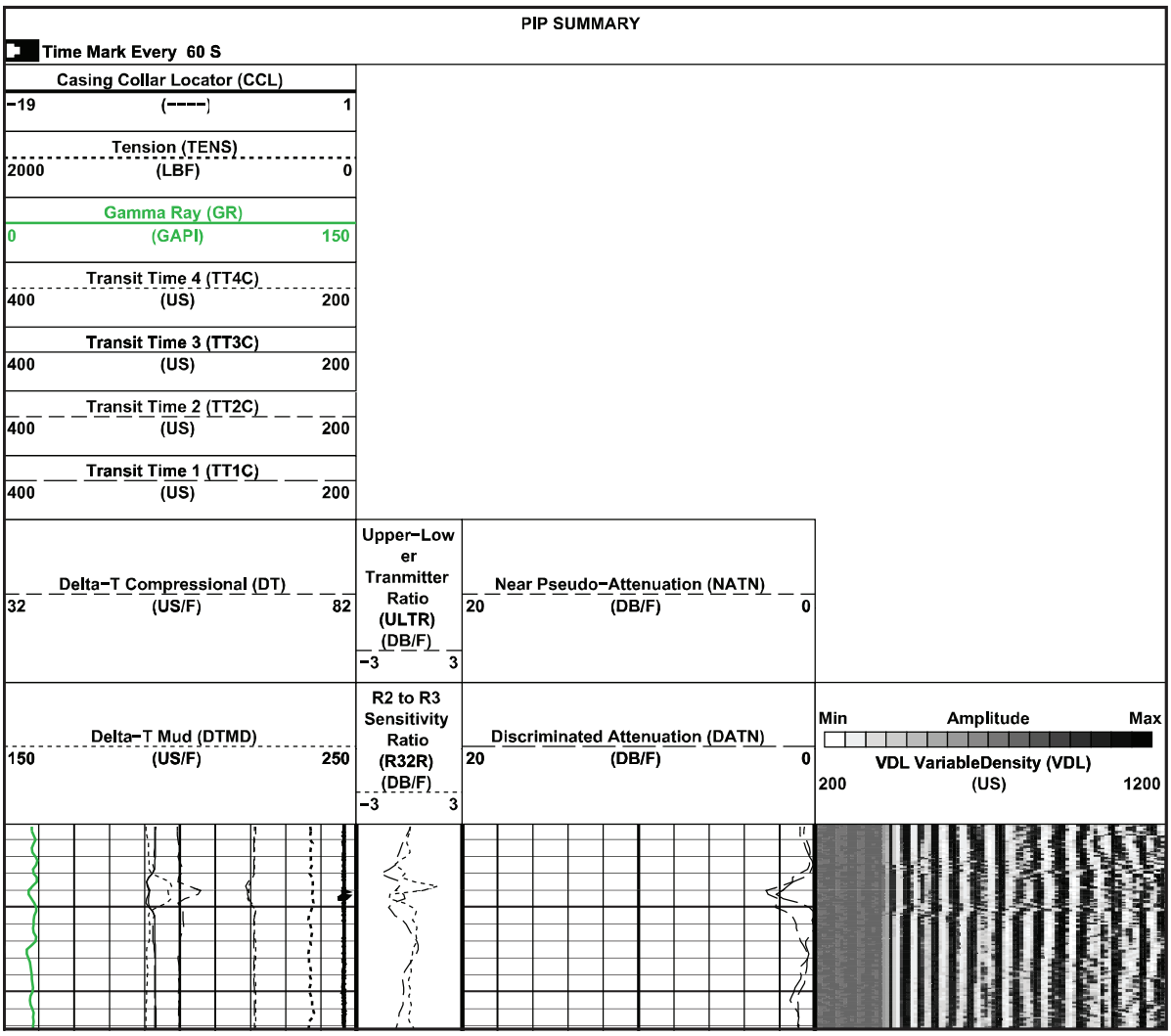

Figure 2. Additional CBT standard format for CBL and VDL.

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

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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 micro-annulus 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).

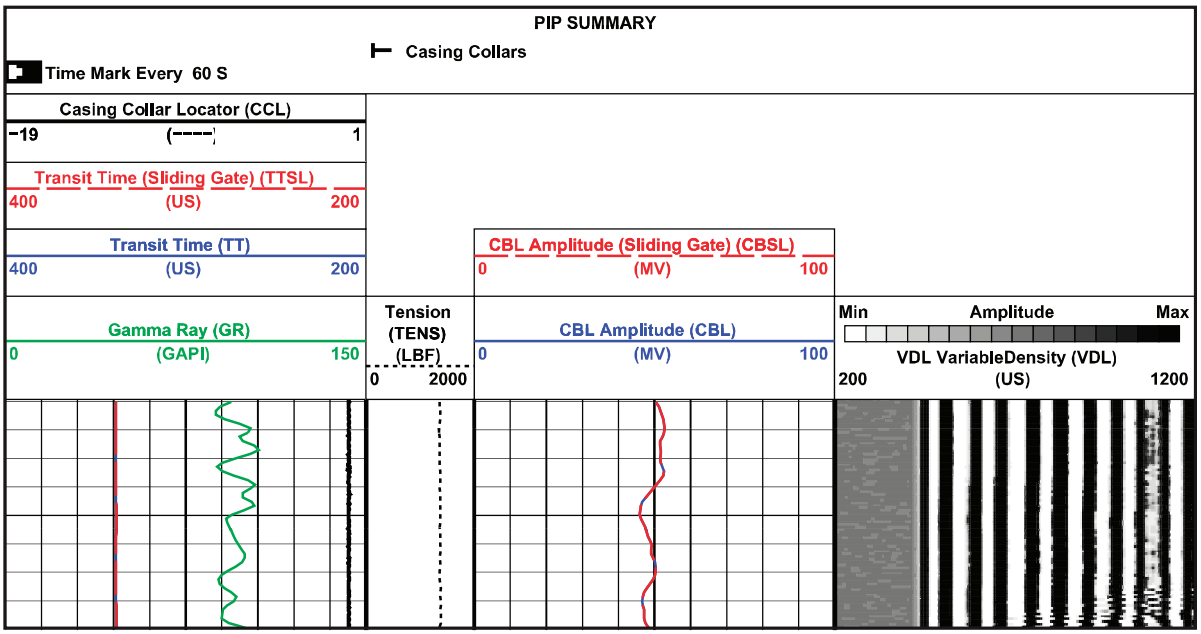

Figure 1. DSLT standard format.

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

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Sonic Scanner

Overview

The Sonic Scanner* acoustic scanning platform provides a true 3D representation of the formations surrounding the borehole by scanning both orthogonally and radially. The tool acquires borehole-compensated monopole with long and short spacings, cross-dipole, and cement bond quality measurements. In addition to making axial and azimuthal measurements, the fully characterized tool radially measures the formation for both near-wellbore and far-field slowness.

The Sonic Scanner* tool also provides a discriminated synthetic cement bond log (DCBL), which is obtained simultaneously with the behind-casing acoustic formation measurements. The DCBL measurement adopts the borehole-compensated (BHC) attenuation method, which enables eliminating fluid, temperature, and pressure effects and thus the need to perform free-pipe adjustment. Two attenuation outputs are computed: default 3- to 5-ft [0.91- to 1.52-m] spacing and backup 3.5- to 4.5-ft [1.07- to 1.37-m] spacing.

In cases of very low sonic amplitude, the measurement automatically switches from BHC attenuation (BATT) to pseudoattenuation (NATN) measurement, which is based on the default 3-ft receiver measurement, with the 3.5-ft measurement as a backup. When NATN is applied to compute the DCBL output, the result is similar to the standard cement bond log (CBL) output in terms of compensation, so free-pipe adjustment (calibration) must be performed before or after the log. The flag for low sonic amplitude (FLSA) determines which attenuation is used to compute the DCBL curve.

The Variable Density* log (VDL) provides qualitative information for CBL interpretation. In Sonic Scanner logging, two VDL results are recorded. One is the 5-ft VDL from the upper monopole (MU), and the other is the 5-ft VDL from the lower monopole (ML). By default the VDL from the MU is presented. Waveforms from five receiver stations, each with eight azimuthal receivers, are acquired for the cement evaluation computations.

Specifications

Measurement Specifications	
Output	2-ft [0.61-m] and 1-ft [0.30-m] DCBL with BATT 3-ft [0.91-m] and 3.5-ft [1.07-m] DCBL with NATN 5-ft [1.52-m] VDL
Logging speed	3,600 ft/h [1,097 m/h]
Vertical resolution	DCBL with BATT: 1 or 2 ft [0.30 or 0.61 m] DCBL with NATN: 3 or 3.5 ft [0.91 or 1.07 m]
Depth of investigation	DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties

Mechanical Specifications	
Temperature rating	350 degF [175 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	4¾ in [12.07 cm]
Borehole size—max.	22 in [55.88 cm]
Outside diameter	3.625 in [9.21 cm]
Length	41.28 ft [12.58 m]
Weight	838 lbm [380 kg] (including isolation joint)
Tension	35,000 lbf [155,688 N]
Compression	3,000 lbf [13,345 N]

Calibration

Master calibration and a vertical casing check are mandatory. Master calibration is conducted every 3 months, after every 10 wireline-conveyed jobs, or after every 5 jobs conveyed with the TLC* tough logging conditions system. A master calibration is also mandatory after exposure to temperatures greater than 320 degF [160 degC]. The master calibration computes a sensor sensitivity correction (SSCF) for each sensor. The SSCF is used to normalize sensor sensitivity to within ±5% across the azimuthal sensors. The vertical casing check applies the SSCF, which is obtained at high frequency, to low-frequency raw waveforms for comparison of the corrected amplitude variation between sensors.

Tool quality control

Standard curves

Sonic Scanner standard curves are listed in Table 1.

Table 1. Sonic Scanner Standard Curves

Output Mnemonic	Output Name
CBSL	CBL amplitude sliding gate
CCL	Casing collar locator
CE_TT7_*x*_FT_AVE_DC	Average transit time computed from the upper transmitter (measurement number 7) and the eight azimuthal receivers of the station, which is spaced *x* ft away from the transmitter (default presentation is the 3-ft station transit time)
DATN	Discriminated attenuation
DCBL	Discriminated synthetic CBL
DCSI*n*	Data copy status indicator for upper (7) and lower (8) monopole measurement
FLSA	Flag for low sonic amplitude
GR	Gamma ray
TTSL	Transit time sliding gate
VDL	Variable Density log

Operation

The tool must be run centralized. Centering the Sonic Scanner tool is of extreme importance for achieving good data quality.

Formats

The format in Fig. 1 is used mainly for sigma quality control.

- Track 1
  - Transit times from the upper and lower transmitters for corresponding 3.0-ft receiver stations (averaged over 8 azimuthal receivers on each station) should overlay and stay constant when tool is properly centered and detection window is properly set. In case of using backup 3.5-4.5 ft spacing for DCBL computation, 3.5-ft station transit time should be presented for the upper and lower transmitters.
  - Upon request, the FSLA flag may be presented to show which attenuation algorithm applied to compute DCBL.
  - GR and CCL are used for correlation purposes.
- Track 2
  - DATN is equal to either BATT or NATN, depending on the value of FLSA.
  - DCBL is computed from DATN. The curves should correlate in normal conditions. When DATN = BATT (FLSA = 0), the BHC attenuation algorithm is used to compute DCBL. When DATN = NATN (FLSA = 1), the pseudoattenuation algorithm is used to compute DCBL.

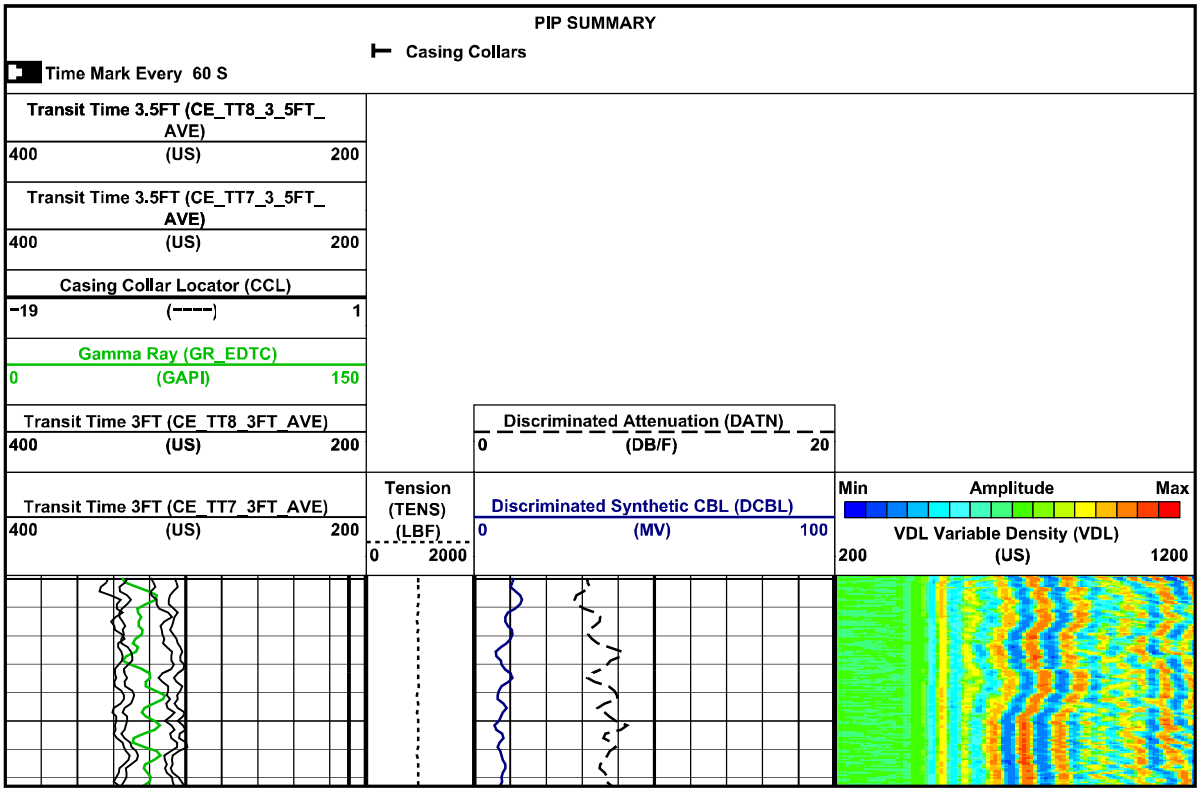

Figure 1. Sonic Scanner attenuation measurement standard format.

- Track 3
  - The VDL map is a presentation of the acoustic waveform at a receiver of a sonic measurement, with the amplitude presented in color. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In good bond, it should reflect low amplitudes or show strong formation signals (wavy lines).

Response in known conditions

Transit time and free-pipe CBL amplitude vary significantly based on the casing size and weight, borehole pressure and temperature, and the mud weight. An estimate of DCBL amplitude from a test well with 7-in, 23-lbm/ft casing filled with fresh water is provided in Table 2.

Table 2. Expected Sonic Scanner Response in Common Casings

Casing Size, in	Casing Weight, lbm/ft	Expected Free-Pipe Amplitude, mV
5	13	75 ± 8
5½	17	71 ± 7
7	23	62 ± 6
8⅝	36	55 ± 6
9⅝	47	52 ± 5
10¾	51	49 ± 5
13⅜	68	43 ± 4

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SCMT

Overview

The SCMT* slim cement mapping tool is a through-tubing cement evaluation tool combinable with PS Platform* production logging service for a variety of well diagnostics. The two sizes are 1 11/16 in [4.29 cm] with a standard (300 degF [149 degC]) temperature rating and 2.065 in [5.25 cm] with a 400 degF [204 degC] temperature rating. The SCMT features a single transmitter, two receivers spaced at 3 and 5 ft [0.91 and 1.52 m] from the transmitter, and eight segmented receivers 2 ft [0.61 m] from the transmitter. The output of the near (3-ft) receiver is used to obtain a cement bond log (CBL) and transit-time measurement. The output of the far (5-ft) receiver is used for the Variable Density* log (VDL) measurement. The eight segmented receivers generate a radial image of the cement bond variation.

The SCMT tool is suitable for running in both workover operations and new wells. SCMT operations provide a clear advantage in workover wells because there is no need to pull tubing above the zone of interest for cement evaluation. The SCMT tool is capable of running through most tubings to evaluate the casing below. In new wells the SCMT tool is an effective approach for evaluating casing that is 7⅝ in [19.36 cm] or less.

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check schedule frequency is 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.

Specifications

Measurement Specifications	
	SCMT-C and SCMT-H
Output	3-ft [0.91-m] amplitude CBL, 5-ft [1.52-m] VDL, cement bond variation map
Logging speed	1,800 ft/h [549 m/h]
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	CBL: Casing and cement interface VDL: Depends on bonding and formation
Mud type or weight limitations	None
Combinability	Combinable with PS Platform system
Special applications	Logging through drillpipe and tubing and in small casing

Mechanical Specifications	
Temperature rating	SCMT-C: 300 degF [149 degC] SCMT-H: 400 degF [204 degC]
Pressure rating	15,000 psi [103 MPa]
Casing size—min.	SCMT-C: 2⅞ in [7.30 cm] SCMT-H: 3½ in [8.89 cm]
Casing size—max.	7⅝ in [19.37 cm]
Outside diameter	SCMT-C: 1.6875 in [4.29 cm] SCMT-H: 2.065 in [5.25 cm]
Length	SCMT-C: 23.4 ft [7.1 m] SCMT-H: 29.8 ft [9.07 m]
Weight	SCMT-C: 107 lbm [48.5 kg] SCMT-H: 168 lbm [76.2 kg]
Tension	5,947 lbf [26,450 N]
Compression	146 lbf [651 N]

Tool quality control

Standard curves

SCMT standard curves are listed in Table 1.

Table 1. Standard curves

Output Mnemonic	Output Name
AVMA	Radial cement mapping image (MAP) average amplitude
AVTT	Average MAP transit time
C5TT	CBL 5-ft transit time
CBL	CBL amplitude
CCLD	Discriminated casing collar locator
GOBO	Good bond
GR	Gamma ray
MIMA	Minimum MAP amplitude
MITT	Minimum MAP transit time
MPWF	CBL amplitude mapping image
MXMA	Maximum MAP amplitude
MXTT	Maximum MAP transit time
RB_SCMT	Relative bearing
TT	CBL 3-ft transit time
VDL	Variable Density log
WPRE	Well pressure
WTEP	Well temperature

Operation

The SCMT tool must be run centralized, using inline centralizers and through-tubing guides. Good centralization is essential for accurate measurements.

Formats

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

- Depth track
  - The depth track includes the CCLD, which indicates the casing collars.
- Track 1
  - GR along with CCLD in the depth track is used for correlation purposes.
  - RB_SCMT can read from 0 to 358°. It is important to ensure that this reading is correct because it is used for the offset compensation in the MAP image.
  - WTEP and WPRE measurements are from the PS Platform Basic Measurement Sonde (PBMS) or High-Temperature PBMS (HBMS) and are reflective of the borehole environment. WTEP and WPRE may be used for temperature and pressure compensation, respectively, for the CBL and MAP amplitudes.
  - TT, MITT, MXTT, and C5TT transit times should be checked against responses in known conditions. However, they are not consistently equal to the known-condition responses because transit time is affected by factors such as casing size and weight, fluid type (e.g., water- or oil-base mud), fluid temperature and pressure, and tool eccentering. A response in known conditions is just a reference.
- Track 2
  - AVMA, MIMA, and MXMA are the amplitude, minimum, and maximum amplitudes of the MAP image waveform.
  - CBL, which is measured in millivolts, gives a quantitative and qualitative measurement of the cement behind the casing.
  - The GOBO area of shading is used as an indication for cemented intervals where the cement bond is not good.
- Track 3
  - The VDL map is a presentation of the acoustic waveform at a receiver of a sonic measurement, with the amplitude presented on 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 good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).
- Track 4
  - The map image presentation of the poor to good cement shows the amplitude of the casing first arrival from the 2-ft directional receiver. A scale of 0 to 100 mV with 41 colors is generally used. The presentation is useful for detecting the presence of a channel.

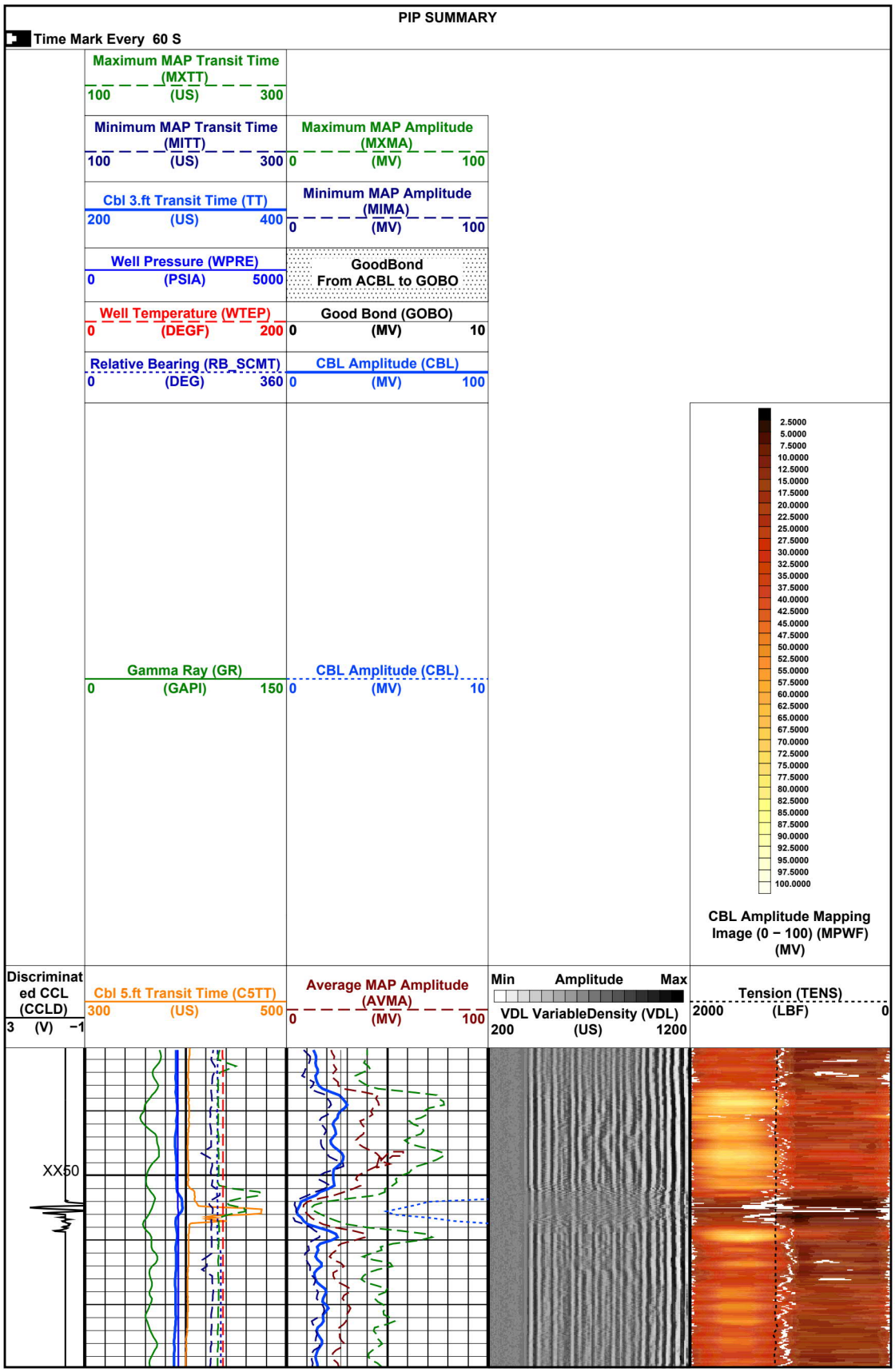

Figure 1. SCMT standard format.

