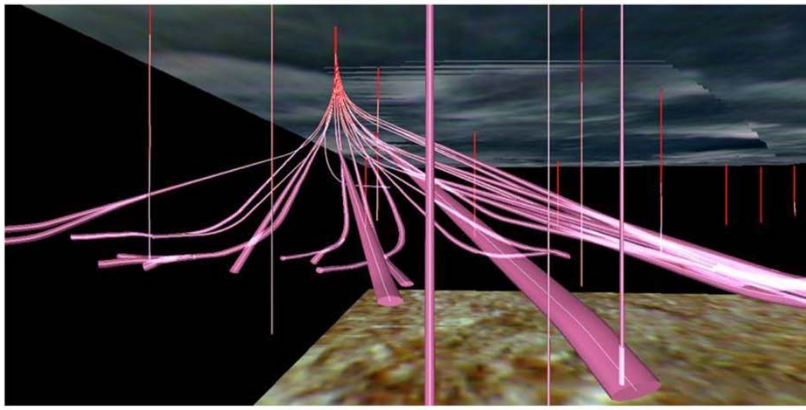
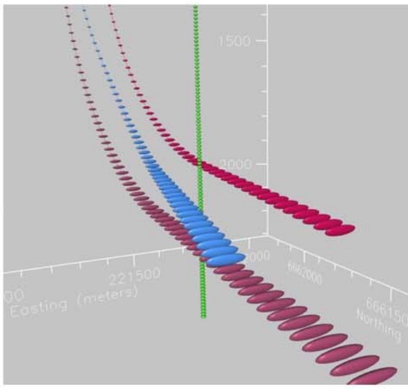
Recommendations for Improvements to Wellbore Surveying and Ranging Regulations

August 2016





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TechRich Consulting

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Final Report

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Notice and Disclaimer

Preparation of this report has been funded by the U.S. Department of Interior, Bureau of Safety and Environmental Enforcement (BSEE) under Contract Number E13PA00010. Information in this report is derived from a variety of sources, including manufacturers and suppliers of wellbore surveying and ranging technologies, as well as from personal communications with experts in the field. This report is not intended, nor can it be relied upon, to create any rights enforceable by any party in litigation with the United States. Mention of trade names, supplier/manufacturer names, or commercial products does not constitute endorsement or recommendation for use.

Executive Summary

The U.S. Department of the Interior (DOI), Bureau of Safety and Environmental Enforcement (BSEE), Technology Assessment Program (TAP), supports research associated with operational safety and pollution prevention in the U.S. Outer Continental Shelf (OCS) to ensure that oil and gas exploration industry operations incorporate the use of the Best Available and Safest Technologies. BSEE engaged ICF International (ICF) under contract E15PB00084 to perform a Wellbore Surveying Technology study to evaluate and catalogue the various operational performance capabilities and limitations of downhole surveying technology/tools, with a focus on greater than 350 degrees F; identify the current best practices, evaluate these technologies and practices; and propose improvements to BSEE regulations as related to wellbore surveying technology associated with surveying accuracy and survey management, as well as relief well/well intersection operations. The work was split into the following seven tasks:

- **Task 1:** Attend a kickoff meeting with the BSEE team.
- **Task 2:** Evaluate and catalogue down hole surveying tools with a focus on 350 degrees F and greater, survey accuracy, and survey management.
- **Task 3:** Identify the current best practices, standards, and regulations at the state and national levels, and make recommendations for improving BSEE's regulations.
- **Task 4:** Provide recommendations for the best methods, processes, procedures, and tools for performing relief well and well intersection operations at 350 degrees F and greater, and to improve survey accuracy and survey management.
- **Task 5:** Identify current ranging technologies, tools, techniques and applications.
- **Task 6:** Prepare a report of the analysis, research, observations, methods, results, and conclusions and recommendations on improving BSEE's regulatory program.
- **Task 7:** Identify future technologies in wellbore surveying, and survey management, and relief well/well intersection operations.

Interim reports for Tasks 2, 3, 4, 5, and 7 were submitted to BSEE as Technical Memoranda as the project progressed. This report incorporates the content from these memoranda and provides a consolidated summary of the findings and recommendations from the study.

Directional Survey and Ranging Technology

Wellbore surveys (directional surveys) are used to steer the bit along a planned wellbore trajectory while drilling or map a wellbore after it has been drilled, using a series of sensors mounted in the lower drilling assemblies. These measurement-while-drilling (MWD) systems are used on essentially all offshore oil and gas wells. Directional survey tools provide measurements to determine the geodetic position of a point or series of points in a wellbore. Directional tools measure the orientation, which includes azimuth, referenced to magnetic or true north, and inclination, which is referenced to the local gravitational field, with down equaling zero degrees. Inclination is measured using accelerometers. Magnetic north is measured by magnetometers, and true north, which coincides with the earth's spin axis, is directly sensed by tools using rate-sensing gyroscopes. Measured depth along the course of the borehole is determined using drill pipe or wireline length. With these three measurements (azimuth, inclination, and depth) the x, y, and z coordinates of a point in a wellbore can be described.

This study identified eight current manufacturers of magnetic directional survey instruments, three of which also offer gyroscopic tools, and catalogued the specifications and attributes of each tool available. One additional company that specializes in gyroscopic tools and services was also identified. These four companies offer high temperature magnetic survey tools which are capable of extended operation at temperatures greater than 350° F/176°C. No gyroscopic tools capable of extended operation at high temperatures were identified.

Ranging tools are used to measure the relative range and bearing to a cased, target borehole (or other ferrous object) from an active borehole, which is being drilled with the objective of intersecting the target borehole (or well). Relief wells are the most widely known type of interception, however, many more intercepting wells are drilled for the purpose of plugging a well before it is abandoned. Ranging systems also are used to guide sidetracks around boreholes that have become plugged with a broken tool or a twisted off drilling tools. Active ranging tools use a transmitter to induce an alternating current (AC) magnetic field in the casing, or other magnetic material, in the target borehole. The induced signal is sensed by magnetometers in the tool and the distance and direction to the target well can be calculated. Passive ranging tools use direct current (DC) magnetometers that are used in magnetic directional tools to sense the distorted local magnetic field created by the target well casing or drill string. Using the field strength measured at several survey points, the distance and direction to the target well can be calculated.

Because the magnetometers used for passive ranging are the same as the ones used in directional surveying, this study found that the directional tool suppliers offered both regular and high temperature passive ranging services. At the time of this report, only one commercially-available, access-independent (meaning access to the target well is not possible or practical), active ranging system suitable for borehole applications was identified.

Directional survey and ranging technology is continually improving. This study identified one new tool, the adaptation of an acoustic logging tool to ranging applications, and a new approach to passive magnetic ranging as emerging tool technologies. The study also found that while the development of high temperature components for directional and gyroscopic tools is possible, it is largely dependent on the market demand, which does not currently support significant investment in these technologies.

The Survey Lifecycle

Survey-related activities performed during the process of drilling an oil and gas well are described as the survey lifecycle and include:

- Wellbore and directional survey planning
- Relief well contingency planning
- Survey operations
- Data management

- Corrections and tool error models
- Anti-collision rules and associated policy
- Survey quality control
- Survey management

Each of these components is critical to the success of the well by ensuring the well is drilled safely and efficiently, placed as planned for optimal resource recovery, and preserves the data collected from surveys. While the components are listed here individually, they are crosscutting and interrelated.

In the planning stage, the wellbore trajectory and directional survey plan is developed to meet the geologic and operational goals. Planning is performed using sophisticated well planning and visualization software that relies on a comprehensive and accurate well database. The most important safety aspect of the planning process is the collision avoidance analysis, in which the proposed wellbore trajectory is evaluated for the presence of nearby wells that could cross the trajectory. Effective collision avoidance requires an accurate understanding of the proposed and nearby wells and a quantitative value of the uncertainty associated with their locations.

During drilling and survey operations, directional data are collected at predetermined intervals (survey stations) and subjected to various quality control (QC) checks. Automated and manual checks are performed in real time and corrections are made to the data to remove the effects of magnetic interferences from the natural environment and drilling tools. An estimate of the positional uncertainty of the x, y, and z location at each survey station is made using a standardized methodology (the tool error model) that is based on tool and well specific information. Drillers use the calculated location and positional uncertainty information to steer the bit to the target (or targets) while avoiding obstacles.

When drilling is completed a final, or definitive, directional survey is prepared and archived in a secure company database, and a copy of the log is submitted to the regulatory agency. Metadata including that associated with the surface location, reference datum, survey tools, applied corrections, tool error models, and all associated parameters, conditions, and operational procedures are preserved along with the definitive survey. Throughout the process there is a continuous assessment of procedures, data quality, data corrections, anti-collision rules, and position uncertainty that is collectively referred to as survey management.

For ranging, each relief well and intercept well operation will have unique conditions that require site-specific analysis and decisions. A common relief well drilling strategy is to obtain an initial range and bearing to the target (the “Locate” phase), then while continually tracking the location of the target well, drill ahead until the target well is within an acceptable range and bearing (the “Track” phase). This sequence is repeated until the range and bearing are acceptable for intercept. The ranging tools are then used to guide the bit for the interception.

Best Practices

The Industry Steering Committee on Wellbore Survey Accuracy (ISCWSA) is a voluntary industry organization that formed in 1995 to improve the awareness and general understanding and application of survey data, associated methodology, and enabling technology. Their mission is to produce and maintain standards for the industry relating to wellbore survey accuracy, set standards for terminology and accuracy specifications, and establish a standard framework for modeling and validation of tool performance. ISCWSA is the only organization to specifically focus on developing best practices for wellbore surveying. Best practices are currently available in the form of position papers and peer reviewed articles from the Society of Petroleum Engineers (SPE) for a number of subjects including collision avoidance, well intercept, error models, well separation calculations and uncertainty calculations for inclination only data. A comprehensive reference manual for all aspects of wellbore surveying is offered as a free e-book by ISCWSA and published by the University of the Highlands and the Islands. ISCWSA is currently preparing American Petroleum Institute (API) Recommended Practice (RP) 78 for Wellbore Surveys, expected to be completed in late 2016. Representatives from the ISCWSA API Committee indicate that many of the areas discussed in this report will be included in the RP.

This study identified more than 25 industry best practices for directional surveying and six best practices for relief and intercept well surveying across the survey lifecycle components of planning, operations, data management, and data quality. The best practices are derived from the ISCWSA and SPE publications and discussions with industry experts.

Regulations

Regulations on wellbore surveying, collision avoidance, survey accuracy, survey management, and relief well/well intersection operations from state and federal jurisdictions in the U.S. as well as international jurisdictions were identified as possible candidates to inform current and possible best regulatory practices. For each topical category related to wellbore survey and relief wells, the regulations for each jurisdiction were identified, and the most stringent regulation was identified. Gaps in regulations for BSEE and the other jurisdictions were also identified.

The following regulatory observations for wellbore surveying, collision avoidance, survey accuracy, survey management, and relief well/well intersection were identified.

- All existing requirements observed (regulation and guidance) were oriented towards specific defined requirements (e.g., frequency of measurements) or specific data elements to be collected or reported. Requirements observed did not include risk-based or performance-based approaches.
- None of the regulations identified rely on industry standards for detailed practices.
- The more detailed approaches often include regulatory reference to more specific guidance, which then becomes *defacto* requirements as a result of the approvals process.
- None of the jurisdictions reviewed identified high temperature environments as a unique condition that requires separate treatment in regulation.
- Only one of the jurisdictions reviewed (Canada) addresses specific requirements for planning or operations in high latitude or arctic drilling conditions.
- Most of the regulations or the implementing guidance documents reviewed specify the survey frequency (survey station interval) or measure frequency, but there is wide variability among the specific frequency requirements.

- Many of the regulations reviewed focus on the requirements for submittal of final data sets, but do not address the elements of survey management including planning, survey quality, errors and corrections or certification and submittal of data.
- There were no noteworthy differences identified between regulations for onshore and offshore jurisdictions as they apply to the scope of this review.
- U.S. state and federal regulations are, in general, badly dated with respect to technology application for survey quality and data management. Most existing regulation, including that of coastal states, was developed for land based drilling operations.

Recommendations

The regulatory improvement recommendations presented in this report are based on and informed by:

- Already existing BSEE requirements,
- Technical and regulatory considerations,
- Regulatory approaches used in other jurisdictions, as they might apply in the context of the BSEE framework, and
- Industry best practices.

Recommendations are categorized as a possible requirement (i.e., a regulation) or guidance to indicate the level of priority and significance that this study believes is appropriate for the action. New actions are recommended in areas where either no regulation or guidance currently exists or in cases where the current action is very general. Improvements to existing regulations and guidance are also recommended to improve, update, or expand the scope of the current action. Some recommendations represent actions for BSEE to consider that do not result in changes to regulations or guidance. The recommendation tables below are structured along each of the survey lifecycle components.

The recommendations recognize that there is an initiative to develop an industry practice for wellbore surveying (American Petroleum Institute Recommended Practice 78, API RP 78) which will cover many of the technical areas identified here. Once the RP is available, BSEE may want to compare the recommendations in this report against the API RP.

Table ES-1: Recommendations for Wellbore Planning

Recommendations for Wellbore Planning	
Area/Subarea	**Recommendation**
Directional Survey Program	**New Requirement** The operator must develop a wellbore survey program that includes a written plan that identifies each directional survey tool or tool type to be used for each section of the wellbore, and the rationale for selection. The plan must address the specific conditions expected to be encountered in the proposed well(s), and identify how the operator will comply with the wellbore survey regulations. The plan must be submitted with the Application for Permit to Drill (APD), and be available for inspection at the well by BSEE, if requested.
Survey Data Quality Checks	**New Guidance** Quality control procedures for ensuring accurate measurement, such as taking check and rotational check surveys, should be included in the Directional Survey Program.
Standby Tools	**New Guidance** The need for standby tools should be assessed in light of tool performance specifications and the expected operating conditions. If standby tools are not to be available at the rig site, the procedures and transit times for obtaining them should be identified and documented. The standby tool policy should be included in the Directional Survey Program.
Elevated Borehole Temperatures	**New Guidance** Expected borehole temperatures should be identified and considered in the selection of MWD and survey tools. If temperatures are expected to approach or exceed the operating temperatures of any tools, means of reducing borehole temperatures (circulating and/or cooling the mud) and/or reducing the tools' exposure to elevated temperatures (dewars) should be considered and documented in the well survey plan.
Minimum Graphics Standard for Well Trajectory Plan	**Improvement of existing requirement** Operators must provide a legible copy of the graphical representation of the proposed well trajectory in the APD. The figure must show the well in plan and vertical section view and identify true north, map north and grid north, convergence and declination angles, and all datum and grid systems presented. The plot should identify any section of the well trajectory in which the dogleg severity is greater than 5 degrees.
Certification of Well Planner on Plan Submitted with APD	**New Requirement** The APD must include a statement of certification from the well planner indicating that the plan was developed in accordance with best industry practices, includes a collision avoidance analysis, and reflects the safety and environmental conditions anticipated in the drilling of the well.

Recommendations for Wellbore Planning	
Area/Subarea	**Recommendation**
Anti-Collision Analysis	**New Requirement** The operator must conduct an anti-collision scan for the proposed well consistent with best industry practices. The well database used for the scan must represent the best and most complete data available for all wells likely to be in the area of review. A summary of the results of the anti-collision analysis must be included in the wellbore survey plan.
Anti-Collision Rules	**New Requirement** The drilling plan in the APD must describe the rules that will be followed for collision avoidance during drilling, including well separation criteria and the associated actions to be taken during drilling for the proposed and offset wells.
High Temperature Surveys	**New Guidance** The operator should clearly identify if any part of the well that will be drilled under high temperature conditions (350°F or greater) and incorporate the effects of high temperature into equipment selection for any data collection activity. The analysis should address the well plan as well as the contingency plan for relief wells.
Well Planning Software	**New Requirement** Software used for well planning must have functionality to produce required formats for reporting and database retention.

Table ES-2: Recommendations for Relief Well Survey Planning

Recommendations for Relief Well Survey Planning	
Area/Subarea	**Recommendation**
Relief and Intercept Well Planning	**New Requirement** The operator must prepare a wellbore survey and ranging plan for each relief well proposed in the contingency plan. The plan must identify each directional survey and ranging tool or tool type to be used for each section of the wellbore, and the rationale for selection, including availability. The plan should address the expected conditions to be encountered in the proposed well (including temperature, difficult ranging conditions [i.e., salt] and magnetic interferences), recognizing that actual conditions may be different at the time of drilling the relief well. The plan must be submitted with the APD, and must be available for inspection at the drilling site by BSEE, if requested.

Table ES-3: Recommendations for Survey Operations

Recommendations for Survey Operations	
Area/Subarea	**Recommendation**
Survey Tool Functional Tests	**New Requirement** Before a survey tool is added to the BHA or tripped downhole, the operator must ensure that all survey tools are calibrated in accordance to their standard calibration procedures. This may include passing the simple, functional tests (i.e., roll test) recommended by the manufacturer.
Continuous Monitoring for Collision Risk	**New Requirement** During drilling, the wellbore must be continuously monitored for collision risk using the approach described in the anti-collision portion of the directional survey plan. The monitoring approach may include a traveling cylinder, ladder plot, three-dimensional visualization, or other real-time analysis of downhole data to evaluate collision risk.
Monitoring Borehole Conditions while Surveying	**New Requirement** During drilling and survey operations, any borehole condition that may affect the quality and accuracy of survey measurements must be monitored on a regular basis. This may include, but is not limited to, monitoring temperature, total magnetic field, dogleg severity, hole size, and hole rugosity.
Survey Station Interval	**Improvement of existing requirement** In boreholes, directional survey measurements must be collected at an interval that ensures an accurate wellbore trajectory is recorded. The survey station interval shall be no greater than 100 feet. In hole sections with dogleg severity greater than 5 degrees, the operator should establish a more frequent survey station interval that ensures accurate representation of the borehole.
Survey Calculations	**New Requirement** The standard for directional survey calculation shall be the Minimum Curvature Method with straight line extrapolation acceptable from last data point in survey to Total Measured Depth.
Survey Concatenation	**New Requirement** In the definitive survey, each depth point shall have a unique and single set of survey data associated with it, and no interpolated, projected, or estimated data shall be included in the definitive survey. Tie-in points for where two subsequent surveys are connected and methods for propagation and concatenation of ellipses shall be identified.
Definitive Survey	**Improvement of existing requirements** Change the term “Composite Survey” or “Final Survey” to “Definitive Survey” in all BSEE regulations and guidance.

Table ES-4: Recommendations for Data Management

Recommendations for Data Management	
Area/Subarea	**Recommendation**
Database Completeness	**New Guidance** The master database used for collision avoidance should represent the best and most complete well data available. It should be checked for accuracy and thoroughness and stored in a manner that preserves the integrity of the data. The database should include all drilled segments of each well identified
Data Submittal Requirements (Header Information)	**Improvement of existing guidance** Data submitted to regulators for the permanent record must include a comprehensive set of header information that clearly identifies all positional information and datum, along with other information that can be used to accurately recreate the well location and survey data.
Composite or Final Survey	**No new or revised guidance or requirement recommended** The current requirement for submission of the Definitive Survey currently required from offshore operators appears to be appropriate.
Re-submission of Surveys	**New Guidance** Operators should be encouraged to resubmit corrected well position and directional survey data to BSEE to improve the overall data quality of the regulatory database. The resubmittal should include a brief explanation of why the re-submitted data are more accurate and representative than the existing BSEE data.
Data Transfer/Electronic Data Content	**Improvement of existing requirement/guidance** BSEE should consider the use of an existing standard data format instead of the current MMS format for reporting directional survey data. An example of such a format is UKOOA P7 Data Exchange.

