Appendices

APPENDIX A. DTS and Down-hole Pressure Gauge Information

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WellWatcher Ultra

Distributed Temperature System

APPLICATIONS

- Distributed temperature measurements
- Control of production rates and drawdown
- Monitoring
  - Reservoir flow contributions and decline
  - Gas lift optimization and tubing integrity
  - Heavy oil thermal recovery
- Production allocation
- Injection profiling
- Gas lift optimization
- Riser flow assurance

FEATURES

- Fiber-optic distributed temperature sensing technology
- No downhole electronics
- Simple-to-use surface software, with auto-setup and optimization
- Reliable, robust instrument and extended system life
- Best-in-class measurements
  - Fast temperature resolution
  - 15-km [9.32-m] range, 6 doubled-ended or 12 single-ended channel interrogation

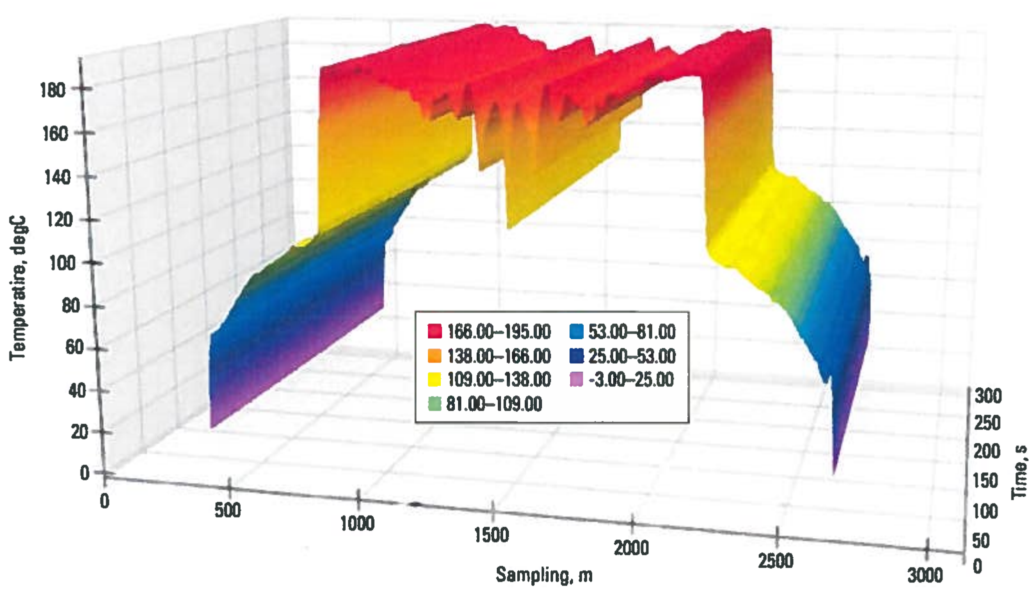
The WellWatcher Ultra* distributed temperature system provides detailed information related to a reservoir's performance through the acquisition of temperature profiles. The extremely versatile system can measure up to 15 km [9.32 mi] of fiber at a meter's resolution, update data in just a few seconds, resolve temperatures to 0.01 degC [0.018 degF], and interrogate numerous fibers from one surface system. The data obtained are available as soon as the measurement is taken. They are communicated via various industry-standard protocols or those customized by Schlumberger's engineering team to the specifics of a particular installation. The data are combinable with data obtained by other Schlumberger sensors, and experts are available to help design the best solution for a particular situation.

ACQUISITION RESULTS

Distributed temperature sensing (DTS) acquisition is configured based on the application. This configuration is typically made up of a combination of profiles, zones, and real-time alarms. Profiles include temperature measurements taken at regular intervals along the fiber. This information can be used to measure reservoir performance and to monitor completion integrity, thereby helping ensure downstream flow. Zonal areas of interest can be specified to facilitate real-time monitoring in SCADA systems and to trigger alarms for critical indicators.

DTS DATA HANDLING

Profile data are temperature measurement profiles of the entire fiber cable consisting of a series of data points. Zone data are statistical data from a particular specified section of the fiber, processed according to specification. Alarm data trigger a signal according to specifications.

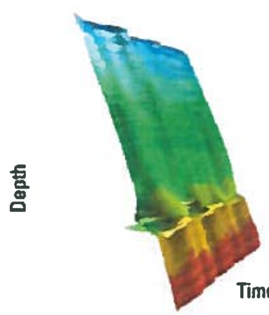


In a heavy oil steam injector, the fiber is connected to the acquisition unit at both ends (for a double-ended configuration) to provide a completely compensated correction for any losses in the fiber. This arrangement helps ensure the maximum life for the monitoring system in this aggressive working environment.

WellWatcher Ultra Distributed Temperature System

BENEFITS

- Permanent in-well reservoir monitoring
- Enhanced recovery through improved reservoir surveillance
- Improved production management
- Faster identification of production problems through best-in-class temperature resolution
- Cost-effective transient analysis
  - Fewer interventions
  - Improved optics, allowing fiber logging for a longer time, increasing system life
- Improved reliability and accuracy for high-temperature monitoring systems



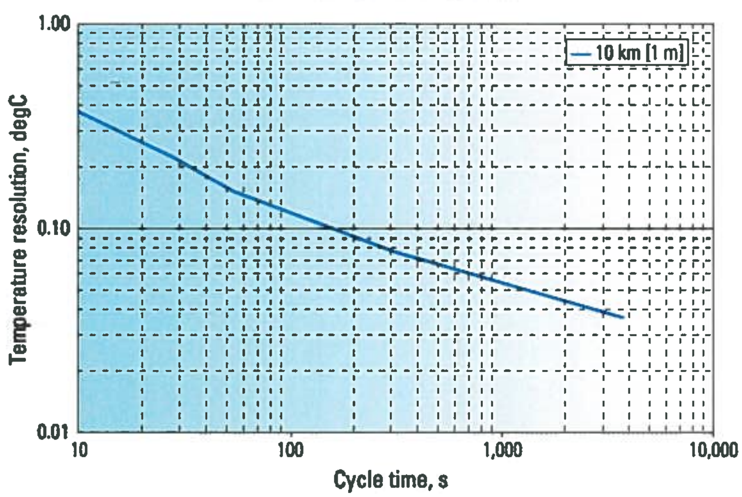
In a gas injection well with a slugging injection valve, distributed temperature measurements can quickly identify a problem valve, saving time during valve replacement and minimizing lost production.

IT INTEGRATION

The WellWatcher Ultra DTS acquisition unit has a robust database that stores all acquired data on site with local backup. In addition, various technologies are available to integrate the data seamlessly into any IT environment. Industry-standard technologies such as the Modbus communication protocol, OPC open connectivity, wellsite information transfer standard markup language (WITSML), and SQL database replication can be used to deliver the data in real time to SCADA systems, data historians, the Schlumberger InterACT* real-time monitoring and data delivery secure Web service, or simply to Microsoft Excel® software on a personal computer.

IT INTEGRATION SUCCESS

A Schlumberger client had a fiber-optic DTS installed in a production field and wanted to integrate the data into its IT environment. The client wanted the data stored and viewable locally but required that the information be quickly accessible from the main office. With the WellWatcher Ultra DTS acquisition unit, the well profiles could be stored locally, the WITSML files provided locally for quick retrieval, and the data uploaded into the reservoir management system. Modbus output provided basic system alarms linked directly to the local control room to help ensure asset integrity.



The log/log metrology plot shows the time required for a typical WellWatcher Ultra DTS acquisition unit out of calibration to reach certain temperature resolutions for 10 km of fiber. Additional optimization is possible to further improve results, depending on the application requirements.