Response in known conditions

- In a free-pipe section, the MAP amplitude should read 100 mV and the CBL amplitude should be as in Table 2.

In other known conditions, the response in Table 3 should be expected.

Table 2. SCMT Response in Free-Pipe 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	24	6.336	61 ± 6

Table 3. Expected SCMT Response in Common Casings†

Casing Size, in	Casing Weight, lbm/ft	2-ft MAP (average), us	3-ft CBL, us	5-ft VDL, us
2.875	6.4	164	221	332
3.5	9.2	174	232	343
4.5	12.6	192	251	362
5.5	17.0	204	268	380
7.0	26.0	233	292	404

† Expected transit times are not absolute numbers and vary with borehole fluids and conditions. These transit times should be used as a guideline only.

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USI

Overview

The USI* ultrasonic imager tool (USIT) uses a single transducer mounted on an Ultrasonic Rotating Sub (USRS) on the bottom of the tool. The transmitter emits ultrasonic pulses between 200 and 700 kHz and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement-to-casing interface, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection.

Because the transducer is mounted on the rotating sub, the entire circumference of the casing is scanned. This 360° data coverage enables evaluation of the quality of the cement bond as well as determination of the internal and external casing condition. The very high angular and vertical resolutions can detect channels as narrow as 1.2 in [3.05 cm]. Cement bond, thickness, internal and external radii, and self-explanatory maps are generated in real time at the wellsite.

Calibration

There is no calibration for the USI tool. The fluid properties measurement (FPM) of the wellbore fluid impedance (AIBK) and the fluid slowness (FVEL) is used for early input into the impedance model. The thickness of the subassembly reference plate (THBK) is also measured and output with FPM. FPM is recorded versus time while running in hole and output both as a time-depth log and as crossplots of FVEL versus depth and AIBK versus depth.

A before-survey tool check is conducted to verify basic tool operation.

Specifications

Measurement Specifications	
Output	Acoustic impedance, cement bonding to casing, internal radius, casing thickness
Logging speed	400 to 3,600 ft/h† [122 to 1,097 m/h]
Range of measurement	Acoustic impedance: 0 to 10 Mrayl [0 to 10 MPa.s/m]
Vertical resolution	Standard: 6 in [15.24 cm]
Accuracy	Less than 3.3 Mrayl: ±0.5 Mrayl
Depth of investigation	Casing-to-cement interface
Mud type or weight limitations‡	Water-base mud: Up to 15.9 lbm/galUS Oil-base mud: Up to 11.2 lbm/galUS
Combinability	Bottom-only tool, combinable with most tools
Special applications	Identification and orientation of narrow channels

† Speed depends on the resolution selected.

‡ Exact value depends on the type of mud system and casing size.

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Casing size—min.	4½ in [11.43 cm]
Casing size—max.	13⅜ in [33.97 cm]
Outside diameter	3.375 in [8.57 cm]
Length†	19.75 ft [6.02 m]
Weight†	333 lbm [151 kg]
Tension	40,000 lbf [177,930 N]
Compression	4,000 lbf [17,790 N]

† Excluding the rotating sub

Tool quality control

Standard curves

The USI standard curves are listed in Table 1.

Table 1. USI Standard Curves

Output Mnemonic	Output Name
AIBK	Acoustic impedance fluid properties measurement (FPM)
AVMN	Minimum amplitude
AWAZ	Average amplitude
AWMX	Maximum amplitude
AZEC	Azimuth of eccentering
ECCE	Tool eccentering
ERAV	Average external radius
ERMN	Minimum external radius
ERMX	Maximum external radius
FVEL	Fluid acoustic slowness
FVEM	Fluid velocity FPM
GNMN	Minimum value of automatic gain (UPGA) in 6-in interval
GNMX	Maximum value of UPGA in 6-in interval
HRTT	Transit-time (TT) histogram
IDQC	Internal diameter quality check
IRAV	Average internal radius
IRMN	Minimum internal radius
IRMX	Maximum internal radius
THAV	Average thickness
THBK	Reference plate thickness FPM
THMN	Minimum thickness
THMX	Maximum thickness
USBI	Ultrasonic bond index
USGI	Ultrasonic gas index
WDMN	Waveform delay minimum
WDMX	Waveform delay maximum
WPKA	Waveform peak amplitude histogram

Operation

The USI tool should be run centered. The tool has centralizers in its sonde. Eccentering should be less than 0.02 in [0.508 mm] per inch of casing diameter.

In deviated wells, knuckle joints must be used along with centralizers on tools above in the string.

Cement information is critical for setting the USIT field parameters.

Formats

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

- Track 1
  - The WPKA histogram is a distribution of the waveform measured by the USIT transducer. The image scale and color represents the number of samples and their corresponding peak amplitude in binary bits.
- Track 2
  - IDQC should match the actual casing internal diameter.
  - WDMN and WDMX should be within 10 us of each other. The difference is due to casing deformation or tool eccentralization.
- Track 3
  - GNMX and GNMN are the maximum and minimum gains, respectively, in the depth frame and should range between 0 and 10 dB.
- Track 4
  - The HRTT image represents the histogram of the TT measurements on a black background, which corresponds to the positions of the peak detection window. The coherence in the log track is desired; most of the echoes should be inside the window. Measured transit times should be well within the peak detection window in a good hole. If the blue color is out of the detection windows, parameters must be adjusted on the job to the windows.

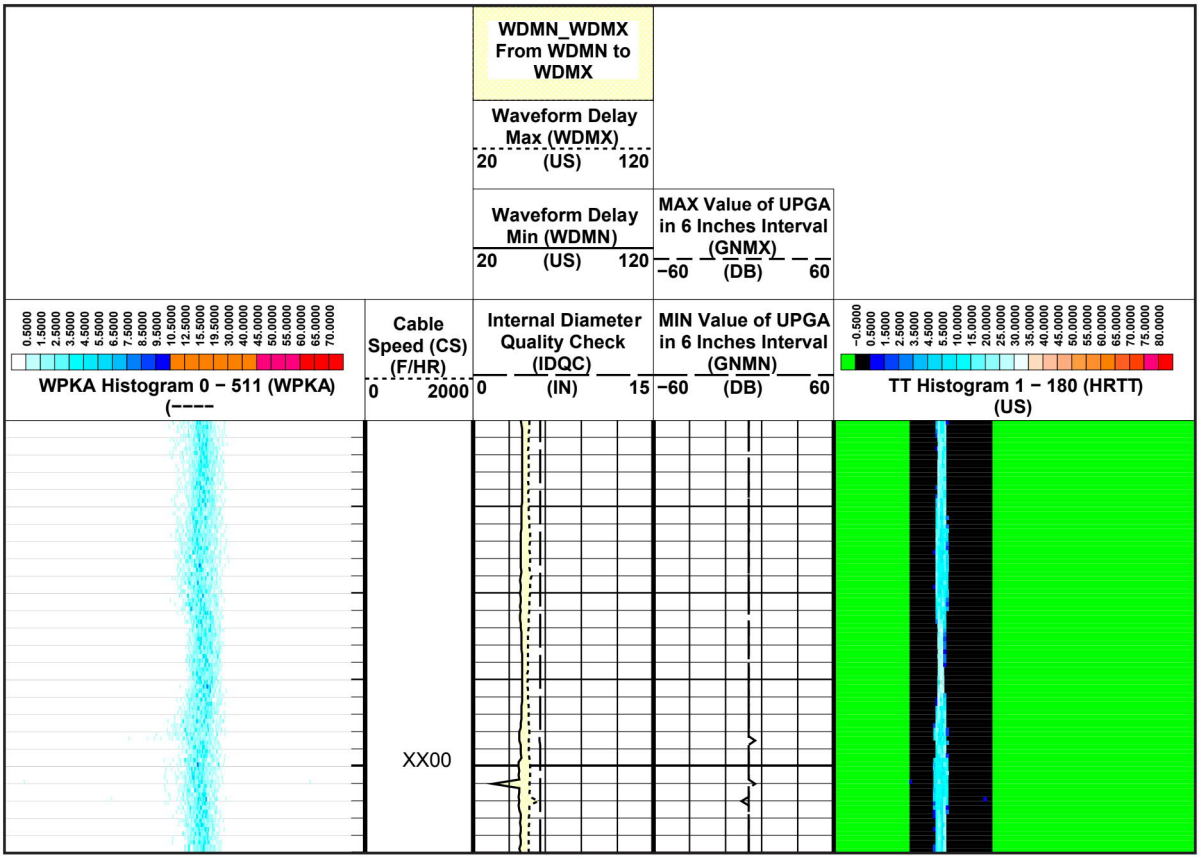

Figure 1. USIT standard format.

Response in known conditions

- The average internal radius and thickness measured by the tool should match the actual nominal internal radius of the casing.
- The expected responses in the measurement mode are listed in Table 2.

Table 2. Typical USI Response in Known Conditions

Formation	Acoustic Impedance, Mrayl
Free gas or gas microannulus	<0.3
Fresh water	1.5
Drilling fluids	1.5 to 3.0
Cement slurries	1.8 to 3.0
LITEFIL* cement (1.4 g/cm^3)	3.7 to 4.3
Neat cement (1.9 g/cm^3)	6.0 to 8.4

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UCI

Overview

The UCI* ultrasonic casing imager is an evolution of the USI* ultrasonic imager. The UCI tool provides all the answers required to locate, identify, and quantify casing damage or corrosion.

The UCI tool (UCIT) design is specifically engineered for high-azimuthal-resolution images and detailed examination of both the inner and outer surfaces of casing ranging from 4½ to 13⅜ in [11.43 to 33.97 cm], resulting in improved echo detection. Full azimuthal coverage with a 2-MHz focused ultrasonic transducer is used to analyze the reflections. Signal arrivals are analyzed to provide the casing thickness and surface condition images, and even small defects on both internal and external casing surfaces are quantified. An improved centralization system ensures proper centralization even in horizontal wells, and eccentering effects are reduced through wellsite signal correction.

Calibration

There is no calibration for the UCI tool; instead, a fluid properties log recorded while running in the hole is used during the log up to convert the measured transit times to radii. The thickness of the sub's reference plate is also measured as a tool check, and a minimum measurable thickness output is computed that gives an indication of the transducer's performance in the well. The minimum (best) value for minimum measurable thickness is 0.15 in [4 mm].

Specifications

Measurement Specifications	
Output	Amplitude image, casing thickness image, internal radius image, fluid velocity
Logging speed	3,000 ft/h [914 m/h] High resolution: 400 ft/h [122 m/h]
Range of measurement	Min. casing thickness: In water = 0.15 in [0.38 cm] In attenuating fluids, including oil-base mud = 0.2 in [0.51 cm]
Vertical resolution	High resolution: 0.2 in [0.51 cm] High speed (3,000 ft/h): 1.5 in [3.81 cm]
Accuracy	Internal radius: ±0.04 in [±1 mm] Casing thickness: ±4%
Depth of investigation	Thickness of casing
Mud type or weight limitations	Oil-base mud: No solids Water-base mud: Solids content < 5%
Combinability	Bottom-only tool, combinable with most tools
Special applications	H_2S service

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Casing size—min.†	4½ in [11.43 cm]
Casing size—max.†	13⅜ in [33.97 cm]
Outside diameter	USRS-AB: 3.41 in [8.66 cm] USRS-A: 3.56 in [9.04 cm] USRS-B: 4.65 in [11.81 cm] USRS-C: 6.69 in [16.99 cm] USRS-D: 8.66 in [22.00 cm]
Length	Without sub: 19.73 ft [6.01 m]
Weight	Without sub: 333 lbm [151 kg]
Tension	40,000 lbf [177,930 N]
Compression	4,000 lbf [17,790 N]

† Minimum and maximum casing sizes depend on the sub used.

Tool quality control

Standard curves

The UCI standard curves are listed in Table 1.

Table 1. UCI Standard Curves

Output Mnemonic	Output Name
A1AV	Average of echo 1 amplitude
A1MN	Minimum of echo 1 amplitude
A1MX	Maximum of echo 1 amplitude
A2AV	Average of AW2F
A2MN	Minimum of AW2F
A2MX	Maximum of AW2F
AW1F	First-echo amplitude minus maximum
AW2F	Amplitude of second echo minus maximum
ECCE	Eccentering modulus
ERNO	Nominal external radius
FTH1	Raw waveform first-echo fall time
FTHV	Average first-echo fall time
HFVL	Fluid velocity from fluid properties measurement (FPM) mode
HTAV	Average transit time
HTHN	Thickness minimum from FPM mode
HTHV	Thickness average from FPM mode
HTHX	Thickness maximum from FPM mode
HTMN	Minimum of the transit time from FPM mode
HTMX	Maximum of the transit time from FPM mode
IMLA	Average internal percentage loss
IMLN	Minimum internal percentage loss
IMLS	Internal percentage metal loss
IMLX	Maximum internal percentage loss
IRAV	Internal radius average
IRBF	Internal radius minus average
IRMN	Internal radius minimum
IRMX	Internal radius maximum
MMTH	Minimum measurable thickness
RFVL	Raw fluid velocity
RSAV	Motor revolution speed
RTHV	Average first-echo rise time
THAV	Thickness average
THBF	Thickness minus average
THMN	Thickness minimum
THMX	Thickness maximum
THNO	Nominal thickness
TMLA	Average thickness percentage loss
TMLN	Minimum thickness percentage loss
TMLS	Thickness percentage metal loss
TMLX	Maximum thickness percentage loss
UCEN	Raw waveform envelope
UEMX	EMEX voltage
UHTT	UCI histogram of first-echo transit time
WMTH	Worst minimum measurable thickness

Operation

The UCI tool must be run centered.

Obtaining a valid thickness measurement requires that the internal surface of the casing is in good condition. Pitting, scale, damage, manufacturing-induced rugosity, and deposits spoil the measurement.

Formats

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

- Track 1
  - ECCE should be less than 4% of the casing OD.
  - Gamma ray (GR) is used for correlation purposes.
  - RSAV should be between 6.5 and 7.2 rps.
- Track 2
  - AW2F is the amplitude of the second echo over the amplitude of the first echo.
- Track 3
  - This track gives an indication of the average of the second amplitude over first-echo amplitude as opposed to the maximum and minimum. The nominal thickness presented should also match that of the casing.
- Processing flags track
  - It is normal to have a small percentage of the thickness data flagged because of internal surface irregularities. However, a map covered with flags means that the internal or external surface is in very bad condition, the tool is eccentered, or there is an action that must be taken.
- Track 4
  - MMTH ideally should be 0.15 in [3.8 mm] in water or brine in many downhole conditions and 0.2 in [5.1 mm] in attenuative fluids such as oil-base mud and most water-base muds.
- Track 5
  - The transit-time histogram (UHTT) measurements should be well within the peak detection window; if not, the field parameters require adjustment to ensure that this condition is met.
- Track 6
  - The UCEN minimum thickness search window, which is the first black line on the left, must always be set to occur after the end of the first peak red area to avoid false detection on the tail of the peak.

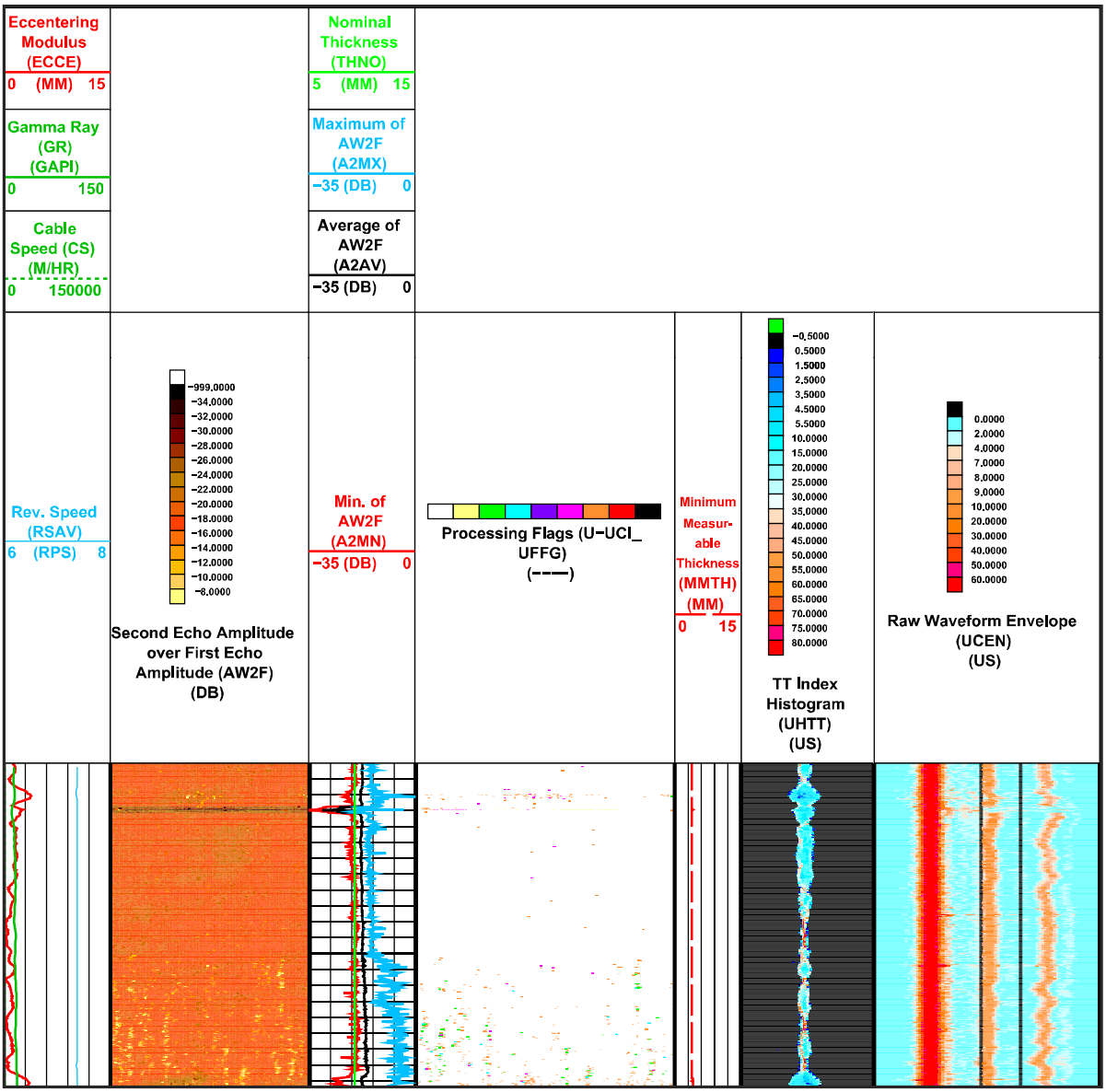

Figure 1. UCIT standard format.

Response in known conditions

- The fluid slowness HFVL should be approximately consistent with the expected values (Table 2).
- The average internal radius, thickness, and external casing should be reasonably close to nominal (±0.039 in [±1 mm]) in good pipe, if present in the well.

Table 2. Typical USI Response in Known Conditions

Fluid	HFVL, us/ft [us/m]	Velocity, in/us [mm/us]
Oil	218 to 254 [715 to 833]	0.047 to 0.055 [1.2 to 1.4]
Lightweight brine or light water-base mud	184 to 218 [604 to 715]	0.055 to 0.065 [1.4 to 1.65]
Brine	160 to 184 [525 to 604]	0.065 to 0.074 [1.65 to 1.9]

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METT

Overview

The METT* multifrequency electromagnetic thickness tool uses nondestructive, noncontact induction methods to detect metal loss and changes in casing geometry, regardless of the fluid type inside the casing. The METT tool is typically used to detect large-scale corrosion or splits, and it can also be used to detect metal loss in the outer casing of multiple casing strings.

A coil centered in the borehole generates an alternating magnetic field that interacts with the casing; a second coil measures the phase shift. These electromagnetic measurements, made at multiple frequencies, are related to the casing wall thickness, inside diameter, and permeability or conductivity. Each parameter is averaged around the pipe circumference.

Specifications

Measurement Specifications	
Output	Casing wall thickness, internal diameter of casing, casing electromagnetic properties
Logging speed	1,800 ft/h [549 m/h]
Range of measurement	Electromagnetic phase system operating frequency: –40 and –10 dB
Repeatability	Internal diameter: ±0.025 in. [±0.635 mm] Low-frequency phase: ±1.5°
Depth of investigation	Up to 10¾-in [27.31-cm] casing
Mud type or weight limitations	None
Combinability	Bottom-only tool, combinable with most services
Special applications	H_2S service Multiple casing strings

Mechanical Specifications		
	METT Tool with Slim Sonde	**METT Tool with Large Sonde**
Temperature rating	350 degF [177 degC]	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]	20,000 psi [138 MPa]
Casing size—min.	4½ in [11.43 cm]	7 in [17.78 cm]
Casing size—max.	7 in [17.78 cm]	10¾ in [27.31 cm]
Outside diameter	2.75 in [6.99 cm]	4.5 in [11.43 cm]
Length	27.83 ft [8.48 m]	29.58 ft [9.02 m]
Weight	294 lbm [133 kg]	399 lbm [181 kg]

Calibration

The downhole sensor readings of METT tools are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration.

Tool quality control

Standard curves

The METT standard curves are listed in Table 1.

Table 1. METT Standard Curves

Output Mnemonic	Output Name
COD	Casing outside diameter
ECIT	Electrical casing inside diameter
LFPX	Low-frequency phase output before wrap
LRAT	Low-frequency amplitude output
PLF	Low-frequency phase
THCK	Thickness of the casing based on the proper selection of electrical conductivity
VRTH	Z system pipe/air voltage magnitude ratio, 6 kHz
VRTL	Z system pipe/air voltage magnitude ratio, 375 Hz
VRTM	Z system pipe/air voltage magnitude ratio, 1.5 kHz

Operation

The METT tool must be run centralized.

When the tool centralizers pass through large casing defects, log anomalies occur if the tool becomes temporarily eccentralized.

Formats

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

- Track 1
  - COD and THCK should read the nominal casing outside diameter and thickness.
- Track 2
  - LRAT should vary between –10 and –40 dB. Short excursions outside this range are acceptable.
  - Voltage magnitude ratio curves VRTH, VRTM, and VRTL should be stable, free of sudden fluctuations, and following the same trend, correlating to each other.
  - PLF in air should be 90°. While logging PLF should be free of noise and repeat well within ±1.5°.