Table ES-5: Recommendations for Data Quality

Recommendations for Data Quality	
Area/Subarea	**Recommendation**
Certification of Survey Accuracy and Qualifications of Wellbore Survey Specialists	**New Requirement** Operators shall provide written certification that the directional survey data they are submitting accurately represents the wellbore trajectory and conforms to the calibration standards and operational procedures set forth by the MWD/directional survey company, and best industry practice. The person certifying the data must be an independent reviewer, such as a third-party survey management organization from either within or outside the operating company. The certification must state the reviewer is authorized and qualified to review the data, calculations, and report.
Corrections Made to Magnetic Survey Station Data	**New Requirement** The definitive survey must provide an accurate representation of the borehole trajectory and include corrections for physical effects on the MWD tools including sag, local magnetic field, and magnetic interference from the BHA where these effects are greater than the allowable error in the standard ISCWSA tool error model. All corrections applied must be noted in the metadata file submitted with the survey data.
Depth Measurements	**New Guidance** Depth measurements should be corrected to account for pipe stretch and other factors that may result in significant depth error (greater than 1 foot per 1,000 feet). Physical measurements (strapping and pipe tally) should be checked for accuracy, if possible.
Actions to Improve Accuracy and Reduce Uncertainty in Survey Data	**New Guidance** Operators should apply the correct tool error model (instrument performance model) and data quality improvement methods to accurately quantify the uncertainty of the borehole location at each survey point. Methods may include, but are not limited to, Multi-Station Analysis, and other methods generally accepted in the industry. Tool error models must be consistent with the framework for tool error models set by ISCWSA, and the operating conditions of the survey must meet the minimum conditions for a valid error model set by ISCWSA.
Quality Control Tests During Survey Operations (Requirement)	**New Requirement** BSEE may require specific quality control activities during the survey, including but limited to check shots, rotational shots, and repeat surveys at various depths, to ensure the data quality of surveys. BSEE may also require two different survey tools to be run over the same interval to evaluate the variability of the resultant wellbore position. Ideally, the tools would be based on different measurement physics. This requirement will be a stipulation on the approved APD on a case-by-case basis.

Recommendations for Data Quality	
Area/Subarea	**Recommendation**
Survey Management	**New Guidance** Operators should ensure the data used for decision making during drilling, and the data submitted to BSEE is an accurate representation of the trajectory of the borehole and accurately represents the uncertainty in the borehole location. Operators should follow the best practices for survey management to ensure the quality of the data.
Redundant Surveys	**New Guidance** In situations where the precise location of a borehole is important, the use of redundant surveys with both magnetic and gyro-based tools should be considered. (i.e., where wells are present nearby and may create a collision hazard, high dogleg severity sections, obstacle avoidance, close proximity to lease lines, or small driller's target)

Table ES-6: Recommendations for Relief and Intercept Wells

Recommendations for Relief and Intercept Wells	
Area/Subarea	**Recommendation**
Relief and Intercept Well Planning	Planning recommendations for relief and intercept wells are included in Table ES-2.
Drilling Efficiency/ Measurements While Rotating	**New Guidance** When selecting MWD tools, operators should consider the added efficiency that might result from obtaining directional measurements while drilling, but also be aware of the effect on uncertainty calculations.
Drilling Efficiency/Running a Mud Motor in Tandem with a Rotary-Steerable System (RSS)	**New Guidance** When selecting drilling methods for relief wells, operators should consider adding a mud motor above an RSS, which will increase the power available to the bit and increase the rate of penetration.
Survey Interval and Accuracy (Relief Well)	**New Guidance** During relief well drilling operations directional survey data should be collected at an interval and level of accuracy such that the position of the well is known at all times and will never approach the target well with a separation factor less than one (1) before ranging.

Recommendations for Relief and Intercept Wells	
Area/Subarea	**Recommendation**
Data Management for Ranging Results	**New Requirement** If ranging results indicate that the original (target) wellbore trajectory or surface location can be more accurately described than the existing data managed by BSEE, the operator must submit the updated definitive survey and revised surface location data to BSEE in accordance with data submittal requirements. The revised submittal must describe why the new data are considered more accurate than the existing data in the BSEE database.

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Acronyms

AC	Alternating Current
ALARP	As low as reasonably practicable
ANSI	American National Standards Association
APD	Application for Permit to Drill
API	American Petroleum Institute
ATSM	American Society for Testing and Materials (now ASTM International)
BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
BHA	Bottom Hole Assembly
CMOS	Complementary metal oxide semiconductor
DC	Direct Current
DOI	U.S. Department of Interior
DGPS	Differential Global Positioning System
FAC	Field Acceptance Criteria
GMWD	Gyro-based Measurement-While-Drilling
GOM	Gulf of Mexico
HSE	Health, Safety, and Environment
HT	High Temperature
IADC	International Association of Drilling Contractors
ID	Inside Diameter
IPM	Instrument Performance Model
IRF	International Regulators Forum
ISCWSA	Industry Steering Committee on Wellbore Survey Accuracy
ISO	International Standards Organization
IWFC	International Well Control Forum
LCM	Lost circulation material
LWD	Logging While Drilling
MAE	Major accident event
MASD	Minimum acceptable separation distance
MD	Measured Depth
MEMS	Micro-electromechanical systems
MMS	Minerals Management Service
MSA	Multi-station analysis

MSL	Mean Sea Level
MWD	Measurement While Drilling
OCS	Outer Continental Shelf
OD	Outside Diameter
OWSG	Operators Wellbore Survey Group
PPDM	Professional Petroleum Data Management
psi	Pounds per square inch
QC	Quality Control
RP	Recommended Practice
RSS	Rotary-Steerable System
SAGD	Steam-assisted gravity-drainage
SCE	Safety Critical Element
SEMS	Safety and Environmental Management System
SOI	Silicon-on-insulator
SPE	Society of Petroleum Engineers
SPWLA	Society of Petrophysicists and Well Log Analysts
TAP	Technology Assessment Program
TD	Total Depth
TVD	True Vertical Depth
UHI	University of the Highlands and Islands
UTM	Universal Transverse Mercator
WITSML	Wellsite Information Transfer Standard Markup Language

1. Introduction

1.1. Background

The mission of the Bureau of Safety and Environmental Enforcement (BSEE) is to promote safety, protect the environment, and conserve resources offshore through regulatory oversight and enforcement. Through its Technology Assessment Program (TAP), BSEE supports research related to operational safety and pollution prevention to provide engineering support to BSEE decision makers, to promote the use of Best Available and Safest Technologies, and to coordinate international research.

Wellbore surveys (directional surveys) employ sensors in oil and gas drilling assemblies, or run independently of drilling, to provide data which is used to determine the position of a wellbore or to steer a drilling assembly in three-dimensional space. A survey measurement typically includes the depth of the point along the course of the borehole (measured depth), the inclination at the point, and the azimuth at the point. These three components are used to calculate the position of the wellbore. A survey report is the compilation of a series of positional calculations (northings, eastings, and vertical depth) listed in association with the survey measurement components.

In addition to steering the bit, wellbore surveying technology and services are used in collision avoidance and relief well drilling/well intersection operations. Ranging uses a special set of tools and services to identify the proximity and direction of nearby wellbores to the wellbore being drilled.

As drilling continues in more hostile and unknown environments, the technology required to conduct surveys and intersect a blowout well may be limited as a result of the tool capabilities.

1.2. Study Objectives

The Wellbore Survey Technology study was undertaken to improve BSEE’s ability to understand the operational performance capabilities and limitations of downhole surveying and ranging technology and operational practices. This knowledge will be used to enhance BSEE’s regulations as related to wellbore surveying technology associated with surveying accuracy and survey management, as well as relief well/well intersection operations. The study included seven tasks to meet the project objectives:

- **Task 1:** Attend a kickoff meeting with BSEE team members including project management, technical, and contracting staff.
- **Task 2:** Evaluate and catalogue the various operational performance capabilities, characteristics, and limitations of down hole surveying technology/tools with a focus on 350 degrees F and greater, survey accuracy, survey management, and other properties which may limit wellbore surveying, steering, and ranging applications.
- **Task 3:** Identify the current best practices, standards, and regulations at the state and national levels, and make recommendations for improving BSEE’s regulations on wellbore surveying, collision avoidance, survey accuracy, survey management, and relief well/well intersection operations.

- **Task 4:** Recommendations for the best methods, processes, procedures, and tools/technologies to use; for performing relief well and well intersection operations at 350 degrees F (176° C) and greater; to improve survey accuracy and survey management; and other properties which may limit ranging technology.
- **Task 5:** Identify current ranging technologies, tools, techniques, and applications that are used in wellbore surveying.
- **Task 6:** Prepare Draft and Final reports of the analysis, research, observations, methods, results, and conclusions, where applicable; and provide BSEE with the results of this work and recommendations on improving our regulatory program, as appropriate.
- **Task 7:** Research, identify, and categorize future technologies, capabilities, practices, process, procedures, and equipment that will improve wellbore surveying accuracy and survey management, as well as relief well/well intersection operations.

1.3. Methodology

The general approach to this study involved three sequential steps:

- Develop an understanding of the tools, technologies, and methods for wellbore surveying and ranging.
- Review current industry best practices and state, federal, and international regulations related to wellbore surveying and ranging. Develop a list of potentially applicable regulatory areas and evaluate current BSEE regulations to identify gaps in regulations and guidance compared to best practice and other jurisdictions.
- Develop recommendations for improving and enhancing the current BSEE regulations and guidance for wellbore surveying.

The technical information presented in this report was gathered from several sources including publications, product literature, discussions with industry experts, and technical workshops attended by the report authors. Initial understanding of the subjects was obtained through professional papers primarily published through the Society of Petroleum Engineers (SPE) and affiliated organizations including the International Association of Drilling Contractors (IADC) and Society of Petrophysicists and Well Log Analysts (SPWLA). Introduction to Wellbore Surveying, a comprehensive resource on wellbore survey techniques published by University of the Highlands and Islands and the International Steering Committee on Wellbore Survey Accuracy (ISCWSA), now a technical section of SPE, also served as a basic reference. Additional technical resources include position papers and recommendations by ISCWSA, industry publications (World Oil, Schlumberger Oilfield Review, Oil & Gas Journal), technical presentations by industry experts, and technical specifications from published product literature.

ICF contacted or received information from the following firms on various aspects of this report: Abel Engineering, add Energy LLC, APS Technology, Baker Hughes, Bench Tree, BP, Copsegrove Developments Ltd., Devon Energy, Digital Graphics, Inc., Enteq Drilling (including XXT and KMS), GE Oil & Gas, Global QC Survey Management, Gyrodata, Halliburton/Sperry Drilling, MagVAR Inc., National Oilwell Varco, Noble Energy, Schlumberger, Scientific Drilling International, Superior QC, SURCON, Vector Magnetics

LLC, Weatherford International, Inc., Applied Physics Systems, Honeywell, JAE, QDC Technology, Stephan Mayer Instruments, TIAX LLC, and Wild Well Control. BSEE and the report authors appreciate the detailed and candid input provided by the extremely knowledgeable and helpful staff from all of these companies.

Regulations for federal and state jurisdictions were identified for BSEE and the Bureau of Land Management (BLM), and states with significant oil and gas production. The 12 International Regulators Forum (IRF) members were the initial list of international jurisdictions. The IRF is a group of 12 regulators of health and safety in the offshore upstream oil and gas industry.

Industry best practices were identified primarily though position papers and initiatives by ISCWSA and SPE papers published by ISCWSA members. Interviews and discussions with industry experts were used to supplement the published information.

1.4. Report Organization

This report provides recommendations for improving current BSEE regulations and guidance in wellbore surveying and ranging. To provide context for the recommendations, the report introduces wellbore directional survey and ranging methods and the practices and regulations that are applied during operations. The report assumes that the reader has a basic understanding of offshore drilling operations.

- **Section 1** is an introduction to the report and describes the purpose of the project, the approach, and a description of how the report is organized.
- **Section 2** discusses the hardware and measurements systems used in directional surveying and ranging and includes discussion of standard and high temperature tool categories. Emerging technologies for hardware (tools, sensors, and system components) are also presented.
- **Section 3** introduces the lifecycle components of directional surveys and ranging including planning, operations, data management, errors and corrections, and survey quality control. New methods and trends in the survey lifecycle are also presented.
- **Section 4** describes the current best practices used in directional surveying and ranging. A summary of the state, federal, and selected international regulations related to wellbore surveying and ranging is also presented.
- **Section 5** provides recommendations for improving the current BSEE regulations in the areas of directional surveying and ranging. The recommendations are based on resolving the gaps between current regulations and the best practices and regulations in other jurisdictions.
- **Section 6** provides bibliographic references for the cited documents.

The Attachments include additional detailed technical material to support the summaries presented in the body of the report. Additional technical information and summaries include:

- **Attachment A:** Tool Descriptions and Lifecycle Components of Directional Surveys and Ranging
- **Attachment B:** Future Technologies for Tools and Lifecycle Components of Directional Surveys and Ranging
- **Attachment C:** Summary of Regulations in State, Federal, and Selected International Jurisdictions

2. Directional Survey and Ranging Tools

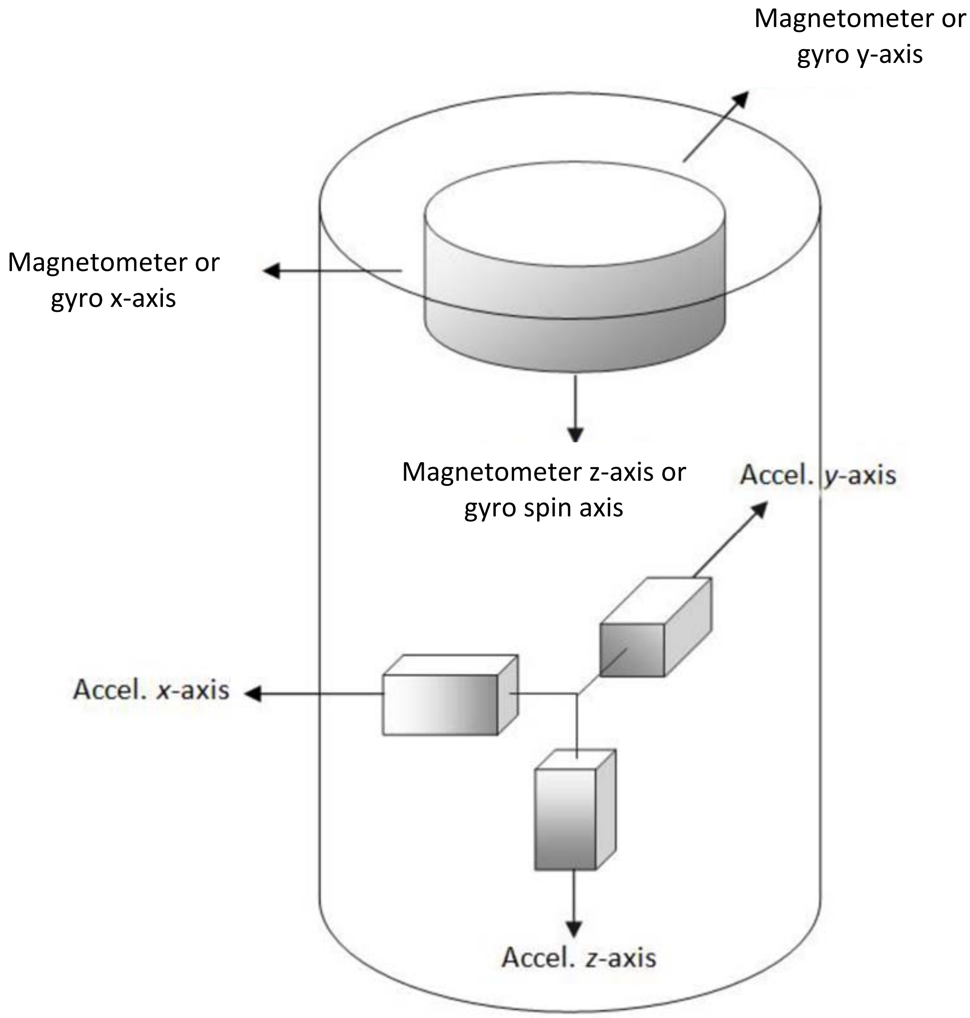
2.1. General Description of Survey and Ranging Tools

This section introduces the tools used in directional surveys and ranging along with their operating characteristics, key features, and subsystems. These tools and measurements form the basis of the data that are used to guide and safely drill an offshore oil and gas well, and efficiently extract valuable minerals from the reservoir. The content of this section is summarized from a Technical Memorandum prepared as an interim work product for this study. The complete Technical Memorandum, provided in Attachment A, contains more detailed descriptions and technical specifications for individual tools and tool systems that are currently available in the offshore well drilling industry.

Two types of tools were evaluated in this project.

- **Directional Survey Tools** provide measurements used to determine the position of a bottom-hole assembly (BHA) or a location along a borehole with respect to the local gravitational and magnetic fields or the local gravitational field and true north (Figure 1). At any point in the borehole the position can be described in terms of its azimuth, inclination, and depth. Directional tools measure the orientation, which includes azimuth, referenced to magnetic or true north, and inclination, which is referenced to the local gravitational field, with down equaling zero degrees. Thus, the azimuth of a tool at 0^{o} inclination is indeterminate. Measured depth along the course of the borehole also is needed to determine position. Inclination is measured using accelerometers. Magnetic north is measured by magnetometers, and true north, which coincides with the earth's spin axis, is directly sensed by tools using rate-sensing gyroscopes. Older generations of gyroscope-based directional tools use other methods and are not within the scope of this study. The measurements, or "surveys," are made by either measurement-while-drilling (MWD) systems or separately run survey tools, but are essentially the same. Magnetic MWD systems are usually called "MWD" systems, while Gyro-based Measurement-While-Drilling are known as "GMWD" tools or systems. ("GWD" is a trademark of Gyrodata and is in the name used for their GMWD tools and modules.)
- **Ranging Tools** determine the direction and distance (range) from the tool, in an active borehole and a target, which often is an already-drilled and cased borehole. Active ranging tools use a transmitter to induce an alternating current (AC) magnetic field in the casing, or other magnetic material, in the target borehole. By sensing the induced field from different locations, it is possible to locate the target with respect to the AC magnetometers in the ranging tool. Passive ranging tools determine the direction and distance to a target by determining how the magnetic materials in the target have distorted the earth's magnetic field. By "overlaying" multiple measurements along a known path, it is possible to construct a model of the target, since the distance between its magnetic poles is known. (Each joint of pipe or casing will have a north and a south pole.) Passive ranging tools use direct current (DC) magnetometers that are used in magnetic directional tools to sense the local magnetic field and accelerometers to determine inclination.

Figure 1: Sensor Configuration in a Directional Survey Tool



Modified from Introduction to Wellbore Surveying ISCWSA, 2016b

Directional measurements normally are used to steer a borehole while it is being drilled, or plot the trajectory after it has been drilled. Usually, MWD systems are used to make such measurements while drilling to enable a directional driller to steer or direct the bit to specified targets, which requires the ability to determine the change in toolface[1] direction that is caused by reactive torque produced by the rotating bit. Surveys can also be conducted when drilling ceases using survey tools conveyed with wireline or through the drill pipe.

[1] Toolface is the angle of the borehole survey instrument within the wellbore measured clockwise relative to up and in the plane perpendicular to the wellbore axis; the high side (maximum build), maximum right, low side (maximum drop) and maximum left directions have gravity toolface angles of 0°, 90°, 180° and 270°, respectively. (from Schlumberger Oilfield Glossary)

2.1.1. Directional Survey Technology Overview

During the last 50 years, the sensors and recording methods used for borehole directional measurements have changed dramatically. Before the introduction of microprocessors and solid-state memory, data gathered by directional instruments and tools were either acquired and stored photographically, on black-and-white film, or were transmitted to the surface on a wireline cable. Early generations of directional tools employed mechanical compasses and inclinometers, whose orientations inside the tool were recorded on film. Single shot instruments took only a single picture, using a disk of film. Multi-shot tools took multiple pictures at timed intervals on a strip of film. Determining the measured inclinations and azimuths required retrieving these instruments, extracting the film, developing it, and “reading” the pictures using special viewers. Obviously, such measurements could not be made while drilling.

As microprocessors and solid-state memory became available and were accepted in borehole applications, film-based single-shot and multi-shot instruments were replaced by electronic multi-shots. The use of microprocessors enabled new operating modes, different data transmission protocols, and new error-checking procedures. Teleco Oilfield Services offered the first commercial MWD services in 1978. As the reliability and market acceptance of MWD tools grew in the 1980’s the industry expanded and new tools were developed to address the more challenging situations faced by operators. Today, essentially all offshore wells and a large number of directionally drilled onshore wells use MWD or gyro measurements to safely and effectively drill wells.

Directional survey tools can be deployed in one of three modes.

