Drilling Automation/Augmentation Technical Pain Points & User Stories

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Introduction

Purpose: to collect a list of thoughts, experiences, ideas, etc. about improvement opportunities (so called pain points and user stories) in drilling augmentation – digitalization and automation. It is not to prioritize those items or to assign action items. This list will be kept publicly available on https://dsabok.org. The "customer" for the list is any organization, group, company, individual, etc. who would like to become inspired about building a solution. This is a Sisyphean task.

Caveat emptor: The list is a non-exhaustive, work in progress which is made available as information that may contain inaccuracies, be out of date, contain typographical errors or may not be applicable to user's (customer's) needs or circumstances. The contributors are not liable for any errors or omissions.

Publication: A snapshot of the document is made publicly available on https://dsabok.org. It is updated regularly as new additions/modifications are gathered.

Rules: Share your thoughts, experiences, ideas, etc. It is okay to have different thoughts, experiences, ideas, etc. (and it is okay to disagree), just add into the document an "Opposing view" or "Comment". This can be done by directly editing the master document that is stored on a web accessible repository. Please contact info@dsabok.org

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Pain Points

1. PAIN POINT: Clock Synchronisation

It would be nice if we would synchronize all time stamps on every system on a rig.

Comment 1: This would fix about half of the problems associated with data quality at the rig site. It seems strange that with all the advancements of automated time that there can be differences of 15 seconds to even 1 minute on various clocks within computers.

2. PAIN POINT: Data Merging

It would be nice if we would have a standard way of getting lagged data (e.g., downhole data) into the real time data store. Examples: mud pulse data, downhole recorded memory data

3. PAIN POINT: Communications

It would be nice if we had a standard for communications (transport protocol without semantics).

Comment1: It is perfectly okay to support more than a single protocol/transport. No single protocol will satisfy all use-cases.

4. PAIN POINT: Steering Command

A standard steering command (45o Left of high side for 10’ or 315o for 10’).

Opposing view 1: I do not think downhole tool related commands must be necessarily standardized – for example, external parties should not send commands to a directional tool but may want to describe the desired trajectory (DLS, surveys ...).

Opposing to Opposing view1: external parties should send commands in a standard format to a directional system, for example, a geosteering system. Also downhole tools aren’t always required. While drilling with a bent sub and motor there isn’t a downhole tool for trajectory control, top drives, drawworks and mud pumps are the controlling machines.

Comment to Opposing view 1: Agree with Opposing view 1. There are several companies commercializing this service. If you have the data governance and friendly tag list, then it allows the various commercial systems to work and have performance drive user acceptance.

5. PAIN POINT: Alarm

Common alarm management terminology

Comment 1: I would suggest ANSI/ISA 18.2-2016 Management Of Alarm Systems For The Process Industries). We tend to use the word “alarm” for both alarms and warnings.

Comment 2: if we can agree on OPC UA, we have the foundation for alarm mechanisms built in. On top of this, available standard for alarm management applies - no need for additional ones.

Comment to comment 2: I agree that there area available standards for alarm management, the task is to pick one and make it a standard on a drilling rig.

6. PAIN POINT: Time to Depth

Time to depth conversions.

7. PAIN POINT: State Definition

State definition for automation, based on rig activity codes from IADC DDR PLUS, needed for interoperable triggering of processes.

Opposing view 1: DDR PLUS is not the path in my opinion. There are several companies that have IP in the space. That being said if you want to focus on AC high spec rigs, you can get 80% of the way there quickly with common knowledge.

Comment to Opposing view 1: Agree to Opposing view 1. DDS PLUS codes are often too generic to unambiguously describe a state of automation at a given moment. Created as a standard for reporting, it is still significantly tailored for that rather than for transfer of automation state.

8. PAIN POINT: Equations

Agreed upon standards for calculation of derived items, such as ROP, MSE, vibration diagnostics, etc.

Comment 1: Agree on some derived items like ROP, trip speed, torque. However, some items companies believe are proprietary such as MSE, vibration.

9. PAIN POINT: Data Model

Understandable and manageable data model or dictionary for drilling information and data (Maybe this is DWIS under OSDU).