Response in known conditions

- The casing diameter and thickness read by the tool should match the actual casing in normal conditions.
- In multiple casings, THCK and COD are not valid.†

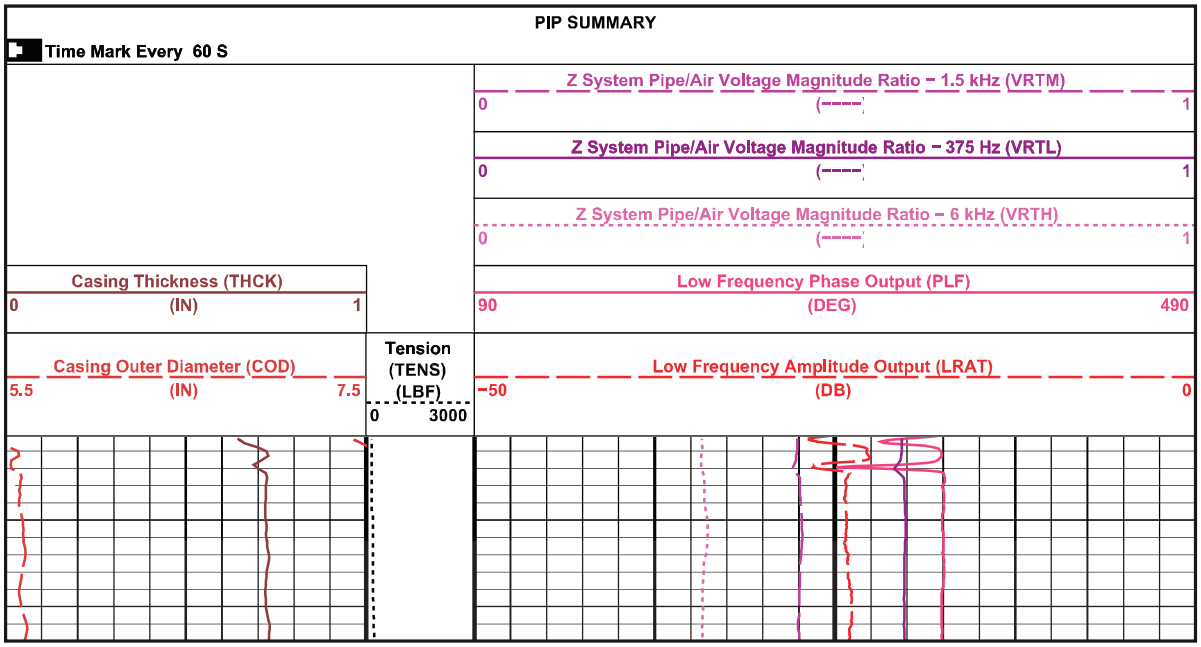

Figure 1. METT standard format.

† In combination with UCI* ultrasonic casing imager measurement of casing corrosion, METT data can be used to compute outer casing corrosion.

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Multifinger Caliper Tool

Overview

The Multifinger Caliper Tool (MFCT) is a mechanical caliper device that uses a circular array of caliper arms to measure the inside diameter of casing. It also gauges the condition of the inside surface of the casing. Using from 36 to 72 fingers, depending on the inside diameter of the casing to be measured, the tool delivers high radial and vertical resolution to identify casing corrosion, pitting, scale, and axial splits.

The caliper fingers are divided into three sections. Each section, covering 120° of the casing, can provide a maximum and minimum radius output. Optionally, the MFCT can be divided into six sections, each covering 60° of the casing, providing one maximum measurement per section.

Specifications

Measurement Specifications			
	MFCA-A	**MFCA-B**	**MFCA-C**
Output	Maximum, minimum, and average casing radii		
Logging speed	6,750 ft/h [2,057 m/h] at 1.5-in [3.81-cm] sampling rate 2,250 ft/h [686 m/h] at 0.5-in [1.27-cm] sampling rate 900 ft/h [274 m/h] at 0.2-in [0.508-cm] sampling rate		
Range of measurement	3.7 to 7.0 in [9.4 to 17.78 cm]	5.795 to 9.625 in [14.72 to 24.45 cm]	9.404 to 13.375 in [23.89 to 33.97 cm]
Accuracy	0.01 in [0.0254 cm]	0.015 in [0.0381 cm]	0.03 in [0.0762 cm]
Vertical resolution	0.2 in [0.508 cm] 0.5 in [1.27 cm] 1.5 in [3.81 cm]	0.2 in [0.508 cm] 0.5 in [1.27 cm] 1.5 in [3.81 cm]	0.2 in [0.508 cm] 0.5 in [1.27 cm] 1.5 in [3.81 cm]

Mechanical Specifications			
	MFCA-A	**MFCA-B**	**MFCA-C**
Temperature rating	350 degF [177 degC]		
Pressure rating	20,000 psi [138 MPa]		
Casing size—min.	3.7 in [9.4 cm]	5.795 in [14.72 cm]	9.404 in [23.89 cm]
Casing size—max.	7 in [17.78 cm]	9.625 in [24.45 cm]	13.375 in [33.97 cm]
Outside diameter	3.55 in [9.02 cm]	5.4 in [13.72 cm]	9.06 in [23.01 cm]
Length	14.4 in [36.58 cm]	16.9 in [42.93 cm]	27.6 in [70.10 cm]
Weight	16.6 lbm [7.53 kg]	37.5 lbm [17.00 kg]	45.6 lbm [20.68 kg]
Arms	36	60	72

Calibration

The downhole readings of MFCTs are periodically compared with a known reference for the master calibration. At the wellsite, zero and plus readings are compared in a before-survey calibration with a well-site reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, readings are verified again in the after-survey calibration.

Tool quality control

Standard curves

The MFCT standard curves are listed in Table 1.

Table 1. MFCT Standard Curves

Output Mnemonic	Output Name
AVMN	Average of all minimum calipers
AVMX	Average of all maximum calipers
AVRD	Average of radii
MNRD	Minimum of radii
MXRD	Maximum of radii
RAD*x*	Minimum caliper in sector *x*

Operation

The tool should be run centralized.

The MFCT arms (MFCA-A, -B, or -C) should be selected according to the casing inside diameter.

Formats

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

- Track 1
  - The curves are the average, minimum, and maximum of the radius measurements as an indication of casing geometry. The curves should read close to casing ID in normal conditions.
- Tracks 2 and 3
  - RAD*x* curves should read the casing inside diameter under normal conditions. In collapsed casing, a finger response may be seen as each centralizer passes through a damaged zone.

Response in known conditions

- Caliper curves should be smooth in sections with no corrosion. Caliper measurements normally fall between the reference casing ID and OD, except where scale buildup decreases the casing or tubing ID.
- Where collapsed casing is encountered, a finger response may be seen as each centralizer passes through the damaged zone.
- MFCT readings should be compared with those of other caliper devices. They should agree.

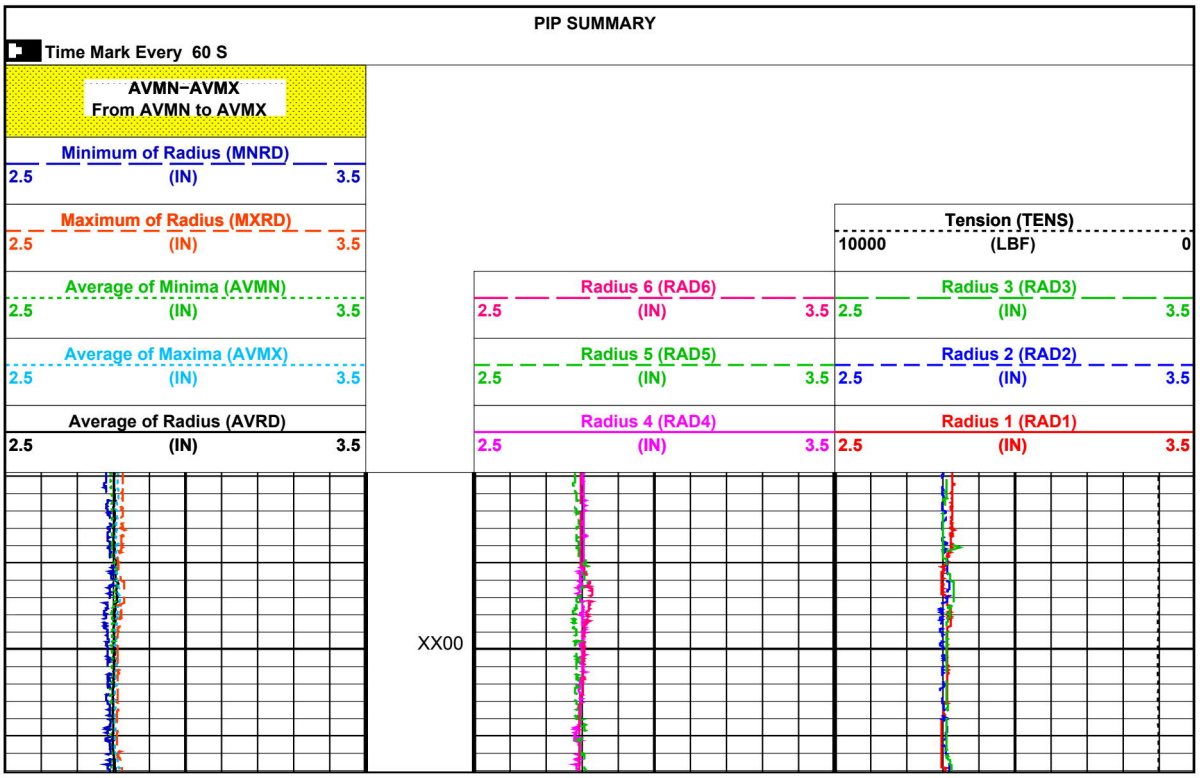

Figure 1. MFCT standard format.

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PS Platform Multifinger Imaging Tool

Overview

The PS Platform* Multifinger Imaging Tool (PMIT) is a multifinger caliper tool that makes highly accurate radial measurements of the internal diameter of tubing and casing strings. The tool is available in three sizes (PMIT-A, PMIT-B, and PMIT-C) to address a wide range of through-tubing and casing size applications.

The tool deploys an array of hard-surfaced fingers, which accurately monitor the inner pipe wall. Eccentricity effects are minimized by equal azimuthal spacing of the fingers, a specific processing algorithm, and centralizers. Centralizers are used with the heavier PMIT-B and PMIT-C tools and can be external inline or integral motorized centralizers (PMIT-B and PMIT-C only because they are much heavier than the PMIT-A). To prevent casing and tubing damage, all centralizers are equipped with rollers. The inclinometer in the tool provides information on well deviation and tool rotation. The PMIT-A tool can be fitted with special extended fingers for logging casing through tubing. The PMIT-C tool can similarly be fitted with special extended fingers for logging large-diameter casings.

Specifications

Measurement Specifications

	PMIT-A	PMIT-B	PMIT-C
Output	Internal casing image from multiple inside diameter measurements	Internal casing image from multiple inside diameter measurements	Internal casing image from multiple inside diameter measurements
Logging speed	Max.: 6,000 ft/h [1,829 m/h]	Max.: 6,000 ft/h [1,829 m/h]	Max.: 6,000 ft/h [1,829 m/h]
Vertical resolution	0.1 in [0.254 cm] at 2,181 ft/h [665 m/h] 0.2 in [0.508 cm] at 4,362 ft/h [1,330 m/h]	0.1 in [0.254 cm] at 1,636 ft/h [499 m/h] 0.2 in [0.508 cm] at 3,272 ft/h [998 m/h]	0.1 in [0.254 cm] at 1,091 ft/h [333 m/h] 0.2 in [0.508 cm] at 2,182 ft/h [666 m/h]
Radial resolution	Standard fingers: 0.004 in [0.10 mm] Extended fingers: 0.007 in [0.178 mm]	0.005 in [0.127 mm]	Standard fingers: 0.007 in [0.178 mm] Extended fingers: 0.009 in [0.229 mm]
Accuracy	Standard fingers: ±0.030 in [±0.76 mm] Extended fingers: ±0.042 in [±1.07 mm] Relative bearing: ±5° at up to 70° deviation	±0.030 in [±0.76 mm] Relative bearing: ±5° at up to 70° deviation	Standard fingers: ±0.030 in [±0.76 mm] Extended fingers: ±0.050 in [±1.27 mm] Relative bearing: ±5° at up to 70° deviation
Depth of investigation	Casing inside surface	Casing inside surface	Casing inside surface
Mud type or weight limitations	None	None	None
Combinability	Combinable with the PS Platform system	Combinable with the PS Platform system	Combinable with the PS Platform system as bottom-only tool Extra centralizers required for casing larger than 9⅝ in [24.45 cm]
Special applications	H_2S service	H_2S service	H_2S service

Mechanical Specifications			
	PMIT-A	**PMIT-B**	**PMIT-C**
Temperature rating	302 degF [150 degC]	302 degF [150 degC]	PMIT-CA: 302 degF [150 degC] PMIT-CB: 350 degF [177 degC]
Pressure rating	15,000 psi [103 MPa]	15,000 psi [103 MPa]	PMIT-CA: 15,000 psi [103 MPa] PMIT-CB: 20,000 psi [138 MPa]
Measurable casing and tubing ID—min.	Standard or extended fingers: 2 in [5.08 cm]	3 in [7.62 cm]	Standard fingers: 5 in [12.7 cm] Extended fingers: 8 in [20.32 cm]
Measurable casing and tubing ID—max.	Standard fingers: 4½ in [11.43 cm] Extended fingers: 7 in [17.78 cm]	7 in [17.78 cm]	Standard fingers: 10 in [25.4 cm] Extended fingers: 13 in [33.02 cm]
Outside diameter	Standard or extended fingers: 1.6875 in [4.29 cm]	2.75 in [6.99 cm]	Standard fingers: 4 in [10.16 cm] Extended fingers: 5.5 in [13.97 cm]
Fingers	24	40	60
Length	11.88 ft [3.62 m] (with centralizers)	8.86 ft [2.70 m]	10.34 ft [3.15 m]
Weight	56.5 lbm [26 kg] (with centralizers)	87.4 lbm [40 kg]	120 lbm [54 kg]
Tension	10,000 lbf [44,480 N]	10,000 lbf [44,480 N]	10,000 lbf [44,480 N]
Compression	1,850 lbf [8,230 N]	2,500 lbf [11,120 N]	2,500 lbf [11,120 N]

Calibration

The downhole sensor readings of PMIT tools are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration. The inclinometer also receives a master calibration.

Tool quality control

Standard curves

The PMIT standard curves are listed in Table 1.

Table 1. PMIT Standard Curves

Output Mnemonic	Output Name
AZEC	Eccentralization angle
CCLD	Casing collar signal from PS Platform Basic Measurement Sonde (PBMS)
CIRC	Nominal internal radius
CMJR	Maximum radius within joint from Corrosion Summary Report (CSR)
CORC	Nominal outer radius
ECCE	Eccentralization
IRAV	Average internal radius
IRMN	Minimum internal radius
IRMX	Maximum internal radius
LACK	Percentage of metal loss
OVA	Percentage of ovalization
PNMA	Maximum penetration
PNMI	Minimum penetration
PNVA	Average penetration

Operation

The PMIT must be run well centered. Any eccentering causes the fingers on one side of the tool to read less than they should and the fingers on the other side to read more than they should. A small degree of eccentering is corrected by the software, but if it is too severe, some fingers may not touch the casing wall and data is irremediably missing.

Formats

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

- Caliper histogram track
  - Each finger is plotted as a vertical line, with the maximum response of the finger at the top and the minimum at the bottom. The deflection of each line to the right shows the frequency at which that reading occurred during the logging interval for that finger. The response of all fingers should be the same over a long logging interval. It is important to examine the histogram to check for indications of problems, such as residual eccentering effects or bad fingers.
- Track 1
  - AZEC is the angle between Finger 0 and the vector describing the eccentering of the tool within the borehole.
  - The burst pressure (BPRE) is indicative of the borehole environment.
  - Both ECCE and OVA should be low for accurate measurements.
  - CIRC and CORC are used as input to algorithms for such values as fractional penetration and metal loss.
  - IRMN, IRMX, and IRAV are the respective minimum, maximum, and median of the calipers after calibration and correction, and they should agree with the actual ID of the casing.
- Track 2
  - This track represents the finger activity of the tool. Individual fingers can be monitored to track finger activity and to identify stuck fingers.

- Track 3
  - Radius minus average (CRAM) colors in blue have a smaller ID than average whereas colors in red have bigger ID than average. In an ovalized well, this image produces two blue stripes for the smaller diameters with red stripes between the blue stripes.

Response in known conditions

- The PMIT fingers should show an agreed response with the casing ID. Under ideal conditions all fingers read the same.

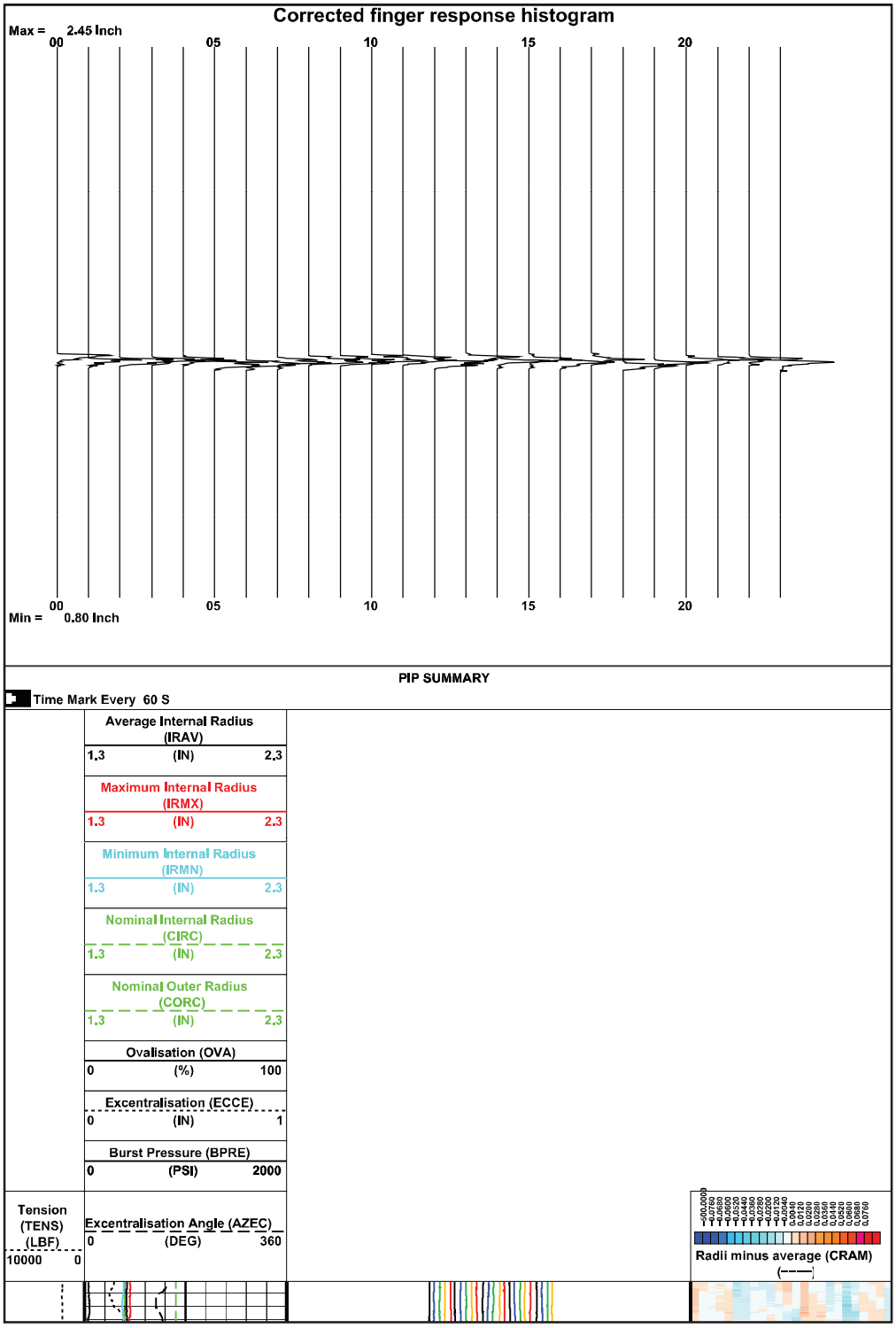

Figure 1. PMIT standard format.

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Flow Scanner

Overview

The Flow Scanner* horizontal and deviated well production logging system measures five minispinner rotational velocities at positions distributed along the vertical pipe diameter. Six water holdup measurements and six gas holdup measurements are also made along the vertical pipe diameter together with a single-axis caliper and tool relative-bearing measurements.

Calibration

The spinner, or turbine, is most commonly calibrated after acquisition by a log analyst using the data from multiple logging passes at 30, 60, and 90 ft/min [10, 20, and 30 m/min].

The caliper is calibrated at surface by using two reference rings. Typical ring sizes are 5.5 and 8 in [13.97 and 20.32 cm].

Specifications

Measurement Specifications	
Output	Spinner (or turbine) rotational speed, caliper, water holdup, gas holdup
Logging speed	Typically up and down at two different speeds for spinner calibration
Range of measurement	Spinners: 0 to 200 rps Caliper: 2 to 9 in [5.08 to 22.86 cm] Water holdup: 0 to 1.0 Gas holdup: 0 to 1.0
Vertical resolution	2 ft [0.61 m]
Accuracy	Water holdup: <10% Gas holdup: <10% Caliper: ±0.2 in [±5.1 mm] Relative bearing: ±6° (for deviations above 10°)
Depth of investigation	Spinners: Swept area of spinner blades Water holdup probes: <0.1 in [<2.5 mm] Gas holdup probes: <0.1 in [<2.5 mm]
Mud type or weight limitations	Water holdup probes require salinity > 2,000-ppm NaCl at 100 degF [40 degC], decreasing to >1,000 ppm above 210 degF [100 degC]

Mechanical Specifications	
Temperature rating	302 degF [150 degC] High-temperature version: 347 degF [175 degC] for a limited time
Pressure rating	15,000 psi [103 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	9 in [22.9 cm]
Outside diameter	1.6875 in [4.29 cm] High-temperature version: 2.125 in 5.4 cm]
Length	FSIS-B with FISM-B: 16.4 ft [5 m] FSIS-B with FSI 8/22 AH: 11.4 ft [3.57 m]
Weight	FSIS-A: 50.6 lbm [23 kg] FSIM-B: 31.4 lbm [14.3 kg] FSIA-A: 2.0 lbm [0.9 kg]
Tension	10,000 lbm [4,500 kg]
Compression	1,000 lbm [450 kg]

Tool quality control

Standard curves

The Flow Scanner standard curves are listed in Table 1.

Table 1. Flow Scanner Standard Curves

Output Mnemonic	Output Name
CALI_FSI	Calibrated caliper
CVEL_FSI	Cable velocity memorized at spinner measure point
DFB*n*_FSI	Bubble count rate at electrical probe *n*
DFBF*n*_FSI	Filtered (sliding window) bubble count rate at electrical probe *n*
DFH*n*_FSI	Water holdup at electrical probe *n*
DFHF*n*_FSI	Filtered (sliding window) water holdup at electrical probe *n*
DFMN*n*_FSI	Electrical probe *n* minimum voltage
DFMX*n*_FSI	Electrical probe *n* maximum voltage
DFTH*n*_FSI	Electrical probe *n* downhole signal threshold
GHB*n*_FSI	Bubble count rate at optical probe *n*
GHBF*n*_FSI	Filtered (sliding window) bubble count rate at optical probe *n*
GHH*n*_FSI	Gas holdup at optical probe *n*
GHHF*n*_FSI	Filtered (sliding window) gas holdup at optical probe *n*
GHMN*n*_FSI	Optical probe *n* minimum voltage
GHMX*n*_FSI	Optical probe *n* maximum voltage
GTH*n*_FSI	Optical probe *n* downhole signal threshold
RB_FSI	Relative bearing memorized
SPIF*y*_FSI	Filtered (sliding window) rotational velocity spinner *y*
SPMN*y*_FSI	Spinner *y* minimum voltage
SPMX*y*_FSI	Spinner *y* maximum voltage
SPTH1	First downhole signal threshold for all spinners
SPTH2	Second downhole signal threshold for all spinners
SPTH3	Third downhole signal threshold for all spinners

Operation

The Flow Scanner tool is normally run eccentered in horizontal wells to quantify three-phase flow. Occasionally the tool is run in highly deviated wells to detect small high-side hydrocarbon holdups.