- Wireline tools are normally run into boreholes after the drill string has been removed (“tripped out”). The need to trip out and trip in (travel back into the hole) with the drill string adds substantially to the rig time needed to run wireline tools. Many gyro tools are wireline deployed. The only commercially-available active ranging system is a wireline tool.
- Drop tools are dropped inside drill pipe, free fall through drilling mud, and come to rest at a predetermined location near the bottom of the hole, usually on a landing special tool sub. Drop tools are programmed to take and store surveys at fixed time intervals. Normally, they are dropped before tripping out of the borehole and are used to obtain directional surveys while each stand of drill pipe is broken off and racked. Drop tools store data internally, so it is available only after the BHA has been brought to the surface. Some drop tools are deployed on “slick lines” which are small diameter non-conducting wire that is used to deploy and retrieve battery powered tools.
- MWD tools are run inside special, non-magnetic collars above the bit in the BHA or, if a mud motor or rotary-steerable system (RSS) is in the BHA, just above them as shown in Figure 2. Some MWD systems can be tripped in and out, inside the drill pipe. Others are permanently mounted in their non-magnetic collar. These tools rapidly penetrated most high-cost drilling projects (many of which are in offshore locations) during the 1980’s. Their acceptance has been become even greater in recent years, as reliable RSS were developed, brought to the market, and proven. As with wireline tools, there are versions of MWD tools that also measure formation properties. They are usually created by adding logging sensors to directional MWD

systems, and are called Logging-while-drilling (LWD) tools. LWD tools are outside the scope of this study.

Table 1 highlights the key components of the directional and ranging tools, including how they store or transmit data, their power sources, and directional sensors.

Table 1: Attributes of Directional and Ranging Tools

		Directional Tools		Ranging Tools	
		Magnetic	Gyroscopic	Active	Passive
Data transmission/storage					
	Solid-state memory	D, M	D, M		M
	Wireline Telemetry	W	W	W	
	Mud Pulse telemetry	M	M		M
Power supply					
	Battery	D	D		
	Wireline		W	W	
	Turbine-Generator	M	M		M
Sensors					
	Accelerometers	D, W, M	D, W, M	W	M
	Rate-sensing Gyroscopes		D, W, M		
	Magnetometers-AC			W	
	Magnetometers-DC	D, W, M			M

Tool Types		
	Drop/Slickline	D
	Wireline	W
	MWD	M

MWD tools transmit their data and/or measurements to the surface through drilling fluid (mud), using pulses, or electromagnetically, through the earth. Electromagnetic MWD tools offer higher bandwidths, but are limited in range by the electrical impedances of the formations between the tool and the surface. MWD tools that transmit acoustically through mud are usually called “mud pulse” tools. This is an oversimplification, since there are three types of mud pulse telemetry:

- Positive mud pulse systems produce pressure pulses by restricting the flow of drilling mud, with a poppet or shear valve;
- Negative mud pulse systems produce pulses by venting mud from the inside (bore) of the tool into annulus, thereby lowering the pressure within the drill pipe; and
- Continuous-wave mud pulse systems (also known as mud sirens) produce a continuous, low-frequency acoustic carrier and transmit data by changing its phase.

As mentioned above, wireline tools use conductors in the electrical cable to transmit their data to the surface. Because the bandwidth of typical logging cables is thousands of times greater that the bandwidth of mud-pulse systems, this transmission speed provides some compensation for the time lost while tripping the drill pipe and BHA out and back in to run a wireline tool.

Over the last 40+ years various borehole telemetry systems that use wired drill pipe have been developed, tested, and promoted. One supplier has such a system available today. Because it only recently has become a commercial product and has limited availability, it is not included in this study. However, MWD and GMWD tools that can be used with this system are included.

Figure 2: Typical BHA Configuration with MWD & GMWD

From Gyrodata Inc. reproduced with permission

2.2. MWD Tools

The tools described and analyzed in this study include “Standard” MWD and GMWD tools, which can be used when borehole temperatures are 350° F (176° C) or below, and “High Temperature” tools, which are capable of operating at borehole temperatures above 350°F (176° C) for extended periods of time.

Following are generic descriptions of the available instruments and tools to provide a general understanding of their capabilities, alternative configurations, and limitations. More detailed descriptions, which document and compare specific tools that are available from different suppliers, are included in the Technical Memoranda in Attachment A.

2.2.1. Available Standard MWD Tools

The study identified eight suppliers of standard MWD tools. The key attributes in the following groups were evaluated: Platforms; Communications & Operating Modes; Environmental Limitations; Directional Measurements; Survey Times; Power Sources & LCM; and Gamma, Other Measurements & Maturity. Table 2 provides a summary of the standard MWD tools discussed below. Attachment A provides specifications and additional technical details on the individual tools. The directional measurements provided by all the MWD systems documented include:

- Inclination, measured by three orthogonally-mounted accelerometers;
- Azimuth, or direction in the horizontal plane, referenced to the earth’s magnetic field (magnetic MWD) or the earth’s spin axis (gyro-based MWD, or GMWD);
    - Magnetic MWD systems use three orthogonally-mounted magnetometers to sense the three components of the earth’s field.
    - Most GMWD systems use a single tuned-rotor, rate gyro to sense angular acceleration around the two axes (“X” and “Y”) that are parallel to the tool’s longitudinal axis (“Z”). One vendor recently has introduced a GMWD system that uses two rate gyros, so it is capable of sensing angular acceleration around all three axes, making it a full-inclination-range tool.

Table 2: Available Standard MWD Tools

Supplier	Model	Description	Nom. O.D. (min)
APS Technology	SureShot MWD	Retrievable MWD/LWD in Std. collar	3.125"
Baker Hughes	OnTrak HT-175	Integrated MWD & LWD system	4.75"
Bench Tree	MWD Kit	Retrievable MWD probe, 1.875" diameter	3.5"
GE Oil & Gas	Tensor MWD	Retrievable MWD/LWD in Std. collar: 1.875" dia.	3.5"
Halliburton/SD	SOLAR MWD/LWD	Collar-based hostile-environment M/LWD system	4.75"
Schlumberger	HDS-1L	Fixed-collar directional service	4.75"
Scientific Drilling	Falcon MWD	Std. collar below Pulser Sub	3.125"
Weatherford	HyperPulse MWD	Probe-based MWD tool: 1.6875" dia.	3.0625"

Many of the MWD and GMWD tools included in this report provide measurements in addition to those listed above. These normally fall into two groups: drilling dynamics and formation evaluation. Drilling dynamics measurements might include vibration, bit or mud motor RPM, torque, annular pressure and/or temperature, and caliper (borehole diameter). Gamma radiation (omnidirectional, focused, or azimuthal) is the most frequently offered formation evaluation measurement, since it is has been used to identify formation boundaries and, more recently, for geosteering. Other formation evaluation measurements offered include resistivity and porosity (typically sonic). The tables presented in Attachment A list the other measurements offered by suppliers of the MWD and GMWD tools listed.

One significant difference between the eight manufacturers whose tools have been included is that three of them, APS Technology, Bench Tree, and GE Oil & Gas, function largely as manufacturers and sell their systems to service providers. The remaining five, Baker-Hughes, Halliburton, Schlumberger, Scientific Drilling, and Weatherford are service companies that design and manufacture most of their own tools, although some systems are sourced from other suppliers.

All of the MWD systems employ positive mud pulse telemetry, although there are some differences. The APS Technology and Baker Hughes' systems use rotary shear valves, which can adapt their pulse widths to conditions in the field. The Schlumberger tool uses a rotary valve, which has been called a "mud siren." It establishes a fixed-frequency, carrier wave, which is then phase modulated.

All of the tools offer a downlink, which is used to communicate from the surface to an MWD tool while it is in the hole. The availability of a downlink may indicate that a tool can be commanded into a different mode to increase or reduce the number of data items that are captured during surveys and subsequently transmitted. It may also provide an ability to change the transmission or encoding modes to improve the reliability of data received on the surface or reduce the transmission time.

The ability to run MWD and GMWD tools in tandem may offer an advantage in situations where a well is being kicked off near other wells. GMWD tools can be run in the upper part of the hole because they are not affected by the magnetic interference. Once the wells achieve sufficient displacement to avoid magnetic interference, the tool can switch over to magnetic measurements. Five of the suppliers offered this feature.

The accuracy and resolution specifications for available, standard MWD tools were reviewed. The azimuth accuracy ranged from 0.25° to 1°, and the inclination accuracy ranged from 0.1° to 0.2°. All MWD systems are capable of also making directional measurements while drilling, although at reduced accuracy.

Survey time may be an important consideration when selecting MWD tools for some operators due to the cost of non-productive rig time during the survey, especially in deep or long lateral holes. The tool manufacturers were asked to provide estimates of the amounts of time needed to conduct and transmit their standard short (azimuth, inclination, and toolface measurements only) and long directional surveys (compensated values from all six directional sensors in addition to other measured variables) from a "test well" meeting the specific criteria. Survey times were provided by five of the manufacturers and ranged from 65 seconds to 192 seconds for short surveys and 76 seconds to 326 seconds for the long surveys. The acoustic properties of the drilling fluid (especially viscosity), attenuation with depth, pressure drop below the pulser, and the amount of noise in the mud system have significant impacts and can overwhelm any differences between tools.

Standard MWD tools are powered by either battery or mud turbine generators. Battery life is an important consideration in tool selection and is dependent on the number and frequency of surveys performed. Five manufactures reported battery life, which ranged from 180 hours to over 800 hours on standard battery packs. The addition of lost circulation material (LCM) in drilling mud can affect tool performance, however our study indicated that most tools claim tolerance of between 40 and 50 pounds of LCM per barrel of mud.

2.2.2. Available Gyro-based MWD (GMWD) Tools

Rate-gyro-based surveying systems are inherently more complicated, with many more moving parts than magnetic surveying systems. This complexity inhibited their use in downhole systems that were exposed to the shocks and vibration caused by operating bits and mud motors. However, as component suppliers and system developers gained experience, gyro-based systems became more rugged, and ultimately were proven in while-drilling applications. Today, Gyrodata and Scientific Drilling are the major manufacturers and suppliers of rate-gyro-based directional modules that can be run with other manufacturers' data acquisition, control, and telemetry systems. Suppliers beyond those whose systems are listed in the tables in Attachment A (Baker Hughes, Schlumberger, and Weatherford) advertise gyro-based MWD systems, but have not responded to requests for information. A summary of the available GMWD tools is presented in Table 3 below.

Table 3: Available GMWD Tools

Supplier	Model	Description	Nom. O.D. (min)
Gyrodata	Gyro-Guide GWD40	Probe-based tool: 1.875" O.D. X 18'	
Gyrodata	Gyro-Guide GWD70	Probe-based tool: 1.875" O.D. X 18'	
Gyrodata	Gyro-Guide GWD90	Probe-based tool: 1.875" O.D. X 18'	
Halliburton/SD	Evader MWD Gyro	Collar-based M/LWD system	4.75"
Scientific Drilling	gyroMWD	Module below Pulser Sub - 1.75" O.D.	3.125"
Scientific Drilling	gyroMWD Module	Module added to 3rd party MWD	3.125"

Attributes of gyro-based MWD tools are similar to MWD tools in many areas, including telemetry systems, downlink capability, and LCM tolerance. However, there are notable differences in accuracy, survey time, and battery life.

Gyros are generally regarded as having better accuracy and resolution than traditional magnetics-based MWD tools. The azimuthal accuracy ranges from 0.15° to 1°. One consideration for gyro-based tools is they can be affected by the inclination angle. Maximum inclination angles range from 40 to 105 degrees for most tools, however Gyrodata's Gyro-Guide GWD90 has three rate-sensing axes, enabling it to provide azimuth measurements at all inclinations.

Rate gyros are very sensitive to vibration and movement while conducting a survey, and must begin each survey by indexing to remove bias and alignment errors. Thus the survey times for gyro-based tools are about three minutes longer than those for magnetometer-based tools.

The operating time is, of course, influenced heavily by the frequency (or number) and data formats of surveys. Generally, gyro tools have lower battery life than MWD tools. This study identified the battery capacity of available GWMD tools is sufficient for 40 to 250 hours of continuous surveying.

2.2.3. Available High-Temperature MWD Tools

There are fewer High-Temperature (HT) MWD systems available than Standard MWD Systems. Attachment A provides a summary of specifications of the available high temperature MWD tools. The following systems were identified and evaluated:

- Halliburton, Quasar Pulse M/LWD
- Schlumberger, TeleScope ICE
- Scientific Drilling, High Temp MWD
- Weatherford, HEL MWD System

The platforms, telemetry systems, downlink capabilities, survey times, and LCM tolerance are similar to standard MWD tools. Although most systems must be housed in special hostile environment non-magnetic subs. Azimuth accuracy ranges from 0.25° to 1°, and the inclination accuracy ranged from 0.1° to 0.15°, which are similar to standard MWD tools.

The main differences between standard and HT MWD systems are in the temperature tolerance and battery life, as shown in Table 4. Because the Halliburton and Schlumberger tools are turbine powered, their maximum operating times are determined by the ability of the downhole systems to continue functioning as exposure to elevated temperatures increases Halliburton's Quasar Pulse tool has no limitation at temperatures as high as 200° C. The Schlumberger TeleScope ICE tool has an operating limit of 200 hours at 200° C.

The Scientific Drilling High Temp MWD and Weatherford HEL MWD tools are battery-powered, so the operating times shown above are determined by battery capacity. At its maximum operating temperature of 180° C, however, the Weatherford tool limit is no more than 200 hours.

Table 4: Available HT MWD Tools - Operating Limitations

Supplier	Model	Max. Operating Temp. (°C)	Max. Operating Time (hrs.)	Power Source	Operating Time (hrs.)
Halliburton/SD	Quasar Pulse M/LWD	200		Turbine	N/A
Schlumberger	TeleScope ICE	200	300	Turbine	N/A
Scientific Drilling	High Temp MWD	177		Battery	300+
Weatherford	HEL MWD System	180	200	Battery	348

2.2.4. Available High-Temperature Gyro Tools

Because gyroscopes generate significant heat, unlike magnetometers, the maximum operating temperature claimed by these tool suppliers is 150° C. However, it is possible to operate some gyro-based directional modules at higher temperatures by enclosing them in insulated dewars (or sondes). When protected by such dewars, Gyrodata's gyro-based modules will operate up to six hours at 170° C when configured as drop or wireline tools. However, no GMWD supplier has indicated their GMWD tools could operate at temperatures above 150° C. This study concludes that there are currently no high temperature gyro tools available.

2.3. Ranging Tools

2.3.1. Scope and Introduction

Ranging tools are used to measure the relative range and bearing to a cased, target borehole (drillstring or other ferrous object) from an active borehole, which is being drilled with the objective of intersecting the target borehole (or well). In other circumstances, a ranging tool may also be used to avoid intersecting the target well. The ranging systems included in the scope of this study all use magnetic or electromagnetic measurements to detect the position of the target. Attachment A provides a summary of specifications of the available passive ranging tools and a summary of specifications of the active ranging tools.

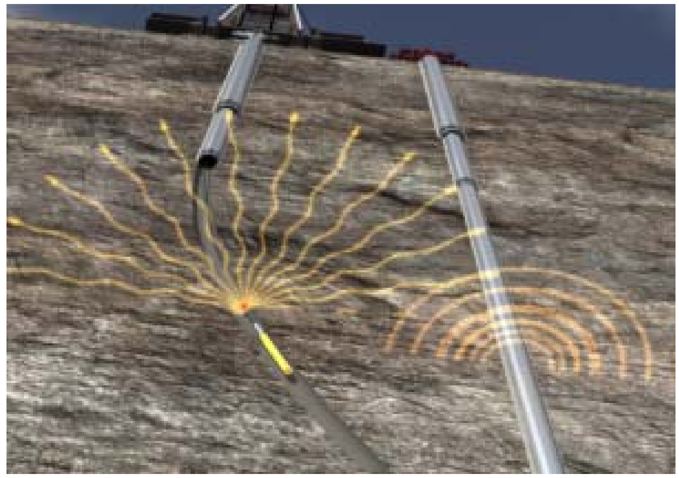
2.3.2. Operating Considerations

From an operational perspective, it is useful to divide ranging systems into two groups. Ranging systems that require access to the target well are called "access dependent," and are most often used to drill wells that are parallel to but displaced – horizontally or vertically – from previously drilled wells. Such systems induce an alternating magnetic field in the target well by connecting to it, electrically, or by insert a rotating permanent magnet or an electromagnet into it. This approach has been widely adopted for the production of heavy oil from the tar sands in Alberta, where steam is injected to reduce the viscosity of the oil in a process called steam-assisted gravity-drainage, or SAGD. Because such systems require access to the target well, they are not compatible with most relief well projects.

The second type of ranging system, known as "access independent," does not require access to the target well.

There are two types of access independent ranging systems: active and passive. Active systems use an electromagnetic transmitter and downhole electrode to induce a magnetic field in the casing (or other ferrous object) in the target well (shown in Figure 3). Because they transmit low frequency AC or pulsed DC to induce a magnetic field in the target, it would be more appropriate to call them "electromagnetic" ranging systems. The induced magnetic field is sensed by magnetometers and used to determine the range and bearing to the target from the tool in the active borehole. The only commercially-available active ranging system is configured as a wireline tool.

Figure 3: WellSpot Tool™



From Halliburton/Sperry Drilling, reproduced with permission

Passive ranging tools, which use precise and repeated measurements of the earth's magnetic field, comprise the second type of access independent ranging system (Figure 4). Standard or modified MWD tools are used for passive magnetic ranging, so they can be incorporated in most BHAs and used while drilling.

Figure 4: Passive Ranging

From Halliburton/Sperry Drilling, reproduced with permission

Thus one key difference between active, electromagnetic and passive, magnetic ranging systems is the former are open-hole tools, run into boreholes on typical logging (wireline) cables, while the latter are in BHAs and used while drilling.

All the available passive ranging systems use standard or slightly modified MWD tools to make the needed measurements. The ranging capability is achieved with special-purpose software to develop the model of the target borehole, using data from iterative long surveys conducted by MWD tools. Scientific Drilling was the first company to develop such a software package, which they call MagTraC MWD Ranging. They offer it as a service with their own MWD tools and with tools manufactured by others. To date, in addition to their own tools, it has been run with MWD tools provided by Baker Hughes, Halliburton, Schlumberger, and others.

Applications and use of ranging tools. Before addressing the subjects of range and accuracy of these two approaches to ranging, it is essential to consider the different situations in which a well is being drilled to intercept an existing well. Relief wells are the most widely known type of interception, however, many more intercepting wells are drilled for the purpose of plugging a well before it is abandoned. Ranging systems also are used to guide sidetracks around boreholes that have become plugged with a broken tool or a twisted off BHA. In such circumstances, guiding the active well around the obstacle so that drilling can be continued in the formation below requires less accuracy than most interceptions.

Detection sensitivity. Promotional brochures and other publications from suppliers make many claims for the ranges that can be achieved with their tools. Based on interviews of many experienced relief-well specialists, the following observations are provided on range and accuracy of these two types of ranging tools, which should be considered consensus-based conclusions.

Active ranging tools usually provide acceptable range and bearing estimates at distances of 100-150 feet from the target. Ranging capabilities of 200 feet and more are claimed, but these are under ideal circumstances. When the distance is close to the maximum range claimed, the error is usually considered to be about 25% of the estimated range. At closer ranges, within 30 feet or less, the error is likely to be about 5%. Gradient measurements are even more accurate at close range.

The maximum ranging distance of passive systems is about half than what is normally achieved with active magnetic ranging systems. It should be recognized, however, that the ranging ability of passive systems is highly dependent on the weight (or mass) of the casing and the residual magnetism in the casing joints in the target well. The range of passive systems is significantly greater when there is a large approach angle between the target and active wells and the active well is near the bottom casing shoe. Thus, there could be situations where the ranging capabilities of a passive tool approach or even exceed those of an active tool. Conversely, passive ranging tools will have their ranging capability reduced if there is little residual magnetism in the target well's casing, if it has become corroded, or is light-weight.

