Sensors, Instrumentation and Measurement

The Drilling Systems Automation Roadmap Sensors Instrumentation and Measurements section describes the quality and attributes of data sources needed to enable successful progression of DSA.

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Functional Description

Sensors, instruments and measurement section covers the strategic development of downhole and surface sensors, instrumentation and measurement (IMS) that support drilling systems automation. The industry has a need to integrate the various IMS that form part of the drilling process to create systems that deliver reliable, quality data to consumers in a timely fashion. Consumers include reporting, monitoring, real-time modeling, advisory, analytical and control tasks.

The scope of IMS includes:

- Both open (conventional) and closed (MPD, UBD, DGD etc.) drilling systems
- Smart machines, which may be considered measurement platforms that deliver valuable measurements for DSA.
- Operational and machine system limits that define the required performance of the sensors.
- Sampling requirements, anti-aliasing, sensor resolution, accuracy and precision, system latency and time synchronization.

The challenge excludes:

- Surface or downhole machines that do not provide measurements but do represent a level of mechanization.
- Context data, such as an Earth Model, Directional Drilling Plan, or BHA configuration are assumed to be available for drilling systems automation.
- Algorithmic processing of data, such as depth tagging, processing, data distribution, data aggregation, data event processing, data visualization and data security.

Systems of Interest for sensors, data and their measurements can be created from the System of Systems architecture. These Systems of Interest are recognized because they contain families of data that deliver subsystem functionality. Progression of data acquisition within a system or subsystem will be more successful than partial acquisition across several subsystems because value can be more readily delivered by the former than the latter.

Systems of interest include:

- Hoisting and Rotating (e.g., hoisting system, top drive, travelling block, power slips)
- Fluids system
    - Solids control
    - Fluids preparation and treatment
    - Fluids pumping
- Mud Logging Surface Data Acquisition

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- Downhole Data Acquisition
  - MWD Data Acquisition
  - LWD Data Acquisition
- Drill string System
- BHA System
- Cementing System
- Pipe handling system

Performance targets

Performance targets include sensor rules, sensor quality, time stamps and levels of IMS attributes.

Sensor Rules

Sensors, Instrumentation and Measurement Systems for Drilling Systems Automation should meet certain rules to ensure users understand how a measurement, or a set of measurements, will affect the process being automated (Table 1).

	Rule	Description
1	**Completeness**	There must be enough information to fully determine the state of the system.
2	**Logic Determination**	There must be all information necessary to choose the correct sensor as a function of the system state.
3	**Proximity**	Sensors shall measure as directly and as closely as possible to the required parameters. The four types of proximity include: a) Direct: measured directly at the desired location. b) Transposed: converted from some measurement conditions to another. c) Derived: depends on at least two consecutive measurements. d) Estimated: depends on a series of measurements and initial conditions.
4	**Accuracy**	There must be enough information to assess the accuracy of the measurement. If a measurement is made remote to the desired location, there must be sufficient information to access the accuracy of the estimated measurement.
5	**Conversion**	There must be enough information to correct the measurement. If this is physically not possible, a new sensor will be envisioned to solve the error.
6	**Criticality**	There must be measurement redundancy for critical parameters, which means there must be different measurement paths for critical parameters and not just different sensors at the same point.
7	**Availability**	The availability of each sensor must meet or exceed the requirement of the most demanding application for which it is used. Availability performance is a statistical specification which is defined as the

Rule	Description

	probability of sensor outage vs. outage duration. Applications are classified into 1 of 4 groups based on availability requirement. These groups, from the most to least demanding are:
	
	a) Closed-Loop Control: No humans in the control loop.
	    a. Fast-Loops: Latency < 1 sec
	    b. Slow-Loops: Latency > 1 sec
	b) Supervisory Control: Human in the control loop.
	c) Diagnostics: Applications delivering visual information for a human.
	d) Archival: Applications that store data for historical reference.