Comment 1: A common data description and dictionary (semantics) – we need to be able to know what data we are looking at. We only need standards for sharing between parties. Maybe we are attempting to share too much "low level" data (e.g. steering commands) instead of choosing a better abstract level (DSL, planned surveys, targets ...) and leave the details to the implementers.

Comment 2: Data model needs to support various “levels” of data. This “depth level” of data would greatly depend on system state and level of RCS automation. For example, for drilling it could be sufficient to specify targets and operational parameters while for setting a liner hanger an exact sequence of events and parameters shall be received by RCS.

10. PAIN POINT: Data Transparency

Metadata describing each data item and covering information such as calibration, accuracy, measurement location, etc.

Comment 1: I am not sure how much this is really needed. Operators will drive this requirement to all the various contractors.

11. PAIN POINT: Data Governance

Guidelines for data governance – Need to establish a friendly tag list for each source of data to share across multiple platforms.

Comment 1: Data governance shall also reflect on trustworthiness of the source, its “quality”,etc.

12. PAIN POINT: Remote Communications

Standard for remote communication protocol (transport).

Comment 1: Not sure if you need a standard protocol or just let if be defined by those sharing the data.

13. PAIN POINT: Interoperation

Capability discovery: how can I detect what functions are currently available to use?

Comment 1: Solving the data governance and communication protocols, this item is no longer required.

14. PAIN POINT: System Governance

Process to process transparency.

Comment 1: Governance will be the key to successful integration and sharing of data.

Comment 2: System governance shall include finite state automata governance. Each state should include information on transition of activities, set of parameters, allowable tolerances for parameters, safe operation window. Further development of system governance should also include information on: fault management (if certain triggers are triggered, to which state the system transfers to), conflict resolution (if two opposing commands are given), transition to contiguency states, safe boat management rules (how to safely return to manual mode in the current state).

15. PAIN POINT: Model Synchronization

Global to local level model synchronization

16. PAIN POINT: OPC UA companion standard for Drilling Control Systems

Rig Interface. In contrast to the Rig Information Model (driven by inventory) and the attempted OPC UA – WITSML companion standard (driven by Energistics/WITSML), this one should be driven by automation folks, who really conduct Drilling Automation and have a solid experience in software engineering. This is more a control systems and OPC UA exercise than it is a data modelling one.

17. PAIN POINT: OPC UA Companion Specification for WITSML

Should be finished – there are several proprietary OPC UA to WISTML converters, we need an agreed upon standard. This is apparently with OPC UA at this time.

18. PAIN POINT: Synchronization on depth

Many systems on the rig site have “depth.” Many times, depth of these systems are not synchronized.

19. PAIN POINT: Configuration data for automation system

The data which is referred here is not rig control system configuration but configuration data coming from outside of closed automation loop. It can include anything from pressure gradient, formation tops to stabilizer size/length and planned trajectory.

The few pain points of this data include:

- If the data is available in digital format (which is not always), it is created for other purposes than automation. So it is lacking sufficient quality, level of details, etc.
- Often this data is created during the planning phase, but updated on the rig and during the automation process itself. The updates can happen in a different system so the source of data is different at different times of the process.
- Config data is not available or updated in a timely manner required for automation process.
- No transparency on the rig if the configuration is ready and validated for current automation process.

Some of the issues can be solved by proper Data Model and Data Governance but overall timely availability of this data of sufficient quality is a pain point on its own.

User Stories

1. USER STORY: Real-Time Drilling Dynamics Flags

While drilling, event flags and dynamics-related data indicate the dynamic behavior of the downhole drilling system. For example, green (all okay), yellow (caution) and red (detrimental). Alternatively, a spider or radar plot could be used. These flags are derived from either downhole or surface data and indicate the presence of behavior such as stick-slip, whirl, bending, bounce, HFTO, severe axial, lateral and tangential vibrations. Obviously, the fidelity (certainty) of the indication is a function of the measurement, processing and measurement location, and the usability of the event flags to mitigate an event depends on standardization in the industry.