2.3.3. Available Standard Passive Ranging Tools

Scientific Drilling's MagTraC software-based service for passive ranging can be used with any MWD system capable of providing long surveys that include the six axes (three magnetic and three gravity-based) of directional information. Baker Hughes' AccuTrak service adds similar ranging capabilities to their OnTrak MWD tools. The availability of these systems implies that all the MWD systems listed in prior sections are capable of providing passive ranging services. These systems, listed in Table 5, are included in this section for completeness, although they were discussed previously in the MWD section above. In addition, Scientific Drilling's Green Eye ranging MWD tool was added. Scientific Drilling's Green Eye Ranging MWD tool has been added to the table. It is identical to their Falcon MWD tool in almost all respects. The key difference is the range and resolution of its magnetometers.

This study found that generally, the attributes of the ranging tools were quite similar to their MWD system counterparts, but noted a few additional considerations. The ability to run MWD and GMWD tools in tandem offers an advantage when conducting passive ranging between the active borehole and a nearby, cased well. Having a gyro-based tool in the hole with a conventional MWD system reduces the time needed to determine the path along the active borehole.

Table 5: Available Standard Passive Ranging Tools

Supplier	Model	Description	Nom. O.D. (min)
APS Technology	SureShot MWD	Retrievable MWD/LWD in Std. collar	3.125"
Baker Hughes	OnTrak HT-175	Integrated MWD & LWD system	4.75"
Bench Tree	MWD Kit	Retrievable MWD probe, 1.875" diameter	3.5"
GE Oil & Gas	Tensor MWD	Retrievable MWD/LWD in Std. collar: 1.875" dia.	3.5"
Halliburton/SD	SOLAR MWD/LWD	Collar-based hostile-environment M/LWD system	4.75"
Schlumberger	HDS-1L	Fixed-collar directional service	4.75"
Scientific Drilling	Falcon MWD	Std. collar below Pulser Sub	3.125"
Scientific Drilling	Green Eye Ranging MWD	Std. collar below Pulser Sub	3.125"
Weatherford	HyperPulse MWD	Probe-based MWD tool: 1.6875" dia.	3.0625"

When these MWD tools are used in passive ranging applications, the resolution of their magnetometers is particularly important. The only apparent difference between Scientific Drilling Falcon and Green Eye Ranging tools is the latter has been designed for ranging applications where it might be exposed to higher magnetic fields. This doubling of the range and resolution of their magnetometers suggests magnetic fields encountered while ranging may exceed normal earth's field magnitudes.

2.3.4. Available High-Temperature Passive Ranging Tools

The tools and analysis in this section are identical to those in the Section 2.2.3 (Available High-Temperature MWD Tools) above, except for the analysis of Magnetic Measurements. The summary of tool attributes is not repeated here. The specifications for resolution of the magnetic measurements made by the available, HT passive ranging/MWD tools provided by the manufacturers are listed in Table 6.

Table 6: Available HT Passive Ranging Tools – Magnetic Measurements

Supplier	Model	Magnetic Field (μT)		
		Range	Acc'y	Resol'n
Halliburton/SD	Quasar Pulse M/LWD			
Schlumberger	TeleScope ICE	0-65	±0.110	0.035
Scientific Drilling	High Temp MWD	±75		0.0023
Weatherford	HEL MWD System			

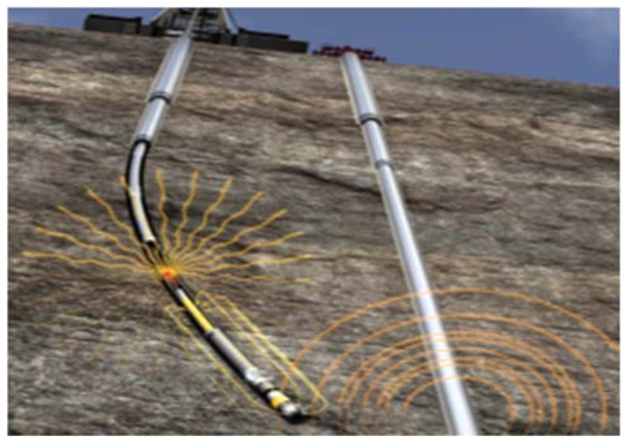
In ranging applications, the resolution of Scientific Drilling's High Temp MWD could be an advantage; however the range of its magnetometers is half that of their Green Eye ranging tool, which is rated for 150° C operating temperature.

2.3.5. Available Active Ranging Systems

At this time, Halliburton/Sperry Drilling has the only commercially-available, access-independent, active ranging system suitable for borehole applications. It is, in fact, a family of products that share the WellSpot Tool™ name. Initial development and commercialization of these products were started by Arthur Kuckes in 1980. In 1985, he founded Vector Magnetics, which manufactured the tools and offered ranging services. In 2010 Halliburton obtained commercial rights to these technologies and tools for all oil- and gas-related markets.

The primary tool, WellSpot RGR, comes in three versions that appear to reflect continuing improvements in their electronics and/or magnetometers. These tools are deployed on a conventional, 7-conductor wireline in open hole. Above the tool is a bridle that incorporates an electrode to transmit a low-frequency electromagnetic AC signal into the surrounding formation. One set of three magnetometers measures all three axes of the local fields, both induced AC and earth's (DC) field. The acronym, RGR, stands for radial-gradient ranging. The tool has two pairs of magnetometers that measure the gradient of the induced AC field in the two directions orthogonal to the tool's longitudinal axis (X and Y). Gradient measurements provide more precise range information when the active and target wells are close.

Figure 5: WellSpot Tool™ with WSAB Sub



From Halliburton/Sperry Drilling, reproduced with permission

An alternative configuration of the WellSpot Tool™ uses the WSAB Sub (Figure 5), which is normally placed between the bit and mud motor or RSS. It uses short-hop telemetry to communicate to its receiver, which is tripped in on 7-conductor wireline, inside drill pipe or open hole to a location above the BHA, within 75 feet of the WSAB Sub.

The WSAB Sub is battery-powered and is activated after rotation has stopped for a set interval. After turning on, it averages the readings of the AC field from its magnetometers for a minute-or-so and, if it finds a signal, activates the short-hop telemetry link to its receiver, which them sends the readings to the surface. This configuration eliminates the need to trip the BHA to make ranging measurements. The disadvantage of this configuration is the need to have a wireline inside the drill pipe (unless the tool is used in open hole).

Additional details and specification of the WellSpot Tool™ family can be found in Attachment A.

2.4. New and Emerging Technologies in Directional Surveys and Ranging

The oil and gas market has grown significantly in recent years, and the drilling and completion technologies that drove the growth continue to evolve as exploration and production move into more challenging areas. Electronics and materials technology markets are evolving to address some of the issues faced by highly deviated and hostile environment drilling. The improvements in drilling, wellbore survey and ranging technologies, procedures, and services are important considerations when developing regulations and guidance. Understanding the emerging tools for wellbore survey and ranging, and new methods will help ensure that the best available technologies are considered in the decision-making process. In this section we identify new and emerging technologies that are likely to (a) improve the performance, reliability, and/or ability to operate at elevated temperatures of tools used for downhole ranging or directional measurements, and (b) become commercially-available within the next 3 to 5 years. Because several years often are needed to evaluate and qualify components and subsystems for use in borehole applications, the technologies considered need to be "visible" today, meaning they exist as tested models or prototypes. As such, this discussion does not include potential technologies that exist only as concepts or untested models.

The content of this section is summarized from a Technical Memorandum prepared during the study which contains more detailed discussion of the technologies. The memo is provided in Attachment B.

2.4.1. Improving Performance at Elevated Temperatures

The elevated temperatures experienced by borehole tools and instruments (often exceeding 125°C) are well above the temperatures found in almost all other environments where modern, solid-state electronics are used. Electronic components designed and manufactured for military and aerospace applications normally are tested and expected to perform at temperatures of 125°C and below. The design, production, and maintenance of borehole tools and instruments capable of performing at elevated temperatures is technically challenging, time consuming, and expensive.

Although resolving the technical issues needed to field high-temperature tools is challenging, resolving the associated economic issues is even more difficult. The cost of a high-temperature survey or MWD tool, capable of performing at temperatures significantly above 175°C, can be many times the cost of a standard tool. However, the market for high-temperature tools is much smaller than that for standard tools, and tool manufacturers normally cannot charge the premium prices needed to yield a fair return, when including development and production costs, and amortization of their investment.

There are several manufacturers of accelerometers and magnetometers that are able to perform at elevated temperatures – to 200°C – so there do not appear to be any unmet needs for these components. However, rate-sensing gyros are more challenging. The spinning-mass, tuned-rotor gyros that are used in most gyro-based survey and MWD tools are capable of performing at temperatures above 150°C for limited periods of time. The current limitations of gyro sensors are such that our team believes other, micro-electromechanical systems (MEMS)-based sensors are more likely to meet the needs of borehole guidance and surveying in the near-to mid-term (4 to 8 years).Today, at least one manufacturer of a MEMS-based rate gyro claims improved stability and accuracy at least 50% better than the performance claimed by the same manufacturer in 2010, so significant progress toward sensors suitable for navigation continues to be made (Johnson et al., 2010; Johnson et al. 2015).

The testing and qualification of semiconductors, integrated circuits, and modules is typically conducted at temperatures of 125°C and below. For military and aerospace applications, the operating limits for components typically are -55° to +125°C. The potential market for high-temperature components capable of performing at 175°C and above is not considered to be large enough for most manufacturers to make the investments needed to adapt and test their products at higher operating temperatures. Honeywell Aerospace is an exception. Components using the silicon-on-insulator (SOI) complementary metal oxide semiconductor (CMOS) technology developed by Honeywell are capable of operating continuously at 225°C. However, two issues have limited their penetration of borehole-related markets:

1. The range of available circuits is limited, so providing the functionality needed in today's survey, MWD, and ranging tools is difficult, and often forces tradeoffs between the desired functions and number of circuits needed to implement the design.
2. Because they use a unique process and are manufactured in limited quantities, SOI components and MCMs are expensive.

Should the markets for steering and survey tools capable of operating at higher temperatures be expanded by the perceived needs of operators, suitable tools would, in all likelihood, be developed and be available in sufficient quantities to meet the market needs. Most of the essential "technologies" are available.

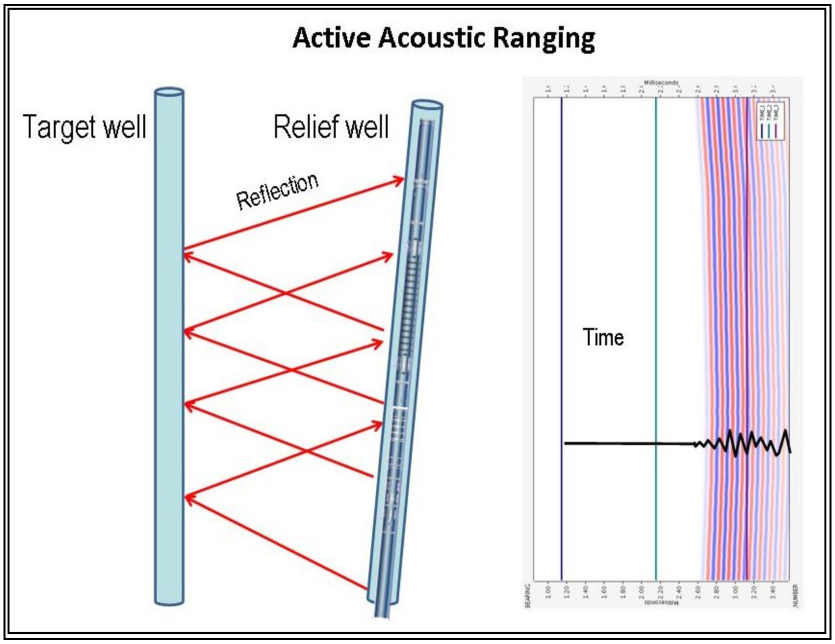
2.4.2. Emerging Tools

This study identified a new tool, an adaptation of a current acoustic logging tool to ranging applications, and a new approach to passive magnetic ranging. Each of these has completed some field tests, but are not considered by their manufacturers to be "commercial" products. We have included them here because the field tests have been encouraging, and each expands the methods and/or tools now used for ranging. Brief summaries of each are provided below, and more detailed descriptions are provided in Attachment B.

2.4.2.1. Acoustic Ranging Tool

Schlumberger has adapted an acoustic wireline tool that was first developed to evaluate formations around boreholes and the quality of cement bonds to ranging applications. With a data acquisition and processing system designed for ranging, it has been successfully tested in an active ranging application. This ranging technique is effective primarily in salt formations, where conductivity inhibits the use of active electromagnetic ranging tools. The basic principle of operation is illustrated in Figure 6. Acoustic waves are transmitted into the surrounding formation from the tool. Reflections from the target are received by the tool and analyzed to determine the range and direction to the target. The Sonic Scanner tool can withstand pressure to 27,000 psi and temperatures to 350°F (177°C). The maximum ranging distance is dependent on the velocity and attenuation of the transmitted acoustic signals in the traversed formations. Salt typically has higher velocities that will enable ranging at greater distances than other formations

Figure 6: Active Acoustic Ranging, Principle of Operation



From Schlumberger (reproduced with permission)

2.4.2.2. BlackShark Active Ranging System

The BlackShark active ranging system was developed by Scientific Drilling International and completed its first field test in February 2016. The tool contains magnetometers and accelerometers, which are located at the Sensor Point, and a data acquisition and telemetry module ("Downhole Processor") that gathers data from the sensors and transmits it to the surface with a Wireline Modem. The tool is 10 feet long and 4.5 inches in diameter, and can be run in tandem with a gyro-based tool. It will withstand borehole pressures to 25,000 psi and is available in a high-temperature version, which can operate at temperatures to 250°C when contained in a dewar. 200 feet is the maximum claimed range.

2.4.2.3. AccuTrak™ Passive Magnetic Ranging

Baker Hughes has developed and tested a new method of Passive Magnetic Ranging for well twinning applications that is based on aerospace navigation technology. The AccuTrak™ PMR Service uses measurements made by their OnTrak™ MWD tools and an adaptive filtering technique. The basic principle of operation is to develop and refine a model for the target well that is based on the residual magnetic fields in its casing.

With repeated measurements which can be acquired while rotating and drilling ahead, an initial magnetic model of the target well is improved and ultimately converges to an accurate model from which range and bearing can be calculated in real-time. The driller's display includes a compass rose depicting the location of the target well, the planned well, and the actual well path, along with range, bearing and confidence factors. Although this modeling technique was developed with SAGD well twinning applications in mind, it also can be applied to collision avoidance and relief well projects.

3. Survey Lifecycle Elements

3.1. The Survey Lifecycle

Many different survey-related activities are performed during the process of drilling an offshore oil and gas well, including:

- Wellbore and directional survey planning
- Survey operations
- Data management
- Corrections and tool error models
- Survey quality control and survey management

Data collected during directional surveys is critical to the success of the well because it provides the driller with real-time understanding of the location of the bit so that the well can be placed as planned for optimal recovery. This data is also critical to ensuring the well is drilled safely. Well location data are a critical asset to the operator so the data must be managed carefully so as to preserve the quality of each record for future use. The operational and management activities described above are herein referred to as the survey lifecycle. Each lifecycle element is made up of several component activities. The following sections describe the elements of the survey lifecycle. The information in this section is summarized from a Technical Memorandum provided to BSEE as an interim deliverable, and is included as Attachment A which provides an expanded discussion and examples of selected subjects.

3.2. Wellbore and Directional Survey Planning

Wellbore planning includes design of the drilling program for the wellbore from surface to total depth. The objective of the wellbore design is to define a drilling plan that will reach the geologic target safely, accurately, and efficiently. Many factors are considered to ensure a safe and useful completed well. Some examples of the factors considered during well planning are shown in Table 7.

Table 7: Factors Considered in Wellbore Planning

Factor	Consideration
Geologic Target	Reach depth and xy location of targeted zone.
Legal Requirements	Maintain lease line setbacks and other legal requirements for surface hole location and wellbore trajectory.
Collision Avoidance	Maintain a safe distance from other wellbores.
Drilling Conditions and Geologic Obstacles	Avoid or optimize drilling through difficult geologic materials. Considers pore pressure, fracture gradient, hole geometry to minimize torque and drag, mud plan, bit and drill string program, drill time projection, and cost estimation. Considers ability to collect reliable directional measurements during drilling, and formation evaluation data during or after drilling.
Final hole conditions	Prepare a clean and smooth borehole that is suitable for completion and production. Avoid severe doglegs that limit equipment selection or cause excessive equipment wear.

The wellbore planning process starts with the operator defining a set of target coordinates for the surface location and bottom hole position. Well planners or drilling engineers design an initial well path, and work with geologic and engineering teams to integrate subsurface geologic models and make sure well designs are technically or economically viable by applying the considerations described above. Multiple well designs are prepared and evaluated, and a final selection is made based on the operator's selection criteria.

Well planning may be performed by the operator, or more commonly is contracted to a directional drilling company and follow internal guidance documents and standard company procedures. Final well plans are reviewed and approved by both the directional driller/well planner, and the operating company. A final well plan, includes a graphical representation of the well in plan and profile views (Figure 7).

A Safety Critical Element (SCE) is a component or activity whose failure could lead to, or whose purpose is to prevent or limit the consequences of a major accident event[2]. An out of control well, or accidental intercept of an adjacent well would be considered a major accident event (MAE). Wells with elevated risk of MAE occurrence with environmental or safety consequences are classified as Health Safety and Environment (HSE) risk wells. Many offshore operators consider wellbore planning to be an SCE because a major part of the planning activity is to avoid hazards such as adjacent wells. The development of a wellbore surveying plan (defining the tools used and quality assurance to be implemented) and the adherence to collision avoidance rules established by operators (discussed below in Section 3.2.2) are the tools used to manage HSE wells. The well survey plan must also minimize the risk of drilling an unsuccessful relief well by accurately representing and minimizing the uncertainty in wellbore positon so that the relief well has a well-defined target.

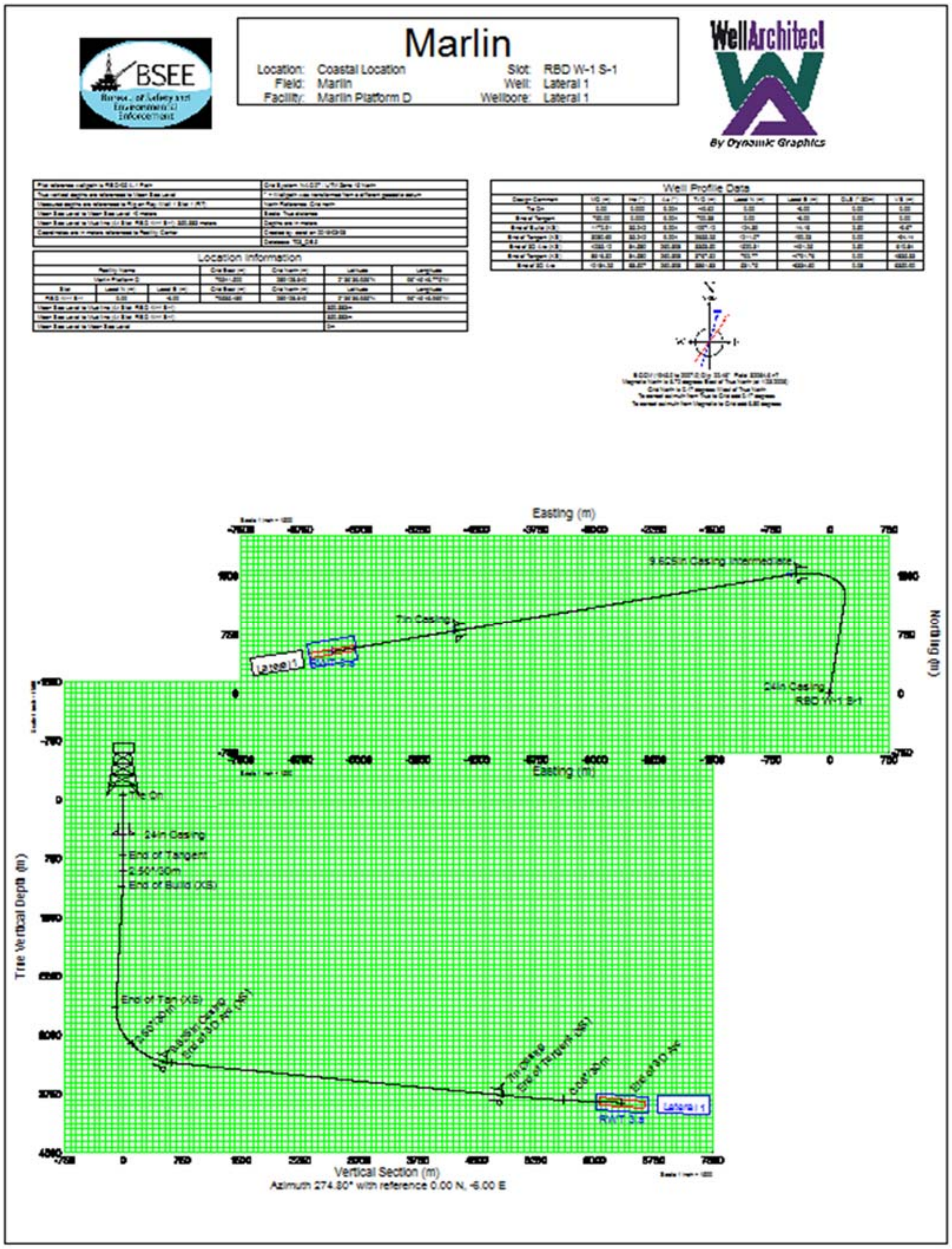
While safety is a primary consideration in wellbore planning, there are also economic and resource conservation considerations. A properly designed wellbore will maximize the resource recovery within the reservoir and allow for economic recovery of the resource from the planned well, as well as subsequent wells drilled in the field. Recent studies (Stockhausen, 2016) have shown that significant volume of reserves can be underestimated if wellbore position is inaccurate. For example, Stockhausen demonstrated that a one-foot error in true vertical depth (TVD) can equate to 10,000 to 100,000 barrels of estimated reserves; wellbore uncertainty is often in the range of tens of feet. Considering that some surveys may have uncertainties of tens to hundreds of feet at total depth (TD), enormous volumes of reserves can be unrealized. Wellbores that appear to penetrate unproductive geologic targets may actually be mislocated in the subsurface. Poorly designed wells may require frequent maintenance and shut downs to repair or replace failed components caused by excessive wear in wells with high angle doglegs and spiraled casings. Unplanned well intersections can incur significant economic and reputation cost and cause the operator to lose the right to drill.