Table 1: Sensor Rules for DSA

When measuring a parameter, several sensors may be needed in different locations to ensure that the measurement is continuous throughout drilling operations. For example, hookload is measured or estimated from several independent locations, such as the deadline, top drive load pins, surface sub, to ensure a measurement as continuous as possible during drilling, tripping and connections. To choose the correct sensor, the system should know which hookload measurement or estimate to use depending on the drilling operation being conducted. if string weight is required then the ideal measurement location would be at the top of the string, below the top drive.

Sensor Quality

Likewise, the sensors and measurements, including those with differing levels of proximity, must be of a quality required for reliable systems automation (Table 2).

	Term	Quality Description
1	Precision	Reproducibility and repeatability of the measurement. This is the precision of the digital value at the end of the measurement chain, rather than the precision of the sensor itself
2	Accuracy	How close the measurement is to the real value
3	Latency	Time delay between the generation of the measurement and its consumption. Latency maybe fixed, variable, or non-deterministic.
4	Calibration	Calibration may be offsite, or onsite, and may affect both the gain and bias of a measurement. Systems that can be calibrated onsite may be calibrated in an automatic or semi-automatic fashion.
5	Validity	If a measurement fails, there must be a diagnostic method of indicating that the reading may be invalid.

Table 2: Sensor Quality for DSA

Time Stamps

All data must be time stamped for correlation, integration and output derivations. A study of three different data aggregation systems found the single biggest source of error in the drilling data was the time measurement[1]. Computer clocks providing independent time measurements differed from 2 minutes on one system to 15 minutes on another compared with the source system. This is. A serious issue that the drilling industry must aggressed to ensure data can be correctly compared by tile correlation which also equates to dept correlation. IEEE 1588, standard that defines time stamping of data, provides a solution[2]. This standard defines a protocol enabling precise synchronization of clocks in measurement and control systems implemented with technologies such as network communication, local computing and distributed objects. To achieve this required state of time synchronization for drilling systems automation, the various systems that combine to collect data and to control a drilling operation must be networked and the downhole system must compensate for latency of signal transmission from surface to downhole and from downhole to surface.

Levels of IMS Attributes

The degree to which an IMS meets these rules, the measures of quality, and the validity of the time stamp, will govern the automation level of a System of Interest because higher levels of automation require higher levels of rules adoption, quality and time stamp validity (attributes).

The Levels of Automation Taxonomy (LOAT) matrix in the Human Systems Integration section defines the various levels anticipated in drilling systems automation through the acquire, analyze, decide and act cycle (Figure 1). The expected growth in performance of a sensor or IMS will drive the capability for increasing levels of automation.

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	A	B	C	D
LEVEL	INFORMATION ACQUISITION	INFORMATION ANALYSIS	DECISION AND ACTION SELECTION	ACTION IMPLEMENTATION
0	Manual	Memory Analysis	Human Decision	Manual Action and Control
1	Artifact-Supported	Artefact-Supported	Artefact-Supported	Artefact-Supported
2	Low Level Automation	Low-Level Automation	Automated Decision Support	Step-by-step Action Support
3	Medium-Level Automation	Medium-Level Automation	Rigid Automated Decision Support	Low-Level Support Action Execution
4	High-Level Automation	High-Level Automation	Low-Level Automatic Decision Making	High-Level Support Action Execution
5	Full Automation	Full Automation	High-Level Automatic Decision Making	Low-Level Action sequence Automation
6			Full Automatic Decision Making	Medium-Level Action sequence Automation
7				High-Level Action Sequence Automation
8				Full Automation

Figure 1 LOAT matrix for DSA

The levels of sensor attributes rules, quality and time stamps can be described in Table 3.

IMS Attributes	Description	LOAT Impact
Low	Very poor application of the rules, very low quality, no time stamp correlations, questionable or sporadic calibration	Suited for manual control of the drilling process. This IMS data requires human oversight to judge reliability. The operator acquires, assesses, decides and takes action.
Limited	Some application of the rules to various degrees, initial application of quality control and recognition of time stamp correlation	Suited for low level automated acquisition and analysis, WITS transmission offsite. Covers display of data and low-level alarms, such as threshold alarms.
Medium	Increased application of the rules, reliable depth tracking, and common time stamping and accounting for latency. May use proprietary communications protocols.	Suited for automated acquisition and analysis (monitoring) at the wellsite or remote to it. Covers display and analysis of the data (KPI tracking) and smart alarms.
Good	Full application of the rules, good quality reliable data that meets communications standards, without	Advice level IMS, suited for supplying information to models

IMS Attributes	Description	LOAT Impact
	full transparency (metadata), interoperability or determinism.	and simulators which can generate open-loop advice to the driller
Excellent	Full application of the rules, common standards, highest quality deterministic data, transparent and interoperable, fully functioning protocol for time stamping per IEEE 1588, known and manageable latency	Full automation capability across the LOAT (acquire, assess, decide, action) – closed loop automation.