Specifications	
Range, km (mi)	15 (9.32)
Spatial resolution, m (ft)	1–4 (3.3–13.1)
Sample interval, m (ft)	0.5–2 (1.64–6.56)
Calibration accuracy, degC (degF)	±0.5 (±0.9) at (0–8 km); ±1 (±1.8) at (8–12 km)
Number of loops or fibers	6 double-ended or 12 single-ended
Fiber type	50 um, multimode
DTS physical dimensions	3U 19-in, rack mounted or mobile
Operating temperature, degC (degF)	0 to 40 (32 to 104)
Storage temperature, degC (degF)	–20 to 65 (–4 to 149)
Relative humidity, %	5–85 (noncondensing)
Power	AC, 90–253 V (optional DC, 24 V); Typical steady state: 50 W; maximum: 150 W
DTS communications DTS to PC DTS to Modbus PLC Relay contact: 32 per box	 Ethernet 100/1000 Base T Ethernet 10/100 Base T RS485
Laser classification	Class 1m; (IEC/EN 60825-1 (2001))

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WellWatcher Quartz

NLQG, NMQG, NPQG, NHQG multidrop pressure and temperature gauges

APPLICATIONS

- Long-term production and reservoir monitoring
- Pressure buildup surveys
- Injection monitoring
- Intelligent completions

BENEFITS

- Saves costs of well intervention by taking continuous pressure and temperature measurements

FEATURES

- Long-term measurement accuracy with excellent sensor and electronic stability
- High system reliability confirmed by rigorous testing
- Long-term, reliable, permanent in-well reservoir monitoring
- Compact gauge design for optimal well integration
- Gauge system with advanced cable connector technology
- Multiple-gauge installation on a single cable with standard 1-s sampling rate
- Compatibility with the WellWatcher Neon* electro-optical cable system for combined distributed temperature- sensing measurements
- Flow rate and fluid density measurements in specific applications
- Hermetically sealed gauge housing, fully welded with inert gas filling
- Availability of IWIS-compliant and vendor-specific subsea cards

WellWatcher Quartz* NLQG, NMQG, NPQG, and NHQG multidrop pressure and temperature gauges are part of the WellWatcher* permanent real-time downhole monitoring system.WellWatcher systems help operators optimize well productivity and reservoir recovery throughout the producing life of a well or field.

Schlumberger has installed more than 7,000 permanent downhole pressure and temperature gauges over the past 25 years and has established numerous engineering and performance benchmarks for downhole monitoring. Continual performance improvement has yielded the most reliable track record in the industry for these types of gauges.

The latest-generation Schlumberger permanent WellWatcher Quartz gauges continue this tradition and incorporate the most recent innovations in quartz transducers, advanced electronic components, and cable head connector sealing technology.

DATA QUALITY

Accurate and stable pressure measurements are essential in long-term reservoir and production monitoring applications. Schlumberger permanent WellWatcher Quartz gauges are engineered to deliver highly stable pressure measurements for long-term applications.

Performance is validated in a controlled test cell where drift stability is measured at simulated reservoir pressure and temperature conditions—not just at ambient temperature and atmospheric conditions.

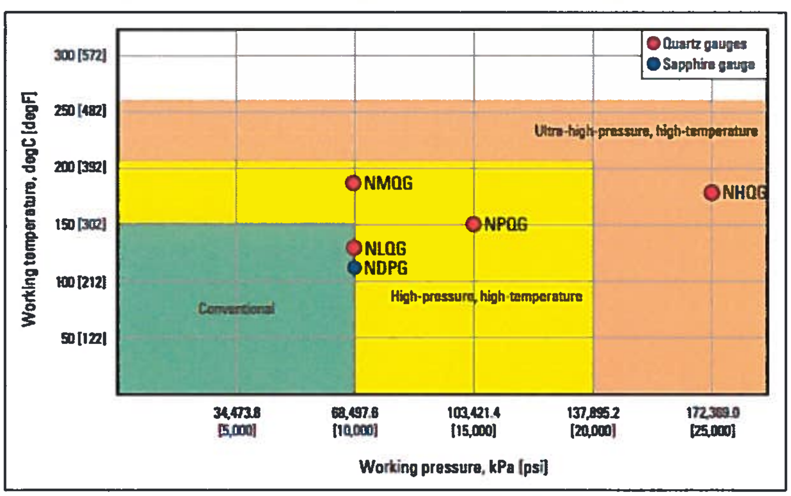
During this measurement period, the gauges are also subjected to power on-off cycles and temperature cycling to simulate the most demanding operating conditions. The NPQG gauge is qualified for a 10-year life cycle and has a measured drift stability better than ±7 kPa at 82,740 kPa and 150 degC [±1 psi at 12,000 psi and 302 degF].

QUALIFICATION TESTING

The gauge system undergoes accelerated testing at 200 degC [392 degF] for about 8 months, in addition to thermal shock cycle testing. This test is equivalent to a 10-year life at 150 degC [302 degF]. The complete gauge assemblies also undergo repeated shock and vibration testing at rigorous levels to meet the environmental qualification for well testing in production and injection wells.

DESIGNED FOR RELIABILITY

The long-term reliability of the WellWatcher Quartz gauges relies on designs including fully welded assemblies, multichip module ceramic high-temperature electronic technology, and corrosion-resistant alloys.



Temperature and pressure environmental applications in which WellWatcher Quartz and WellWatcher Sapphire gauges are most appropriate.*

WellWatcher Quartz

Also furthering the gauge technology is the excellent reliability at system level achieved with the Schlumberger proprietary advanced connector technology.

The standard NMQG (68,947 kPa [10,000 psi]),NPQG (110,320 kPa [16,000 psi]), and NHQG (172,375 kPa [25,000 psi]) gauges feature the innovative and fully field-proven Intellitite* electrical dry-mate cable head connector options. The welded cable head, which can be deployed even in Zone 1, delivers the best system protection against corrosive liquids, shock, vibration, and tensile load. The nonwelded cable head provides three independent seals, including two fully redundant metal-to-metal seals, and is fully pressure testable using a microleak detection system. Both cable head connector options deliver significant reliability improvement over industry-standard connectors.

The standard NLQG (10,000-psi) gauge is equipped with the Sealtite* connector, providing two independent seals, including an improved metal-to-metal seal. When dictated by demanding downhole conditions such as sour fluids or below-packer applications, the gauge is equipped with the Intellitite electrical dry-mate connector for an incremental level of reliability.

WORLDWIDE QUALITY SERVICE

WellWatcher systems are supported and deployed by a specialized group of engineers and technicians highly trained on permanent monitoring systems and intelligent completion technology. This specific central support for project preparation and operations contributes to delivering best-in-class service quality worldwide.