2. USER STORY: Kick Detection

Kick detection is often broken into two phases, early kick detection and consequences (formation flow). However, in many circumstances, the actual transition from drilling with an overbalance to drilling with an underbalance is progressive over time. In these cases, signals may indicate the higher probability of a kick occurring if encountering a zone of higher fluid transmissivity. This gives time for the drilling contractor to react, for example by raising the mud weight.

3. USER STORY: Rig activity Codes- rig states

The drilling contractor indicates the activity of the rig over time, for the daily drilling report, using rig activity codes as defined by the IADC DDR Plus. Service companies use higher fidelity activity codes, for activity-based KPI’s (for example, for measuring connection times). In automation, the triggering of applications may depend on the change in rig activity. In this last case, the resolution and certainty of measuring the change of rig state is important.

4. USER STORY: Process activity Codes

Similar to the rig codes, but looking at the various process that execute on a given rig activity, these can change based on what is happening with equipment and wellbore without any change in the rig activity. The triggering of applications may also depend on this and the associated risk matrix.

5. USER STORY: Time Stamping

There are multiple measurement and processing systems on surface at the wellsite, and remotely, all with independent time clocks. To reduce uncertainty in surface time measurement and processing there should be only one master clock in the system, and all reference clocks should synchronize to that clock.

6. USER STORY: Asynchronous timestamping

Building upon the Time Stamping user story, In some operations there is no control loop. It is an Asynchronous stream of commands. This can lead to issues with controlling the rate of execution on these. Having asynchronous time stamping would remove the need for adaptive rate algorithms that estimate timing and execution in this scenario

7. USER STORY: Sensor Risk Index

Not all sensors measure the physical property of a process, and all sensors suffer from degradation of accuracy. Having the ability to adequately asses the quality of a certain measurement based on intended use for a given situation (Flow rate from gas cut mud) and the level of uncertainty based on last calibration would be useful in enabling algorithms to account for this.

8. USER STORY: Depth Measurement

The measurement of “measured depth” (MD) is quite uncertain. It is an inferred value typically based on the length of pipe in the string and the height of the hoist above the rotary table. However, the length of pipe changes depending on temperature and loads, and the height of the top drive may be inaccurately measured. The true vertical depth (TVD) is based on the estimated MD, and the MD and TVD are used in many derived values.

9. USER Story: Bit/Tool Depth Measurement

The determination of bit depth is a key source of error for most data streams. This problem is linked to the depth measurement of the hole. The user wants to receive a corrected bit depth which considers drill string mechanics to know where the bit is located in the hole?

10. USER STORY: Merging downhole and surface data in real-time

There is considerable uncertainty in merging downhole data with surface data. There are time delays in the acquisition of downhole data (measurement, processing, transmission, decoding) that have to be applied to the surface time stamp to derive the correct merging time. In addition, the downhole clock will drift with respect to the surface clock. Aligning downhole and surface time stamps will allow the merging of downhole and surface data sets with confidence.

11. USER STORY: Data Quality Issue Alarms

The user wants to receive alarms if the data quality of data streams and other process relevant data is outside a defined set of quality parameters. The data stream responsible shall be informed and a mitigation workflow including an escalation process initiated.

12. USER STORY: Standardized Drill String Component List

The user wants to have a quality assured list of drill string components/tools which are in the hole with all relevant information included.

13. USER STORY: Standardized Surface Drilling System Equipment List

The user wants to have access to a standardized equipment list which covers relevant properties of equipment used on the surface (rig components etc.).

14. USER STORY: Standardized Inventory List

The user wants to central repository where a standardized inventory of equipment and materials available (including consumables) on the rig site can be pulled by all the parties involved.

15. USER STORY: Data Filtering and Manipulation Audit Trail

The user wants to have a trail of all the data treatment, e.g. filtering steps which took place from the original sensor signal to the point where the data is pulled. This would help to understand how data has been filtered or manipulated from the source further downstream.