Offshore rig time is an important consideration in the development of a well survey plan. Collecting measurements with MWD tools generally requires the drill string to be stationary for several minutes. Collecting frequent measurements in a deep offshore well (20,000 to 30,000 feet) may add considerable

[2] Adapted from : API RP 2FB, Recommended Practice for the Design of Offshore Facilities Against Fire and Blast Loading, First Edition, April 2006, and The Offshore Installations (Safety Case) Regulations 2005, UK S.I. 2005/3117, 2005

rig time to the drilling program. Additionally, singleshot and multi-shot tools require the drill string to be stable during tripping, which increases rig time. Well survey plans must balance the time required to take survey measurements against the rig time. Likewise, quality control procedures while tripping in and out, and during drilling also add to rig time.

Figure 7: Graphical Representation of Well Plan showing Plan and Profile Views



Well Plan courtesy of Dynamic Graphics Inc. reproduced with permission.

A wellbore survey plan is a part of the wellbore planning process and provides a set of instructions for collecting information to locate the wellbore trajectory. It includes a description of the proposed survey tools, the depth interval the tool will be used and the frequency of measurements. Drillers and survey managers are responsible for implementing the plan and using the data to safely and effectively drill to TD.

When planning and evaluating the survey program, it is useful to consider the effect of tool selection on the final accuracy. The tool specifications are an important factor in determining the accuracy of the final measurement. For example, a small inclination error of 0.25 degrees will produce 0.5% of step out as an error in TVD that can lead to substantial uncertainty at the target location for long boreholes.

No specific planning procedures are required for wells that are expected to encounter high temperature conditions. However, tools selected for inclusion in the survey plan must be rated for the environments for which they will operate, and operated in accordance with all quality control (QC) or the readings and error models will not be valid. Likewise, some gyro tools have limitations on the maximum inclination angle in which they will operate and the maximum latitude in which they can obtain accurate readings[3].

The final wellbore survey plan submitted to BSEE in the Application for Permit to Drill (APD) is often a general description of the directional survey program and may include only plan and profile view of the well trajectory with annotation of the type of survey to be performed (MWD or gyro).

3.2.1. Well Planning Software

Well planning software is universally used to plan and document well trajectories for offshore wells. It is normally part of a larger software package used during directional drilling and may also function as a survey management system for large well data sets.

Two major vendor licensed software products, Compass™ (by Landmark, a Haliburton company) and WellArchitect™ (Dynamic Graphics Inc.), are the most commonly used licensed well planning software for offshore applications. DrillingOffice™ is a proprietary well planning and drilling engineering software package developed and used by Schlumberger for well planning and directional drilling. It is generally not licensed for external use. A number of smaller vendor-supplied software products are also available for wellbore planning. With respect to wellbore planning, each of the major software products provide:

- A database function to store and manage a set of well survey data,
- A selection of error models to be applied to the well survey data to generate cones of uncertainty,
- A well planning module to select well path and BHA components,
- A collision avoidance scan with choices for scanning methodologies,
- Report outputs for well plans and collision scans, and
- Integration with real time data collection during drilling.

[3] At high latitude (the Arctic Circle) the horizontal component of the earth's spin vector is very low and gyro tools may be unable to obtain necessary resolution in spin rate to make accurate readings.

The outputs from the planning module of the software include plan and profile views of the well trajectory, various anti-collision plots (travelling cylinder, ladder and spider plots, described in Section 3.3.2.1) and a wide range of reports of anti-collision scans, and well survey plans. The well survey plan provides a listing of the tools and vendors to be used, the start and end depth for each tool, survey frequency, and other information such as QC requirements and specific tool codes.

3.2.2. Collision Avoidance Analysis

Anti-collision analysis (also called collision avoidance) is a key part of the well planning process and one of the most important safety considerations related to wellbore surveying. Because of the significance of the topic the subject is addressed in detail.

Operating companies and directional drilling companies have established rules to ensure the risks from unplanned well intersections are properly identified and evaluated during the wellbore planning process. After the planning phase, the execution of the recommended drilling plan adheres to strict collision avoidance procedures during drilling to avoid collision. Actions taken to avoid wellbore collision during drilling are part of a comprehensive collision avoidance policy and are addressed in Section 3.3 Survey Operations.

Platforms for offshore fields contain drilling slots for several dozen or more wells located in close proximity to each other at the surface. In the subsurface the wells often have complex trajectories and include bypasses and sidetracks. Operators are increasing the number of available slots on a platform to avoid the expense of major additions to infrastructure. The large number of existing wells and the need to add new ones to extend platform life creates a congested drilling environment and very challenging collision-avoidance scenarios. Collision avoidance policies are statements that define the limits of risk, and the management approach that the business will adopt to mitigate the risk. Successful collision avoidance policies define roles for operators and directional drilling company staff at multiple levels.

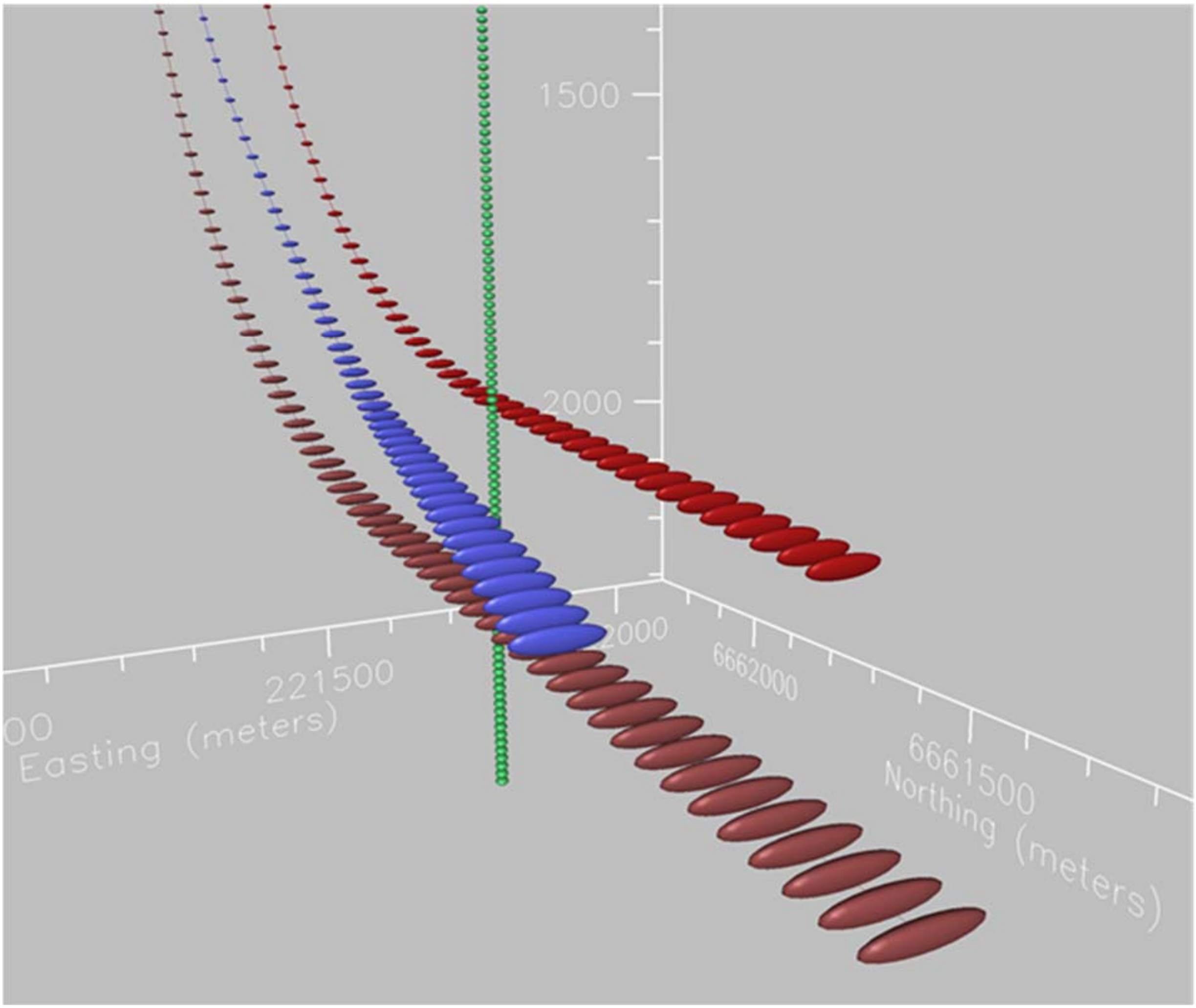
The general procedure for conducting collision avoidance analysis is to assemble the well construction and survey data from all nearby wells and conduct a proximity analysis along the proposed wellbore path to determine if any adjacent wells are within a specified distance from the proposed well using a geometrical spacing approach. The well trajectory for the proposed well incorporates the uncertainty in the wellbore position of the drilling well due to the survey accuracy, and therefore is represented by a volume (ellipsoid) around the wellbore[4] at a single point. When the ellipses are connected along the wellbore they form a three-dimensional surface represented by a cone. Likewise, the trajectories of adjacent wells incorporate their positional uncertainty, represented by a series of ellipses around the wellbore (Figure 8). The operator or directional driller defines the minimum acceptable allowable distance between the two ellipses of uncertainty, and the proximity analysis is conducted using a collision avoidance software package[5]. If an unacceptable risk of collision is identified the wellbore trajectory is revised. For most operators, the collision avoidance policy requires that results of the

[4] The concept of wellbore position uncertainty and the calculation of ellipses of uncertainty is covered more thoroughly in Section 3.5 – Corrections and Tool Error Models.

[5] Collision avoidance analysis can be conducted manually, but due to the large amount of data required it is generally conducted using specialized automated software. Collision avoidance analysis modules are included in the major well planning software products described in Section 3.2.1 Well Planning Software, or as standalone software products.

collision avoidance analysis are documented and auditable, reviewed, and approved by authorized senior staff.

Figure 8: Ellipsoids of Uncertainty Around Planned and Target Wells



Anti-collision analysis example courtesy of Dynamic Graphics Inc., reproduced with permission.

Specific rules for collision avoidance are established by the operators and directional drillers and documented in a corporate Collision Avoidance Policy or Rules. These policies are normally part of the company Risk Management procedures. An example of collision avoidance rules from a major international operator is shown in Figure 9. Prior to preparing the well plan, the operator and directional driller must agree on the rules to be applied to the collision avoidance analysis. To ensure an appropriate margin of safety, operators may have different rules and mitigations for well planning and drilling.

Figure 9: Example of Major International Operator Collision Avoidance Rules

Well Proximity Category	Well to Well Separation Criteria as Defined by Proximity Rates	Drilling Well Operational Constraints	Offset Well Operational Constraints
Category 1: Wells are not close	**Proximity Ratio** ≥ 1.75	No special precautions necessary.	No special precautions necessary.
Category 2: Wells are close	1.75 > **Proximity Ratio** ≥ 1.5	Use most accurate surveying methods, including use of independent confirmation checks. Survey as required to prevent unacceptable deviation from the well plan.	Each producing offset well must be shut-in and lift gas bled down from its casing x tubing annulus. No special precautions for well injectors.
Category 3: Wells are very close	1.0 < **Proximity Ratio** < 1.5	Use most accurate survey methods, surveying to allow maximum 30% decline in separation distance per survey interval. Observers, with earphones, must be paced at offsetting well(s) to detect well-to-well contact. Provide additional Directional supervision on the rig.	Each producing object well must be shut-in and lift gas bled down from its annulus. A Wireline plug must be set in the tailpipe to isolate the formation. Water injectors must be shut-in and plugged as above.
Category 4: Wells are within uncertainty limits	**Proximity Ratio** ≤ 1.0	Drilling can only continue with Drilling Manager's approval. If approval is given, survey and monitor as in category 3 above. In addition, log well with ultra-long spaced electrode log or magnetic proximity device to determine distance to object well. Maximum course length between logging runs to set such that well-to-well separation distance does not decrease more than 50% over the drilled course.	Object well(s) shut-in as described in category 3.

From Burton 1991, SPE 22546, (reproduced with permission, re-typed for readability)

As shown in Table 8, an effective anti-collision analysis relies on several factors including having a complete and accurate database of all wells (including sidetracks and bypasses) in the area of review. On land, there are many undocumented wells that create potential risks to directional drilling. Many of these wells were drilled before comprehensive regulations for well spacing and permitting were in place. While undocumented wells are less of a problem for offshore areas, incomplete databases due to data loss can be a significant issue, especially in fields where the operator has changed several times over the life of the field. Industry sources familiar with this issue have noted that in some cases up to 60 percent of wells in offshore fields have incomplete or no data suitable for use in collision avoidance analysis. When well data are incomplete, a conservative risk factor is often used to calculate the positional uncertainty, which can lead to inefficient production of the resource.

Table 8: Considerations for a Valid Anti-Collision Analysis

Consideration	Information Required
Completeness of the well database	What assurance is there that the well database is complete and includes all potential collision risks? How does the collision avoidance policy address the risk of "ghost wells" or incomplete data?
Accurate representation of the positional uncertainty of adjacent wells	Do the locations of the adjacent wells accurately depict the uncertainty around each wellbore, taking into consideration the survey tools run, and the error models and corrections applied to the surveys? How does the collision avoidance policy and subsequent risk assessment address the uncertainty of known adjacent well locations? Is there survey redundancy to limit the presence of unobserved gross error?
Separation Distance Rules (for geometric method)	What mathematical rules are used to calculate the separation distance? How was the separation distance factor selected? Are there separate anti-collision rules for surface versus deep portions of the wellbore?
Completeness of scan	What method was used to search for adjacent wells – horizontal plane, normal plane, or 3-dimensional least distance, or closest distance (not necessarily at survey points)? Do survey station intervals allow for the closest point to be identified in high angle dogleg sections?

Uncertainty in survey measurements stems from the effect of the environment on the measurement sensors, and to a lesser extent the accuracy and precision of the sensors. The magnitude of the uncertainty of measurements can be calculated mathematically and used to generate an estimate of the error in the wellbore position. Uncertainty estimates (tool error models) are specific to the survey tool and BHA configuration used so the well planner must consider the type of survey tools and BHA to be used on the proposed well, and select the proper error model to accurately calculate the uncertainty in wellbore position. The well planner must consider the tools and BHA used on adjacent wells also in order to generate an accurate representation of the uncertainty of their wellbore position.

The accuracy of the ellipses of uncertainty for both the planned well and the adjacent wells, and the method of calculating and applying the minimum acceptable separation distance (MASD) between wells, also affect the effectiveness of the collision avoidance analysis. The calculation of error[6] and ellipses of uncertainty is discussed in Attachment A, as is an overview of methods for MASD calculations. For a more thorough discussion of the topics the reader is referred to the ISCWSA documents *Current Common Practice in Collision Avoidance Calculations* (ISCWSA, 2013), *The Fundamentals of Successful*

[6] The use of the term "error" in this context refers to the mathematical difference between the actual value and the measured value, and does not necessarily represent a mistake. Error values in wellbore survey work are derived through rigorous mathematical models and statistical analysis. Tool error models are discussed in Section 3.5.

Well Collision Avoidance Management (ISCWSA, 2014) and *Introduction to Wellbore Surveying* (ISCWSA, 2016b).

Most collision avoidance software allows for several methods of calculating separation factors that account for various geometries and mathematical relationships (pedal curve method, scalar expansion method, etc.). The reader is referred to *Introduction to Wellbore Surveying* (ISCWSA, 2016b) for more information on these methods. The most conservative method, recommended by ISCWSA, is the 3-dimensional closest approach which scans for wells in three dimensions around the proposed wellbore to identify the minimum distance to the closest well. Older software may scan only perpendicular or horizontal to the wellbore which may lead to missed collision risk. Once the acceptable separation factors are determined the MASD rule is applied and the entire wellbore is scanned for potential collision risk.

Results of the clearance scan are classified by risk level to prioritize sections of the well trajectory that have higher risk of intersection. The classification of risk is often a function of the separation factor ratio with lower separation ratios representing higher risk of collision. For example, a company may identify the action levels for well planning shown in Table 9 below.

Table 9: Example Action Levels for Anti-collision Well Planning

Separation Factor Ratio (SF) or Center to Center (C-C) Distance	Rule	Action
SF greater than 5, or C-C <100 feet	Include in Collision Scan	Routine directional drilling survey and monitoring.
Between 1.5 and 5	Acceptable for well planning purposes	Continuously monitor separation factor form both onshore and offshore locations. Review action plans for SF < 1.5.
SF between 1 and 1.5	Not permitted during planning phase, but may be present during operations.	Corrective actions required during drilling to change direction or improve survey accuracy. Shut in offset wellbores to reduce HSE risk.
SF less than 1	Not permitted during planning phase, but may be present during operations. Only acceptable when planning relief or intended intercept wells.	Stop drilling. Take corrective actions to immediately increase SF, including plug back to safe point, improve survey accuracy.

An assumption of the collision avoidance scan is that the error models are appropriately applied and accurately depict the uncertainty around the wellbore. If directional survey tools are run outside of their operating range readings may be unstable and not reflect the true conditions. Results of error models are considered valid only if the survey is run in accordance with all calibration and operating requirements. If tools are run in high temperature environments outside the calibration and operating ranges the tool error model and associated uncertainty is invalid. Recently, some operators and service companies have applied a probability and risk assessment approach to collision analysis.

Operators have identified a higher level of risk (likelihood and consequences) for near surface well intersections due to the proximity of drilling slots, and consequences of near surface release of gas and oil. To account for the higher risk scenario a different set of collision avoidance rules are often prepared for the surface casing section of the hole.

3.2.3. Relief and Intercept Well Planning

Relief wells and intercept wells have unique planning requirements because they are designed to purposely intersect a target well at a specific depth. Additionally, the well trajectory details are generally developed and revised in near real-time to address time-critical activities. Basic elements of the survey tools used for relief and intercept well surveys were presented in Section 2.3 Ranging Tools.