WellWatcher Quartz Gauge Specifications

	NLQG Light Quartz Gauge	NMQG Median Quartz Gauge	NPQG Pressure Quartz Gauge	NHQG Hyper Quartz Gauge
Sensor metrological performance				
Sensor type	Quartz	Quartz	Quartz	Quartz
Calibrated working pressure range, kPa [psi]	Atmospheric to 68,947 [10,000]	Atmospheric to 68,947 [10,000]	Atmospheric to 110,320 [16,000]	Atmospheric to 172,375 [25,000]
Calibrated working temperature range, degC [degF]	25 to 130 [77 to 266]	25 to 177 [68 to 350]	25 to 150 [68 to 302]	25 to 177 [68 to 350]
Other calibrated ranges†	Available upon request	Available upon request	Available upon request	Available upon request
Initial pressure accuracy, kPa [psi]	<±13.8 [±2] max. over full scale	<±13.8 [±2] max. over full scale	<±20.7 [±3] max. over full scale	<±34.5 [±5] max. over full scale
Pressure resolution, kPa [psi]	0.03 [0.005] at 1-s sample rate	0.03 [0.005] at 1-s sample rate	0.07 [0.01] at 1-s sample rate	0.14 [0.02] at 1-s sample rate
Pressure drift stability, kPa [psi]	<± 6.9 [±1] per year over full scale	<± 6.9 [±1]/year over full scale	<±6.9 [±1] per year at 82,740 kPa [12,000 psi] and 150 degC [302 degF]	<±6.9 [±1] per year at 82,740 kPa [12,000 psi] and 150 degC [302 degF]
Initial temperature accuracy, max., degC [degF]/typical degC [degF]	<±0.5 [±0.9] per ±0.15 [±0.27]	<±0.5 [±0.9] per ±0.15 [±0.27]	<±0.5 [±0.9] per ±0.15 [±0.27]	<±0.5 [±0.9] per ±0.15 [±0.27]
Temperature resolution, degC [degF]	0.005 [0.009] at 1-s sample rate	0.001 [0.002] at 1-s sample rate	0.001 [0.002] at 1-s sample rate	0.001 [0.002] at 1-s sample rate
Temperature drift stability, degC [degF]	<±0.1 [±0.18] per year at 150 [302]	<±0.1 [±0.18]/year at 177 [350]	<±0.1 [±0.18] per year at 150 [302]	<±0.1 [±0.18] per year at 177 [350]
Max. overtemperature, degC [degF]	150 [302]	200 [392]	200 [392]	200 [392]
Physical characteristics				
Max. housing diameter, mm [in]	19 [0.75]	19 [0.75]	19 [0.75]	19 [0.75]
Cable head connector options				
Intellitite R: true redundant metal/metal seal	Special request	Yes	Yes	Yes
Intellitite W: fully welded	na‡	Yes	Yes	Yes
Sealtite: metal/metal seal	Yes	na	na	na
Multigauge connections options	Fully welded Y, T, and W connector block assembly	Fully welded Y, T, and W connector block assembly	Fully welded Y, T, and W gauge assembly	Fully welded Y, T, and W gauge assembly
Gauge pressure port reading options	Tubing measurement, annulus measurement, measurement through control line by HDMC hydraulic connector, and flowmeter application			
Material	Corrosion-resistant alloys per ISO 15156 [with Intellitite connector option]	Corrosion-resistant alloys per ISO 15156	Corrosion-resistant alloys per ISO 15156	Corrosion-resistant alloys per ISO 15156
Service	H_2S (with Intellitite connector option)	H_2S	H_2S	H_2S
Collapse pressure, kPa [psi]	75,842 [11,000]	75,842 [11,000]	137,900 [20,000]	189,613 [27,500]
Storage and shipping temperature, degC [degF]	–40 to 75 [–40 to 167]	–40 to 75 [–40 to 167]	–40 to 75 [–40 to 167]	–40 to 75 [–40 to 167]
Well integration				
Max. number of gauges per single cable§	4 at 1-s sampling rate			
Max. cable length, m [ft]	10,000 [32,800]			
Max. distance between gauges, m [ft]	1,000 [3,281]			
Qualification test data				
Long-term qualification test equivalent life cycle	10 years at 82,740 kPa [12,000 psi] and 150 degC [302 degF]			
Vibration	10 to 2,000 Hz at up to 4 g in any axis			
Shock	400 impacts at 250 g (2-ms half sine, 4 axis) and 6 drop impacts at 500 g (2-ms half sine, 6 axis)			

† A lower temperature calibration may be required for injection wells.
‡ Not applicable.
§ Consult a Schlumberger representative for additional specifications.

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*Mark of Schlumberger

APPENDIX B. Log Quality Control Reference Manual (LQCRM)

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Wireline Log Quality Control Reference Manual

Schlumberger

Wireline Log Quality Control Reference Manual

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3750 Briarpark Drive
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Produced by Schlumberger Oilfield Marketing Communications

11-FE-0131

Contents

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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.

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.

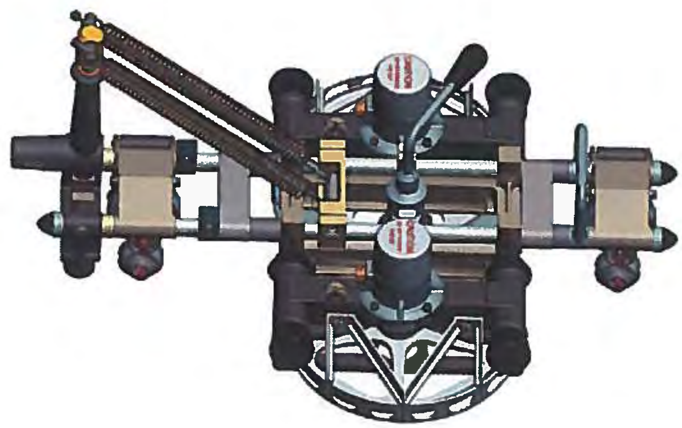

Figure 1. Integrated Depth Wheel device.

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.

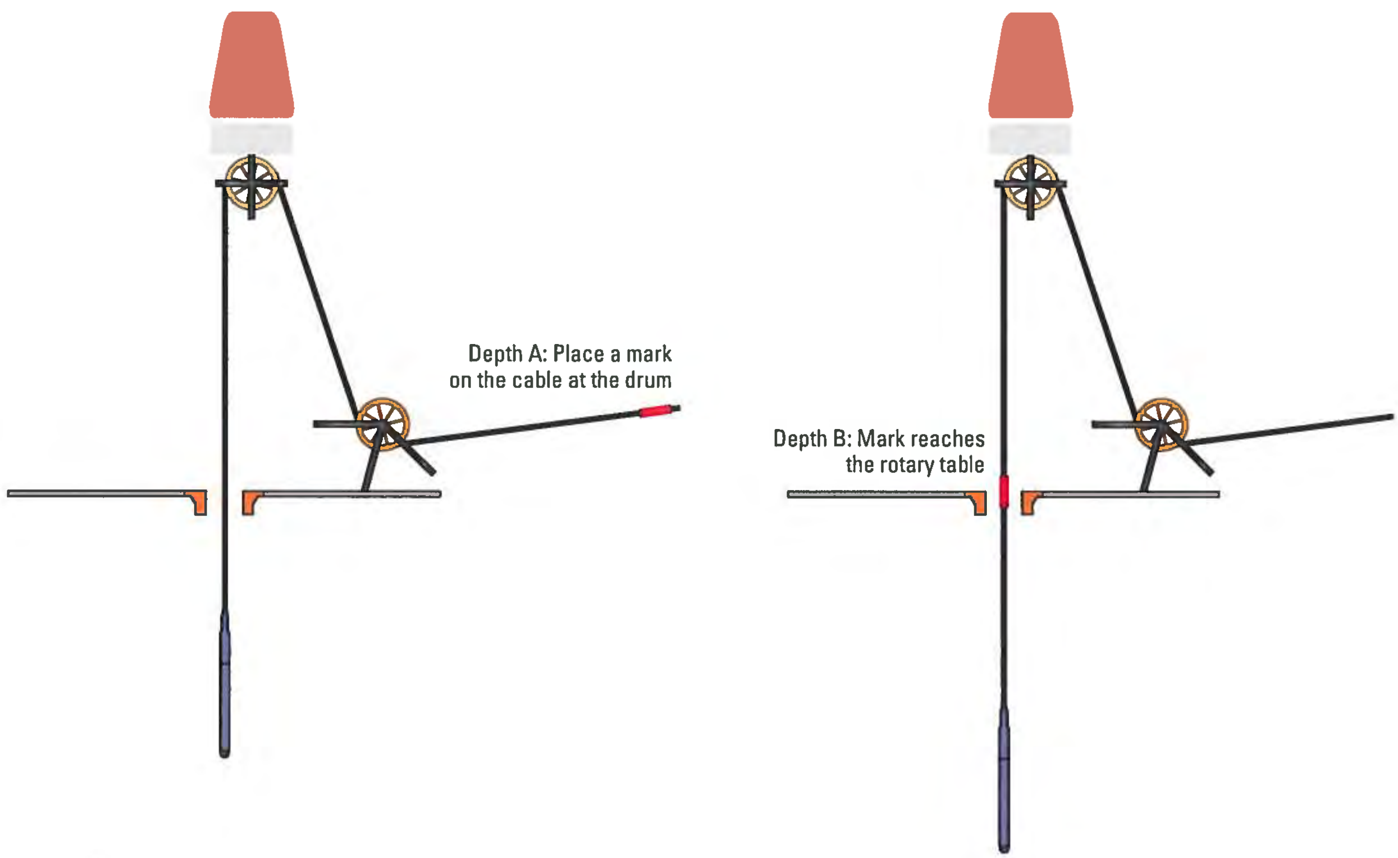

Figure 3. Rig-up length measurement procedure.