16. USER STORY: Time and Depth Based Measurements

Sampling typically occurs based on time (time-based). Conversion to depth-based measurements is quite undefined. It may simply use an associate time for each equal increment of depth, and use interpolation to find time, depth pair. It may use an associated depth with each equal increments of time, and again interpolate to find the time, depth pairs. Alternatively, it may take the closest depth to a specific time, or … The lack of standardization leads to many questions on the relationship between time and depth-based measurements.

17. USER STORY: DDR Operation Codes

The DDR operation codes are still widely used and cannot be replaced by real-time activity detection yet. The operations codes are the cornerstone of all operation analytics and benchmark in drilling. It is not possible to discuss ILT and NPT analyses without those codes. But they are subjective, prone to errors and hard to verify they correct start/end time and depths. There are many different ontologies (and granularities) which turns even harder to compare wells from different companies, and sometimes, within the same company.

18. USER STORY: Data cross-reference

One of the biggest hurdles to share, collaborate and re-used drilling data is on cross reference between databases, inside organization and inter-organizations. In order to increase data flow between systems there is a need to address cross reference, such as unique/uniform well name; explicit metadata for units and date format; datum used for measurements; Geo-data format used (projection, UTM); and similar items. Without this, the industry will continue to build data silos, isolated applications and cumbersome data sharing.

19. USER STORY: Along-Hole Depth Quality assurance and Uncertainty from WPTS

It is some time unclear what depth reference is used, the so-called Zero depth point (ZDP). This concerns both the curvilinear abscissa, often referred as the along hole depth (AHD) or measured depth (MD), and the true vertical depth. Sometime the ZDP is defined as the ground level: this can reveal to be problematic over time for instance, when there is subsidence or with drilling operations in desertic region where sand dunes move constantly. Utilizing a reference that is rig specific, e.g. rotary table elevation (RTE), can also be problematic as some wells may be drilled with one RTE, while others may be drilled with another RTE therefore causing problems when estimating collision potentials.

20. USER STORY: Rounding of numerical depth values

Tabulations of well survey data is typically to 2 decimal places when the uncertainty, at deeper depths, is in whole meters / feet and multiples thereof. This is misleading to the end user and subsurface modelling (especially cross correlation of pressures) suffers badly. A common representation of uncertainty on shared TVD data is needed to ensure end users take into account the real uncertainty.

21. USER STORY: Well placement Planned vs. actual by WPTS

Planning a large DLS build to horizontal drain section, 2D well. Geological model reservoir top, thickness and dip angle are not constrained due to early field development stage. Wellplacement survey program for a planned well includes QAQC processes for *managing* :

- surface platform
- slot location,
- horizontal, vertical reference and water depth or ground level
- depth QAQC tracking process
- EOU drawn at 2sigma 95% confidence level

Geomodel reservoir top and bottom defined as points taken from the seismic 3D model

Primary TVD uncertainty method to intersect target was to use LWD response from geological marker beds prior to starting build and landing the well out

No geodata vertical (TVD) uncertainty is defined in the drilling program to incorporate DD reported drilling uncertainty

Reservoir contact sensitivity, uncertainty and production performance / quality done on the plan center line not the outside Vertical Dimension to the ellipsoid of uncertainty edges for the signed off drilling program complete with low tier vertical correction

Realistic angle of incidence, relation to the reservoir contact engineering analysis not possible due to lack of incorporation of well uncertainty magnitudes shallower and deeper than the planned well bore. Without quantifying geological and drilling uncertainty there is significant risk of the well not intersecting the planned target sweet spot.

22. USER STORY: Failure to follow Well Position Quality Controls and Manage Error Sources can lead to a well collision by WPTS

Controls and control types used to prevent those errors. It is a routine approach to establish and maintain those controls with no bad outcome. See Appendix for scenarios.

23. USER STORY: Process / Equipment Alarms.

The user wants to receive alarms on processes and equipment relevant to the operation being undertaken and the alarm screen to change in a standard manner to accommodate this.

24. Well Quality definition

The end user desires a quality well for their subsequent use during production and maintenance (OPEX). There is no (common) definition of a measurable quality wellbore.