Because of the publicity that usually surrounds relief wells, they are certainly the most widely known. Most often, the interception is made by milling into the casing of the target well, some distance above the last coupling. However, many more intercepting wells are drilled for the purpose of plugging a well before it is abandoned (so-called "P&A" projects) or for re-entering previously drilled wells ("re-entries"). Under these circumstances, the location of the interception is usually less critical, and perforating guns may be used to establish communication between the two wells. Ranging systems also are used to guide sidetracks around boreholes that have become plugged with a broken tool or a twisted off BHA. In such circumstances, guiding the active well around the obstacle so that drilling can be continued in the formation below requires less accuracy than most interceptions. So the starting point in any discussion of accuracy should be the purpose of the intercepting well or sidetrack, and the type "completion" the situation requires.

The ranging strategy for a relief well is only one of several elements of a relief-well plan. Other important elements are:

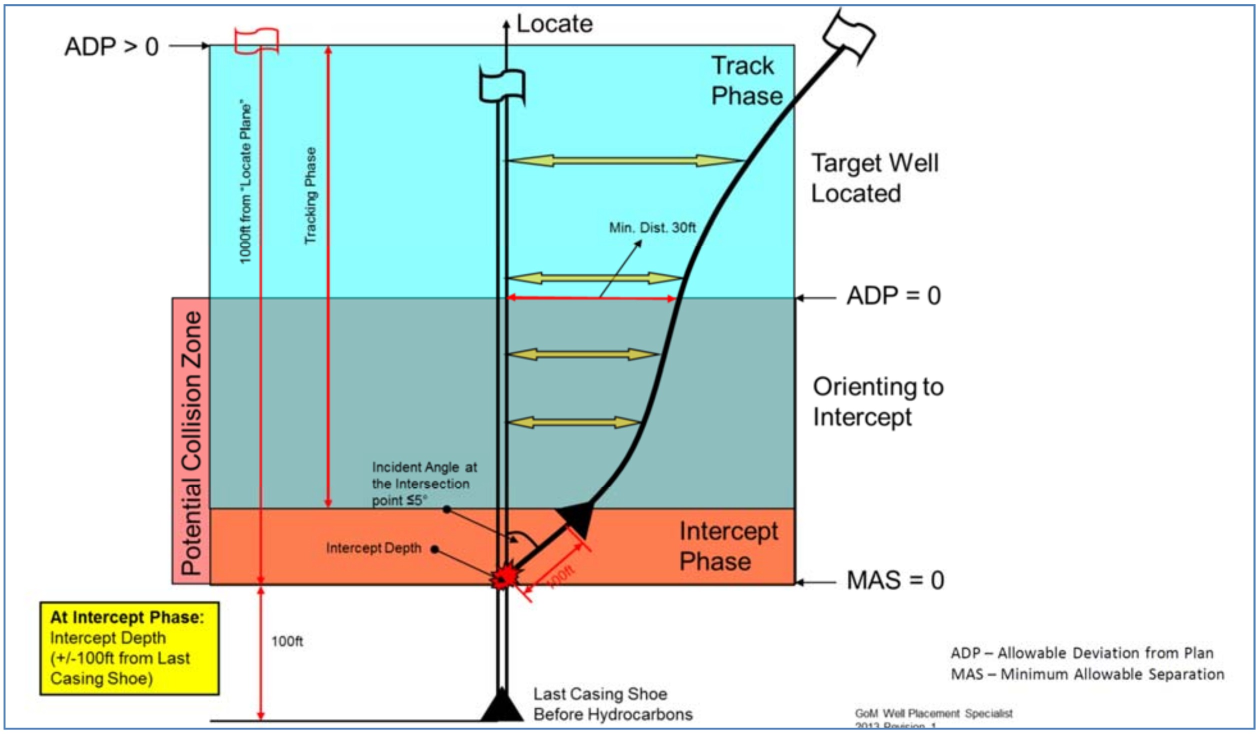
- Relief well objectives and constraints;
- Casing plan, including geology, pressures, etc.
- Directional plan, including trajectory, attack angle, survey program and uncertainty;
- Kill plan, including kill point, intersection & communication strategy, hydraulics; and
- Required services, equipment, and materials

The general sequence of activity for both relief and intercept wells includes five stages, each employing some aspect of ranging strategy (Goobie, 2015). Figure 10 illustrates the details of the conceptual design for the track and intercept phases.

- **Data Gathering** – Collecting known information on the wells and subsurface conditions to identify the best approach for intercept. In this stage the accuracy of the well path (ellipses of uncertainty) are reviewed and refined if possible. Precise definition of the position of both wells improves the level of confidence in locating, tracking and intercepting the blow out well (Goobie, 2015).
- **Drilling** – Accurately drill along proposed well path at a distance from the surface to a point at which the target well can be located using ranging techniques. Use MWD or gyro survey to accurately determine positon of well at all times.

- **Locate** – Establish the presence of the target well using ranging technology and continue drilling alongside the target well.
- **Track** – Continue drilling while maintaining a known and safe distance from the target well using sensitive ranging technology. Decrease distance to target well and maintain an appropriate angle for intercept.
- **Intercept** – Make physical connection and communication with the target well, or its immediate environment (cement).

Figure 10: Conceptual Design of the Track and Intercept Phases of a Relief Well



From Goobie, 2015 SPE/IADC-173097-MS, reproduced with permission

The maximum ranging distance of the tools selected for use is an important consideration for relief well planning. This is normally a situation-specific decision that is affected by many environmental and drilling factors, and is likely to change as the relief or intercept target is approached. See Section 2.3.2 for more detailed information on the factors affecting passive systems range of detection. Generally active ranging tools are effective at distances of 100-150 feet from the target, and passive ranging tools are effective when the target is less than 40 feet.

3.3. Survey Operations

Real-time wellbore position data are collected during drilling and used to avoid intersecting adjacent wellbores and to accurately reach the geologic target. These measurements also form the basis of the permanent well trajectory record that will be submitted to the regulatory agency and used by others to ensure safety in subsequent operations.

3.3.1. Surveying Under Normal Operating Operations

The execution of the well survey plan is conducted as part of the normal directional drilling process. Before drilling begins the directional drilling company and survey company conduct pre-spud meetings to review all plans and contingencies, then mobilize the drilling and survey tools to the offshore rig or platform.

Essentially all offshore directional drilling in the U.S. is performed using MWD tools as the primary source of well survey and position data. MWD tools transmit azimuth and inclination position data uphole as the well is being drilled. In some cases gyro tools or other surveys may be run during or after a drilling run to provide QC or tie-in data from previous surveys.

3.3.1.1. Pre-survey Operations

Prior to placing a tool in service downhole the tool is checked for operational functionality. Although this step is often referred to as “calibration” this step is actually a calibration check because the tools are not adjusted to change the sensor outputs[7]. Service companies have developed Field Acceptance Criteria (FAC) for tool checks to ensure tools are functioning within an expected range. Examples of tool checks are provided in Attachment A.

Other checks are made to ensure the reference points the tool will use are accurate and minimize the risk of gross error. These include:

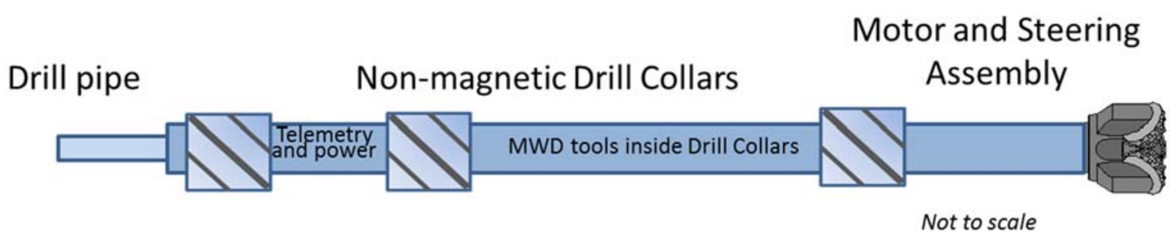
- **Well tie-on location.** For surveys that are run over a deeper interval than the previous survey and not run to surface, a tie-on point that links the two surveys is defined.
- **Surface hole location.** The latitude and longitude, or UTM coordinate of surface hole location is verified, and the accuracy of that location (and reference points) are documented. The surface hole location is important for absolute positioning, and is critical to the survey quality assurance program for comparing to local magnetic field strength and earth rotation.
- **The magnetic declination** (the angle between True North and Magnetic North as measured from True). The date and time when the declination was determined (magnetic north varies over time) is recorded and the sign of the declination measurement is checked (easterly declination (clockwise) is positive and westerly declination (anticlockwise) is negative).
- **Map reference and grid convergence** (the angle between True North and Grid North as measured from True North). The map projection is identified (Lambert, Universal Transverse Mercator) and the convergence value checked to ensure it is applied accurately (easterly convergence (clockwise) is positive and westerly convergence (anticlockwise) is negative). The datum to be used (NAD27, NAD84) is also verified.

[7] Calibration, as used in this document, refers to procedures at the manufacturing facility and shop to test tool performance under controlled simulated field conditions, and make adjustments to the outputs so that tools meet specified performance and measurement standards.

- **Toolface offset.** The angle (in the X-Y plane) needed to align the MWD tool with the toolface of the BHA.
- **Elevation reference** and other relevant data are collected and verified. Elevation reference is particularly important on deep water wells drilled from a drill ship or rig which is removed before production. Depths need to be referenced to permanent datum such as MSL or the mud line. The distances from the drilling/survey reference (Kelly Bushing or drill floor, etc.) to the water (MSL) and the water depth are needed for future reference.

MWD tools are placed in non-magnetic drill collars of sufficient length to allow the measurement of the earth's magnetic field without magnetic interference. Non-magnetic drill collars were developed to allow magnetic surveying of the well trajectory, and were originally made of Monel (a nickel-copper alloy with high tensile strength and resistance to corrosion) but, due to cost have been replaced by stainless steel. Figure 11 shows the placement of the MWD and non-magnetic drill collars in the BHA. Directional survey tools are often located more than 30 feet above the drill bit to allow for drill motors and other steering assemblies, and to avoid magnetic interference from the lower BHA. When making up the BHA the MWD tool must be aligned and oriented properly with the other BHA components to ensure it accurately reflects the orientation of the bit face. Misalignment of MWD tools can be a source of error in directional measurements.

Figure 11: Bottom Hole Assembly showing location of MWD Tools



3.3.2. MWD Survey Frequency

During drilling, the MWD tools transmit measurements at predefined intervals or times, usually every stand (three drill pipe sections, or 90 to 96 feet), or at some other intervals depending on the project and regulatory requirements. In some sections of relatively vertical holes, directional measurements are taken at less frequent intervals, for example every 300 to 500 feet; and at some critical points, such as high build angles (doglegs), data are collected every pipe joint (30 feet). The ISCWSA error model documentation recommends that the survey interval be no greater than 100 feet (30 m) (ISCWSA, 2016b). Industry studies suggest that collecting measurements every 60 feet in high dogleg sections reduces depth error significantly. Well survey plans must balance the need for directional data, and the additional rig time required for taking readings with some tools. Battery powered survey systems take surveys when the pumps turn off then transmit when the pumps come back on, and no additional rig time used.

In most deep-water offshore locations, MWD tools are used in upper sections because their inclination readings are useful for determining if the well should be "nudged" to retain separation from nearby wells and the readings of the magnetic field magnitude and dip angle can be used to determine when magnetic measurements can be relied on (when the readings are no longer affected by interference from nearby wells and equipment). If there's any doubt or reason for concern, a wireline or drop gyro tool can be run inside the drill pipe.

The frequency of MWD survey stations (survey measurement points) can affect the quality of the directional survey data when widely spaced survey points are collected and used to calculate curvature between survey points. Widely spaced data may result in a wellbore trajectory that is significantly different from the actual trajectory between points. Because positional errors are propagated downhole the uncertainty of bottom hole location can be significantly affected by MWD survey frequency.

MWD tools can also be run in a continuous mode, however not all service companies offer this alternative. In the continuous mode measurements are made in the same manner as in the stationary survey mode but are taken at specified time intervals during drilling and periodically transmitted uphole. In order to acquire reliable continuous survey measurements the tool must compensate or correct for the effects of shock, vibration and drill string rotation.

3.3.2.1. MWD Survey Analysis

Wellbore survey data is used during drilling to avoid obstacles (anti-collision) and steer the bit along the planned well trajectory. Once received uphole, data are stored, corrected if necessary, and analyzed to determine the current location of the drill bit. In offshore operations wellbore positioning data analysis and corrections are performed using directional drilling software, typically the same program used for well planning (refer to Section 3.2.1 for a discussion of well planning software). For many operators an independent concurrent data analysis is performed onshore or at remote locations for quality assurance and safety management.

Directional survey measurement data is often corrected for environmental effects prior to use in steering and anti-collision analysis. Most commonly readings are corrected for BHA sag, and many are further corrected for variations in the local magnetic field, and pipe or wireline stretch. Sag and local magnetic field corrections are often the largest source of error in survey readings. These corrections are described in greater detail in Section 3.5. Uncorrected survey data results in larger uncertainties in the position of the wellbore.

During drilling quality control procedures are conducted to ensure the tools are operating properly and measurements accurately represent the wellbore position. These quality control checks sometimes require re-occupying a previous survey station or collecting repeat readings at new stations, and are described in greater detail in Section 3.6. Survey data are often sent simultaneously to the rig and an on-shore facility for quality control and decision analysis support.

After corrections are made with the software, directional survey data are reported in a table format and reviewed by the driller for steering and anti-collision analysis (Figure 12). The driller analyzes the positional data to determine if any changes need to be made to correct or maintain the trajectory. Most directional drilling programs provide an estimate of the amount of deviation between the plan and actual position, and an estimate of the uncertainty in position, expressed in feet, as well as a plot showing the planned and actual trajectories, similar to the one shown in Figure 12. As part of the analysis the driller may consider the magnitude of the deviation from plan, and the ability of the existing

BHA to correct the deviation. Drilling programs can also provide a "look ahead" calculation to extrapolate the bit location at the next survey point.

Figure 12: Example of Directional Survey Data Report

(Def Survey)

Report Date:	November 05, 2015 - 01:42 PM	Survey / DLS Computation:	Minimum Curvature / Lubinski
Client:	BP	Vertical Section Azimuth:	64.610 ° (Grid North)
Field:	Fall ATW Training Field	Vertical Section Origin:	3.361 m, 3.551 m
Structure / Slot:	A Structure / 9	TVD Reference Datum:	Rotary Table
Well:	A9 Well	TVD Reference Elevation:	68.300 m above MSL
Borehole:	A9 OH	Seabed / Ground Elevation:	100.000 m below MSL
UWI / API#:	Unknown / Unknown	Magnetic Declination:	-0.480 °
Survey Name:	A9 Keeper + MWD ft	Total Gravity Field Strength:	1000.9965mgn (9.80665 Based)
Survey Date:	April 10, 2012	Gravity Model:	DOX
Tort / AHD / DDI / ERD Ratio:	91.965 ° / 1493.290 m / 5.715 / 0.527	Total Magnetic Field Strength:	49951.532 nT
Coordinate Reference System:	UTM Zone 31N - WGS84, Meters	Magnetic Dip Angle:	70.120 °
Location Lat / Long:	N 56° 10' 40.52341", E 3° 27' 36.36214"	Declination Date:	April 10, 2012
Location Grid N/E Y/X:	N 6225977.520 m, E 528563.380 m	Magnetic Declination Model:	BGGM 2011
CRS Grid Convergence Angle:	0.3822 °	North Reference:	Grid North
Grid Scale Factor:	0.99961001	Grid Convergence Used:	0.3822 °
Version / Patch:	2.8.572.0	Total Corr Mag North->Grid North:	-0.8622 °
		Local Coord Referenced To:	Structure Reference Point

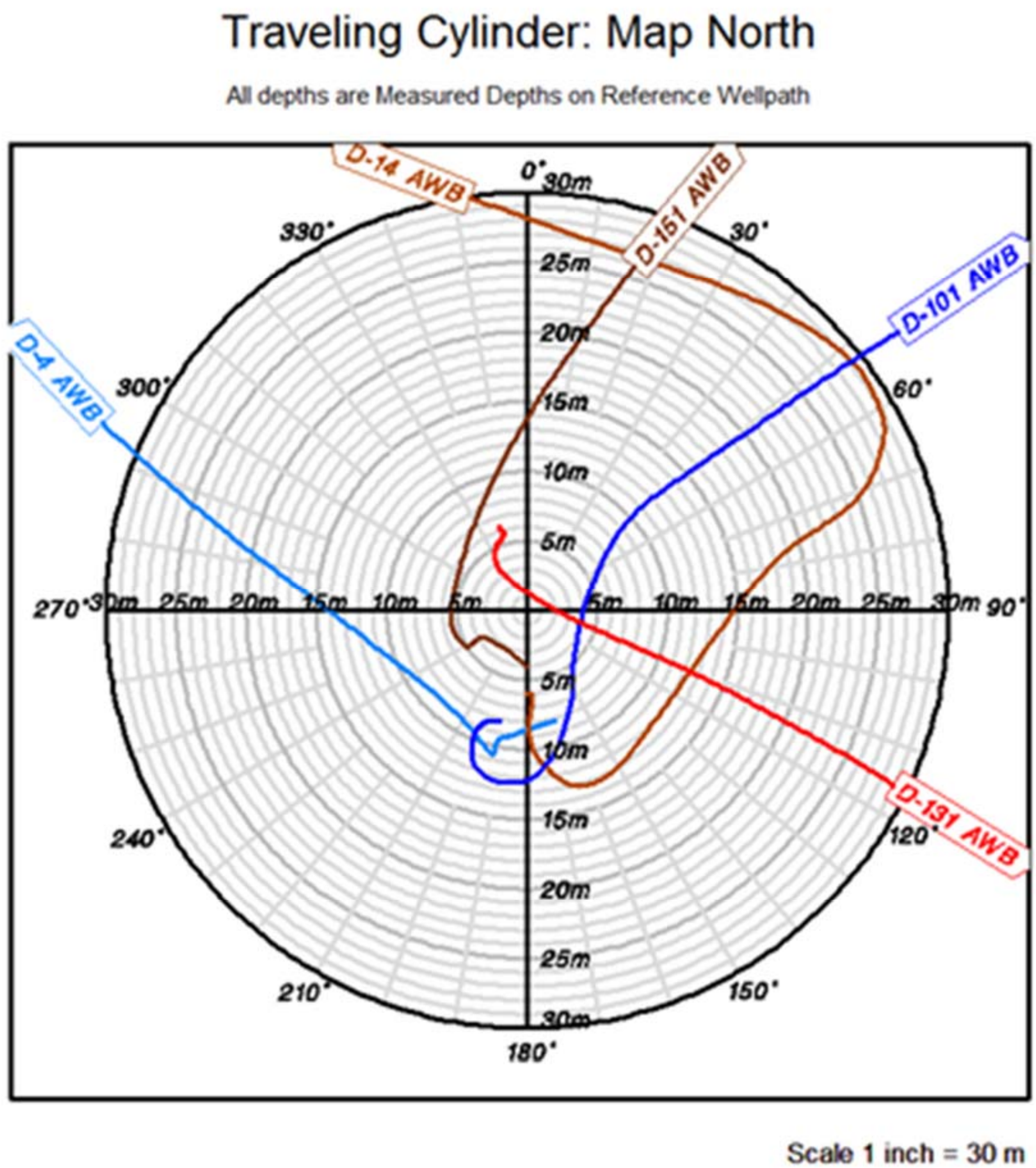
Comments	MD (m)	Incl (°)	Azim Grid (°)	TVD (m)	VSEC (m)	NS (m)	EW (m)	DLS (°/30m)	Northing (m)	Easting (m)	Latitude (N/S ° ' ")	Longitude (E/W ° ' ")
	3048.00	16.46	60.11	2629.79	1428.17	613.47	1294.85	0.52	6226587.39	529854.18	N 56 10 59.96	E 3 28 51.46
	3077.00	16.88	60.32	2657.57	1436.47	617.60	1302.07	0.44	6226591.52	529861.39	N 56 11 0.10	E 3 28 51.88
	3105.00	16.46	60.40	2684.39	1444.48	621.57	1309.05	0.45	6226595.49	529868.37	N 56 11 0.22	E 3 28 52.28
	3134.00	15.28	59.14	2712.29	1452.38	625.56	1315.90	1.27	6226599.48	529875.22	N 56 11 0.35	E 3 28 52.68
	3171.00	15.78	58.76	2747.94	1462.24	630.67	1324.39	0.41	6226604.59	529883.70	N 56 11 0.51	E 3 28 53.18
	3189.00	16.67	59.33	2765.22	1467.24	633.26	1328.70	1.51	6226607.17	529888.02	N 56 11 0.60	E 3 28 53.43
	3216.00	17.32	58.20	2791.04	1475.09	637.35	1335.45	0.81	6226611.26	529894.76	N 56 11 0.73	E 3 28 53.82
	3244.00	17.71	57.64	2817.74	1483.46	641.83	1342.59	0.46	6226615.74	529901.90	N 56 11 0.87	E 3 28 54.24
	3261.00	17.98	58.20	2833.92	1488.64	644.60	1347.01	0.56	6226618.50	529906.31	N 56 11 0.96	E 3 28 54.49
Interpolation	3194.00	16.79	59.11	2770.01	1468.68	634.00	1329.94	0.81	6226607.91	529889.25	N 56 11 0.62	E 3 28 53.50
												E 3 27 41.81

From Course Materials for SPE Well Placement and Intersection Best Practices workshop, November 2015

For anti-collision analysis, the software program provides an estimate of the wellbore position uncertainty, based on the corrections and tool error models selected in the software. If there are wells nearby the software will calculate the separation distance and separation factor. Some software programs compare separation distance to company anti-collision rules (minimum distance and acceptable separation factors) and generate a warning if rules are violated. For visualization of the anti-collision potential, the Traveling Cylinder plot is commonly used. The travelling cylinder is a radial projection showing the current location as a point at the center of a disk onto which the paths of nearby offset wells are plotted (Figure 13). It is a view looking down the wellbore along the proposed trajectory at a specific depth. A point on a travelling cylinder is specified by the radial distance from the center of the plot, and the angular direction to a point on the offset well. Traveling cylinder plots are generally referenced with north at top (twelve o'clock) position. In Figure 13, five offset wells located within 30 meters of the planned wellbore are shown along the drill path, and well D-131 is within a few feet of the current well path. Travelling cylinder presentations often present the depth of the nearby wells along their well paths.