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).

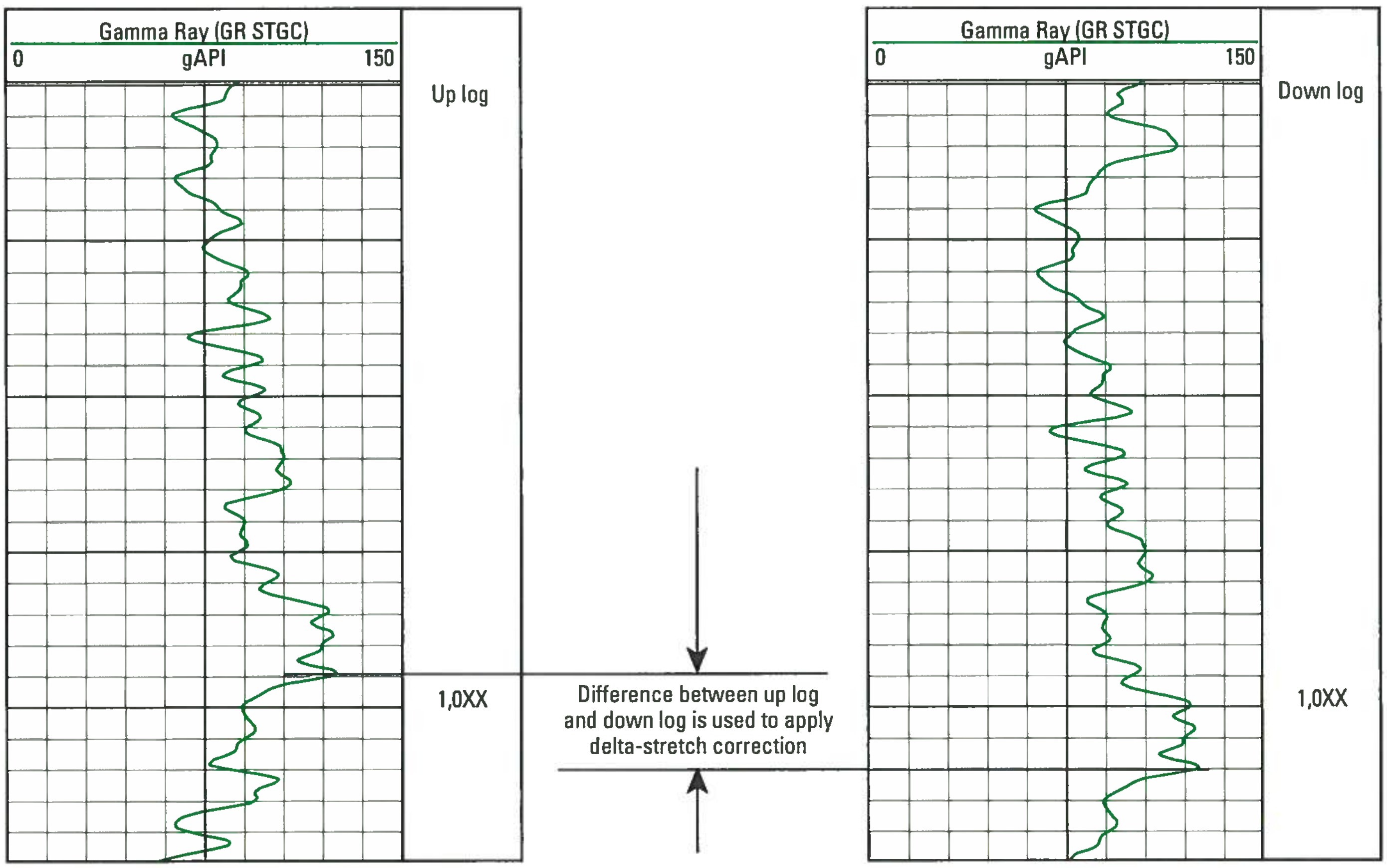

Figure 4. Stretch correction.

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.

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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.

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
ExSZ[*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.

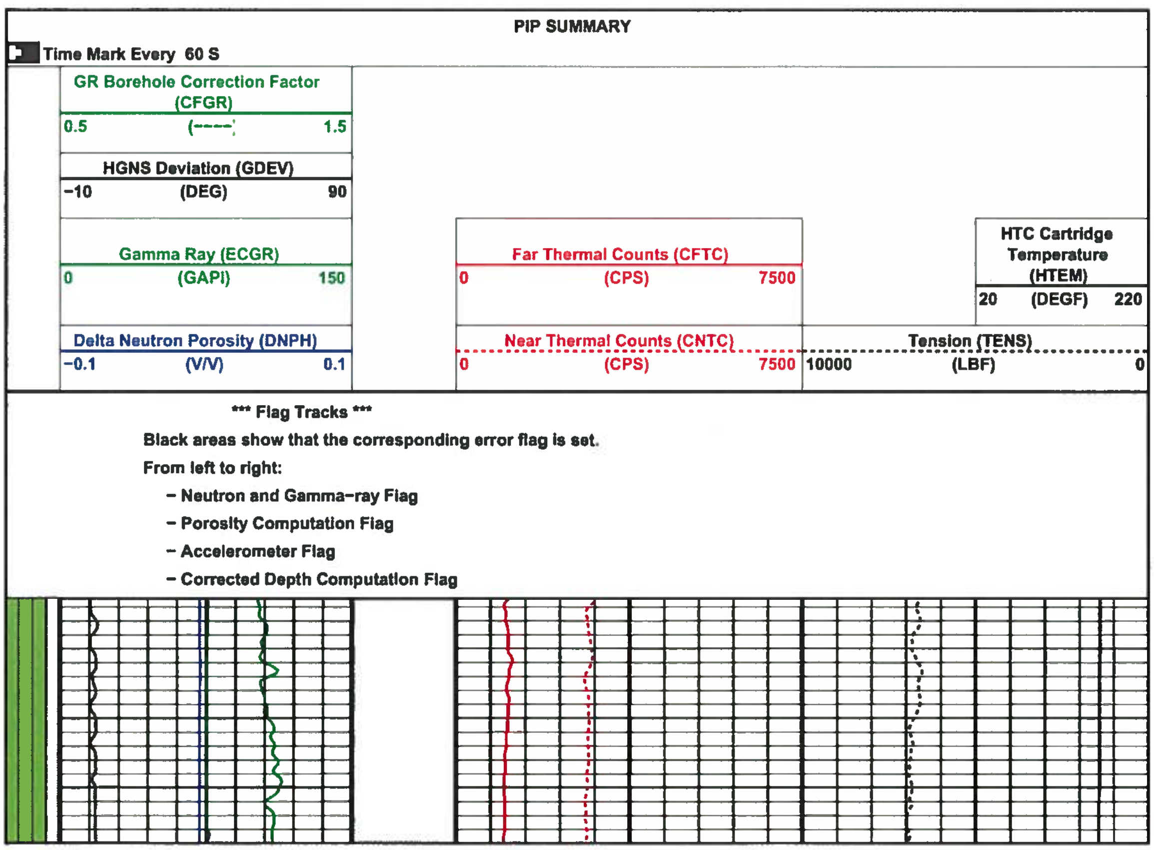

Figure 1. HGNS standard format for hardware.