25. USER STORY: Calibration of deadline anchor hook-load

During the commissioning of the draw-works, the hook-load from the dead-line anchor is calibrated by weighing known amounts of barite sacks. The correction factors are put directly into the PLC code and afterward nobody has any knowledge of this correction table. The problem is that some of the measurements have been made when lifting the known amount of barite sacks and others have been when lowering other amounts of barite sacks. The result is an inconsistent correction table deeply embedded in the drilling control that nobody can be made aware of its existence unless someone, someday, open the source code and wanders what this table is for?!

26. USER STORY: mud pump flowrate in

The drilling control system on a rig shows the flow-rate in measured by a Coriolis flowmeter. An app connected to the drilling control system through an “open” interface receives an unspecified flow-rate in. It happens that it is the one calculated based on the pump rate from the stroke counter and the pump efficiency. The app is supposed to detect pack-offs and take proactive actions. During an operation, there is a pack-off while starting the mud pumps. The driller notices immediately based on the Coriolis flowmeter measurement, while the app does not react because the flowrate has not yet increased according to the stroke counter.

27. USER STORY: Pit temperature sensor measuring air temperature instead of mud temperature

A drilling automation app controls the axial velocity of the drill-string to protect the well against swab and surge. While circulating the hole clean, the mud is transferred to the reserve pit which is not equipped with a temperature sensor. The app continues to receive the temperature from the active pit, but now it is the air temperature that is measured and not the mud temperature. As the temperature has decreased by more than 30°C, the app finds that the mud density has increased, therefore allowing to pull out of hole with a much larger axial velocity than what is tolerable by the well.

28. USER STORY: External influences on the mud density sensor in the mixing unit

A drilling automation app controls the maximum allowable flow-rate. It utilizes the mud density measured in the mud mixing unit for its calculations of hydrostatic and hydrodynamic downhole pressures. However, occasionally, the mud density sensor provides values that are substantially lower than expected. Yet the reported values could be actual values and cannot be simply disregarded as outliers. After investigation, it appears that the deviations of the mud density measurements always happen while performing X-ray inspection on the lower decks.

29. USER STORY: Additional pumping with the cement pump while drilling

While drilling the 12 ¼-in section of an ERD, it is found that there is not enough flow to clean the hole. It is therefore decided to use the cement pump to provide an additional flow. The cement pump is not integrated in the drilling control system. Any apps that is connected to the drilling control system receives an erroneous flowrate which only accounts for the mud pumps and not the additional flow provided by the cement pump.

30. USER STORY: Automatic kick detection and booster pumping in the marine riser

An automatic kick detection app gives systematically false alarms each time booster pumping is used to clean the marine riser. This is simply because the booster pump is not included in the signals provided to external apps by the open interface of the drilling control system.

31. USER STORY: Multiple collision criteria

An operator has taken responsibility of an existing field that has been developed for many decades. The operator does not trust the measurements made by the previous operator of the wellbore position. The new operator desires to utilize two different collision criteria: one for older wells and one the wells that are new drilled.

32. USER STORY: Repetition of real-time signals

A service company has been asked to increase the refresh rate of its real-time signals from 0.2Hz to 1Hz. Instead of acquiring new signals every second, the same signal is repeated every second for 5s. Consequently, any app that calculates accelerations will have consider that there is no “movement” for 4s and a sudden acceleration over 1s.

33. USER STORY: Downlinking to the RSS by flow diversion

An app connected to the open interface of a drilling control system monitors the flow-rate and the pump pressure. When utilizing an RSS, the pump pressure "oscillates" for a few minutes, while the flow-rate reported by the drilling control system seems to be steady. The reason is simply that downlinking to the RSS is made using flow-diversion and the commands to the flow-diverter are not made available through the open interface of the drilling control system.

34. USER STORY: Downhole pressure measured in the BHA compared to downhole pressure measured by ASMs

A drilling operation makes use of high-speed telemetry and several ASMs. When comparing the downhole pressure measured by the PWD in the BHA and the downhole pressure measured by the ASMs, there is large difference in dynamic response: the downhole pressure from the PWD does not show any of the micro pack-offs that are visible on the ASMs measurements. The reason is that the PWD provides average values over a much longer time window than the time window used by the ASMs.