Table 3: Sensor Attributes versus LOAT Capability

Current Situation

Currently, sensors, instrumentation and measurements systems typically found on even the most advanced deepwater drilling rigs do not meet the needs of drilling systems automation. This is not a reflection on available technology because in almost all cases sensor technology is available to meet most of the criteria presented in the previous section. Instead, it is a reflection of the disjointed nature of the drilling operation having many conflicting interests at the wellsite.

The roles and responsibilities of the major drilling operation participants (operator, drilling contractor, service company, equipment supplier, shipyard, etc.) are rarely aligned to provide the level of data required for drilling automation. This has led to a reliance on outdated low-cost technology and an inability to merge downhole, surface and context data in real-time, to distribute timely data to interested consumers, to perceive the worth of good timely sensor measurement systems and, ultimately, to; a sacrifice of performance and safety.

The current state of rig subsystems required for automation from a sensor and measurement perspective can be described in terms of mechanization, integrated control systems, measurements, data collection, data handling, interpretation and visualization, and security and authorization.

Mechanization

A prerequisite to automation is that the system components be mechanized to a degree that will allow for overarching control. Most recently constructed land and offshore units have sufficient mechanization of individual drilling machines. Various makes and models of the machines have different levels of mechanization and different sensor technologies.

For drilling automation, the rig should have a top drive used for rotating the drillstring because although a rig equipped only with a rotary table could possibly be used for drilling automation, it would not be a likely candidate.

Some rig systems, such as low-pressure mud systems, have manual valves on lines to and from the pits. These could be automated through addition of position indicators or automated valves. Newer offshore rigs may be fitted with automation-ready valves and automated drilling fluid dosing systems have been employed on offshore rigs. Other rig systems, such as bulk mud, cement and air will probably require upgrading.

Integrated Controls Systems

Newly built units typically have a SCADA-like integrated control package. Some older units may be retrofitted to provide drilling automation to some degree. Many of these systems have proprietary software protocols that do not readily connect to an automation controller. The addition of a drilling automation controller would normally be done on a case-by-case, rig specific basis. Even if two rigs were originally delivered with the same equipment and software, it would be prudent to verify the current as-built conditions prior to any system modifications.

Measurements

Rig sensors often have a complicated line of ownership. The drilling contractor usually provides a basic set of surface sensors. Additional sensors are sometimes rented. Many service companies provide their own sensors, but occasionally will use the contractor's measurements. It is not unusual to see multiple pressure transducers in a row along a standpipe manifold.

The rig contractor's basic sensors are often chosen to comply with contract specifications that were probably written to provide trending information used to drill an average well. For drilling automation, enhanced sensors may be needed to provide more details, accuracy or precision. Sometimes these enhanced sensors will duplicate the basic measurements. Dealing with different values of the same parameter at the same time can complicate the automation algorithms.

Data Collection

Most of today's rig data collection systems aggregate measurements taken from analog surface sensors and time-stamp or depth-stamp them when adding them to a database. Depending on supplier, resolution may be one-second up to 30 seconds. Although it is rare, some systems have digital measurements with individual time stamping. Other data types can be exchanged via WITS or WITS ML. Downhole tool providers collect their own data at the surface and may share only a small portion of that information with others on the rig site or at remote locations. Although their role for drilling automation is evolving and not yet clearly defined, in 2019, data aggregators are beginning to be employed at the rig site.

Data Handling

The collection and storage of increased data volume that is consumed by drilling automation far exceeds present rig capabilities to process these data streams. To address this shortcoming, a separate device, or server, will have to be added to the rig's data and control network.