Formats

The format in Fig. 1 is used to check the quality control of the spinner data and decide whether further logging is required or if sufficient data has been acquired.

- Track 1
  - CVEL_FSI should show a constant or very slowly drifting tool velocity.
  - RB_FSI shows the tool inclination away from the vertical pipe diameter. Readings of more than 30° are unusual and may compromise the interpretation.
  - CALI_FSI gives the opening diameter of the Flow Scanner sonde and should be close to the nominal casing ID.
  - The gamma ray (GR) normally is between 0 and 150 gAPI but may be considerably larger in the presence of radioactive scale or when the Flow Scanner tool is run with a pulsed neutron tool.
- Track 2
  - The rotational velocity image (RAW_SPSIMAGE_16C) shows the five spinner speeds as a color image.
- Tracks 3 through 7
  - The spinner rotational velocity (SPI*n*_FSI) should be at a constant speed between producing intervals while at a constant deviation, constant tool speed, and constant cross-sectional area.

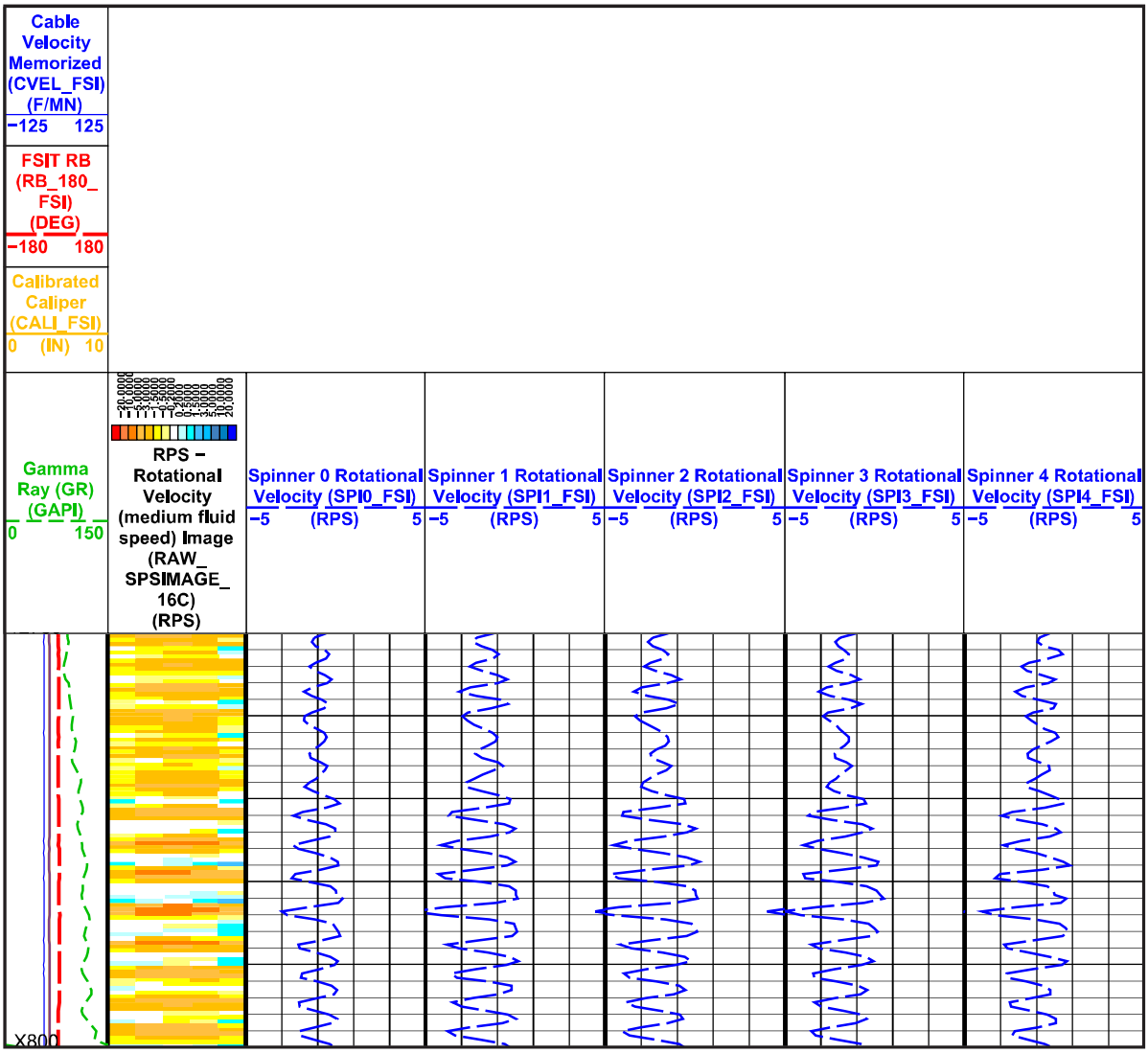

Figure 1. Flow Scanner spinner data format.

The format in Fig. 2 is used to check the quality of the probe holdup data and identify broken or sticky probe responses. The unfiltered probe responses are displayed (instead of the usual filtered channels) to pinpoint any defects.

- Track 1
  - CVEL_FSI should show a constant or very slowly drifting tool velocity.
  - CALI_FSI gives the opening diameter of the Flow Scanner sonde and should be close to the nominal casing ID.
  - GR normally is between 0 and 150 gAPI but may be considerably larger in the presence of radioactive scale or when run with a pulsed neutron tool.
  - The perforated zone is identified.
- Track 2
  - The well pressure (WPRE) normally increases with increasing true vertical depth.
  - The well temperature (WTEP) shows the geothermal temperature unless disturbed by flow and warm or cold entries.
- Track 3
  - RAW_SPSIMAGE_16C shows the five spinner speeds as a color image.
- Tracks 4 through 9
  - Areas are coded to show water or gas or in the absence of both, oil, for the various probes.
  - For small values of n there should be more water holdup whereas for large values of n there should be more gas holdup. The bubble counts increase with increasing spinner speeds.

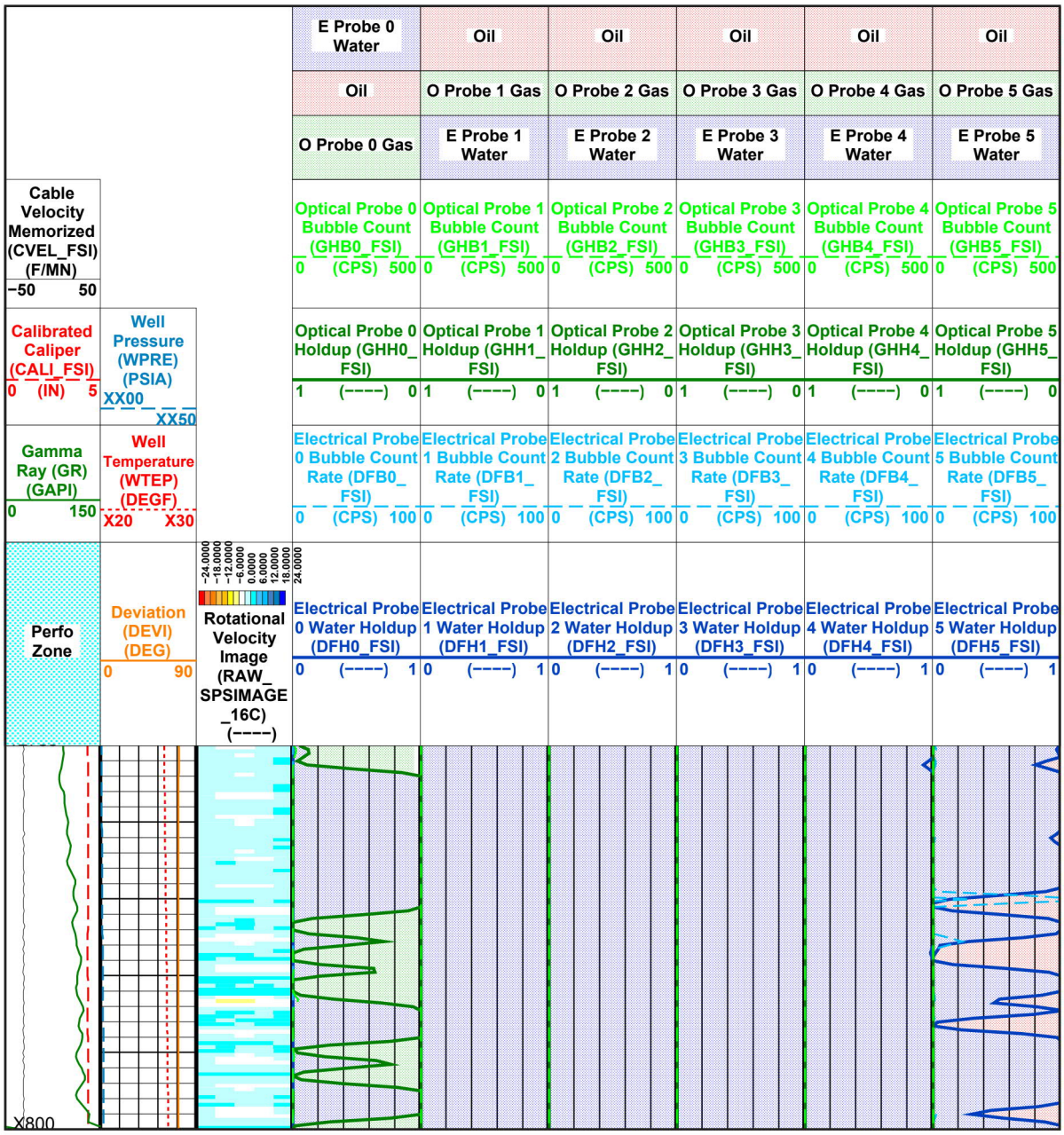

Figure 2. Flow Scanner holdup data format.

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PS Platform

Overview

The PS Platform* production services platform uses a modular design comprising the following main tools:

- Platform Basic Measurement Sonde (PBMS) for measuring pressure, temperature, gamma ray, and casing collar location
- Gradiomanometer* (PGMC) sonde for measuring the density of the well fluid and well deviation
- PS Platform Inline Spinner (PILS) for measuring high-velocity flow in small-diameter tubulars
- Flow-Caliper Imaging Sonde (PFCS) for measuring fluid velocity and water holdup and also has a dual-axis caliper.

Additional production logging tools combinable with the PS Platform system are

- GHOST* gas optical holdup sensor tool for measuring gas holdup and also has a caliper
- Digital Entry and Fluid Imaging Tool (DEFT) for measuring water and also has a caliper
- Flow Scanner* horizontal and deviated well production logging system for measuring three-phase flow rate in horizontal wells
- RST* reservoir saturation tool for measuring water velocity and three-phase holdup.

Also combinable with the PS Platform system are

- SCMT* slim cement mapping tool for a through-tubing cement quality log
- PS Platform Multifinger Imaging Tool (PMIT) for multifinger caliper surveys of pitting and erosion
- EM Pipe Scanner* electromagnetic casing inspection tool for electromagnetic inspection of corrosion and erosion
- RST reservoir saturation tool for capture sigma saturation logging, carbon/oxygen saturation logging, capture lithology identification, and silicon-activation gravel-pack quality logging.

In horizontal wells the PBMS can be replaced by the MaxTRAC* downhole well tractor system or the TuffTRAC* cased hole services tractor.

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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.	2⅜-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.

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Gradiomanometer

Overview

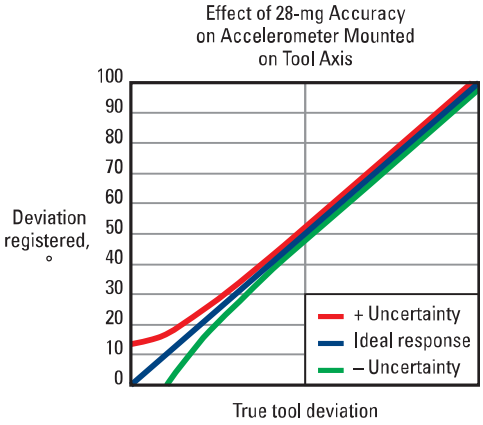
The Gradiomanometer* sonde (PGMS) measures the average density of the wellbore fluid, from which the water, oil, and gas holdups are derived. Accelerometer measurements provide deviation correction for the measured fluid density.

Calibration

The differential pressure sensor (PSOI) and the accelerometer are factory calibrated over the entire pressure and temperature range of the tool and a polynomial calibration coefficient table is created for each. No wellsite calibration is performed.

Specifications

Measurement Specifications	
Output	Well fluid density filtered and corrected for deviation, tool deviation from the vertical, acceleration along the z-axis
Logging speed	Typically 30, 60, and 90 ft/min (10, 20, and 30 m/min)
Range of measurement	Density: 0 to 2.0 g/cm^3 Deviation: 0 to 180°
Vertical resolution	Density: 2 ft [0.61 m] Deviation: 15 ft [4.6 m]
Accuracy	Density: $\frac{0.025}{\cos(\text{deviation})}$ g/cm^3 Deviation: $\cos^{-1}\left(\cos(\text{deviation}) - 0.028\right) - \text{deviation}°$



Depth of investigation	Borehole averaging
Mud type or weight limitations	None

Mechanical Specifications	
Temperature rating	302 degF [150 degC] PGMC-E: 392 degF [200 degC] for a limited time
Pressure rating	15,000 psi [103.4 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	None
Outside diameter	1.6875 in [4.29 cm] PGMC-E: 2.125 in [5.4 cm]
Length	4.8 ft [1.46 m]
Weight	23.4 lbm [10.6 kg]

Tool quality control

Standard curves

The Gradiomanometer standard curves are listed in Table 1.

Table 1. Gradiomanometer Standard Curves

Output Mnemonic	Output Name
ATCOR	Gradiomanometer carrier (PGMC) accelerometer correction temperature
ATEP	PGMC accelerometer temperature
AZ_PGMS	PGMC acceleration along the z-axis
DEVI_PGM	PGMC hole deviation
GTEP	PGMC gradiomanometer temperature
RHOSB	PGMS bottomhole silicon oil density
UWFD	PGMC raw well fluid density
WFDE	Well fluid density

Operation

The Gradiomanometer tool can be run centered, eccentered, or tilted; however, a tilted tool compromises the accelerometer measurement of well deviation although it still delivers an accurate density.

Formats

The WFDE curve is normally displayed on a scale from 0 to 2.0 g/cm^3.

Response in known conditions

In a shut-in well containing water of a known salinity, the WFDE curve should match the modeled water density at the pressure and temperature.

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PS Platform Inline Spinner

Overview

PS Platform* Inline Spinner (PILS) can be used in high-flow-rate environments to determine fluid velocity.

Specifications

Measurement Specifications	
Output	Spinner (or turbine) rotational speed
Logging speed	Typically 30, 60, and 90 ft/min [10, 20, and 30 m/min]
Range of measurement	0 to 200 rps
Vertical resolution	2 ft [0.6 m]
Depth of investigation	Swept area of spinner blades
Mud type or weight limitations	None

Mechanical Specifications	
Temperature rating	347 degF [175 degC]
Pressure rating	18,000 psi [124 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	None
Outside diameter	1.6875 in [4.29 cm]
Length	2.58 ft [0.79 m]
Weight	12.6 lbm [5.7 kg]

Calibration

The spinner is usually calibrated after acquisition by a log analyst using the data acquired from multiple logging passes at 30, 60, and 90 ft/min [10, 20, and 30 m/min].

Tool quality control

Standard curves

The PILS standard curves are listed in Table 1.

Table 1. PILS Standard Curves

Output Mnemonic	Output Name
SCV1	Auxiliary spinner cable velocity
SPI1	Auxiliary spinner velocity

Operation

The tool is normally run centered to avoid low-side spinner-jamming debris and to enable calculation of a spinner correction factor; however, acceptable results can often be obtained from eccentered operations in high-velocity wells.

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Flow-Caliper Imaging Sonde

Overview

The Flow-Caliper Imaging Sonde (PFCS) measures a spinner rotational velocity, water and hydrocarbon holdups, and bubble counts from four independent probes. It also provides dual-axis (x-y) caliper measurements and relative-bearing measurements. The bubble counts can be used to identify the deepest hydrocarbon entry.

Specifications

Measurement Specifications	
Output	Spinner (or turbine) rotational speed, dual-axis caliper, water holdup, bubble count
Logging speed	Typically 30, 60, and 90 ft/min [10, 20, and 30 m/min]
Range of measurement	Spinner: 0 to 200 rps Caliper: 2 to 11 in [5.08 to 27.94 cm] Water holdup: 0 to 1.0
Vertical resolution	Spinner: 2 ft [0.61 m] Caliper and holdup probes: 0.5 ft [0.15 m]
Accuracy	Water holdup: <10%, decreasing to 0.5% at extremely high water holdups Caliper: ±0.2 in [±5 mm] Relative bearing: ±6° for deviations above 10°
Depth of investigation	Spinner: Swept area of spinner blades Water holdup probes: <0.1 in [<2.5 mm]
Mud type or weight limitations	Water holdup probes require salinity > 2,000-ppm NaCl at 100 degF [40 degC] decreasing to > 1,000 ppm above 210 degF [100 degC]

Mechanical Specifications	
Temperature rating	302 degF [150 degC] PFCS-E: 392 degF [200 degC] for a limited time
Pressure rating	15,000 psi [103.4 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	Caliper: 11 in [27.94 cm]
Outside diameter	1.6875 in [4.29 cm] PFCS-E: 2.125 in [5.4 cm]
Length	5.14 ft [1.57 m]
Weight	19.7 lbm [8.9 kg]

Calibration

The spinner is usually calibrated after acquisition by a log analyst from the data acquired during multiple logging passes at 30, 60, and 90 ft/min [10, 20, and 30 m/min] and using the in situ multispeed calibration technique.

The caliper is calibrated at surface using two reference rings. Typical ring sizes are 5.5 and 8 in [13.97 and 20.32 cm].

Tool quality control

Standard curves

The PFCS standard curves are listed in Table 1.

Table 1. PFCS Standard Curves

Output Mnemonic	Output Name
D1RB	PFCS probe 1 relative bearing
DFB*i*	PFCS bubble count probe *i*
DFBM	PFCS bubble count average
DFCHM	Digital Entry and Fluid Imager Tool (DEFT) computed holdup average
DFH*i*	PFCS holdup probe *i*
DFHM	PFCS holdup average
DFN*i*	PFCS minimum voltage probe *i*
DFX*i*	PFCS maximum voltage probe *i*
PFC1	PFCS calibrated X caliper
PFC2	PFCS calibrated Y caliper
PFTH*i*	PFCS probe *i* water/hydrocarbon voltage threshold
RB_PFCS	Memorized relative bearing
SCVL	Spinner cable velocity
SPIN	Main spinner velocity

Operation

The PFCS is run centered. The force from the two-axis caliper is sufficient to center the tool.

Formats

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

- Track 1
  - These curves are unrelated to log quality control for the probes.
- Track 2
  - DFBM reads zero in zero-flow regions and in the absence of hydrocarbons.
  - DFHM reads 1.0 in a water-filled sump. In most wells DFHM diminishes with decreasing depth. Readings of exactly 0.25, 0.5, and 0.75 should be viewed with suspicion because this is commonly associated with a failed probe.
  - The D1RB relative-bearing measurement is valid for wellbore deviations above 10° deviation and should show either little activity or a slow rotation to the left or right under the action of any cable torque.
- Track 3
  - The 4 probes OK (DPOK) curve is 0 if for all probes DFNi < PFTHi < (DFXi – 0.3). Otherwise DPOK is set to 1 and an area coding flags an alarm.
  - The 4 probes status (DPAS) identifies which curves are in error using the identity DPAS $= A_1 + 2A_2 + 4A_3 + 8A_4$, where $A_i = 0$ if DFNi < PFTHi < DFXi – 0.3. Otherwise $A_i = 1$.
  - DPOK and DPAS erroneously flag an error in oil or gas zones with no water bubbles.
- Depth track
  - The depth track is between Tracks 3 and 4.
- Track 4
  - The image flags (DEFT_LQC) are composed of four stripes, one for each probe, with probe 1 on the left-hand side. The stripe is red if the PFTHi data channel is outside the interval (DFNi, DFXi), orange if PFTHi is in the interval (DFXi – 0.3, DFXi), and blank otherwise.
- Tracks 5–8
  - In bubble flow PFTHi is between DFNi and DFXi.
  - In monophasic water conditions PFTHi should be close to but slightly less than DFNi.
  - In monophasic hydrocarbon conditions PFTHi should be close to but slightly more than DFXi.

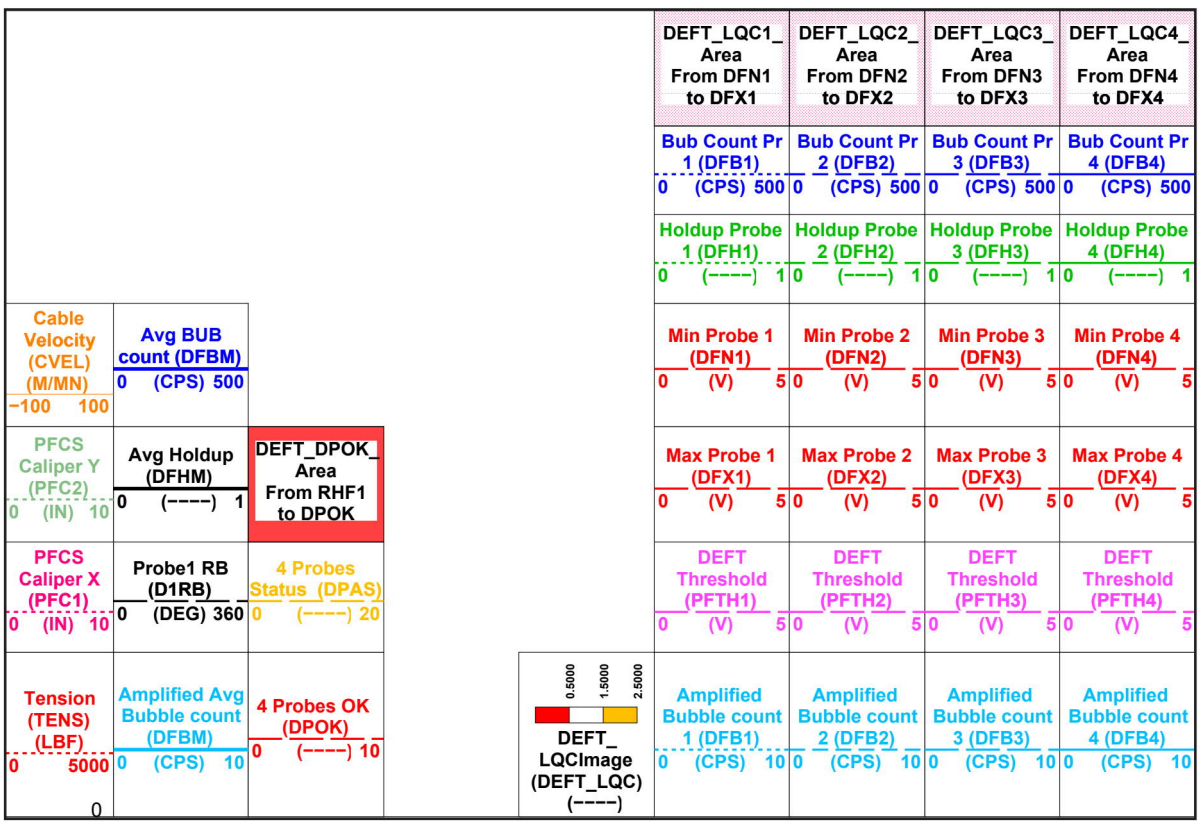

Figure 1. FloView probes log quality control format for the Flow-Caliper Imaging Sonde.*

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Digital Entry and Fluid Imager Tool

Overview

The Digital Entry and Fluid Imager Tool (DEFT) measures water and hydrocarbon holdups and bubble counts from four independent probes. It also provides caliper measurements and relative-bearing measurements. The bubble counts can be used to identify the deepest hydrocarbon entry.