In practice on offshore rigs, the well positon data is often plotted on a traveling cylinder plot by hand, which is posted in a centrally located place on the rig. This practice encourages communication between the survey team and the drilling team and is believed to improve the visualization and recognition of drilling obstacles.

Figure 13: Traveling Cylinder Plot

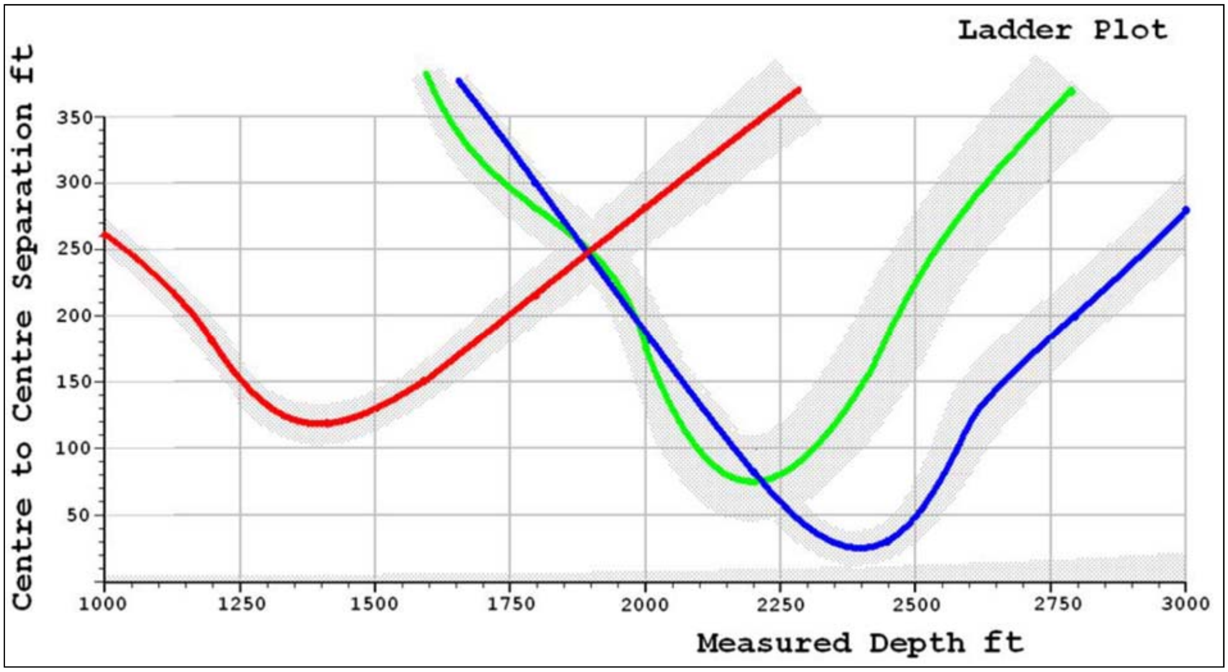


Traveling Cylinder example courtesy of Dynamic Graphics Inc., reproduced with permission.

Another common plot for anti-collision analysis is the ladder plot, showing the separation to target wells against the measured depth of the well being drilled. Ladder plots are most useful when the uncertainty of the well positions is included, as shown in Figure 14. Most directional drilling software allows for many other types of visualizations including three-dimensional renderings of all nearby well trajectories (Figure 15).

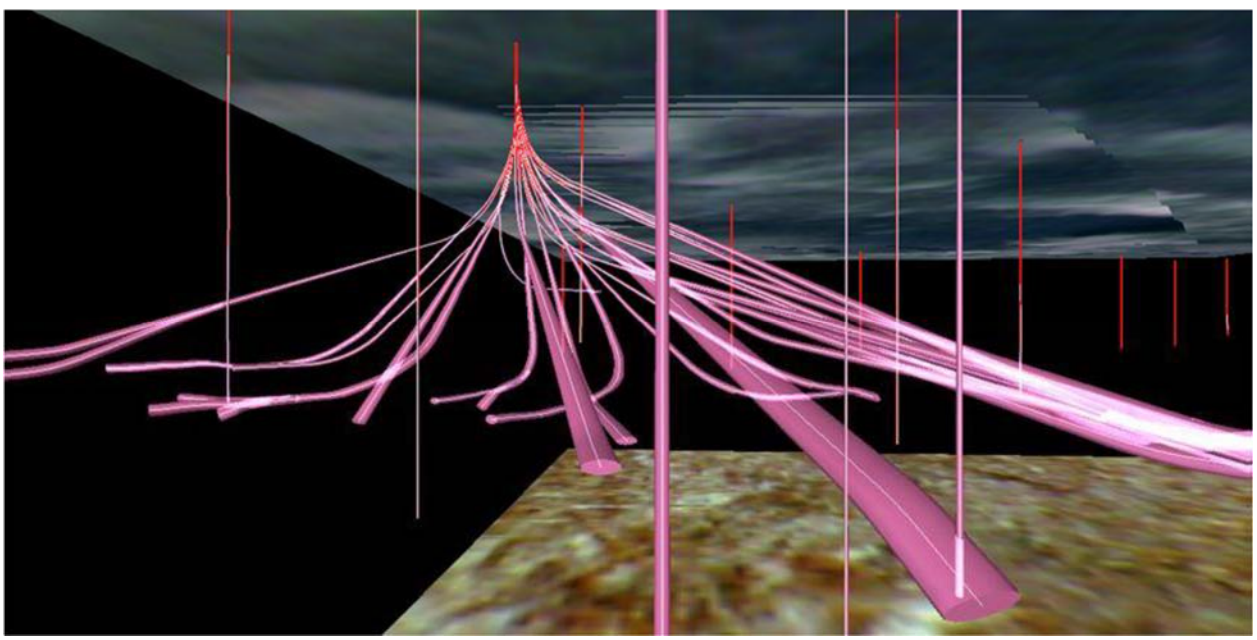
Figure 14: Ladder Plot with Uncertainty Ranges

From



From Introduction to Wellbore Surveying ISCWSA, 2016b

Figure 15: Three Dimensional Spider Plot showing Multiple Wells from the Same Platform



From Introduction to Wellbore Surveying ISCWSA, 2016b

3.3.2.2. Survey Concatenation

Multiple runs of the same tool combination with different BHAs are often run. Additionally, gyro surveys are sometimes run over sections that have already been surveyed with MWD tools. Concatenation is the process of integrating and stacking the surveys to create a final comprehensive survey of the wellbore. A critical aspect of the concatenation process is assigning the correct tool code to the survey section to facilitate tool error modeling. Operators and service companies have jointly developed specific requirements for combining surveys, but generally all require that each depth point has a unique and single set of survey data associated with it, and that no interpolated, projected or estimated data be included in the definitive (also referred to as the final survey). Tie in points for where two subsequent surveys are connected are required to be identified. Concatenated surveys do not include interpolated data (some operators request data to be regenerated at even depth increments, such as every 100 feet).

3.3.3. Gyro Surveys

Gyro surveys[8] can be run to provide an interim or final directional survey of the wellbore trajectory. The advantage of using a gyro survey is that it is not affected by magnetic interference and can be run in cased hole. Gyro surveys are most commonly run on wireline or as drop tools, but may also be included in some newer MWD systems. In MWD systems gyroscopes are more likely to be affected by shock and vibration than magnetometers and accelerometers, so rough drilling conditions may preclude their use. Historically the industry has considered rate gyro surveys to provide a more reliable and accurate description of the wellbore position. While this was true for older surveys, some industry experts now debate if modern MWD tools combined with a better understanding of the error sources and corrections provide MWD data that is of comparable quality as gyro tools.

Surface sections of wells are normally surveyed with gyro tools because the high magnetic interference from other wells and equipment make magnetic surveys ineffective. It is commonly assumed that surface conductor casings are driven straight and plumb, but this is not always the case. It is not uncommon for driven conductors to cross two rows of slots from their original surface position (ISCWSA 2012), therefore accurate surveys are required in conductor casings.

Wireline conveyed gyro tools are often run as a quality check after a section of hole is drilled with MWD. Other common uses for gyro surveys include:

- In sections with high dogleg severities (exceeding 6°/100ft) and MWD survey points are every stand (90 feet) or more. Gyro surveys can provide a higher resolution using very small station intervals (commonly 25 feet).
- In collision risk sections of the wellbore where the separation factor requirements cannot be met using MWD alone.

[8] Unless otherwise specified the description of gyro surveys refers to the use of north seeking rate gyros, which have been the standard in the industry for many years. Occasionally legacy survey data may include free gyros used in near surface single shot applications.

- In side-tracks where the original hole contains a fish, or casing and the accuracy requirements demand an adequate survey during the side-track section close to the original hole.
- Anywhere the survey accuracy cannot be met with MWD surveys, including lease lines, geologic hazards, fault blocks, and tight reservoir targets.

When gyro surveys are run over an interval previously surveyed by MWD, the ellipse of uncertainty for the MWD section is reduced due to the more accurate nature of gyro readings[9]. If drilling with MWD resumes below the gyro survey, the ellipse of uncertainty for the new MWD section will be smaller than if the gyro were not run. For this reason, gyro surveys are often used to decrease uncertainty in critical sections of the hole, such as when approaching the geological target. When switching between gyro and MWD surveys, a survey station where both data are collected is identified as a reference point to compare and transition the results of the surveys. This survey station is called a tie-in point (also called a tie-on point) and is a critical part of survey quality control procedures, and required to be identified in submittals to some regulatory agencies.

High temperature environments are a challenge for gyro tools, and as described in Section 2.2.4. This study identified no tools available for high temperature applications (operating at 350°F (176° C) for extended periods of time.

During drilling quality control checks are conducted to ensure the tools are operating properly and measurements accurately represent the wellbore position. The most common check is to collect gyro survey data at the same survey station depths while tripping/running in and out of the hole. These quality control checks are described in greater detail in Section 3.6.

3.3.4. Surveying for Ranging Applications

Each relief well and intercept well operation will have unique conditions that require site-specific analysis and decisions. One relief-well drilling strategy that has been found to have wide support is to use an active ranging tool first, to obtain an initial range and bearing to the target before the two ellipses of uncertainty overlap (the “Locate” phase). Then drill ahead with a passive MWD-based ranging tool until it provides an acceptable range and bearing, or until the ellipses overlap (the “Track” phase). If an unintentional interception is not acceptable, additional runs of an active tool should be considered if the ellipses overlap and the passive tool has not provided an acceptable range or bearing. This sequence should normally be repeated until the range and bearing from the passive tool are acceptable, after which it can be used to guide the bit until the time comes for the interception.

Passive ranging tools have two disadvantages in interception situations. First, their magnetic sensors are typically at least 30 feet above the bit, so the actual position of the bit is based on an extrapolation. Secondly, the ability of a passive tool to accurately determine range and bearing to a casing diminishes as the range decreases. Conversely, the accuracy of an active tool increases when it is close enough to use gradient measurements. During operations the tool selection and operational conditions must be considered.

[9] This assumes that the gyro is within calibration, and is operated in accordance with all specifications and parameters that are contained in the gyro tool error model.

It is generally believed that an active ranging tool should be used to guide the actual interception, especially if the plan calls for milling a window in the casing of the target well. If communication between the two wells is to be established by perforating or in open hole by breaking down the formation, the accuracy requirements are less, and the use of a passive ranging tool during this phase may be acceptable. This choice should be made considering the consequences of intercepting the target well above the planned location, the consequences of drilling past the planned interception point, and the time and cost associated with running an active ranging tool.

Ranging operations may require many ranging runs to provide the level of accuracy for proximity information required to intercept a wellbore. Industry experts have noted examples where in some cases multiple ranging runs have been made after advancing the bit one joint (about 30 feet) or even as little as 5 to 10 feet in sensitive operations. The intercept team must balance the time required to collect additional survey measurements, which may require tripping out of the hole and adds one to two days on a deep well, against the likelihood of intercepting the well. Failure of intercept could require the hole to be plugged back to a safe depth and re-drilling a sidetrack which could take considerably longer than collecting the additional data for determining accurate bit location. In HSE wells the decision becomes critical.

3.4. Data Management

Data management occurs across the survey lifecycle and is a key component to ensure the safe and efficient drilling of offshore wells. Because data management is integrally related to planning, operation, error and uncertainty modeling, and survey quality, certain aspects of the applications of data management are covered in other sections.

In this section, two general categories of data are discussed – completed survey data reports and survey data components. A completed survey data report includes the final or definitive data on wellbore position (measured depth, inclination, azimuth, calculated northing and easting, TVD coordinates, vertical section, and dogleg severity), along with header information that represent the location and survey conditions. This is generally the data set provided to regulatory agencies for the permanent record. Survey data components include all the information that are used to generate the final wellbore position including the raw data (if available), operating conditions, tool error codes used, survey corrections applied, calibration and QC data, signoffs and approvals, and any ancillary data that was used to generate the final survey.

3.4.1. Planning

The data management procedures required for wellbore planning are one of the most critical components for ensuring safety in offshore drilling. During the planning process the universe of risks that may be encountered during drilling is identified and addressed. The data set used to identify and quantify the potential risks must be thorough and accurate so that well planners and those responsible for review and approval address all potential risks.

Wellbore planners rely on a database to identify all potential wells with risk of collision. This database is developed and maintained by the operator, directional service company or third party software service that specializes in oil and gas data management. Databases for offshore fields can be very large and commonly use a sophisticated database software system such as Oracle or SQL Server. These databases are used for many activities including regulatory reporting and asset inventory, wellbore planning and future field development, collision avoidance, reservoir modeling, hydraulic fracturing analysis and P&A planning.

Data sets contained in the databases are available from a number of different sources including databases managed by the regulatory agencies (BSEE, Texas Railroad Commission, and other state agencies), commercially available data sets from oil and gas data suppliers[10] (TGS, DrilingInfo, EGI, LEXCO, and others), and organic data sets prepared and maintained by operators (data assets of the operator and partners). Well planning is most commonly conducted using data that has been thoroughly evaluated for completeness and quality, and is part of an auditable data management system. Operators invest significant resources into developing reliable and auditable data sets that become the “definitive database” for all well and field planning. ISCWSA anti-collision best practice (ISCWSA, 2014a) states that there should be only one Master Database that is free from errors and remains free from errors as new data are added over the life of the field.

Errors and incomplete data in regulatory databases are not uncommon. One industry expert contacted for this study noted that in a recent database integrity study of 10,000 wells in a regulatory database, the mean difference in the accuracy of surface location was 67 feet, with the 3-sigma standard deviation more than 200 feet. A recent presentation from a data management company estimated that 15 to 20 percent of the drilled wellbores are missing in regulatory databases (Stolle, 2013). The nature of the error can be incorrect surface locations, which displaces location of the entire wellbore, or incorrect and missing wellbore survey data which may affect all or only portions of the wellbore. Some examples of database errors are provided in Attachment A.

Offshore operators have recognized the importance and value of accurate well databases. The data represents a valuable company asset and the database is commonly considered safety critical software which is subject to stringent quality control and security policies. Wells drilled recently tend to have better quality data, as do fields currently under development. Generally these databases have been scrubbed and checked. Offshore fields that have undergone change in ownership present a challenge, especially if those fields are older and have had multiple operators. During the asset transfer data and information can be lost or corrupted.

Database integrity and security during planning are important aspects of the data lifecycle. During planning multiple iterations of a well plan may be generated and stored in the working database. Some companies retain the working files to document the workflow and support audit requirements. Changes are sometimes made to wellbore trajectories after approval and company signoff or submission to regulatory agencies. These changes should be reflected in the final wellbore plan. At some point the well plan is locked for editing and a final version of the plan is entered into the definitive database for later use.

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[10] The source of data for commercial database is often based on regulatory submissions that have been subjected to rigorous quality control procedures.

3.4.2. Operations

During survey operations, real time position data are collected, transmitted to the surface and onshore offices for analysis, and stored in a database. Generally, the data sent to the surface includes a computed inclination and azimuth value and other supporting information. Data may include a set of inclination and azimuth readings from each of the sensors[11]. Other quality control and operating condition information is collected and transmitted, although not all companies choose to retain the "raw" readings and information. Raw data is a valuable asset for quality control and provides the ability to reconstruct the final survey readings.

Some service companies can modify the type of data collected and transmitted to the surface and offer a comprehensive suite of information for the user to manage. The amount of data that can be sent to the surface through mud pulse systems is limited by the data pulse size and complexity (see description of mud pulse transmission systems in Section 2.1.1). Wireline platforms are not restricted by pulse size and allow for a large amount of data to be transmitted to the surface rapidly. Battery powered systems use onboard data storage memory and may limit to the amount of data collected and stored especially in long survey sections.

Log header information provides critical data to perform corrections and conduct quality control checks. Historically the header information submitted with a directional survey contained survey company information, well name and general location and reference data, but did not provide any insight to the map or magnetic references used, or the various tool error models applied to the data. Newer survey data files provide a thorough understanding of the conditions under which the data was acquired and presented. Header data is part of the permanent well file and should be verified at the time of the survey.

3.4.3. Final Survey and Data Archiving

Upon completion of all surveys, a final or definitive survey data set is established for permanent record and submittal to regulatory agencies. The definitive survey may include position data that is a combination of more than one survey, but in no case includes duplicate data points, except where required for tie-in accuracy demonstration. For example, if MWD data is initially collected during drilling to support steering and anti-collision, and subsequently a higher quality gyro survey is run over the same interval, the operator may choose to retain the gyro survey as the final definitive survey for that portion of the hole. After operators perform quality control and audit checks the final survey data are approved by a supervisor and are locked for editing and become part of the permanent well record.

When more than one survey run is used to generate the definitive survey, a survey reading from each run at a common depth is made to demonstrate accuracy between two surveys. The point at which the two surveys are linked is the tie-in (or tie-on) point. Tie-ins are based on actual readings and do not use

[11] Most MWD and survey tools determine their orientation by sensing two sets of data along the three axes of the tool (X, Y, and Z, which is the longitudinal axis). Thus the raw data will contain six sensor values, three from accelerometers (for gravity), three from magnetometers (for the magnetic field) or three from two rate-sensing gyros (for earth's spin rate), plus data-quality and other house-keeping values. Some gyro-based survey and MWD tools have only one rate-sensing gyro, so they measure and can store only two axes for the earth's rate (X and Y).

projections or interpolations of values between measurement points. Retention of all data sets may be necessary to provide demonstration that the overlapping surveys and tie-ins match.