And satellite links that exist for bi-directional transportation of the data to offsite locations may not have sufficient bandwidth to handle future loads as demand grows.

Interpretation and Visualization

Today, the sensor provider also provides interpretation and visualization, which often involves adding monitors to the rig floor and rig offices. Data interoperability efforts should reduce the number of monitors needed. However, most of today's displays do not allow for the presentation of images or data visualization in a format that is friendly to the existing system design, or in a format that allows for mobile devices. To address this problem, rig display providers will need to enhance their systems.

Security and Authorization

Most automation systems deployed today reside behind a contractor's or operator's firewall. Individual security within the firewall is addressed minimally. Similarly, authorization to adjust parameters or commands is usually done via procedures with some software restrictions. DSATS started to address this via the recommended adoption of the OPC UA protocol and a standard data model which is still under debate. IADC has addressed cyber security and is well advanced through their Cyber Security Committee and the guidelines they have issued.

Problem Statement

The challenge for sensor, instrumentation and measurement systems is to overcome barriers and meet specific needs in order to achieve success.

Barriers

Barriers to the IMS challenge include the costs to meet required levels of data performance targets to advance automation, perceived benefit or lack thereof from adopting these levels, and the fragmented business environment at the wellsite.

Traditionally the industry has struggled to articulate the value proposition from new sensors that are significant enhancements over current sensors (e.g. an instrumented sub at the top of the drill string versus the line tension measurement at the deadline anchor). Adoption of advanced sensors for automation must articulate the value proposition, which may be a combination of change in sensor technology and more advanced use of data from the sensor.

Land drilling rigs face a challenge in sensor maintenance because equipment is regularly dismantled and moved, which impacts sensor connections and incurs sensor damage. Therefore, rigs that drill multiple wells on pads are more suited to the installation of additional sensors.

Data accuracy from sensors on land drilling rigs has become a major cause for concern, following an operator's initiative to measure the accuracy of multiple sensors. [3] Figure 2 summarizes the range of errors found in the testing of sensors on land rigs; the significance of these errors has resulted in the formation of an Operators Group on Data Quality (OGDQ), which found that:

- Every rig has devices that are significantly out of calibration
- Most rigs have rig-ups or practices that will lead to device error or drift
- Errors are common to all rigs and contractors

The consequences of these errors are shown in Figure 3.

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	Rig A	Rig B	Rig C	Rig D	Rig E	Rig F
Rotary Torque	17%	17%	22%	24%	21%	18%
Makeup Torque	23%	11%	12%	17%	60%	13%
Rotary RPM	1%	1%	1%	1%	2%	1%
Block Position	6"	<0.5”	<0.5”	6ft	<0.5”	<0.5”
Hookload	11%		18%		12%	
Pit Volumes	15%	12%	18%	16%	15%	22%
Pump Rate	1%	32%	1%	1%	40%	1%
Pump Pressure	5%	4%	4%	4%	3%	5%

Figure 2: Sensor Errors Identified Across Multiple Land Rigs

Why it matters on the rig

Variable	Observed Errors in Field	Derivative Variable Errors	Small Error	Consequence	Large Error	Consequence	Worst Case Scenario
Commonly Found Errors in Drilling Data and Corresponding Repercussions							
Torque	>100%	MSE Rig State	5%-10%	Sub-optimal drilling, analysis, planning.	>20%	Bit Failure, Motor Failure, MWD Failure, Tubular Failure, Vibrational Dysfunction, Poor Drilling Performance	**Loss of Drill String**
RPM	>100%	MSE, Rig State	2%-10%	Sub-optimal drilling	>20%	Bit Failure, Vibrational Dysfunction, MWD Failure, Poor Drilling Performance	**Loss of Drill String**
Block Position	>25% (cumulative >50%)	Bit Depth, ROP	1%-2%	Block Position Error is Cumulative. Incorrect MD/TVD/Survey Measurements.	>5%	Could lead to significant survey errors and TD compromise.	**Wellbore Intersection**
HookLoad	>100%	WOB, MSE, Bit Depth, Rig State	2%-5%	Sub-optimal drilling. Poor ROP or bit wear/damage.	>10%	This would represent ~50,000 lb for most sensors.	**Loss of Drill String**
Pit Volumes	>5% (100% delta)	ΔPit Volume, Kick Size /Density	1%-2%	Poor well control detection/performance.	>5%	5bbl error could be 100% error in well control calculations	**Well Control**
Pump Rate/ Pump Pressure	>100%	ΔP, MSE, Rig State	2%-5%	Sub-optimal drilling. Poor well control performance. Wear/damage to down-hole motors/turbines.	>10%	Potential damage to motors/turbines/MWD. Potential for kicks/fracturing when near pore pressure/frac gradient	**Well Control**