Specifications

Measurement Specifications	
Output	Caliper, water holdup, bubble count
Logging speed	Typically 30, 60, and 90 ft/min [10, 20, and 30 m/min]
Range of measurement	Caliper: 2 to 9 in [5.08 to 22.86 cm] Water holdup: 0 to 1.0
Vertical resolution	Caliper and holdup probes: 0.5 ft [0.15 m]
Accuracy	Water holdup: <10%, decreasing to 0.5% at extremely high water holdups Caliper: ±0.2 in [±5 mm] Relative bearing: ±6° for deviations above 10°
Depth of investigation	Water holdup probes: <0.1 in [<2.5 mm]
Mud type or weight limitations	Water holdup probes require salinity > 2,000-ppm NaCl at 100 degF [40 degC] decreasing to >1,000 ppm above 210 degF [100 degC]

Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	Caliper: 9 in [22.9 cm]
Outside diameter	1.6875 in [4.29 cm]
Length	5.74 ft [1.75 m]
Weight	26.0 lbm [11.8 kg]

Calibration

The caliper is calibrated at surface using two reference rings. Typical ring sizes are 5.5 and 8 in [13.97 and 20.32 cm].

Tool quality control

Standard curves

The DEFT standard curves are listed in Table 1.

Table 1. DEFT Standard Curves

Output Mnemonic	Output Name
D1RB2	DEFT probe 5 relative bearing
DFB*i*	DEFT bubble count probe *i*
DFBM	DEFT bubble count average
DFCHM	DEFT computed holdup average
DFH*i*	DEFT holdup probe *i*
DFHM	DEFT holdup average
DFN*i*	DEFT minimum voltage probe *i*
DFX*i*	DEFT maximum voltage probe *i*
PFC12	DEFT caliper
PFTH*i*	DEFT probe *i* water/hydrocarbon voltage threshold

Note: *i* is usually from 5 to 8.

Operation

The DEFT is run centered. The force from the two-axis caliper is sufficient to center the tool.

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GHOST

Overview

The GHOST* gas holdup optical sensor tool is based on the localized measurement of gas holdup in multiphase flows. Four optical probes, deployed 90° apart on the arms of a centralizer-like tool, measure the refractive index of the surrounding fluid.

Specifications

Measurement Specifications	
Output	Gas holdup, bubble count, caliper
Logging speed	Typically 30, 60, and 90 ft/min [10, 20, and 30 m/min]
Range of measurement	Caliper: 2 to 9 in [5.08 to 22.86 cm] Gas holdup: 0 to 1.0
Vertical resolution	Point of measurement
Accuracy	Gas holdup: <10%, decreasing to 0.5% at extremely high gas holdups Caliper: ±0.2 in [±5 mm] Relative bearing: ±6° for deviations above 10°
Depth of investigation	Gas holdup probes: <0.05 in [<1.2 mm]
Mud type or weight limitations	None

Mechanical Specifications	
Temperature rating	302 degF [150 degC] High-temperature version: 392 degF [200 degC] for a limited time
Pressure rating	15,000 psi [103 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	9 in [22.86 cm]
Outside diameter	1.6875 in [4.29 cm] High-temperature version: 2.125 in [5.4 cm]
Length	7.1 ft [2.16 m]
Weight	28.4 lbm [12.9 kg]

Calibration

Before every job, the GHOST tool requires two calibrations: one for the caliper and one for the probes. A check of the relative bearing is also required to ensure that probe orientation is correct in deviated or horizontal wells. Caliper calibration caliper uses a two-point calibration method. For calibration of the probes, the tool is in air. The noise level is measured first and then the minimum LED power is measured to determine the maximum signal level.

Tool quality control

Standard curves

The GHOST standard curves are listed in Table 1.

Table 1. GHOST Standard Curves

Output Mnemonic	Output Name
D1RB2	GHOST probe 5 relative bearing
DEFT_D1RB2	Relative bearing of probe 5 on tools with probes 5–8
DEFT_DFCA2	Caliper of tool with probes 5–8
DEFT_DFN*i*	Minimum voltage on probes 5–8
DEFT_DFX*i*	Maximum voltage on probes 5–8
DEFTH*j*	Threshold voltage of probe *j*
DFN*i*	GHOST minimum probe *i*
DFX*i*	GHOST maximum probe *i*
GFBM2	GHOST bubble count average
GFHM2	GHOST holdup average
GHB*i*	GHOST bubble count probe *i*
GHH*i*	GHOST holdup probe *i*
PFC12	GHOST caliper
PFTH*i*	GHOST probe *i* gas/liquid threshold

Note: On most GHOST logs, *i* is numbered from 5 to 8 and *j* from 1 to 4.

Operation

The GHOST toolstring must be run centralized as much as possible. It should be placed as close as possible to the spinner tool.

Formats

The format in Fig. 1 is used for quality control.

- Track 1
  - The LED power (PFGR) is adjusted up to 100% to provide optical signals of sufficient amplitude. A low dynamic range on the waveforms and the minimum and maximum voltages should have been countered by applying the maximum LED power of 100%.
  - DEFT_DFCA2 for the GHOST caliper should read close to the nominal casing ID except in regions of scale buildup or severe corrosion.
- Tracks 2–5
  - A fragment of the probe waveform can be sent to surface. Tracks 2 through 5 show the probe waveforms from probes 5 through 8, respectively. Channel names from the Digital Entry and Fluid Imager Tool (DEFT) are reused here.
- Tracks 6–9
  - In bubble flow DEFTH*j* is between DEFT_DFN*i* and DEFT_DFX*i*.
  - In monophasic gas conditions DEFTH*j* should be close to but less than DEFT_DFN*i*.
  - In monophasic liquid conditions DEFTH*j* should be close to but slightly more than DEFT_DFX*i*.
  - The area coding extends between the minimum and the maximum voltage and shows the dynamic range of the measurement.

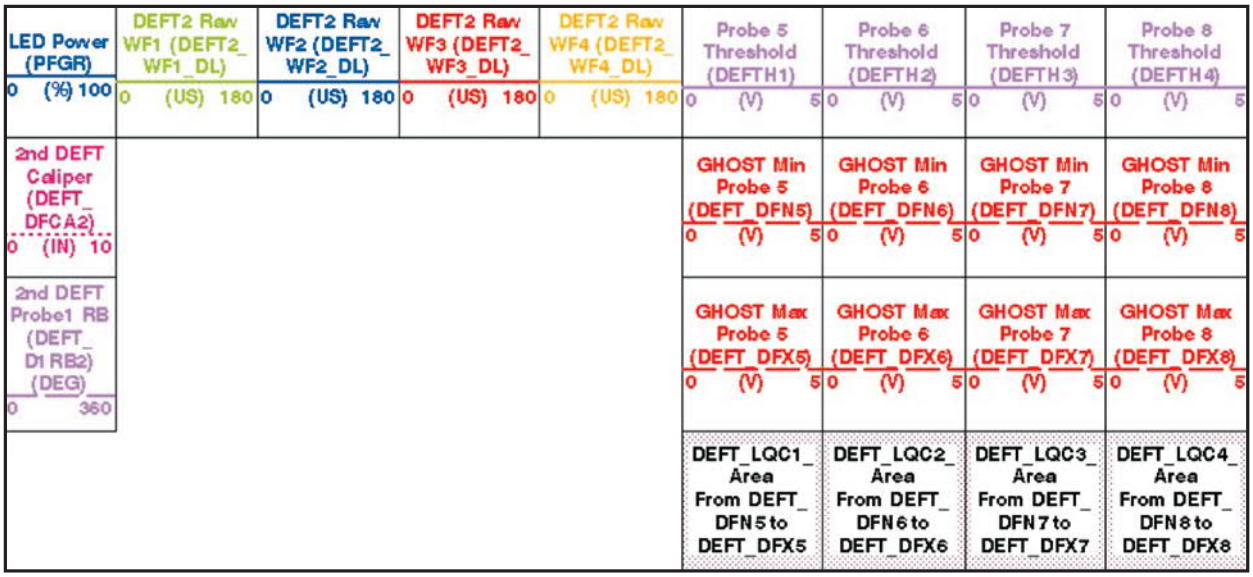

Figure 1. GHOST depth log for log quality control.

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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: 2 1/4 in [5.72 cm]	2 7/8 in [7.30 cm]
Borehole size—max.	9 5/8 in [24.45 cm] With flask: 9 5/8 in [24.45 cm]	9 5/8 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 far effective capture count rate
RSCN_RST	RST near effective capture 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.

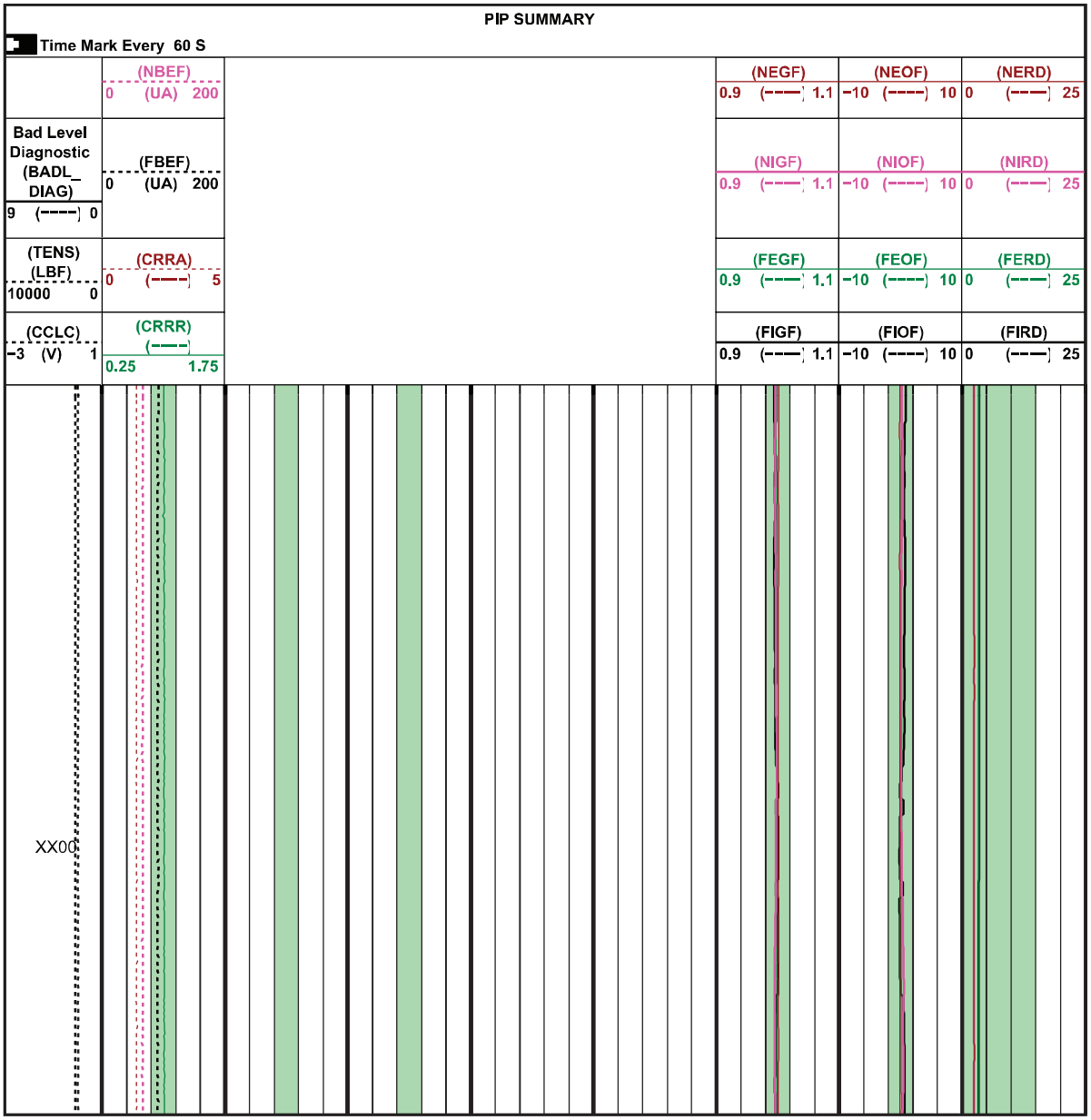

Figure 1. RST and RSTPro hardware format.

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.

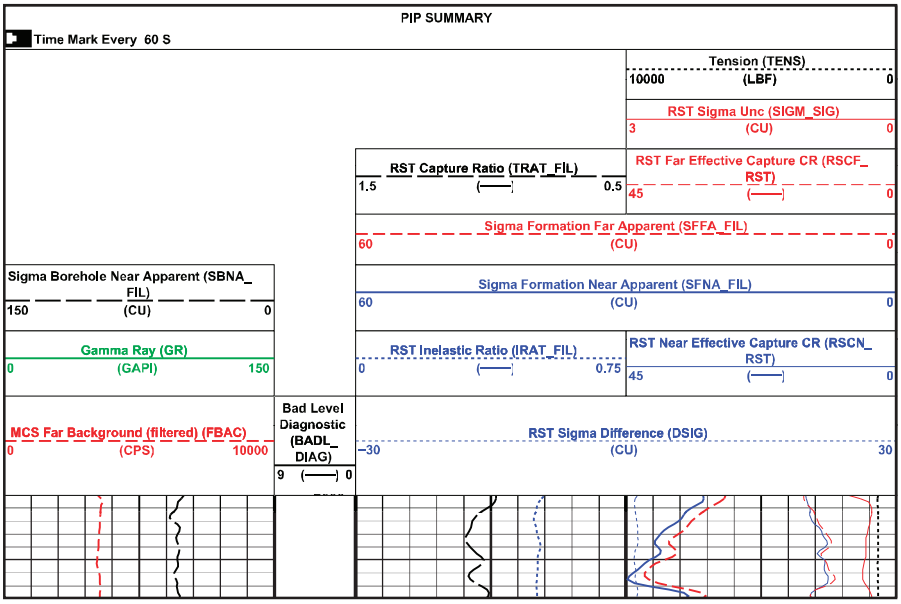

Figure 2. RST and RSTPro sigma standard format.

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

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WFL

Overview

The WFL* water flow log obtained with the RST* or RSTPro* reservoir saturation tool uses the temporary activation of oxygen within flowing water to mark the water as it passes a pulsed neutron generator and then detect the resulting gamma rays as the activated water passes various gamma ray detectors downstream. From the time to detection and the spacing between the neutron generator and gamma ray detector, the water velocity is computed.

Specifications

Measurement Specifications	
Output	Water velocity
Logging speed	Station measurement
Range of measurement	1 to 400 ft/min [0.3 to 122 m/min][1]
Vertical resolution	RST-C near detector: 1 ft [0.3 m] RST-C far detector: 1.5 ft [0.5 m] PBMS detector: >14 ft [>4.33 m]
Accuracy	Not quantifiable
Depth of investigation	Borehole and cement channels
Mud type or weight limitations	None

[1] Range using RST-C detectors, with higher velocities requiring the PS Platform* basic measurement sonde (PBMS) detector.

Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	10 in [25.4 cm]
Outside diameter	1.6875 in [4.29 cm]
Weight	101 lbm [46 kg]
Tension	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N]

Calibration

The WFL mode of the RST detectors does not require calibration.

Tool quality control

Operation

To look for flow in a low-side cement channel, an eccentred tool position is preferred.

For production logging in large casings (9⅝ in and larger), a centered position is preferred. In smaller casing sizes the tool can be centered or eccentered.

WFL measurements should be referenced to the pulsed neutron depth because a large and variable distance separates the tool zero from the pulsed neutron source or Minitron* pulsed neutron generator device.

The measured gamma ray counts are corrected for the background stationary decay signal and result in the net count rate. This signal is in turn corrected for the 7.2-s half-life decay and plotted on a velocity scale.

Multiple bursts are stacked until a satisfactory signal-to-noise ratio is observed.

Formats

The WFL station summary is shown in Fig. 1.

- WFL detector
  - The gamma ray detector used for computing the velocity is typically the RST-far, RST-near, or PBMS-GR.
- Start and stop depths
  - These depths are the neutron generator and the gamma ray detector, respectively.
- Flow detected
  - A basic algorithm makes an initial attempt to distinguish between the presence of moving water and no-flow conditions.
- Velocity
  - This value is used in any interpretation.
- Velocity error
  - The difference is between the current reported velocity and the velocity that would be computed after an infinite number of cycles. (The true velocity error is typically much larger and indeterminate.)

- WFL subcycle time
  - The time when the neutrons were turned on is followed by the time they were turned off.
- Number of WFL cycles
  - The number of neutron bursts is averaged to compute the answer displayed.

Response in known conditions

Caliper readings checked in casing should read the casing ID ± 0.25 in.

RST WFL Station Summary

Log File Number	WFL Detector	Start Depth, m	Stop Depth, m	Flow Detected	Velocity, m/min	Velocity Error, m/min
NNN	RST-Far	XXXX	YYYY	Yes	20.2	1.4

Data acquired on: dd-mm-yyyy hh:mm
Detector is above Minitron (sensitive to Up Flow)
WFT Subcycle Time: 0.80 sec On - 52.27 sec Off
Number of WFL Cycles: 15

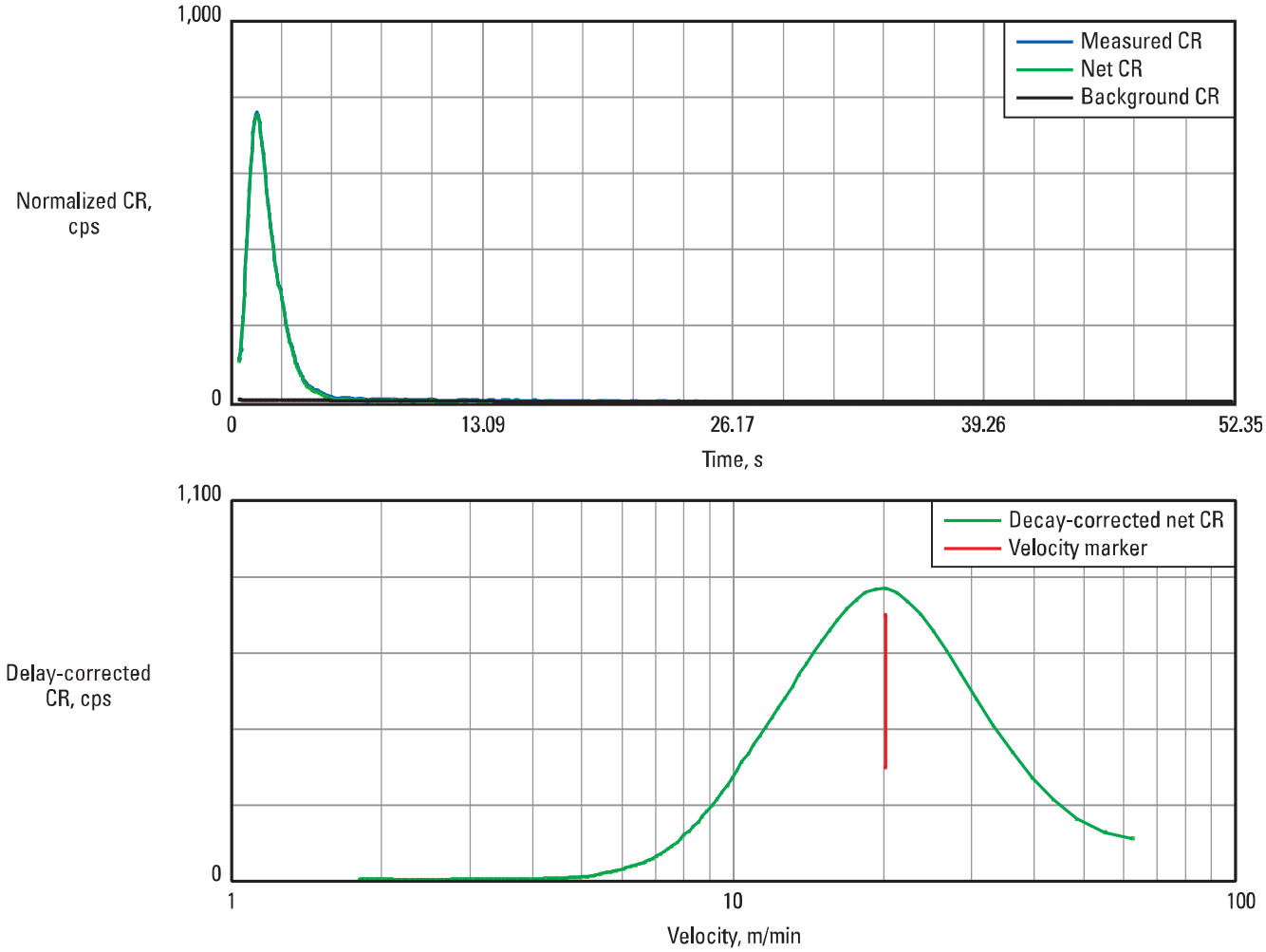

Figure 1. RST WFL station format. CR = count rate.

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TPHL

Overview

The TPHL* three-phase fluid holdup log, made with a centered RST* or RSTPro* reservoir saturation tool, processes the carbon/oxygen data to deliver the holdups of water, oil, and gas. Under favorable conditions, a formation oil and water saturation can also be computed.

Specifications

Measurement Specifications	
Output	Oil holdup, water holdup, gas holdup
Logging speed	Depends on hole size and required vertical resolution
Range of measurement	Water holdup: 0 to 1 Oil holdup: 0 to 1 Gas holdup: 0 to 1
Vertical resolution	2.5 to 25 ft [0.76 to 7.6 m]
Accuracy	5% to 10%, depending on conditions
Depth of investigation	Borehole
Mud type or weight limitations	None

Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa]
Borehole size—min.	2⅜-in tubing 1.781-in nipple on coiled tubing 1.813-in nipple on wireline
Borehole size—max.	9⅝-in casing 12-in open hole
Outside diameter	1.6875 in [4.29 cm]
Length	23.0 ft [7.01 m]
Weight	101 lbm [46 kg]

Calibration

No calibration is required.

Tool quality control

Standard curves

The TPHL standard curves are listed in Table 1.

Table 1. TPHL Standard Curves

Output Mnemonic	Output Name
FBEF	Far beam effective current
NCOR	Near-detector carbon to oxygen ratio
NCOR_SIG	Statistical uncertainty of NCOR
FCOR	Far-detector carbon to oxygen ratio
FCOR_SIG	Statistical uncertainty of FCOR
NICR	Net inelastic count rate ratio
NICR_SIG	Statistical uncertainty of NICR

Operation

The tool must be run centered for valid modeling and accurate answers.