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 xWTO 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 xSFF 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 xCQR 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 xLEW 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 xOFC unitless integer controls the average offset value and should ranges from 5 to 20.
  - HRDD backscatter dither frequency (xDTH) can range from 1 to 900 Hz.
  - The xPHV 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%

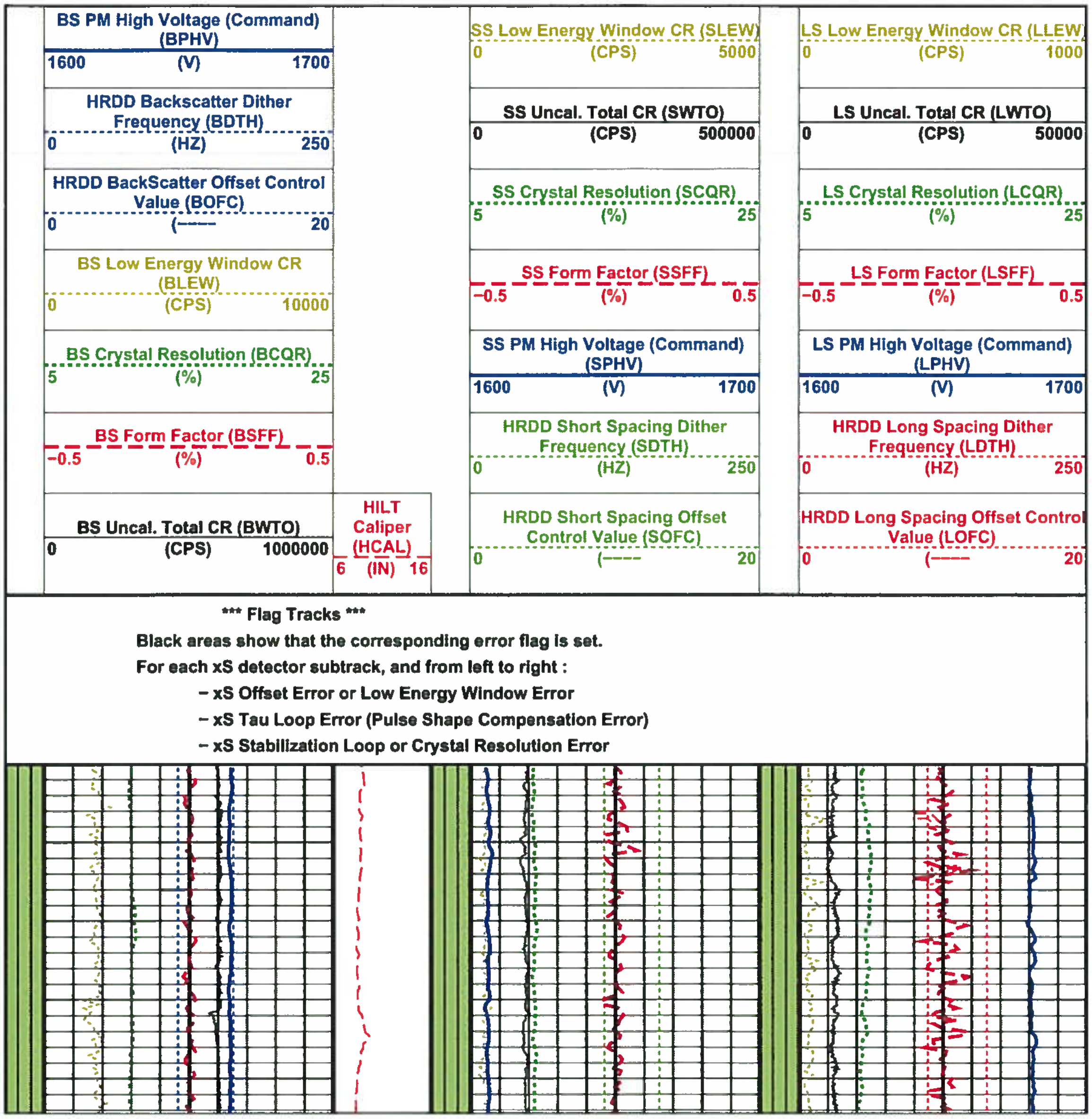

Figure 2. HRDD standard format for hardware.

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.

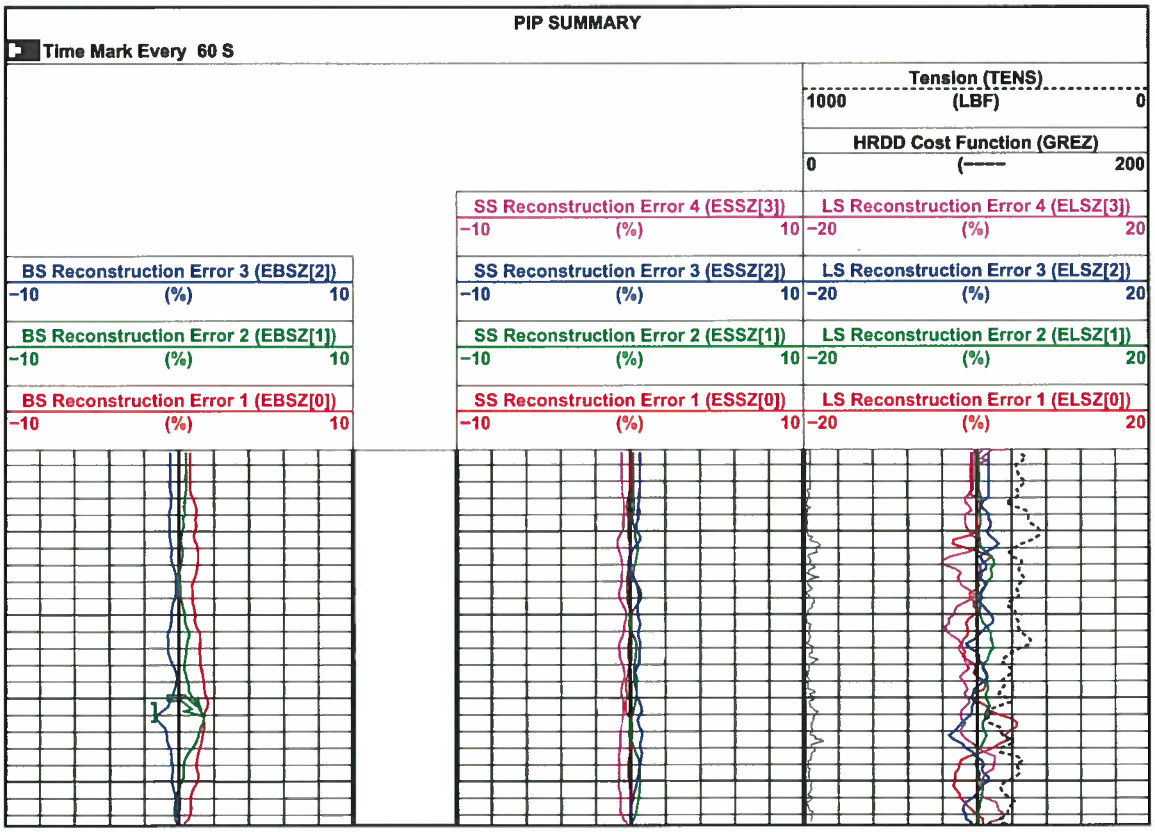

Figure 3. HRDD standard format for processing.

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).