Source: SPE presentation – Chesapeake (The Role of Data in Drilling)

Figure 3: Tabulation of Consequences of Poor Drilling Data

This situation has high risks for manual drilling operations and is untenable for automated drilling operations. The OGDQ have begun a program to define and implement multiple sensor calibration requirements, primarily for manual and semi-automated drilling, through common specifications in drilling contracts. An initiative was launched to have these standards formally adopted by an industry recognized organization (IADC) such that they can be referred to in contracts rather than being written into the specifications section each time a new contract is issued.

Although this initiative has stalled and is being reviewed, it could lay the foundation for the calibration of sensors to the level required for automation and thus reduce the risk of erroneous data for automation. The drilling industry is reticent to adopt improvements, which incur cost without reasonable compensation through the typically employed contracts and business models. This delays implementation of needed technology improvements including improved sensors.

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While the adoption of open guidelines will help to break down technical barriers, these obstacles can best be addressed by demonstrating that quality sensors and IMS deliver a clear financial benefit.

Needs
IMS and sensors are needed that conform to the criteria listed in Performance Targets above. More directly, a basic need is adoption of the DSA roadmap by the drilling industry and a collaborative adherence to industry standards where they make economic sense. Adoption includes a commitment to periodically update the roadmap and maintain its relevance.

Success Factors
One measure of technical success uses an estimation of the accuracy, reliability and latency of a target desired value, which may be different from the measured value. (e.g. dead line tension to obtain the top of string force) and compares this with acceptable tolerances. These tolerances are established in view of the objectives and acceptable risks that drilling system automation would like to achieve.
If the estimation is good enough, then the system is judged successful. If it is not , then perhaps it can be corrected (i.e., made good enough) by combining with other measurements algorithmically. However, the extra measurements shall also respect the same criteria.
If the estimation fails or does not exist, then a new sensor or algorithm has to be identified and installed.
From a business perspective, the ability to adopt open standards and guidelines which meet the criteria listed in in this roadmap, requires acceptance of the risk in developing and selling sensors and instrumentation and measurement systems.

Way Ahead

The focus is on instrumentation that delivers reliable, quality data in a timely fashion to the consumer. For automation, the sensors and IMS must meet the rules, or performance targets, outlined in this section of the report.
If it is relevant to the operation being performed, improvement in sensor accuracy and precision will enable construction of more complex wells. For the drilling systems automation construction of simple wells, it is permissible to use measurement systems that have a much larger uncertainty, but the key for automation is that the uncertainty is known.

An automated system must consider precision and accuracy to avoid system instability. A paddle type flow meter might be perfectly acceptable as a flow out measurement for some automated drilling operations if its measurement uncertainty, including both repeatability and deviation from the 'true' value, is known.

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The roadmap recognizes numerous steps to be undertaken in an environment which seeks to drive the adoption of an open infrastructure for data in drilling systems automation.

Development of an Industry Norm

One step is to develop an industry norm for each Systems of Interest and relating it to relevant primary measurement standards such that a statement of accuracy and precision can be derived for components of each sub-system.

Development of onsite calibration procedures

Another step is to develop fit for purpose onsite calibration procedures for all measurement systems of each block. Calibration procedures should be to a selected reference, such as a verified reference device, or to a real-time reference, such as pressure at a known depth in the hole.

Development of measurement system robustness

Further, the roadmap included development of measurement system robustness (in particular for process safety related sub systems) by defining redundancy requirements and measurement of critical parameters by two independent physical methods.