The following equations can be used to compute the logging speed required to obtain a 10% uncertainty or precision in the computed water and oil holdup (owing to statistical noise). The gas holdup is usually much smoother.

$$v_{\text{logging}} = \left(0.25 \times A_{\text{annular}}{}^{2} + 2.05 \times A_{\text{annular}}\right) \times L_a, \qquad (1)$$

$$A_{\text{annular}} = \frac{\left(d_{\text{pipe}}{}^{2} - d_{\text{tool}}{}^{2}\right)\pi}{4} \qquad (2)$$

where

v_{logging} = logging speed (ft/h)
A_{annular} = pipe-to-tool annular area (in^2)
L_a = depth smoothing interval (ft)
d_{pipe} = completion ID (in)
d_{tool} = tool outside diameter (1.6875 in).

For a 6-in-ID liner with a 20-ft depth-smoothing interval along the measured depth, the suggested logging speed is 700 ft/h.

Response in known conditions

The best answers are delivered from conditions matching the characterization database (Table 2). Good answers are delivered from conditions interpolated within the database, whereas the weakest answers are delivered from conditions that require extrapolation outside of the database.

Table 2. TPHL Characterizations

Hole Size, in	Casing Size, in	Casing Weight, lbm/ft	Limestone Formation Porosity†	Sandstone Formation Porosity†	Formation Fluid‡	Borehole Fluid‡
6	Open hole	na	Z, M, H	Z, M, H	W, O	W, O, A
	4.5	10.5	Z, M, H	Z, M, H	W, O	W, O, A
	5	11.5	Z, M, H	Z, M, H	W, O	W, O, A
8.5	Open hole	na	Z, M, H	M, H	W, O	W, O, A
	6.625	20	Z, M, H	M, H	W, O	W, O, A
	7	23	Z, M, H	M, H	W, O	W, O, A
10	Open hole	na	Z, M, H	Z, M, H	W, O	W, O, A
	7	23	Z, M, H	Z, M, H	W, O	W, O, A
	7.625	26.4	Z, M, H	Z, M, H	W, O	W, O, A
12	Open hole	na	Z, M, H	M, H	W, O	W, O, A
	7.625	26.4	Z, M, H	M, H	W, O	W, O, A
	9.265	32.3	Z, M, H	M, H	W, O	W, O, A

na = not applicable

†Porosity: Z = zero, 0 pu; M = medium, 15 to 19 pu; H = high, 33 to 35 pu

‡Fluid: W = fresh water, O = No. 2 diesel fuel, A = air

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CPLT

Overview

The CPLT* combinable production logging tool provides a production profile for a producing wellbore. The profile includes measurements of the flow rate, fluid density, temperature, and in situ pressure in the wellbore. A three-arm caliper can be included when the CPLT toolstring is run in open hole. Other uses of the CPLT tool include monitoring the profile of injection fluids into an injection well and determining the existence of fluid channeling behind casing.

Specifications

Measurement Specifications	
Output	Flow rate, fluid density, temperature, pressure, caliper
Logging speed	Stationary to variable based on application
Range of measurement	Spinner: 0.5 to 100 rps Density: 0 to 2 g/cm^3 Temperature: –13 to 350° degF [–25 to 177 degC] Pressure: 0 to 20,000 psi [0 to 138 MPa] Caliper: 2 to 18 in [5.08 to 45.72 cm]
Vertical resolution	Spinner, temperature, pressure, and caliper: Point of measurement Density: 15 in [38.10 cm]
Accuracy	Spinner: ±0.1 rps Density†: ±0.04 g/cm^3 (accuracy), 0.004 g/cm^3 (resolution) Temperature: ±1.8 degF [±1 degC] (accuracy), 0.011 degF [0.006 degC] (resolution) Pressure: ±10 psi [±0.07 MPa] (accuracy), 0.1 psi [689 Pa] (resolution) Caliper: ±0.5%
Depth of investigation	Borehole measurement only
Special applications	H_2S service

† Density accuracy valid for near-vertical well conditions

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	12 5/32-in [4.52-cm] seating nipple
Borehole size—max.	18 in [45.72 cm]
Outside diameter	With Continuous Flowmeter Sonde CFS-H: 1 11/16 in [4.29 cm] With CFS-J: 2 1/8 in [5.40 cm] With CFS-K: 2 7/8 in [7.30 cm]
Length	Basic tool body: 15.2 ft [4.6 m]
Weight	Basic tool body: 75 lbm [34 kg]
Tension	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N]

Calibration

The downhole sensor readings of the CPLT tool are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration.

To improve the electronics accuracy over previous tools, an automatic downhole calibration while logging has been implemented in the CPLT tool.

Tool quality control

Standard curves

The CPLT standard curves are listed in Table 1.

Table 1. CPLT Standard Curves

Output Mnemonic	Output Name
AZ	Acceleration of the tool on the z-axis
CALI	Caliper
CCLD	Casing collar locator (discriminated)
DEVI	Tool deviation
FWFD	Filtered well fluid density
GR	Gamma ray
HPGP	Quartz gauge pressure
MWFD	Manometer well fluid density
PCVL	Cable velocity
S1F	Spinner rate from flowmeter 1
S2F	Spinner rate from flowmeter 2
WPRE	Well pressure
WTEP	Well temperature

Operation

The tool is run centered for the flowmeter section.

The spinner size must be correctly selected based on the casing size and the flow rate.

Logs should be recorded to 100 ft [30 m] above the top perforations, where possible, or to tubing shoe.

Shut-in passes, where possible, are useful for checking the fluid density readings against the expected values. If crossflow is suspected, shut-in passes should always be performed.

Formats

The format in Fig. 1 is for a downgoing log.

- Track 1
  - WPRE is the well pressure output from the manometer in the tool.
  - PCVL is the cable velocity.
  - GR and CCLD are used for correlation purposes.
- Depth track
  - The depth track includes a shaded presentation of the perforated zone, which is helpful for interpretation.
- Track 3
  - WTEP is the well temperature used to identify fluid entries through comparison with the geothermal gradient.
  - S1F reads the flow rate of the fluid in spinner rotation per second (rps).
  - MWFD is density derived from the pressure (manometer measurement WPRE) and tool acceleration.
  - FWFD is the density usually used because it is corrected for deviation and acceleration.

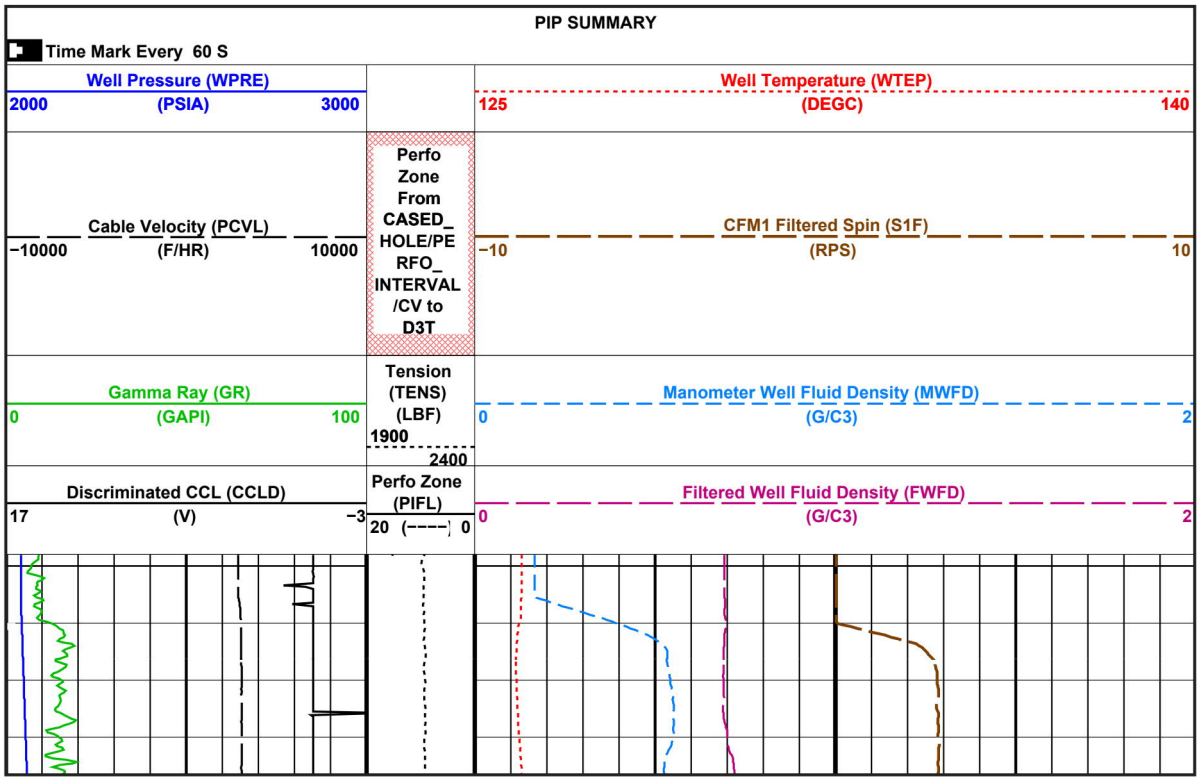

Figure 1. CPLT downgoing format.

The format in Fig. 2 is for a spinner log with different cable velocities.

- Track 1
  - The different cable velocities (P0*x*CVL) are shown for the passes and correlated using GR and CCLD.
- Depth track
  - The depth track includes a presentation of the perforated zone through shading, which is helpful for log interpretation.
- Track 3
  - P0*x*SPIN shows the different spinner flow rates (in rps) for the passes. The tracks are annotated for whether they are up- or downgoing logs. By using the multiple-passes technique, interpreters can quantify individual flow rates in relation to the casing diameter.

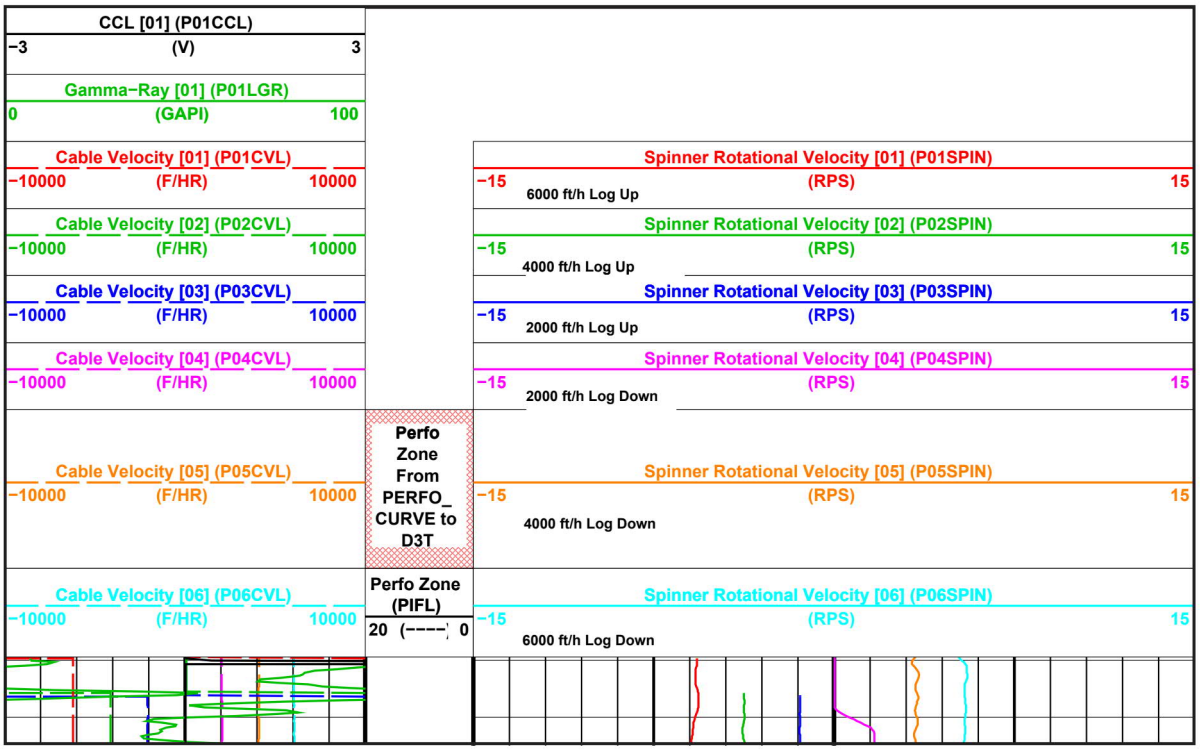

Figure 2. Spinner log format with different velocities.

The format in Fig. 3 is for a pressure and temperature log with different velocities.

- Track 1
  - The different cable velocities (P0*x*CVL) are shown for the passes and are correlated using GR and CCL.
- Depth track
  - The depth track also includes a shaded presentation of the perforated zone, which is helpful for interpretation.
- Track 2
  - P0*x*FDS is the different fluid densities and P0*x*LPR is the different pressures from the passes. Pressure normally increases with depth.
- Track 3
  - The different P0*x*TMP temperatures from the passes are an indicator of fluid entry. With no fluid entry, all temperatures should be equal, increasing with depth. If there is fluid entry, the gradient is distorted. Fluid entries are interpreted referenced to the geothermal gradient through temperature gradient changes.

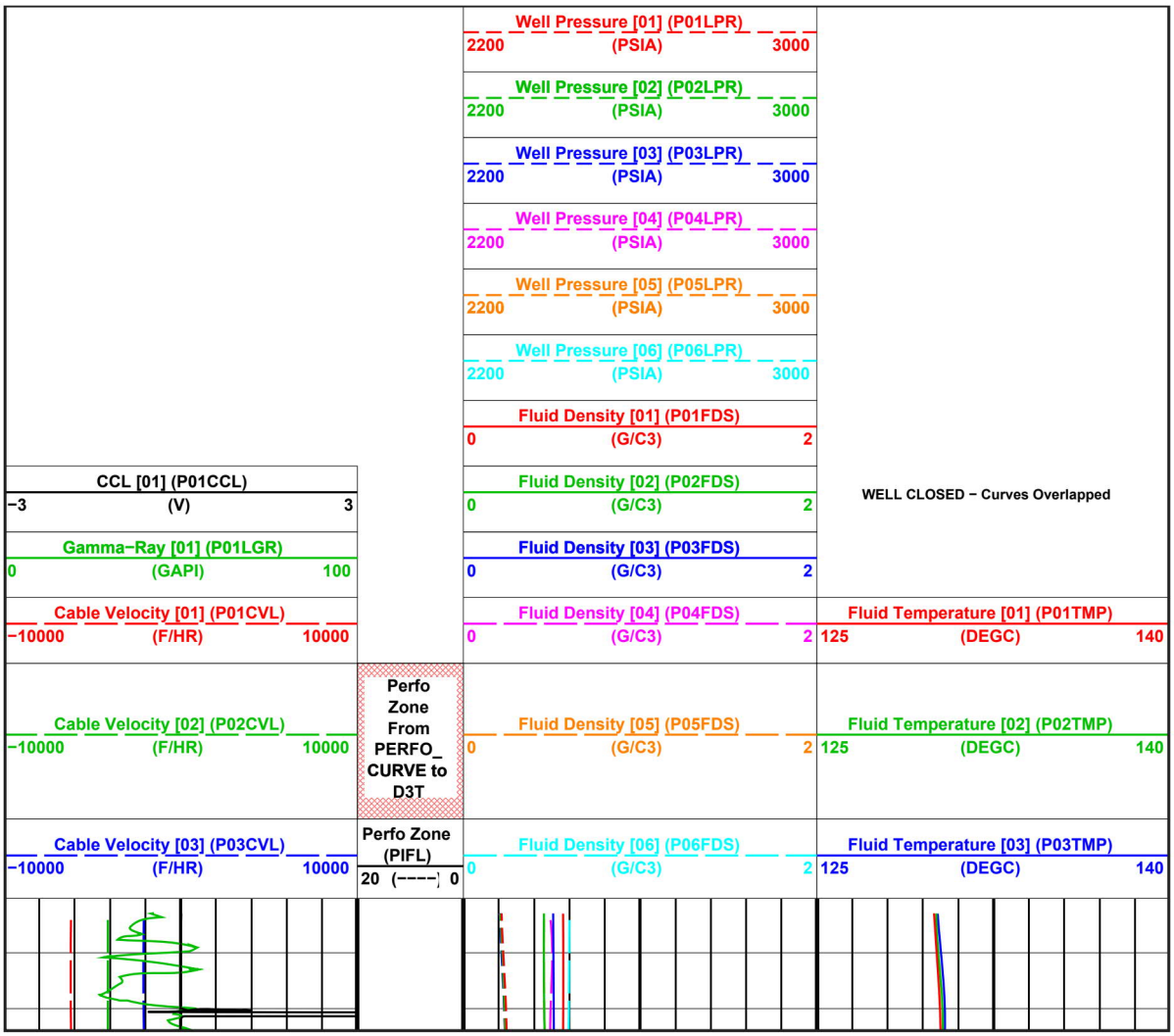

Figure 3. CPLT merged temperature and density log format.

The format in Fig. 4 is for a stationary station log.

- Time track
  - The time of job curve shows the station log time.
- Track 1
  - WFDE_TL is the density of the well fluid.
- Track 2
  - WPRE-TL shows the well pressure.
- Track 3
  - WTEP is the well temperature.
- Track 4
  - S2F_TL and S1F_TL are the spinner flow rates, reported as speed of rotation.

All the tracks in Fig. 4 are values for the fluid at a specific depth in different time intervals. For the depth shown, they are used to identify the nature of fluid entries as well as determine the flow rates.

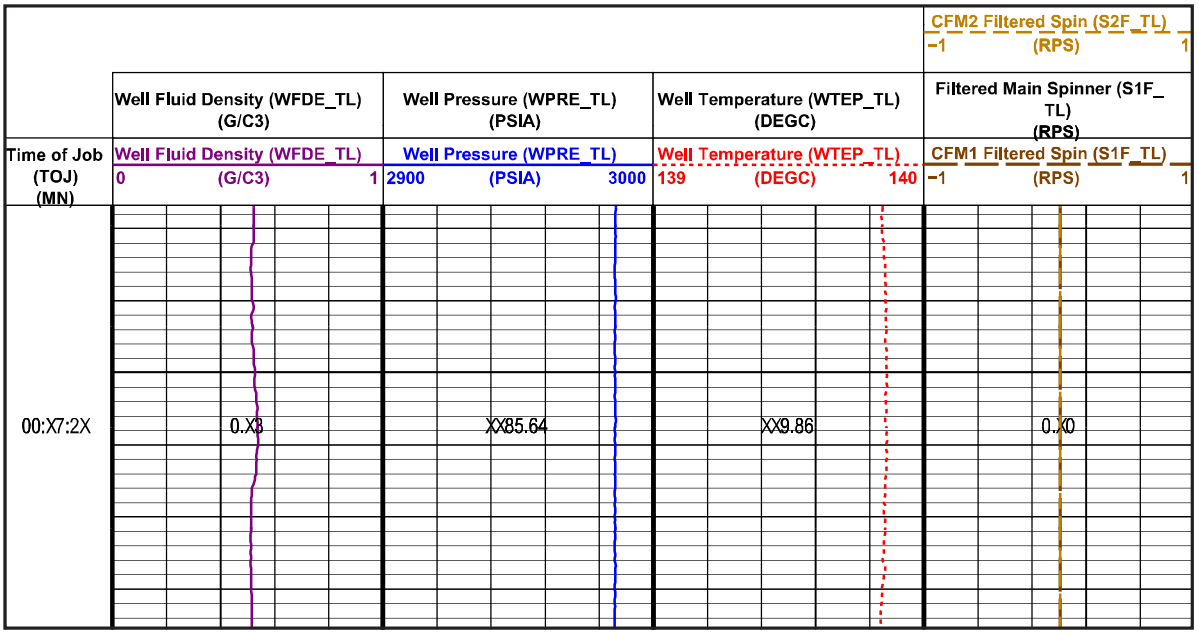

Figure 4. CPLT station format.

Response in known conditions

An evaluation of the log quality of production logs normally requires making some interpretation of the results. Production Logging Quicklook (PLQL) is wellsite interpretation software available to assist with both graphical and statistical analysis of data processed from several passes. For a single pass, Single-Pass Rate Interpretation (SPRINT) software provides data interpretation and validation. SPRINT and PLQL are computation modules embedded in the Schlumberger acquisition software. They are not available as stand-alone applications.

The following responses are expected.

- The well temperature and gauge temperature readings are in accordance. Temperature should follow the geothermal gradient. In zones of fluid entry, a temperature shift is expected.
- Pressure readings should increase with depth.
- The filtered spinner should show a curve response with changes in flow at perforated intervals as a result of fluid entry or crossflow. In deviated or horizontal wells, spinner response changes considerably with the changes in flow regime depending on the deviation and the flow velocity.
- While running in the hole with the well shut in, the CPLT density measurement in fluids should match the known density of the fluids (e.g., 1 g/cm^3 in fresh water).
- In deviated wells, flow segregation can occur. Oil can flow faster than water when working against gravity; conversely, oil flows slower than water when working with gravity.

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Perforating Depth Control

Overview

Prior to perforating a well, the position of the perforating gun must be confirmed. The Perforating Depth Control (PDC) log provides this confirmation along with a record of the number and type of perforating charges. It can also have information about the plug or packer. The positioning sensor is usually a casing collar locator (CCL)—a gamma ray can also be used—that is referenced to the primary CCL correlation log. The primary CCL correlation log is depth referenced to formation characteristics from a gamma ray, cement bond, or RST* reservoir saturation tool log.

Specifications

The tool specifications depend on which CCL or other tool is used to obtain the PDC log.

Calibration

Calibration procedures depend on which log is run.

Tool quality control

Standard curves

The standard curves for a PDC log are listed in Table 1.

Table 1. Standard PDC Curves

Output Mnemonic	Output Name
CCL	Casing collar locator
DCC	DC main current
DCV	DC main voltage
RCCL	Raw casing collar locator
SCCL	Shifted casing collar locator

Operation

The logging speed should be the same as that used for the primary correlation log.

A minimum of three collars must be recorded above and below the top shot of the perforated zone unless there is not enough space to move the perforating string. The casing collar log is recorded up to the stop depth for perforating. After the perforation, the SCCL measurement is shifted and the log is continued to record casing collars above the shot depth.

Casing collars recorded on the CCL log before perforating should be within ±0.5 ft [±0.15 m] of the same collars recorded on the primary CCL correlation log.

Formats

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

- Track 1
  - The CCL curve is used to correlate the collars on the perforating run to the primary log.
- Track 2
  - SCCL shows the stop depth for perforating. The stop depth and the distance between the CCL measurement point and the top shot are used to compute the perforated depth on the Gun Position Summary.