35. USER STORY: Synthetic signals vs Actual Measurements

A dynamic sub measures axial acceleration and 3 tangential accelerations at 120° from each other's. It also provides a synthetic radial acceleration based on the tangential accelerations and the rotational speed measured with a gyro. It is important to know that the radial acceleration is synthetic and not measured as the synthetic value will not be able to account for lateral displacement effects and therefore that synthetic signal cannot be used to reconstruct the pipe lateral movement.

36. USER STORY: Practical accuracy compared to given accuracy of downhole pressure measurements

A downhole pressure sensor has a given accuracy (possible bias compared to a true value) and precision (statistical discrepancies of multiple measurements). In practice, pressure is transmitted to the sensor through a small piston-like element. Small solid particles may jam the displacement of the piston resulting in a much large inaccuracy than the theoretical one given by the manufacturer.

37. USER STORY: Side effect of daylight saving on real-time logged data

A real-time drilling data acquisition system timestamps recorded data using the local day-time clock. If the local daylight-saving procedure change clock in spring and autumn, there are inconsistencies in the continuity of the timestamps.

38. USER STORY: change of hook-load measurement configuration in the middle of an operation

During a drilling operation, the driller decides to change the configuration of the hook-load measurement, from using the two load cells at the top of the top-drive, to using only of the two. The change causes a permanent deviation of the hook-load measurements which can be misinterpreted by an app that monitors overpulls and set-down weights.

39. USER STORY: False zero of the standpipe pressure

The standpipe pressure is influenced by the mud column in the standpipe and therefore always reports a pressure even when the mud pumps are turned off as long as there is mud in the standpipe. On a rig, the mud pump PLC has been modified to apply a false zero such that the SPP is approx. zero when not pumping. As a consequence, the SPP is negative when the standpipe is drained out or when the fluid density is lighter than the one that has been used to define the false zero.

40. USER STORY: Discrepancy between pump rate command and measured pump rate

A drilling control system sends a mud pump rate command based on the request from an app. This mud pump rate command is translated by the mud pump PLC into a motor speed which is applied by the VFD drive on the AC motor of the mud pumps. i.e. a rotational velocity of the magnetic field generated by the stator of the AC motor. But the actual mud pump speed is the one the rotor which is always smaller than the one of the rotating magnetic field generated by the stator. As a consequence, the obtained mud pump speed is always lower than the one requested. The difference between the two depends on the pump pressure (in fact the torque on the AC motor).

41. USER STORY: In situ tortuosity from continuous inclination and azimuth

When using an RSS, the continuous inclination and azimuth is sent by mud pulse telemetry. This information is used to calculate the local micro-tortuosity. In the same BHA, there is a high frequency/high precision accelerometer and magnetometer recording data in memory, but position at the top of the BHA. When comparing the two set of measurements, it appears that the micro-tortuosity calculated from continuous inclination and azimuth is much larger than the one from the memory data. A plausible explanation for the discrepancy is that the continuous incl and azimuth is measured inside the RSS which is subject to much more sag effects than the memory-based instrument placed at the top of the BHA.

42. USER STORY: calculation of inclination from a dynamic sub

A dynamic sub has three tangential accelerometers and one axial accelerometer. Under uniform rotation, the amplitude of the tangential accelerometers shall be related to the local inclination. However, none of accelerometer measurements are compatible with the same inclination because the accuracy of accelerometers. One wants to use sensor fusion to extract a plausible local inclination.

43. USER STORY: Fann 35 measurements at high temperature

Once a day, the mud engineer performs Fann35 measurements of the mud at 20, 50 and 80 °C. However, at 80 °C, there is substantial evaporation of the fluids and therefore the measurements are not representative of the real rheological behavior.

44. USER STORY: Fann 35 measurements of a thixotropic and weighted fluid

To measure the rheological behavior of a thixotropic fluid, it is important to wait sufficiently between each change of speed of the rheometer. But, if the fluid is weighted, then at high shear rates, there is a risk that the high gravity solids will settle in the cup during the waiting period. As a consequence, further measurements are made with a fluid that is actually different from the original one. These two aspects are conflictual, and it is practically impossible to correctly measure the rheological behavior of a thixotropic, weighted fluid with a mechanical rheometer that does not have a large number of possibilities for the measurement speeds.