The deliverable of these steps should be a measurement table specifically for drilling systems automation and similar to one in Annex B of NORSOK D-001.[4] This table can serve as a recommended industry reference for measurement quality and should feature a complete list of parameters including source, whether there should be redundancy, what kind of an alarm should be connected, whether it is a measured or calculated or derived variable, the display requirements in resolution and the measurement system accuracy.

In parallel, the adoption of technical development must be encouraged so that sensors meet applicable open standards such as those required by the Industrial Internet of Things.

Implementation of Sensor Standards

Sensors will meet applicable open standards, such as the developing IEEE 1451 standard for smart sensors, or the standards of the OCF (Open Connectivity Foundation), so that a process using a sensor (defined as a sensor, actuator, or event) can attach to and discover information (metadata) about that sensor. To handle legacy sensors, non-complying sensors could be grouped below a network device that emulates IEEE 1451 or OCF standards.

In parallel, standards for contextual (or environment) data need to be developed, which define the equipment, operation and wellbore, such as the pipe and BHA that are in the hole and its safe operating limits.

Context Data Standards

Development of a standard for data that describes the equipment, operation and wellbore is critical to drilling systems automation. As with sensors, it is important that all parties controlling a rig have access to the same information describing that rig and its capabilities and limitations (constraints).

This is data supplied to all “subscribers” that indicates the current specifications of all equipment. This should include rig equipment, wellbore construction (casing) and downhole equipment. Examples involving context data:

- Pipe size
- Ram size
- Ability to close on the pipe in the BOP
- Ability to shear pipe
- Pump relief valve setting
- Elevators height, various length elevator links, hanging straight, azimuth if at angle
- Rig equipment capacity and capability
- Number of drill lines, design factor, diameter
- Surface pressure losses
- Presence of riser booster line

The determination and communication of the state of the drilling operation (see Systems Architecture section) and its components is a key enabler for drilling automation. In manual operations, this is determined by a state engine that uses logic from sensor measurements. In full automation, the automated system determines the operations (drilling) state.

State Variables

To achieve full automation through interoperable sub systems requires a centralized state algorithm that broadcasts the current state to any requesting applications. State definition through automated means will itself create a requirement for sensors and instruments. The ability to develop sensors and instruments suited to this purpose will be a critical factor in the advancement of automation. Improvement in data for states definition will occur within the advancements described previously. Broader improvements will require the application of new technologies (e.g. automated video analysis of cuttings discharge on a shaker screen or automated video analysis of non-instrumented operations such as nippling up) that can discern the situation. The accuracy and the timeliness requirements of the rig state algorithm is extremely high and immediate, respectively, to ensure safe operation of automation programs.

The advancement of rig sensor technology will enable future key automation and modeling applications. In certain markets, such as the land drilling market, it will be imperative that these new sensor technologies are not accompanied by a significant increase in capital or operating cost.

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Enhanced Sensor Capabilities

Table 4 is an example of the advancement in sensors that will be required to meet the vision of drilling systems automation. Much of this advancement will be made possible by the implementation of steps 1 through 4 of the Performance Targets for sensors and IMS.

Sensor	Advancement	Example Apps Enabled	Timing
Hookload	Improved accuracy of hookload measurement.	• Drillstring model • Automatic drilling • Drag calculations	0-5 yrs.
Surface Torque	Measurement of torque (in absolute units) applied to the top of drillstring.	• Drillstring model • Automatic drilling	0-5 yrs.
Surface Acceleration	Measurement of 3-axis acceleration at the top of the drillstring.	• Vibration model	0-5 yrs.
Advanced Mud Logging	Real-time measurement of the mass of formation removed from the borehole and its characteristics	• Hole cleaning, borehole stability, formation evaluation	0-10 yrs.
Flow Line In	Accurate measurement of mud flow in.	• Hydraulic model • Kick/lost circulation detection • Automatic pumps	5-10 yrs.
Flow Line Out	Accurate measurement of mud flow out.	• Hydraulic model • Kick/lost circulation detection • Automatic pumps	5-10 yrs.
Real-time Mud Properties	Real-time measurement of mud composition, density, rheology, viscoelastic and thermo-physical properties.	• Hydraulic model • Pore pressure prediction	5-10 yrs.
Along-String Measurements	Measurement of pressure, acceleration, RPM, torque, and tension at several points along the drillstring	• Drillstring model • Vibration model • Hydraulic model • Kick detection • Mud rheology	5-10 yrs.