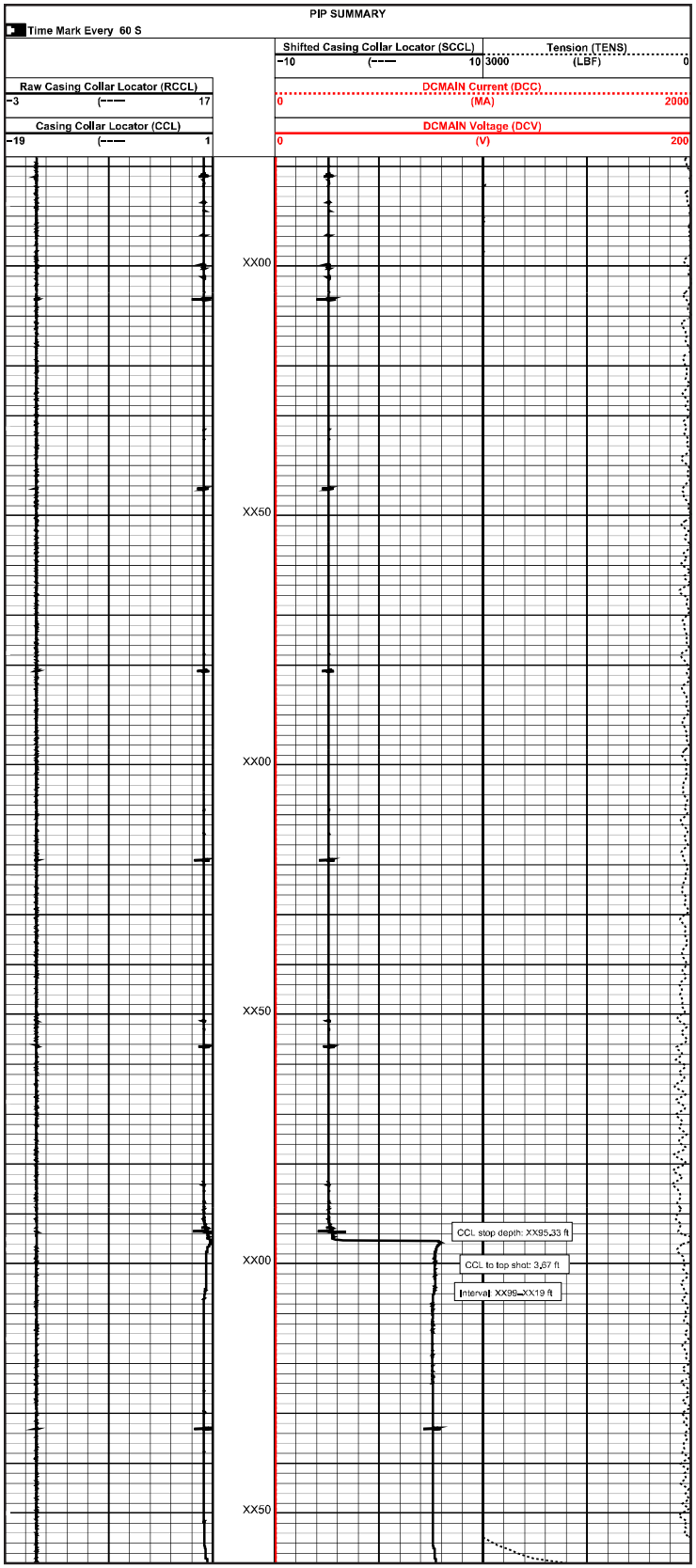

Figure 1. PDC standard format.

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PosiSet

Overview

The PosiSet* mechanical plugback tool (MPBT) is used in rigless through-tubing recompletions. By using a mast or a crane, recompletions can be accomplished without the cost of a workover rig.

The PosiSet anchored elastomeric plug is run through tubing and set in casing to plug off fluid flow in the casing below the plug. The electric motor within the MPBT Setting Unit (MPSU) is used to contract the elastomer sealing assembly to form a firm seal against the casing wall. The expansion ratio is typically 3:1. An anchoring system keeps the tool in place while cement is placed on top of the plug to a height of 10 ft [3 m] or more to provide additional differential pressure.

The Positive Displacement Dump Bailer is used to place the required cement plug on top of the PosiSet plug. Release of a weight bar displaces cement from the bailer sections. The plug can be pressure-tested 24 h after the last bailer run, when the cement is at approximately 90% of its ultimate compressive strength.

Specifications

Mechanical Specifications

	MPSU-BA	MPSU-CA
Temperature rating	350 degF [177 degC]	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]	20,000 psi [138 MPa]
Casing size	4½ to 7⅝ in	4½ to 9⅝ in
Outside diameter	1.6875 in [4.29 cm]	2.125 in [5.40 cm]
Length	20.5 ft [6.25 m]	21 ft [6.40 m]
Weight	89 lbm [40 kg]	129 lbm [58 kg]

Tool quality control

Standard curves

The PosiSet standard curves are listed in Table 1.

Table 1. PosiSet MPBT Standard Curves

Output Mnemonic	Output Name
CCUR	Cable current
DTEN	Differential tension
HV	MPSU head voltage
RTIM	MPSU run time
STAT	MPSU run status

Operation

If conditions allow, the PosiSet plug may be tagged after setting to confirm its setting depth and that the plug had not moved during the setting process.

PosiSet Plug Mechanical Specifications

	4½-in Casing	5-in Casing	5½-in Casing	7-in Casing†	7⅝-in Casing	9⅝-in Casing
Temperature rating	340 degF [171 degC]	340 degF [171 degC]	302 degF [150 degC]	302–340 degF [150–171 degC]	275 degF [135 degC]	275 degF [135 degC]
Differential pressure‡	1,000 psi [7 MPa]	1,000 psi [7 MPa]	500 psi [3 MPa]	500–1,500 psi [3–10 MPa]	1,000 psi [7 MPa]	500 psi [3 MPa]
Casing size—min. ID	3.5 in [8.89 cm]	4 in [10.16 cm]	4.5 in [11.43 cm]	5.88 in [14.93 cm]	6.5 in [16.51 cm]	8.43 in [21.41 cm]
Casing size—max. ID	4.02 in [10.21 cm]	4.52 in [11.48 cm]	5.02 in [12.75 cm]	6.53 in [16.59 cm]	7.02 in [17.83 cm]	9.01 in [22.88 cm]
Outside diameter	1.6875 in [4.29 cm]	1.6875 in [4.29 cm]	1.6875 in [4.29 cm]	1.6875–2.125 in [4.29–5.40 cm]	2.125 in [5.40 cm]	2.625 in [6.67 cm]
Setting time	17 min	17 min	60 min	42–60 min	60 min	90 min

† There are several types of PosiSet plugs for 7-in casing. Validate the specifications of particular PosiSet plugs with your Schlumberger representative.
‡ Pressure ratings are for the PosiSet plugs only. The desired differential pressure rating is achieved by placing cement (usually 10 ft [3 m]) on top of the PosiSet plug.

Formats

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

- Track 1
  - When the PosiSet plug is set, the MPSU head voltage drops sharply.
- Tracks 2 and 3
  - Once the PosiSet plug is set, the MPSU unit should be powered down immediately to avoid flooding the tool. This results in the cable current dropping to zero.

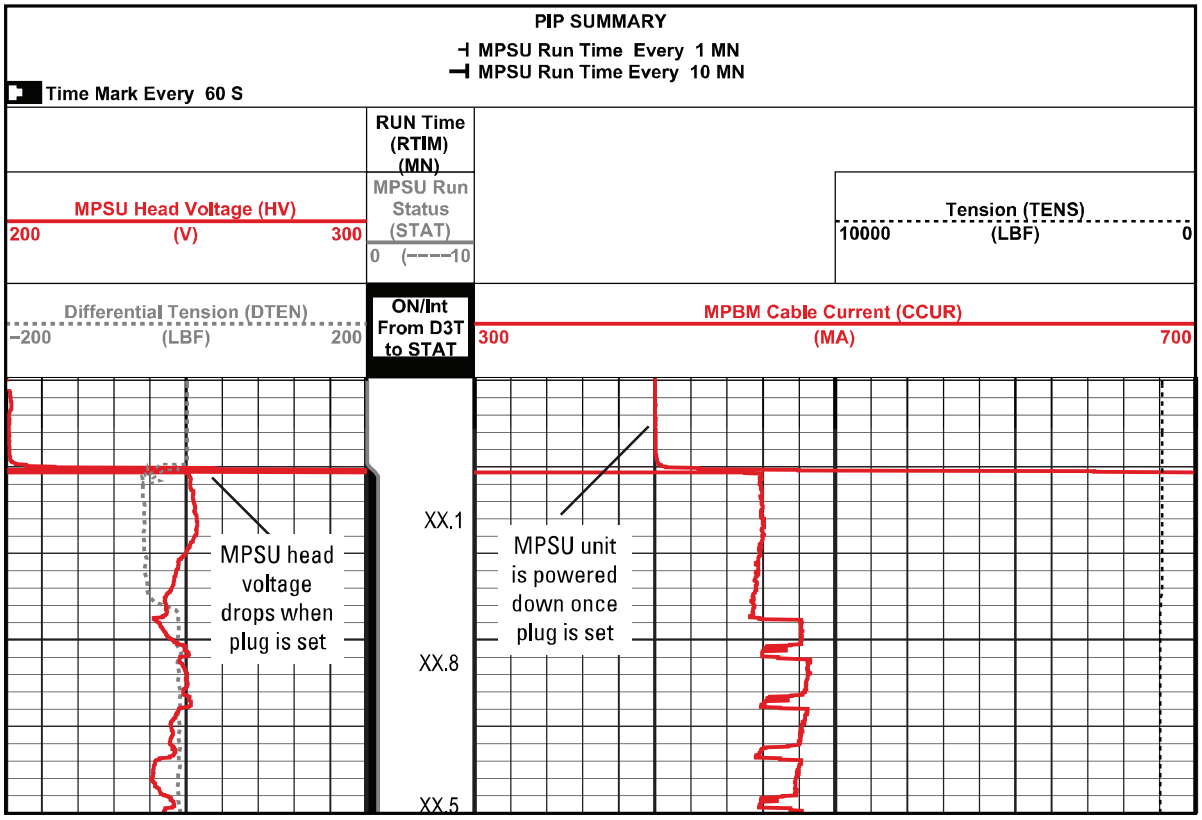

Figure 1. PosiSet MPBT log format.

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Borehole Geometry Log

Overview

Caliper devices are integral to most standard logging tools because measurement of the borehole axes is an extremely useful parameter for environmental correction, quantitative interpretation, and cement volume computation.

Borehole geometry logs (BGLs) are recorded from one-, three-, four-, or six-arm caliper devices. If the borehole is uniform and circular, all the calipers read the same value.

In an elliptical hole, the single-arm caliper generally lines up with the long axis, and the three-arm caliper indicates a diameter greater than the short axis but less than the long axis. The four-arm caliper measures both the short and long axes of the hole and provides a more accurate value of borehole volume.

The six-arm Environmental Measurement Sonde (EMS) caliper is described in a separate document

Calibration

If a caliper device is calibrated at surface, the caliper readings should not be adjusted in casing at the end of a logging run. Any drift observed is important information that can be used to correct for a drifting device. If a suspicious drift is observed, a post-survey verification should be performed.

It is authorized, however, to calibrate the caliper device in the casing after collecting accurate information on the casing inside diameter. The calibration in casing procedure should be documented in the Remarks section.

Caliper calibration frequency should be performed before each run in the hole and preferably at the wellsite. Calibration can be performed with the tools in horizontal or vertical position.

Caliper calibrations are performed with two jig measurements. The jigs are usually calibration rings with a specified diameter. A zero measurement is taken using the smaller of the two rings. A plus measurement is taken using the larger ring. The calibration rings must be continuous, without notched or removed sections, not have any visible damage, and not be ovalized.

Specifications

Measurement Specifications			
	One-Arm Caliper	**Two-Arm Caliper**	**Four-Arm Caliper**
Output	Borehole size	Borehole size	Borehole size
Range of measurement	4 to 22 in [10.16 to 55.88 cm]	4.5 to 16 in [11.43 to 40.64 cm]	4 to 22 in [10.16 to 55.88 cm]
Vertical resolution	6 in [15.24 cm]	6 in [15.24 cm]	6 in [15.24 cm]
Accuracy	0.25 in [0.64 cm]	0.25 in [0.64 cm]	0.2 in [0.51 cm]

Mechanical Specifications			
	One-Arm Caliper	**Two-Arm Caliper**	**Four-Arm Caliper**
Temperature rating	350 degF [177 degC]	350 degF [177 degC]	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]	20,000 psi [138 MPa]	20,000 psi [138 MPa]

Tool quality control

Standard curves

The standard outputs depend on the caliper tool used to record the borehole diameter.

Operation

Measurements are performed downhole in an environment that cannot be exhaustively described. The caliper measurement should be checked in casing against a known response to validate its accuracy.

Formats

The format in Fig. 1 is used mainly as a display of the final product and for quality control.

- Track 1
  - Gamma ray is displayed for correlation.
- Tracks 2 and 3
  - Calipers are displayed versus the future casing diameter (for cement volume) and bit size (for washouts or cave-ins).

Response in known conditions

The caliper check in casing should read the casing nominal inside diameter within the defined accuracy range of the measurement (±0.25 in [±0.64 cm] for one- and three-arm caliper tools and ±0.2 in [±0.51 cm] for four-arm caliper tools).

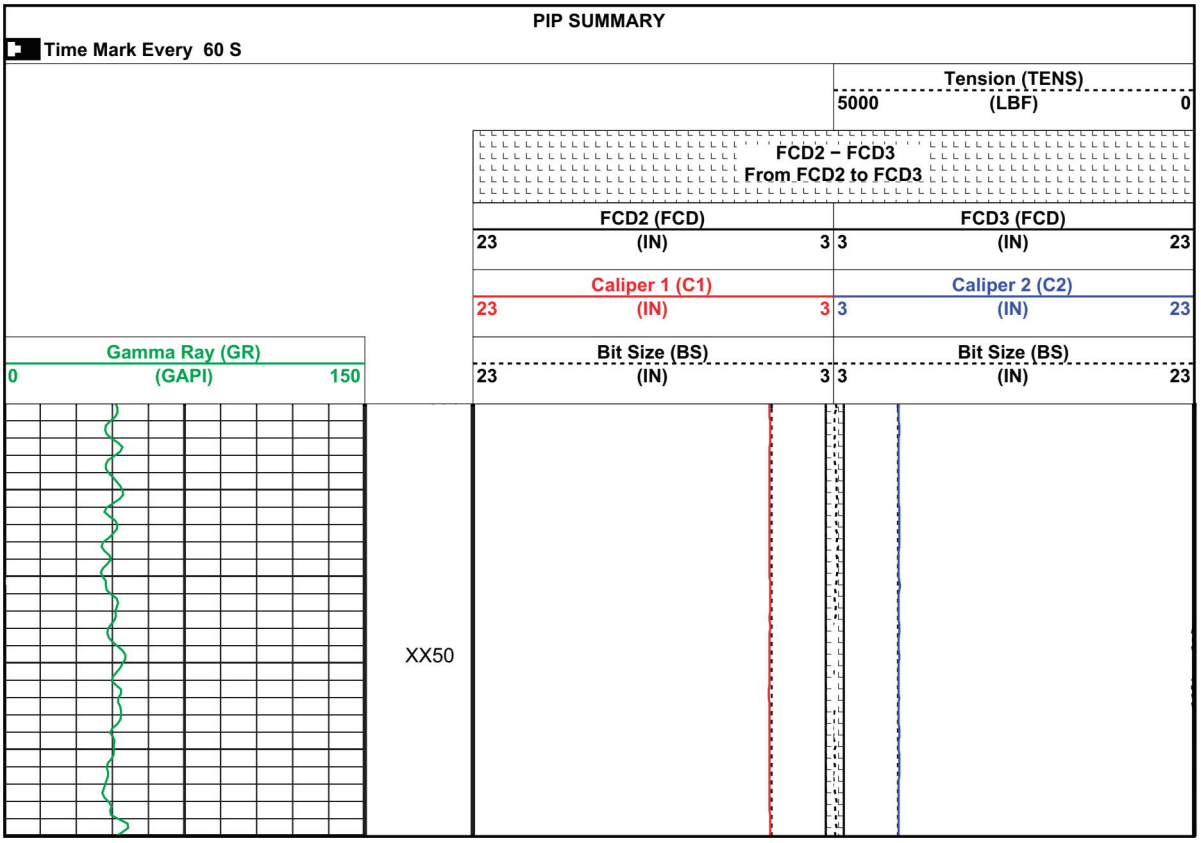

Figure 1. Borehole geometry log.

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Powered Positioning Device and Caliper

Overview

The Powered Positioning Device and Caliper (PPC) is a multipurpose four-arm caliper tool. The four independent, movable calipers provide an accurate hole-volume computation. The PPC works as an active positioning device (i.e., an adjustable force centralizer, short-axis positioning device, eccentralizer, or active standoff.) The PPC can improve the data quality of sonic and density tools in washed-out and oval holes, and the caliper extension kit makes it possible to log in large holes. The main feature of the PPC is its selectable setup. At the surface, prior to running the PPC in the hole, the setup can be changed for each caliper to powered or nonpowered. When power is sent to the calipers from the surface, all calipers open, but only those set up for powered mode can receive up to four power levels to increase their force.

Specifications

Measurement Specifications	
Logging speed	7,200 ft/h [2,195 m/h]
Range of measurement	Min. hole size: 5 in [12.7 cm]
	Max. hole size:† 18 to 40 in [45.72 to 101.6 cm]
Accuracy‡	3% or ±0.1 in [±0.25 cm], whichever is greater for the radius reading with standard arm and tool centered in the caliper open position
	3% or ±0.2 in [0.51 cm], whichever is greater for the radius reading with 17-in [43.18-cm] extension arm and tool centered in the caliper open position

† Maximum hole size depends on the type of arm used.
‡ For arms not powered

Mechanical Specifications	
Temperature rating	PPC-B and PPC-B30: 347 degF [175 degC]
	PPC-HA: 450 degF [232 degC]
Pressure rating	PPC-B : 20,000 psi [138 MPa]
	PPC-B30: 30,000 psi [207 MPa]
	PPC-HA: 20,000 psi [138 MPa]
Outside diameter	3.375 in [8.57 cm]
Length	PPC-B: 8 ft [2.44 m]
	PPC-B30: 8.07 ft [2.46 m]
	PPC-HA: 9.62 ft [2.93 m]
Weight	PPC-B: 170 lbm [77 kg]
	PPC-B30: 190.4 lbm [86.4 kg]
	PPC-HA: 234.8 lbm [106.5 kg]
Tension	50,000 lbf [222,410 N]
Compression	10,000 lbf [44,480 N]

Calibration

If a caliper device is calibrated at surface, the caliper readings should not be adjusted in casing at the end of a logging run. Any drift observed is important information that can be used to correct for a drifting device. If a suspicious drift is observed, a post-survey verification should be performed.

It is authorized, however, to calibrate the caliper device in the casing after collecting accurate information on the casing inside diameter. The calibration in casing procedure should be documented in the Remarks section.

Caliper calibration frequency should be performed before each run in the hole and preferably at the wellsite. Calibration can be performed with the tools in horizontal or vertical position.

Caliper calibrations are performed with two jig measurements. The jigs are usually calibration rings with a specified diameter. A zero measurement is taken using the smaller of the two rings. A plus measurement is taken using the larger ring. The calibration rings must be continuous, without notched or removed sections, not have any visible damage, and not be ovalized.

Tool quality control

Standard curves

The PPC standard curves are listed in Table 1.

Table 1. PPC Standard Curves

Output Mnemonic	Output Name
BS	Bit size
CRD*x*_PPC*x*	PPC radius
EHD*z*_PPC*x*	PPC hole diameter
RB_PPC*x*	PPC*x* relative bearing
TENS	Tension

Operation

In addition to the standard arm, the PPC can be run with two types of extension arm. An 8-in [20.32-cm] extension arm and a 17-in [43.18-cm] extension arm are available depending on the eccentricity required.

As dictated by centering or eccentering requirements for the toolstring, up to four PPCs can be used in the toolstring.

Formats

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

- Track 1
  - The Relative Bearing reading, which defines the orientation of the tool in the well, is useful in logging deviated wells.
- Track 2
  - CRD*x*_PPC*x* is the radius measurement acquired by each of the four arms of the tool.
- Track 3
  - EHD*z*_PPC*x* is the diameter measurement of the borehole acquired by each tool arm.

Response in known conditions

The caliper check in casing should match the casing nominal inside diameter within the defined accuracy of the tool.

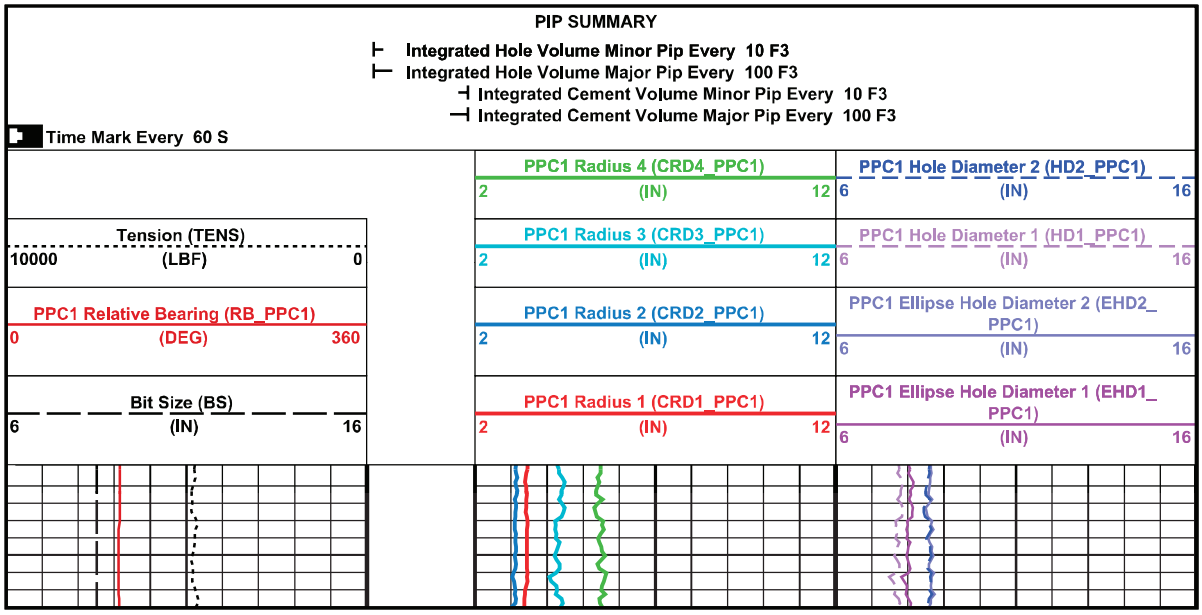

Figure 1. PPC standard format.

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Auxiliary Measurement Sonde

Overview

The Auxiliary Measurement Sonde (AMS) provides the following measurements:

- wellbore fluid resistivity
- wellbore fluid temperature
- direct measurement of cable tension immediately below the head of the toolstring.

The in situ mud measurements are used to improve openhole log interpretation by means of an accurately known mud resistivity (R_m). This is particularly useful in cases of nonhomogeneous mud systems. The mud temperature measurement can also be used to derive temperature gradients (and hence correct the resistivity of the mud filtrate [R_{mf}] and resistivity of the formation water [R_w]), to detect zones of lost circulation, and to evaluate the cement top.

The tool head tension measurement provides an important safety feature, particularly in sticky or deviated holes.

Specifications

Measurement Specifications	
Range	Head tension: –500 to 7,000 lbf [–2,220 to 31,140 N]
	Mud resistivity: 0.01 to 5.0 ohm.m
	Mud temperature: –32 to 350 degF [0 to 175 degC]
Accuracy	Mud resistivity: ±10% of measured value
	Mud temperature: ±1% of measured value
	Head tension: ±3% of measured value
Resolution	Mud resistivity: 1% of measured value
	Mud temperature: 0.1 degC [1.8 degF]
	Head tension: 10 lbf [44 N]

Tool quality control

Standard curves

The AMS standard curves are listed in Table 1.

Table 1. AMS Standard Curves

Output Mnemonic	Output Name
HTEN	Head tension
MTEM	Mud temperature
AMTE	Average mud temperature
MRES	Mud resistivity

Formats

The format in Fig. 1 is used mainly as a quality control and display of the main outputs of the AMS tool.