45. USER STORY: Fluid rheological behavior when drilling reactive shales

When drilling reactive shales, the mud gets continuously contaminated. The mud engineer is very busy managing the quality of the mud and therefore has not much time to send mud reports. Therefore, any applications that depend on these mud reports will not get this information in a timely fashion while it is the moment for which the mud rheological behavior changes the most.

46. USER STORY: Unclear temperature conditions for mud density

In many mud reports, the temperature conditions of the mud density are absent or unclear. This is a source of uncertainty when performing hydrostatic and hydrodynamic pressure calculations.

47. USER STORY: Unclear source of the fluid sample

In many mud reports, it is unclear whether the mud sample has been taken from the pit or the flow-line. Also, if some samples are taken from the pits and others from the flow-line, they are not necessarily comparable, especially while drilling reactive formations or when cuttings may dissolve in the drilling fluid like for instance in a chalk reservoir.

48. USER STORY: Unclear measurement of the mud density when utilizing loss circulation material

When loss circulation materials (LCM) are used, it is often unclear whether the mud density has been measured with the LCM or after being filtered. This can impact both hydrostatic and hydrodynamic pressure calculations.

49. USER STORY: Rheological measurement of drilling fluids with LCM

When utilizing a Fann 35 rheometer, the drilling fluid is filtered to remove LCM. Therefore, the measured rheological behavior is not the one of the fluid that is pumped into the well. Solid particles in suspension influence the rheological behavior and therefore calculating pressure losses based on the filtered fluid will lead to biases on pressure drop estimations.

50. USER STORY: Effect of Thixotropy on Pipe Rheometers

When utilizing a pipe rheometer with thixotropic fluids, any change of pipe diameter causes a change in the shear history of the fluid and therefore influences the measured pressure drop over a certain distance. If this is not accounted for, then the measured rheological behavior is biased, which in turn impact estimations of pressure drops.

51. USER STORY: WOB Calibration

The surface WOB (SWOB) is deducted from the subtraction of the free-rotating weight (FRW) to the hook-load. The driller needs to “zero the WOB” prior to tagging the bottom. If he does so before the flow has reached steady state conditions, then the FRW may not had reached yet a nominal value since it depends on the pressure losses along the hydraulic circuit. Similarly, if the flow rate is changed while drilling, the zero WOB is falsified. In addition, it is really an FRW if the drill-string was fully rotating, which is not necessarily the case when utilizing a low top-drive speed as there may be static to kinetic friction induced stick-slips. An erroneous SWOB can influence mechanical specific energy (MSE) calculations.

52. USER STORY: pick-up/slack-off friction test executed without removing torque on the top-drive

After drilling a stand in a deviated well, when the top-drive is stopped, there is still a torque on the top-drive. This remnant torque is caused by static friction along the drill-string keeping the drill-string to be twisted. If the driller performs a pick-up/slack-off procedure to measure the pick-up weight (PUW) and slack-off weight (SOW), without removing the torque on the top-drive then the drill-string untwist while moving axially and therefore the measured PUW and SOW are not the one of pure drag but a combination of axial and rotational movements. There is a function on the drilling control system to untwist the drill-string, usually called “Zero top-drive torque”. However, whether the “zero torque” has been used or not is not necessarily passed. This has an influence when filling information on hook-load “roadmaps” (also called “Hockey Sticks”).

53. USER STORY: Influence of the mud hose and umbilical on the hook-load

When the travelling block is high in the derrick, the pull exerted by the mud hose and umbilical is larger than when the block is closed to the drill-floor. This influences the measured hook-load when it is not measured directly by an instrumented saver-sub or iBOP. As a consequence, there are biases in hook-loads and consequently on SWOB depending on the block elevation when the hook-load is measured at the deadline anchor, at the top of the top-drive or at the crown blocks.