Table 4: Outlook for Enhanced Sensor Capabilities

References

1. Isbell M, Un-synced time measurements can lead to data aggregation challenges, published in IADC Drilling Contractor, Nov 7, 2017

2. IEEE 1588-2008 - IEEE Standard for a Precision Clock Synchronization Protocol for Networked Measurement and Control Systems.

3. Chesapeake 2014 SPE DSATS Workshop in Halifax, Canada.

4. See http://www.standard.no/en/nyheter/nyhetsarkiv/petroleum/2014/energy-and-petroleum---collection-of-standards-for-drilling/

Appendix I: Systems of Interest IMS Examples

Systems of Interest	IMS	Device/Measurment Sets
Surface Rig	Hoisting and Lowering	{block height, hookload, bi-directional motion and brake, SWOB}
	Sea Motion	{heave, tide, depth}
	Top Drive	{rotary speed, surface torque, drillstring rotated angle, transmission gear, link tilt angle, link tilt azimuth}
	Surface Sub	{axial load, surface torque, surface pump pressure, rotary speed, accelerations}
	Elevators	{open, closed, locked}
	Rig Pumps	{SPM, stroke length, liner and piston diameter}
	Power Slips	{open, closed}
	Wellhead/Casing	{csg/choke setting, csg/choke pressure, LOT/FIT pressure}
	Flow-in piping	{suface pump pressure, standpipe pressure}
	Auxilliary Equipment	*need to make sure that pipe handlers, mud buckets, etc. are out of the way before trying to start drilling with automation system*
Fluids Flow	Mud Pits {active, standby, slug, trip,etc}	{volume, gain/loss, density, viscosity, temperature}
	Flow Line In	{input flow rate, pump rate, density, visocsity, temperature, pressure}
	Flow Line Out	{configuration, return flow rate, density, visocsity, temperature, pressure, cuttings volume, cuttings size distribution}
	MPD/DGD/UBD	{configuration, CCS Sub or device, gate valve settings, choke settings, choke pressure, back pressure pumps, lift pumps, RCD}
Fluids Treatment	Basic Rheology	{density, viscosity, resistivity, temperature}
	Automated Fluid Monitoring	{density, shear stress, shear rate, plastic visocsity, gel strength, oil/water ratio, salinity, solids}
MWD	MWD Telemetry	{Electromagnetic, Mud Pulse, Acoustic, Wired Pipe}
	Steering Unit	{RSS, Motor}
	Directional	{off-bottom survey, gyro, rotational survey, flow-off survey, near bit}
	Gamma Ray	{gamma, azimuthal gamma, near bit gamma}
	Drilling Mechanics/Dynamics	{DWOB, DTOB, DRPM, bending, pressure, accelerations}
LWD	Resistivity	{propagation, azimuthal, deep azimuthal, imaging, bit resis}
	Magnetic Resonance	{porosity, free fluid, bound fluid, permeability}
	Acoustic	{compressional dT, shear dT, porosity}
	Neutron	{Neutron porosity}
	Density	{compensated density, azimuthal density, porosity}
	Caliper	{avg diam, azimuthal}
	Formation Pressure Testing	{drawdown, buildup, fluid ID, fluid typing}
	Seismic	{checkshot, VSP}
MUD Logging	Geologic	{cuttings lithology, cuttings gas, cavings, anhydrite, calcimetery, bulk density, shale density, shale factor, QFT, XRD, XRF, NMR,}
	Gas	{total gas, C1-C5, gas ratios, Mass Spec, H2S, CO2}
Cement		{density, viscosity, pH, temperature}
Future	Along String	Fluid {pressure, temperature}
		Mechanical {axial load, torsional load, rotational rate, accelerations, caliper}
		Formation Evaluation
		Seismic

Full spread sheet available at: http://dsaroadmap.org/ims/