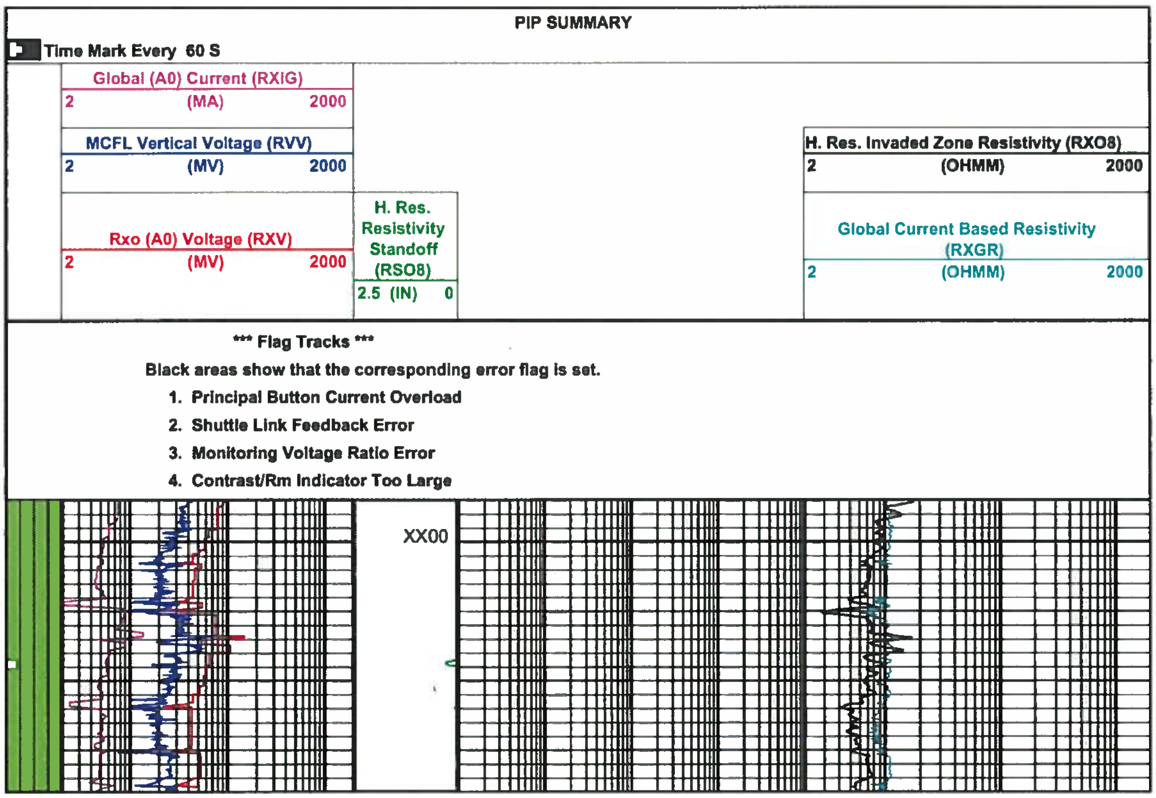

Figure 4. MCFL standard format for hardware.

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.

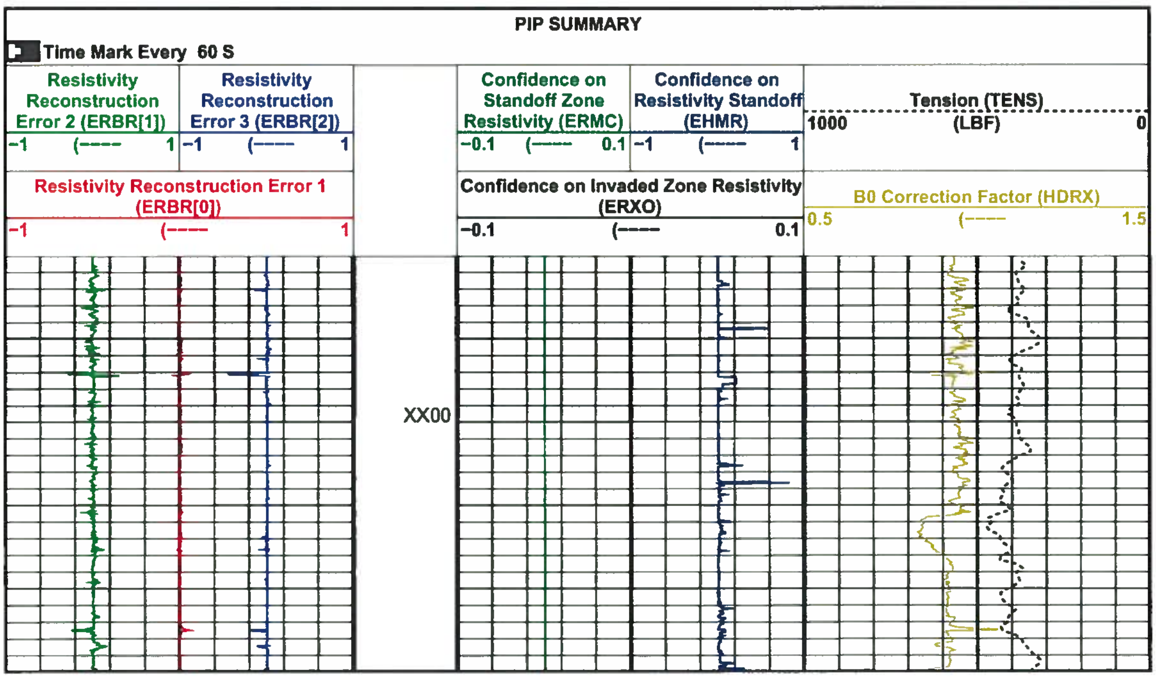

Figure 5. MCFL standard format for processing.

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/cm³	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.

Schlumberger

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.