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Appendix

Appendix for 22. USER STORY: Failure to follow Well Position Quality Controls and Manage Error Sources can lead to a well collision by WPTS

Hypothetical Scenario

Three wells planned with drilling programs for a 36 slot platform

- 10ft slot spacing
- 30" conductors
- Inside slots picked to drill out first
- All slots contain a plan to target to conserve the drilling window below each slot

Well 1 (1 of 3)

Planned kick off from 30" conductor shoe

Conductors were driven deeper than planned and not gyro surveyed

Assumption conductors vertical, (not surveyed after driven)

MWD surveys 450' interval no surveys and BAD MWD surveys out of the shoe for 200' not 50' as planned

Survey program specification not met

Difficulty drilling with motor BHA to plan with planned flow rate

Assumption collision can not occur

Confusion of multiple survey programs sent to rig adding to complacency (it was going to change anyways)

Collision avoidance travelling cylinders plots were not produced as planned

Internal operator, DD and survey review performed – decision to drill ahead section and use contingency – drop gyro at TD if needed..

Review of Well 01 operation

- *Team unfamiliar with AC method required*
- *Congested field with development planning*
- *Training and Coaching lacking*
- *Low to no team experience in drilling close proximity collision avoidance wells*

Plan was signed by operator and DD supplier

- *No challenge to change of survey program and no TC plots available to plot proximity*
- *No mention of collision avoidance issue in correspondences between town and rig*
- *No STOP Drilling, No MOC raised*
- *Decision to keep to plan, follow Inc / Azi as best as possible*

No Team escalation or decision to stop drilling.

RESULT:

Well 1 was poorly positioned, poorly defined in well directional survey software

Well 2

Conductors were driven deeper than planned and not gyro surveyed

Assumption conductors were all vertical, (not surveyed after driven)

Planned kick off from 30” conductor shoe

New Survey program specification used

Assumption collision can not occur

Instruction to run GWD to take conductor surveys running in hole and continue GWD until feree of magnetic interference switching to reporting MWD as definitive

Modified flow rates with improved BHA tool face

Internal operator, DD and survey review performed –

Travelling cylinders plot contained crossing tolerance lines for offset wells (Well 1 of 3 and planned well 3 of 3)

Decision to drill ahead no MOC performed as Travelling cylinders plot TOLERANCE LINES NOT CROSSED

No Team escalation or decision to stop drilling.

- *No mention of collision avoidance issue in correspondences between town and rig*
- *No STOP Drilling, No MOC raised*
- *Team unfamiliar with AC method*
- *Congested field with development planning*
- *Training and Coaching lacking*
- *Low to no team experience in drilling close proximity collision avoidance wells*

RESULT:

Well 2 was poorly positioned, poorly defined in well directional survey software

Well 3

Well 3 plan expedited due to change in batch drilling

Well 3 plan crossed tolerance line

- Well 1 is closer than planned (conductor gyro surveyed and surface MWD surveys define drilled well)
- Team need to save the slot (Well 3)

Anti-collision situation escalated and communicated

Assumption conductors were all vertical

- Team unfamiliar with AC method / Congested field with development planning
- Training and Coaching lacking

Anti-collision method deemed “busy work”

Projection crossed tolerance line

Well 3 plan collision tolerance increased

Plan signed off by Operator and Supplier

Planned kick off from 30” conductor shoe

Well 3 DD Projection crosses tolerance line

Drilled ahead – MOC limits for controlled drilling 1st stand out of 30” shoe

Cement Returns Trace reported at surface

Drilled ahead – MOC limits for controlled drilling first half of second stand

Cement Returns 20% reported at surface

Drilled ahead – MOC limits for controlled drilling second full stand

Cement Returns 90% reported at surface

Stopped Drilling Due to Well 1 close proximity

RESULT:

Well 3 collided with Well 1

Well 1, 2 and 3 were poorly positioned, poorly defined in well directional survey software

In Summary

Quality controls mostly admin controls which rely on individuals to be highly trained and work without operations bias

Competency excellence is difficult to obtain, needs leadership and courage to STOP the job

Cause(s)

Over bearing operational pressure to drill ahead when STOP the job / stop drilling when failing the collision avoidance drill ahead conditions