- Track 1
  - Mud resistivity and temperature are displayed.
- Tracks 2 and 3
  - Mud resistivity is displayed on an expanded scale along with the average mud temperature and head tension.

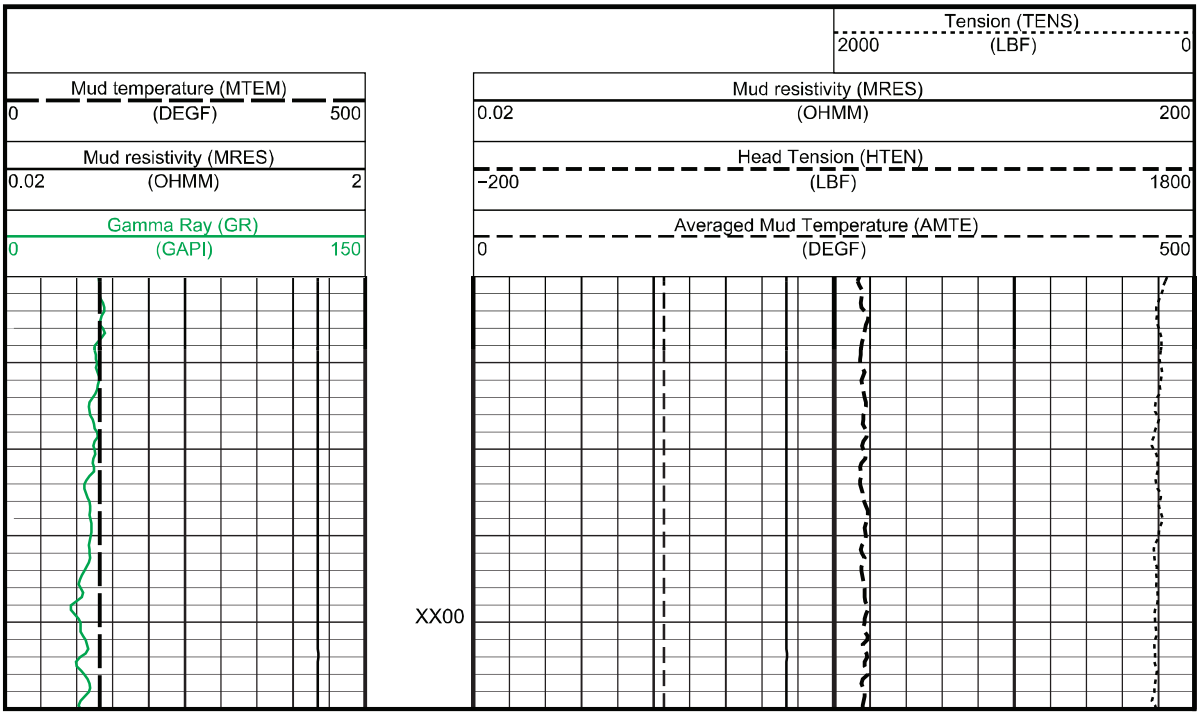

Figure 1. AMS standard format.

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Environmental Measurement Sonde

Overview

The Environmental Measurement Sonde (EMS) significantly enhances the precision of the determination of borehole shape. Six independent caliper measurements are made around the borehole to determine the true ovality of the borehole for stress analysis studies. In addition, the EMS tool obtains measurements of mud resistivity, mud temperature,† and acceleration along the tool axis.

Specifications

Measurement Specifications	
Logging speed	3,600 ft/h [1,097 m/h]
	Without caliper or accelerometer: 7,200 ft/h [2,194 m/h]
Range of measurement	Resistivity: 0.01 to 5.0 ohm.m
	Temperature: 32 to 350 degF [0 to 177 degC]
	Caliper, centered: 30 in [76.2 cm]
	Caliper, eccentered: 17 in [43.18 cm]
Vertical resolution	6 in [15.24 cm]
	Resistivity: ±10% from 0.02 to 0.5 ohm.m, ±7% from >0.5 to 5 ohm.m
	Temperature: ±1.8 degF [±1 degC]
	Caliper: ±0.1 in [±0.25 cm]
	Accelerometer: ±1.6 in/s^2 [±4 cm/s^2]
Resolution	Temperature: 0.18 degF [0.1 degC]
	Caliper: 0.06 in [0.15 cm]
	Accelerometer: 0.4 in/s^2 [1 cm/s^2]

Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size	6 to 30 in [15.42 to 76.2 cm]
Outside diameter	3.375 in [8.57 cm]
Length	14.23 ft [4.34 m]
Tension	50,000 lbf [224,110 N]
Compression	11,000 lbf [48,930 N]

Calibration

If the EMS is calibrated at surface, the caliper readings should not be adjusted in casing at the end of a logging run. Any drift observed is important information that can be used to correct for a drifting device. If a suspicious drift is observed, a post-survey verification should be performed.

It is authorized, however, to calibrate the caliper device in the casing after collecting accurate information on the casing inside diameter. The calibration in casing procedure should be documented in the Remarks section.

Caliper calibration frequency should be performed before each run in the hole and preferably at the wellsite. Calibration can be performed with the tools in horizontal or vertical position.

EMS caliper calibrations are performed with two jig measurements. A zero measurement is taken using the short radius of the jig, and a plus measurement is taken using long radius.

Tool quality control

Standard curves

The standard EMS curves are listed in Table 1.

Table 1. Standard EMS Curves

Output Mnemonic	Output Name
ACC	Acceleration
ADG	Analog-to-digital converter gain
ADO	Analog-to-digital converter offset
CMR	Caliper minus reference
CPR	Caliper plus reference
EDV	EMS deviation
EFNF	EMS frame number
EMDF	EMS mode
EOPF	EMS option
HDAR	Hole diameter from area computation
HDMI	Hole diameter minimum
HDMX	Hole diameter maximum
MAV	Minus analog voltage

†Mud resistivity and mud temperature require use of the EMS adapter (EMA) module.

Operation

The EMS tool can be run centered or eccentered, depending on the overall toolstring requirements. For correct mud measurement, the mud resistivity sensor should be offset by at least 1.0 in [2.54 cm] from the borehole wall.

Formats

The format in Fig. 1 is used mainly as a quality control to monitor the EMS tool operation.

- Track 1
  - Minus and plus voltages should be stable.
  - Analog-to-digital converter gain and offset should be stable.
- Track 2
  - The six radii are displayed and should overlie in a perfectly round hole.
- Track 3
  - The raw cartridge temperature should be stable.

Response in known conditions

The caliper check in casing should match the casing nominal inside diameter within the defined accuracy of the tool (±0.25 in [±0.64 cm]).

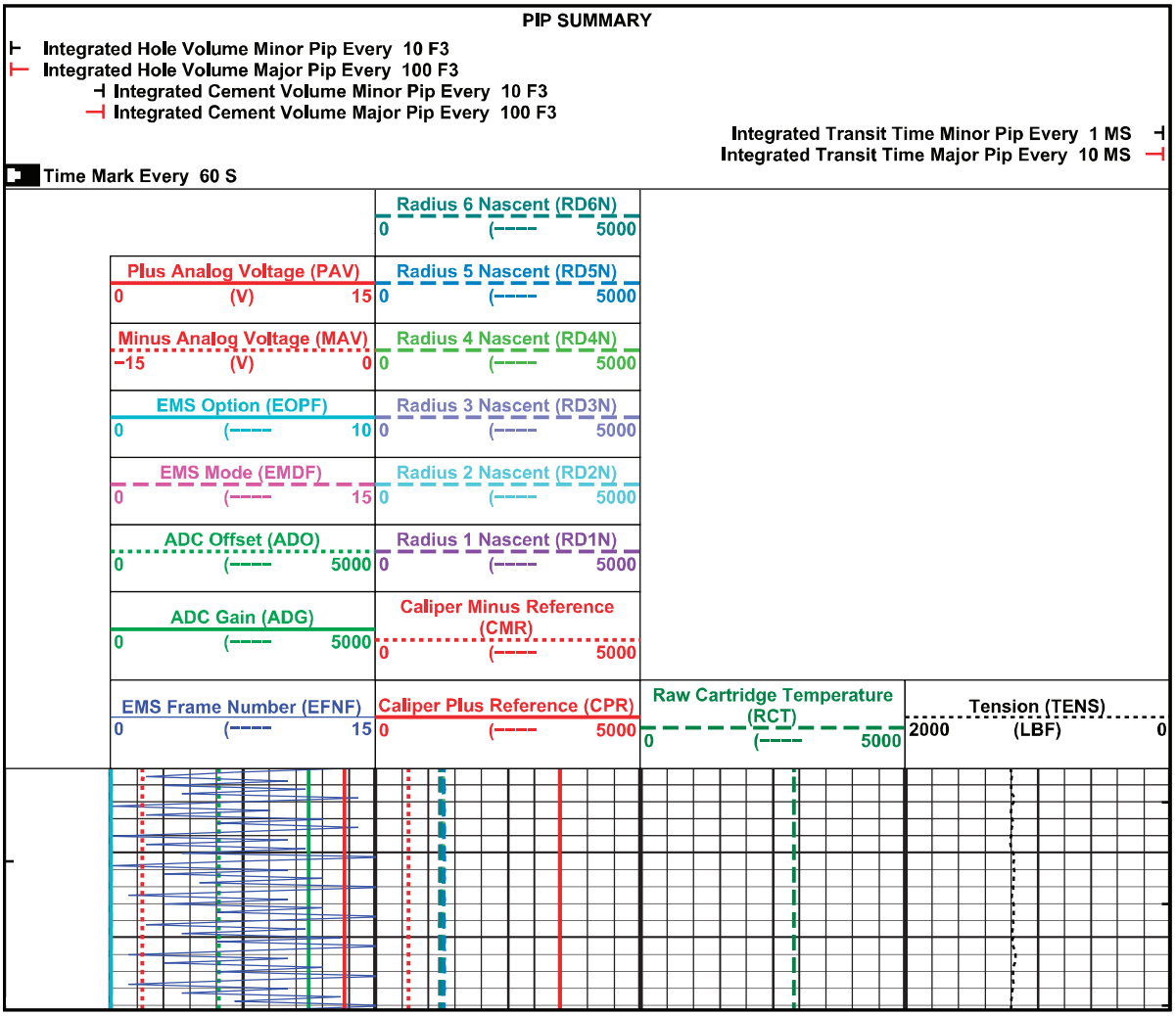

Figure 1. EMS log format.

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FPIT

Overview

The FPIT* free-point indicator tool measures pipe stretch and torque to accurately determine the free-point depth of stuck drillpipe, drill collars, casing, and tubing. After free-point determination, a backoff shot or a colliding tool can be run to free the drillstring above the stuck point.

Specifications

Measurement Specifications	FPIT Tool
Logging speed	Stationary measurement
Range of measurement	Stretch: 0.12 to 3.6 in per 1,000 ft [10 to 300 USTR]
	Torque: 0.02 to 0.5 revolutions per 1,000 ft [0.02 to 0.5 c per 305 m]
Vertical resolution	7.24 ft [2.21 m] (distance between anchors)
Accuracy	±10% at 350 degF [177 degC]

Mechanical Specifications	FPIT-D
Temperature rating	350 degF [177 degC]
Pressure rating	25,000 psi [172 MPa]
Borehole size	1.5 to 5 in [3.81 to 12.70 cm]
Outside diameter	1.375 in [3.49 cm]
Length	13.92 ft [4.24 m]
Weight	40.75 lbm [18 kg]

Tool quality control

Standard curves

The standard curves of the FPIT tool are listed in Table 1.

Table 1. FPIT Standard Curves

Output Mnemonic	Output Name
HVFP	FPIT head voltage (FPIT-C tool only)
MSIN	Motor supply indicator
MSUP	Motor supply voltage (FPIT-C tool only)
PFST	Percent free in stretch
PFTO	Percent free in torque
STRH	Pipe stretch
TORQ	Pipe torque

Formats

The format in Fig. 1 is used mainly as a quality control and as an FPIT station log.

- Track 1
  - The motor indicators show when the motor is switched on to anchor or disengage the FPIT tool.
- Track 2
  - The stretch curves represent the stretch over a fixed distance of the drillstring to calculate the amount of free pipe according to the theoretical deformation.
- Track 3
  - The torque curves represent the torque over a fixed distance of the drillstring to calculate the amount of free pipe according to the theoretical deformation.

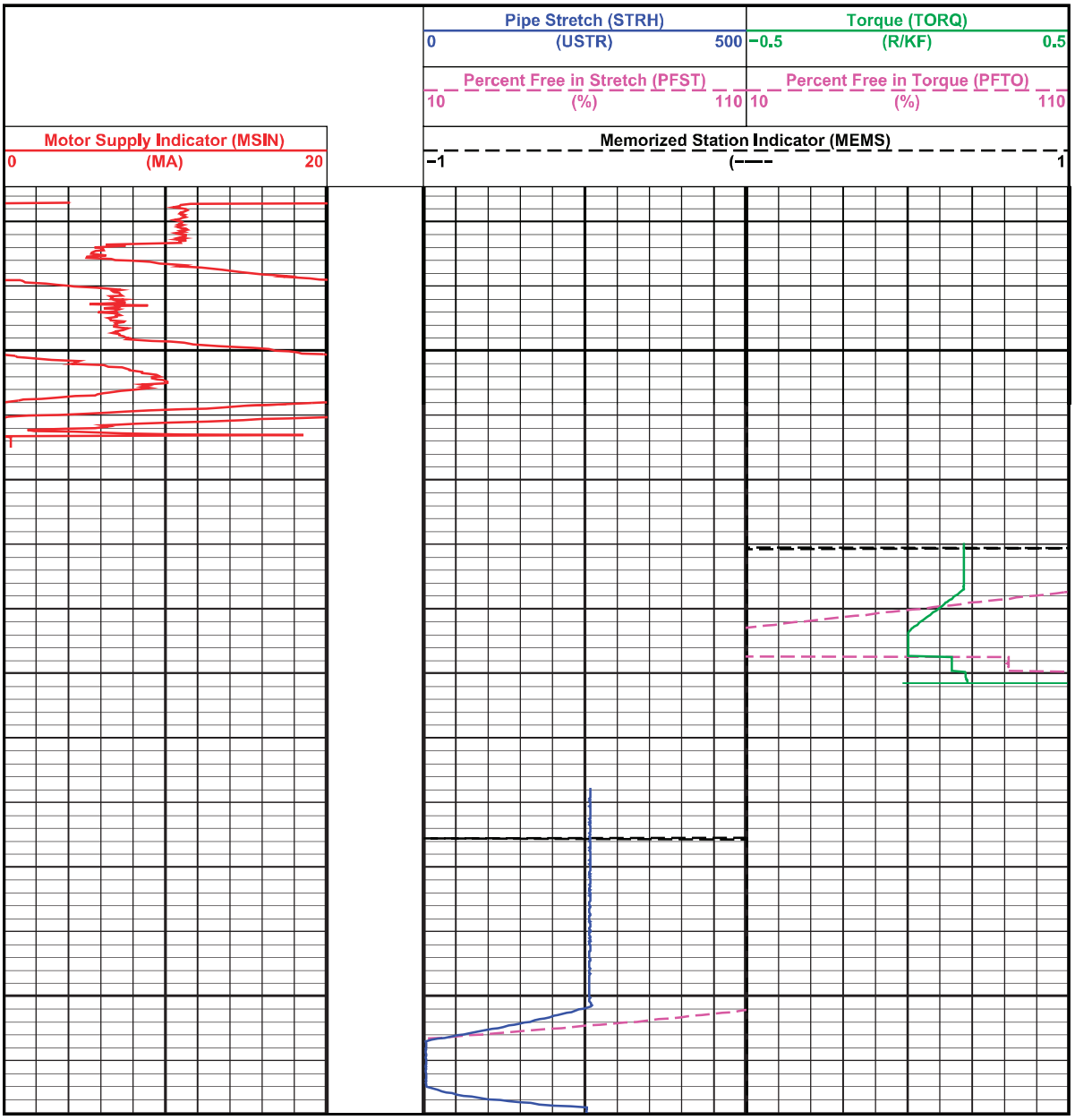

Figure 1. FPIT log format.

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TDT

Overview

The dual-spacing TDT* thermal decay time log provides a determination of the decay time constant of the decay of thermal neutrons in the formation. This is accomplished by measuring the rate at which thermal neutrons are absorbed into the formation. The capture rate of the thermal neutrons is largely dependent on the capture cross section of the elements present in the formation. Chlorine is the strongest neutron absorber of the common Earth elements; therefore, the thermal decay time of a formation is strongly affected by the amount of chlorine present in the formation water.

Specifications

Measurement Specifications	
Output	Neutron porosity, sigma
Logging speed	1,800 ft/h [9 m/min] 900 ft/h [4.5 m/min] over zones of interest
Vertical resolution	24 in [61 cm]
Accuracy	Sigma formation: ±5% of reading up to 40 cu Porosity: ±4 V/V
Depth of investigation	12 to 15 in [30.5 to 38.1 cm] in medium-porosity logging environment

Mechanical Specifications	
Temperature rating	TDT-P: 325 degF [163 degC] HTDT-P: 400 degF [204 degC]
Pressure rating	17,000 psi [117.2 MPa]
Borehole size—min.	3.25 in [8.26 cm]
Borehole size—max.	12 in [30.48 cm]
Length	234 in [594.36 cm]
Weight	98 lbm [44.45 kg]

Calibration

The TDT sensor readings are periodically compared with a known reference for the master calibration. At the wellsite, sensor readings are compared in a before-survey calibration with a wellsite reference to ensure that no drift has occurred since the last master calibration. At the end of the survey, sensor readings are verified again in the after-survey calibration.

Tool quality control

Standard curves

The TDT standard curves are listed in Table 1.

Table 1. TDT Standard Curves

Output Mnemonic	Output Name
CCL	Casing collar locator
FBAC	Far background count rate
INFD	Inelastic count rate far detector
ISHU	Shunt regulator current
MMOF	Minitron* monitor far (ratio)
SDSI	Standard deviation of sigma
SFFD	Sigma formation far detector
SFND	Sigma formation near detector
SIBH	Sigma borehole corrected
SIGC	Sigma correction
SIGM	Sigma formation corrected (neutron capture cross section)
TCAF	Total counts analyzed far detector
TENS	Tension
TPHI	Thermal decay porosity
TSCF	Total selected counts far detector
TSCN	Total selected counts near detector

Operation

The TDT tool does not need a centralizer or standoff for logging.

To also conduct a WFL* water flow log, a WFL kit must be installed.

Formats

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

- Track 1
  - FBAC measured in counts per second is for the background count rates of the far gate.
  - MMOF is the ratio of the far detector net inelastic counts long to short neutron burst. MMOF should generally be greater than 1 during logging.
  - SIBH is the final borehole sigma.
  - CCL shows a kick when a casing collar is detected. It is useful for correlation purposes.
- Track 2
  - ISHU should range between 20 mA and 200 mA. If the shunt current drops below the operating limit, the indicator track shows a gray band flowing from right to left in the depth track.
- Track 3
  - TCAF should be greater than 5,000 counts/s. If the total counts drops to a point where processing cannot depend on sufficient statistics for accurate computation, a gray indicator appears, moving from the right-hand side of this track.
  - TPHI is the thermal decay porosity.
  - SFFD and SFND are formation sigma values from the far and near detectors, respectively.
- Track 4
  - TSCN and TSCF are the total selected counts from the near and far detectors, respectively.
  - SDSI is based on the number of counts processed. Normally it should be <2.
  - SIGC should be <5 cu.
  - The INFD inelastic count is dead-time corrected, background subtracted, normalized, and net measured during the long neutron burst.
- Tracks 3 and 4
  - SIGM is the true, intrinsic, formation capture cross section.

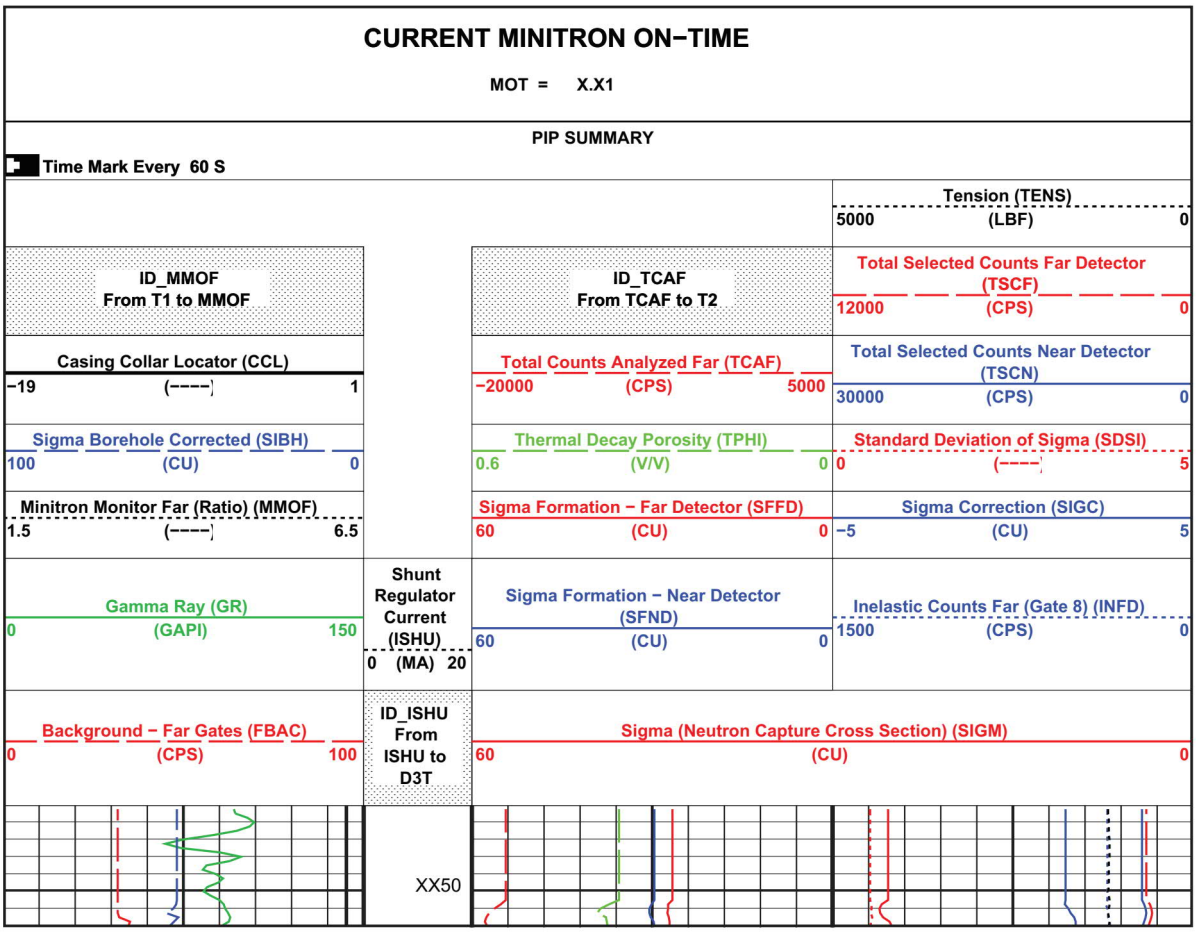

Figure 1. TDT standard format.

Response in known conditions

The typical TDT response in known conditions is listed in Table 2.

Table 2. Typical TDT Response in Known Conditions

Formation	Capture cross section, cu
Formation water (saline)	22 to 120
Fresh water	22
Gas	0 to 12
Matrix	8 to 12
Oil	18 to 22
Shale	35 to 55

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