*Mark of Schlumberger

RST and RSTPro

Overview

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

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

Calibration

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

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

Specifications

Measurement Specifications

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

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

Mechanical Specifications

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

Tool quality control

Standard curves

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

Table 1. RST and RSTPro Standard Curves

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

Operation

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

Formats

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

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

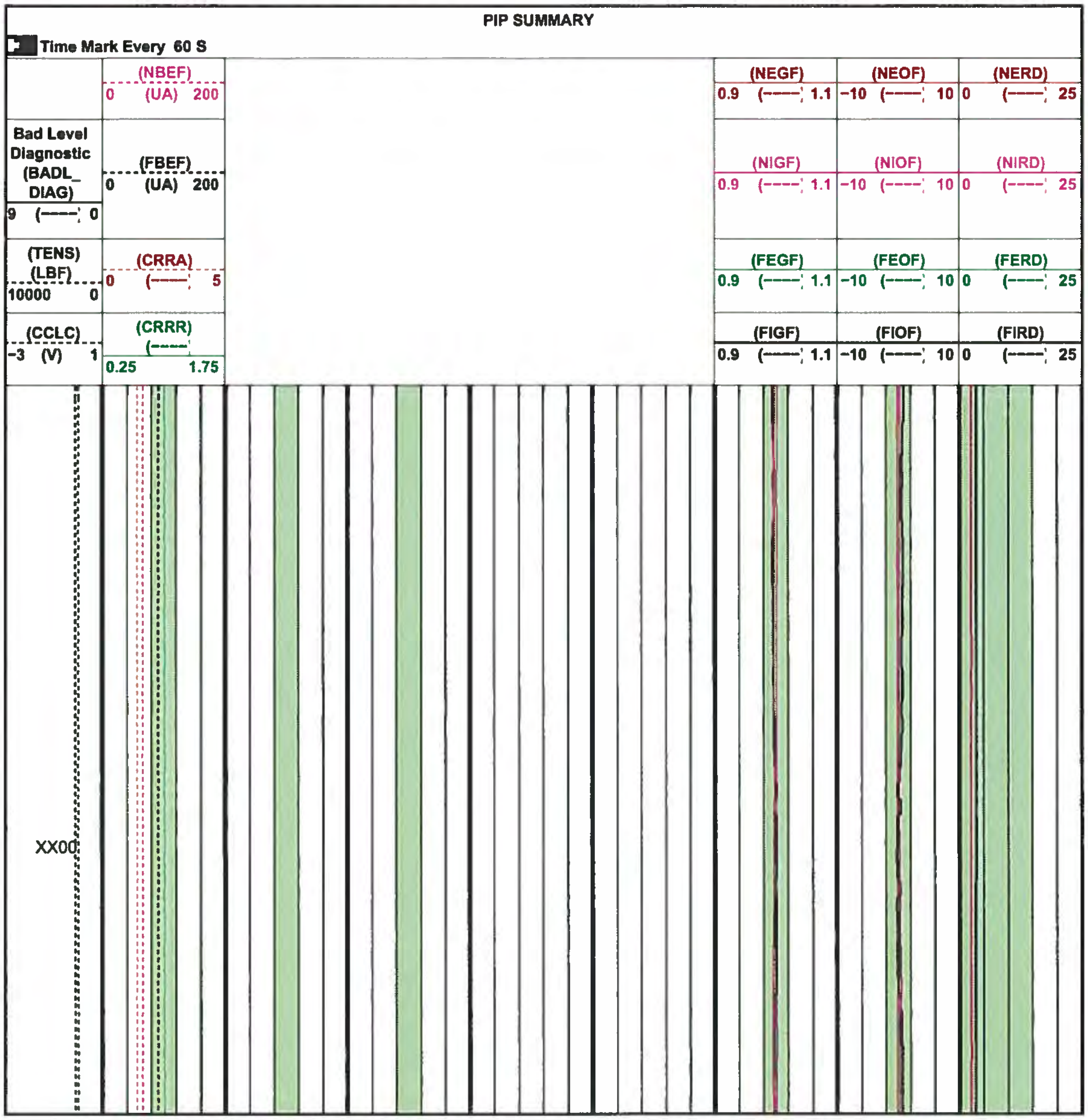

Figure 1. RST and RSTPro hardware format.

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

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

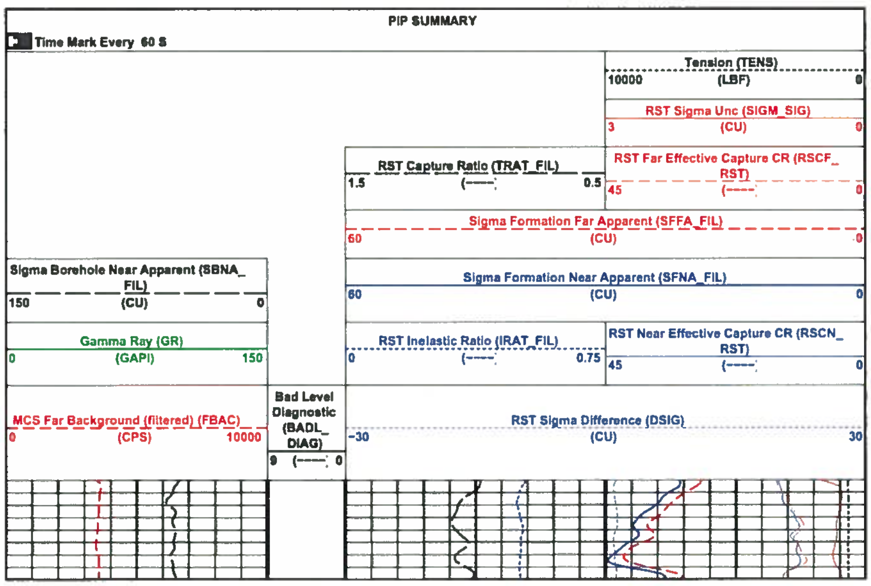

Figure 2. RST and RSTPro sigma standard format.

Response in known conditions

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

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

Table 2. Contributing Materials to RST and RSTPro Yields

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

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

Table 3. RST and RSTPro Capture and Sigma Modes

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

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.

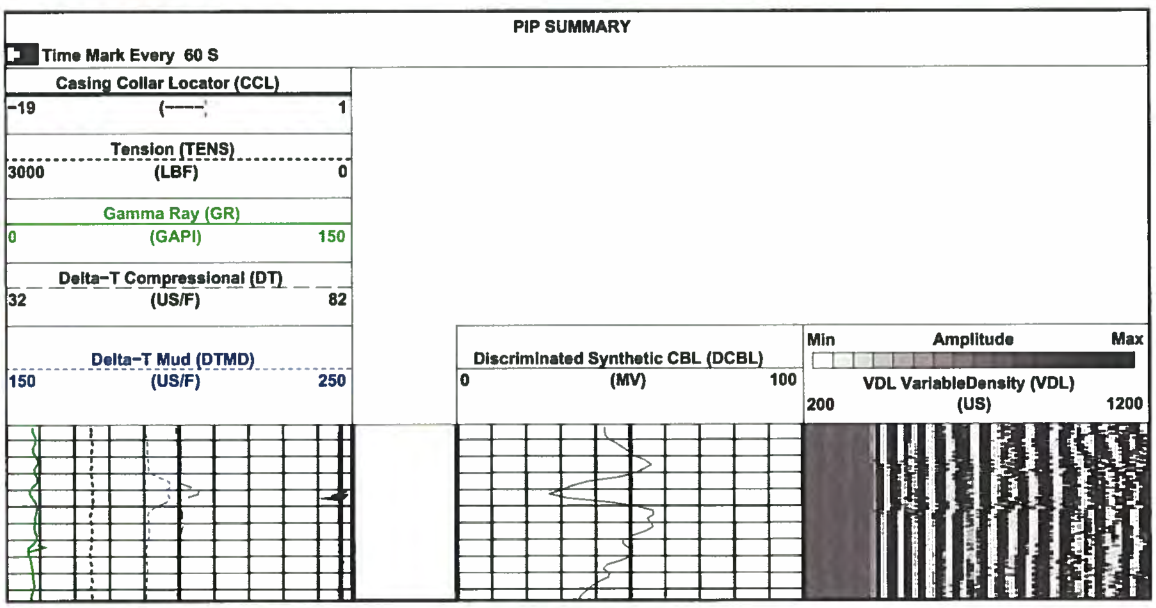

Figure 1. CBT standard format for CBL and VDL.

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.

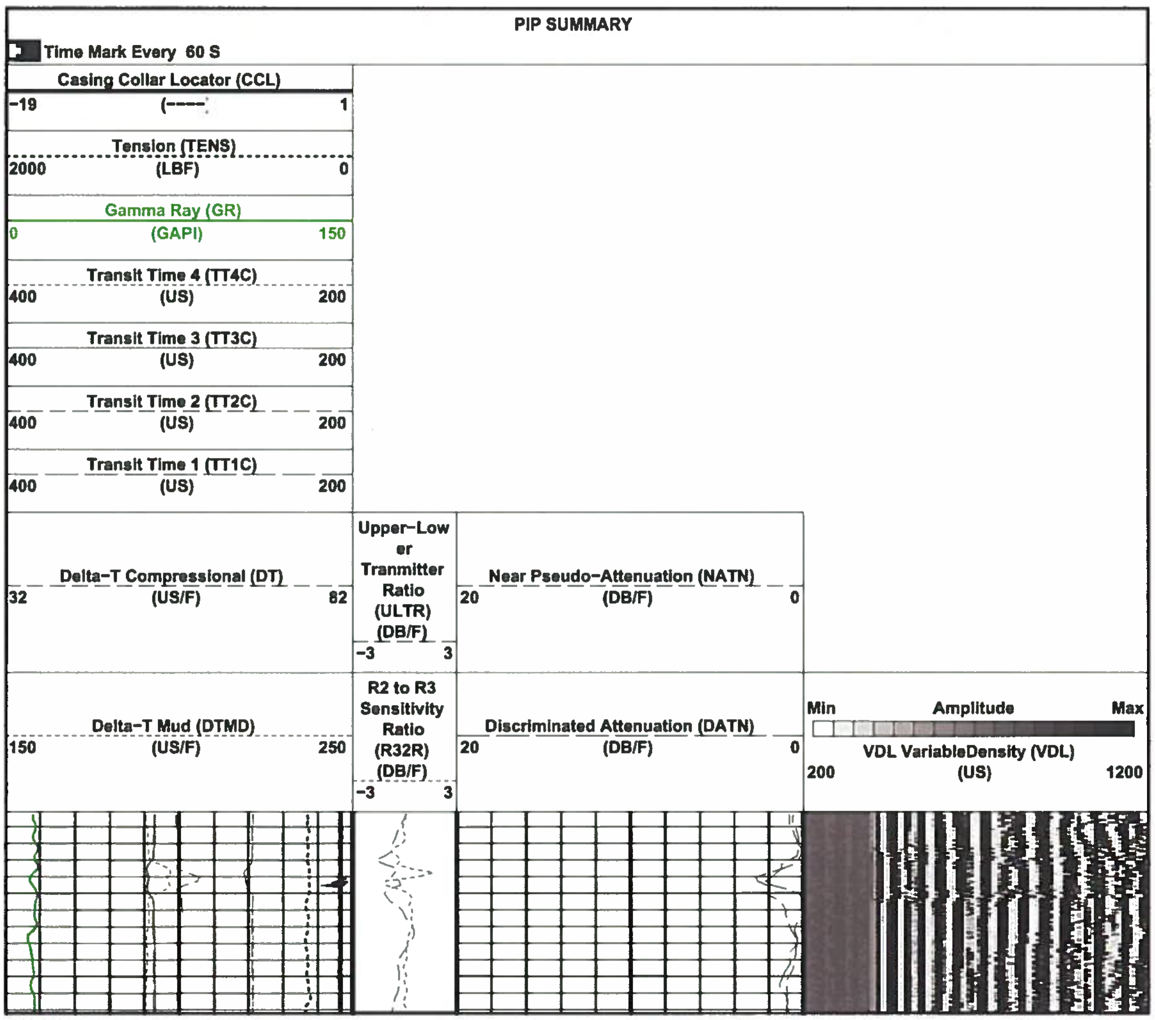

Figure 2. Additional CBT standard format for CBL and VDL.

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

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).

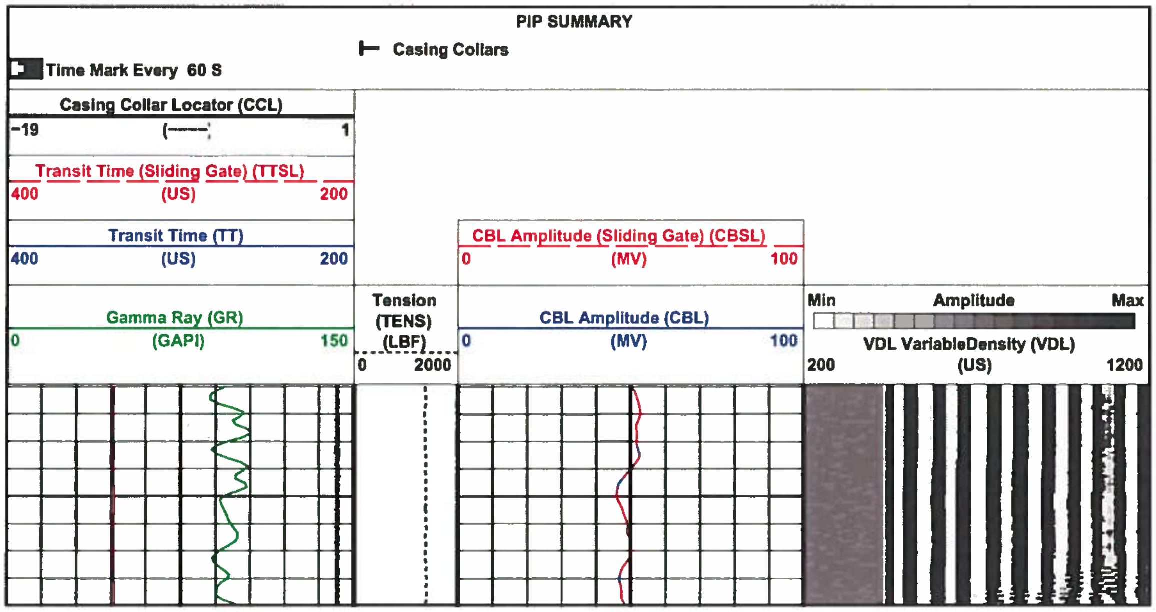

Figure 1. DSLT standard format.

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

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.

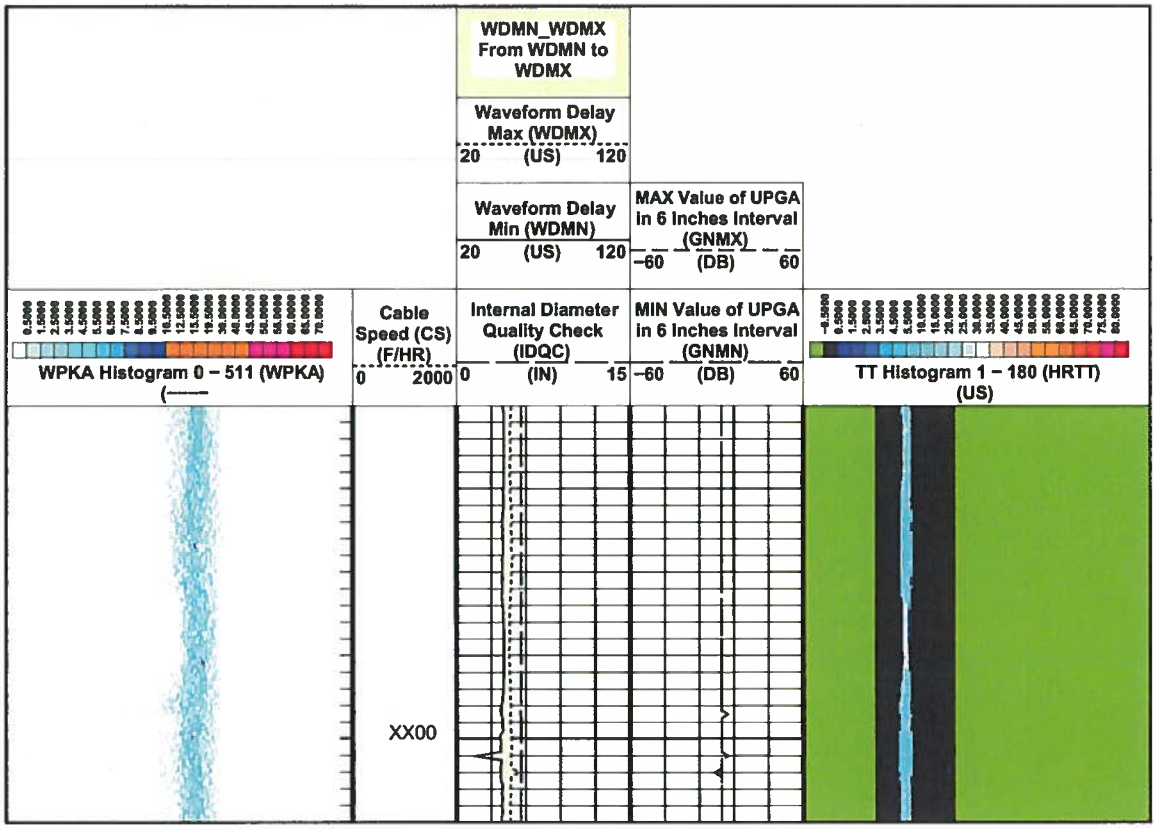

Figure 1. USIT standard format.

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

*Mark of Schlumberger