The key elements in a definitive survey file are dependent on company polices and regulatory requirements and may differ within regions. Regardless, each definitive survey should represent the most accurate data for the wellbore preserved in a manner to ensure integrity and maximize future use.

Policies for the permanent storage or archive of well data are a company specific decision, and may be included in regulatory requirements[12]. Some international offshore operators consider data an asset and have developed survey data management plans and procedures for database development and maintenance that include requirements for access, user read/write permissions, workflows, accountability and auditing procedures. The intent of these procedures is to ensure data integrity.

Correcting data once it is archived or submitted is the subject of ongoing discussion in the industry. Operators conducting regular checks and audits on wellbore survey data often identify and correct mistakes and missing information in existing data. Changes to the operator's database are documented and become part of the permanent audit record. Discussions with operators indicate that once data are submitted to the regulatory agencies, it is generally not revised or resubmitted voluntarily by the operator, even if errors are discovered. Some operators felt that resubmission could create version control concerns or complicate the regulatory archive with multiple versions of the same data with only minor differences. Other operators felt that resubmittal might require extensive explanations and lead to additional data review and corrections.

3.4.4. Data Transfer

Well survey data is often transferred between many different teams during the asset life. Handoffs between the planning and execution teams, and between the completion and asset management teams may require data to be re-formatted to support the new user's needs. Regulatory agencies, such as BSEE and other state agencies may also have a specified electronic format for well survey data. There is currently no single data standard for well survey data. Most software programs used for well planning and survey analysis offer a wide range of output options for transfer. Major directional drilling software packages (Compass™, WellArchitect™, DrillingOffice™) have indicated that the format of the data output is not a significant challenge, and that all major outputs are, or can be supported. Examples of commonly used outputs are shown in Table 10.

[12] As an example, the U.K. (DECC PON-9) requires that operators retain all data for the term of the license and must provide it if requested. The discussion of regulatory requirements for well data is included in Section 4.4 of this report.

Table 10: Common Output Formats used in Well Survey Data Transfer

Output	Description
MMS/BSEE	ASCII file format compliant with BSEE requirements in NTL-2009-N10.
NPD	Data requirements from the Norwegian Petroleum Directorate.
Openworks®	Oil and gas project data management system that supports multi user collaborations and cross-domain workflow across asset teams and asset life. Developed and sold through Landmark (Halliburton).
UKOOA P7/2000	ASCII file format designed to support data exchange format for well deviation data as recommended by UK Offshore Operators Association. The format is widely used and generally regarded in the industry as good practice.
WITSML™ (maintained by Energistics)	Wellsite Information Transfer Standard Markup Language (WITSML) is a web-based XML technology for data transfer, which is both platform- and language-independent. It is broadly used in the transfer of survey data from the rig to communicate data to the operators. Some survey systems use WITSML to acquire the data from the MWD tools for real time data analysis.

3.5. Corrections and Tool Error Models

This section addresses three different, but related, concepts related to wellbore survey accuracy – the corrections made to compensate for the environmental effects inherent in the wellbore (such as magnetic influences), tool error models, which are used to calculate the mathematical uncertainty of the tool readings, and, the method of survey calculations. Neither error models nor corrections address unmodellable errors caused by human error (referred to as blunders or gross error). Gross errors may include wrong datum, incorrect reference data, missing data, misapplication of error models, transcription error and may other random error types. Gross errors are discussed in Section 3.6.1 Survey Quality Control.

Error modeling is a complex and highly specialized aspect of wellbore survey management. This section will provide a high level summary of the key aspects of error modeling that are necessary to understand their application in accuracy and survey management. More detailed discussion of error models is provided in referenced texts and professional papers.

Technically, the application of magnetic declination and grid convergence to azimuth readings is a mapping correction, not an environmental correction. Improvement of the declination value (via IFR) is an environmental correction of the same type discussed below. The reader is referred to ISCWSA *Introduction to Wellbore Surveying* (ISCWSA, 2016b) for a more thorough description of maps and reference corrections.

3.5.1. Environmental Corrections

Corrections are applied to survey data to correct for physical effects on MWD tools. These corrections commonly include:

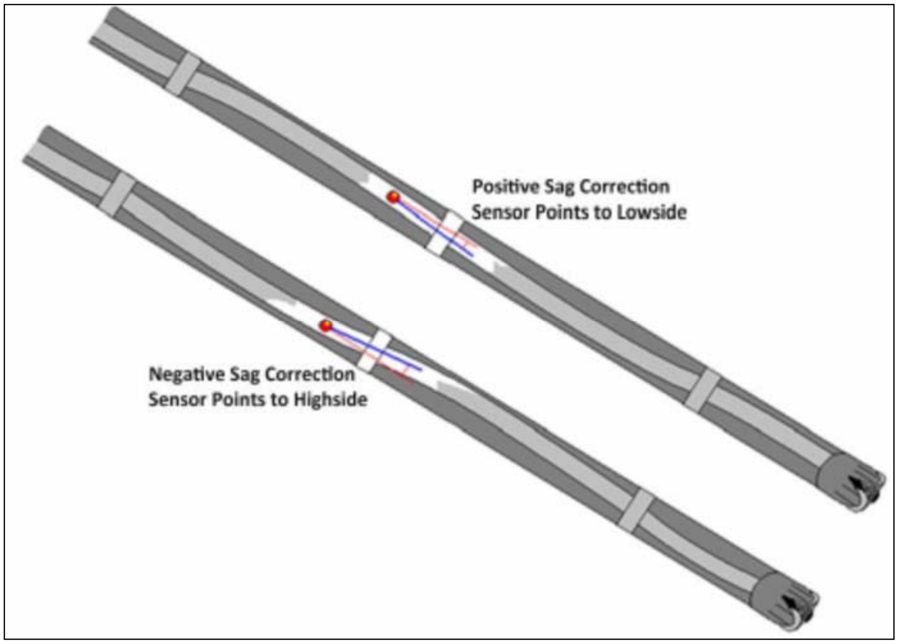
- Sag
- Magnetic field
- Short sub/short collar (magnetic interference)

3.5.1.1. Sag Correction

The length and diameter dimensions of drill collars is such that they will bend when traversing curved sections of boreholes, and will sag when not uniformly supported at higher inclinations. Collar-based MWD tools will sag between support points (typically stabilizers). Probe-based tools are subject to two types of sagging. The first comes from the sag of the collar between stabilizers. The second is caused by less-than-perfect centralization of the probe (or sonde) inside the collar. Gyro surveys conducted inside drill pipe also will experience sag. The effect is illustrated in Figure 16. The amount of sag is negligible at low inclinations but increases as inclination increases. It is one of the most important corrections made in wellbores with high angles and can have a significant effect on TVD accuracy. To determine the effect of sag on the accuracy of directional measurements, it is necessary to know the locations of the support points, the stiffness of the collar and the probe (for probe-based tools), the locations of the directional sensors, and the inclination.

ISCWSA recommends that sections of the well with deviation above 45 degrees at any point should be sag corrected. The sag correction is most commonly applied using software that models the performance of BHA, or specifically designed for sag correction. To make the correction the survey operator must obtain information on the BHA that is in use including the size (ID and OD) and position of stabilizers, drill collars and subs present in the BHA, the bend for any steerable elements in the BHA, the mud weight, and expected survey angles. If the BHA changes a new sag correction calculation must be determined and applied to that hole section. Calculations can also be made manually.

Figure 16: Misalignment Due to Drill String Sag



From Introduction to Wellbore Positioning (ISCWSA 2016b)

3.5.1.2. Local Magnetic Field Correction

The azimuth measurements made by magnetic sensors rely on referencing to the earth's magnetic north pole. The magnetic pole is normally thought of as a fixed and stable reference, but in reality it changes in both strength and location over time. In addition, the magnetic pole is buried deep within the earth and not at the geographic north. Readings from the magnetometers must be adjusted to reflect the correct north reference.

The strength of the earth's magnetic field is made up of three component fields; the main field, crustal variations, and diurnal variations. Each field has some variability that can be identified and corrected to improve the accuracy of magnetic azimuth readings. Attachment A provides additional information on the magnitude and methods for improving the accuracy of each magnetic field component.

3.5.1.3. Magnetic Interference (Short Collar) Correction

Non-magnetic drill collars that house magnetic field sensors must be long enough to effectively isolate magnetic components (drill string and BHA) from the magnetic interference caused by the components. In some cases non-magnetic drill collars are not long enough to isolate the magnetic sensors from the magnetic interference of the drill string. The effect of the "short collar" will be reflected in the axial component (along the drill string) of the total magnetic field. The magnitude of the interference can be calculated manually or with software programs. The most common and simplest method for correcting for short collar is the single station analysis or rotational shot analysis and requires collecting multiple magnetic sensor readings at the same depth while rotating the drill string. If the total magnetic field is accurately known (from IFR) and the x and y components of the field are measured, the z, or axial component can be identified and corrected. Other methods, such as multi station analysis, addressed in Section 3.5, can also be used for short collar corrections.

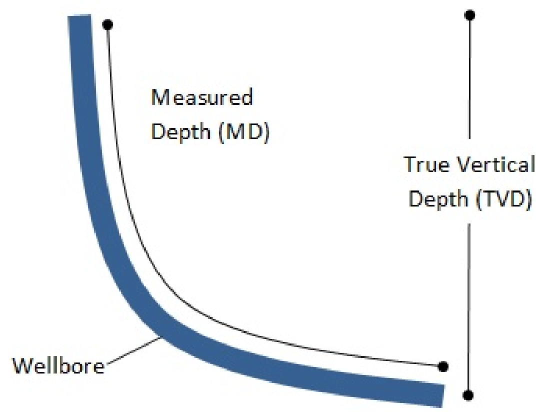
Corrections for magnetic interferences of the drill string are sensitive to high inclination, latitude and azimuth of the wellbore. At high latitudes, such as Alaska[13], the horizontal component of the magnetic field is small so the effect of magnetic interference has a large effect on the accuracy of the magnetic reading. Likewise, when drilling at a high angle in the east-west direction the axial component of the magnetic field is small and uncertainty in the total field may be greater than the effect of the drill string interference.

3.5.2. Depth Errors

Direction and inclination measurements are tied to a depth. Depth errors add to positional uncertainty and if not addressed will misrepresent the actual ellipse of uncertainty or proximity to a downhole hazard. The depth of a borehole, both during directional drilling and as a permanent reference, is a critical safety data point to ensure safe drilling. Knowing the correct depth of a well at all points along the trajectory helps avoid well collisions during drilling, and provides accurate steering of the drill bit to the target depth and location.

[13] SPE paper 173047-MS presents a discuss of Anti-Collision Considerations for Arctic and Other High Latitude Locations

Figure 17: TVD versus MD



During drilling, depth measurements are calculated based on the length of the drill pipe and wireline depth measurement methods. True Vertical Depth (TVD) is the vertical distance from a point in the well to a point on the surface (Figure 17). TVD is independent of the directional path of the wellbore. TVD is important in determining bottom hole pressures, which are dependent on hydrostatic head of the fluid in the wellbore. Measured Depth (MD) is the length of the path of the wellbore, which will only be equal to TVD for vertical wells (Figure 17). When no designation is given by drilling crews, depth typically refers to the MD. However, it is important for a designation to be given to allow for a complete understanding of the wellbore. MD is always longer than TVD, due to intentional or unintentional curvature in the wellbore.

Driller's depth is a measurement based on the depth of pipe going into the hole. This depth is determined from the pipe tally, measuring each pipe or collar at the surface and adding up the measurements. There are, however, several factors that can cause the driller's depth to be inaccurate (Table 11). The measurement of the pipe itself is a significant source of error, and human error in both the measurement (strapping or mechanical measurement system) and the tally can also affect accuracy.

Table 11: Factors Contributing to Drill Pipe Depth Error

	Potential error for a depth of 10,000 ft.	
Factor	**(m)**	**(ft.)**
Drill pipe stretch	5 to 10	16 to 33
Thermal expansion	3 to 4	10 to 13
Pressure effects	1 to 2	3 to 6
Ballooning effects	2	6
Other effects	1	3

From Theys, 1999

The allowance for depth measurement error for drill pipe depth in the ISCWSA error model is 1 foot of error per 1,000 feet of pipe.

In wireline survey operations, the cable lowered into the well is used as the depth measuring device, while the logging tool gathers other properties which can be related to the well depth. The cable is typically lowered into the well and drawn down using gravity, which can cause difficulties in highly deviated wells. In some cases, roller and power tractor subassemblies have been used to assist the cable in reaching the end of the borehole. Magnetic marks placed on the wireline cable (typically spaced every 10 to 100 feet) are used to help calibrate the raw depth, resulting in the Calibrated Depth. Calibrated depth that is corrected for cable stretch, temperature, and tension is called Corrected Depth. Corrected depth represents the best estimate of the true depth of the wellbore. Wireline depth corrections are often made in real time during logging or surveying by the service company.

Depth errors, reflecting either corrected or uncorrected depths, are included in MWD and gyro tool error models.

3.5.3. Tool Error Models

The accuracy of wellbore survey measurements can be affected by many factors. The effect of the major environmental effects, discussed above, can be quantified and corrected, but there are other conditions that create uncertainty in the readings, that are more difficult to correct. The uncertainty of the wellbore location is a critical safety factor used during wellbore planning and drilling to ensure there is safe working distance between wellbores. Tool error models, also referred to as an Instrument Performance Model (IPM), provide a mathematical estimate of the uncertainty of the survey station in the x, y, and z directions based on the average operational conditions of survey tools. The mathematical estimate is translated into distances from the wellbore in the x, y and z directions to generate an ellipsoid[14]. The actual location of the wellbore could be anywhere within the ellipsoid although the highest probability is at the survey coordinates (as per standard distribution).

ISCWSA is a voluntary group of industry professionals whose goal is "to produce and maintain standards for the industry relating to wellbore survey accuracy" and "(E)stablish a standard framework for modelling and validation of tool performance." (ISCWSA, 2016a) They have developed and maintained tool error models which have become the standard for the industry. The group's error model work focused initially on MWD systems because they provide a large proportion of the total directional survey data and there are many similarities between the various suppliers' tools, and have also developed tool error models for gyro surveys. The details of the models and their development are presented in two SPE papers; SPE-67616 (Williamson, 2000) and SPE-90408 (Torkildsen, 2008). ISCWSA members have published many other technical articles that describe the models, and have made available worksheets and examples to support use of the error models. These materials are available through the ISCWSA website at http://www.iscwsa.net/. The ISCWSA is affiliated to the SPE as the Wellbore Positioning Technical Section and has a web site with the SPE at: www.spe.org. Additional information tool error development and use is provided in Attachment A.

An example of the application of tool error models is provided below (Table 12, from Maus and DeVerse, 2015) to show the effect of various models on the ellipse of uncertainty. In this example from a deep horizontal onshore well in South Texas, the author summarizes the resulting uncertainties at TD for eastward, southeastward and southward wellbore orientations by applying three different tool models to the wellbore survey data. In the first tool model, the basic MWD model, the lateral uncertainty (semi-major axis of the ellipse) ranges from 259 to 439 feet. Performing an IFR survey and adding that correction to the tool model reduces the ellipse by 11 to 38 percent. Further reductions in the ellipse can be achieved if the data are corrected using a Multi Station Analysis technique to remove the effects of magnetic interference. The authors also performed a study to evaluate the effect of these same corrections on depth which resulted in reducing depth error from 119 to 71 feet, a reduction of 40 percent.

[14] The ellipsoidal shape occurs because the azimuthal error is normally larger than either the inclination or depth errors. Inclination errors tend to be small.

Table 12: Lateral Uncertainties for Three Wells using Different Error Models

Well Orientation	Lateral Length	MWD	MWD+IFR1	MWD+IFR1+MS
	(ft)	(ft)	(ft)	(ft)
Eastward	11000	± 439	± 390 (-11%)	± 173 (-61%)*
Southeastward	11000	± 387	± 329 (-15%)	± 160 (-59%)
Southward	11000	± 259	± 161 (-38%)	± 129 (-50%)

*With limitations

From Table 1 in Maus and DeVerse, 2015, SPE-175539-MS, reproduced with permission

The use of error models is a specialized skill that is best left to experienced individuals. The improper application of tool error models can underestimate the risk of collision if the model is too optimistic, or unnecessarily restrict the wellbore trajectory plan if the model is too conservative.

3.5.4. Surface Position Uncertainty

The position of wellbore at the surface is assumed to be accurate, but is often a considerable source of error. As well spacing becomes smaller and platforms become more crowded, an accurate surface position is necessary to properly evaluate collision risk with nearby wells and maximize resource access and recovery. The role and general causes of surface position error were introduced in Section 3.1 as part of the discussion of wellbore planning and collision avoidance, and also discussed in Section 3.4, as an element of Data Management.

The location of a well at the surface is normally tied to a reference point on the platform that was initially surveyed using differential global positioning system (DGPS) and is accurate to less than 0.1 meter. At this level of accuracy instrument error is generally not a major contributor to surface well positon error. Some error is introduced if the drilling template on the floating platform or drill ship is not positioned exactly over the well entry point in the mudline. Offsets can occur due to ocean currents, tilting, and surface casing placement errors. In shallow water the effect of the offset is minimal, however in deeper water the offsets can be large. Uncertainties and errors in surface well locations most often occur as the original survey point is translated into different coordinate systems or measured off secondary reference points. These errors fall under the category of blunders or gross errors, which cannot be modeled mathematically, and can be difficult to recognize without specific quality control checks.

Industry experts who work with operators to certify databases have found that surface position errors due to gross error are common in regulatory databases, commercial databases, and operator databases. The problem is exacerbated in fields where the asset has been transferred multiple times and data is subjected to multiple transformations to align the reference datum with company standards. Common sources of errors are:

- Using the wrong map reference datum (NAD27, NAD83, WGS84)
- Using the wrong map projection type or UTM Zone
- North reference not correct (True North, Grid North or Magnetic North) or inconsistent with other data sets

- Magnetic declination value incorrect, has wrong sign (- or +), or is applied for the wrong year
- Grid convergence (Grid North to True North angle) incorrect or has wrong sign (- or +)
- Northing and easting coordinates not tied into local datum (based on 0.0 starting point)
- Mixed or incorrect units, or unit conversions (U.S. feet, meters, international feet)
- Rounding or truncating latitude/longitude or x, y coordinates due to software
- Incorrect or inconsistent reference point for depth measurement (mean sea level, kelly bushing, rig floor, other)
- Surface position based on incorrect platform slot, or slot locations transposed

These and other surface location errors are more common in older surveys, but persist in newer surveys where quality control procedures have not been effectively implemented.

3.5.5. Survey Calculations

Wellbore direction and inclination measurements are recorded at discrete depth intervals (often hundreds of feet apart) while advancing the bit or moving the drill pipe or wireline tool. The wellbore path between two adjacent points must be extrapolated using a model. Early models applied simple straight line estimation (Tangential Method, and Balanced Tangential Method) but modern complex wellbore geometries are not accurately represented by a series of straight lines, and will create significant uncertainty in location that propagates downhole.

Several mathematical models are available to calculate the distance between two points in a non-linear borehole. These are discussed further in Attachment A. The Minimum Curvature method assumes that the hole is a spherical arc with a minimum curvature or a maximum radius of curvature between stations and the wellbore follows a smooth circular arc between stations. Although the calculations are complex and must be performed with a computer it has become the standard method for calculating wellbore trajectory, and recommended by ISCWSA. However, because it is a mathematical approximation of a mechanical process it may not accurately represent the actual borehole in all situations, especially in areas where rotary steerable drilling switches between slide and rotate modes.

3.6. Survey Quality Control and Survey Management

Wellbore survey data is susceptible to many factors that affect the accuracy of the data. The directional survey industry has developed many techniques, such as tool error models and corrections, to help the data user improve and assess the accuracy of the survey data. However, before these techniques can be used the integrity and soundness of the data needs to be verified. Quality control procedures are a critical part of ensuring the directional survey will meet the user needs and can meet the specific conditions for use in tool error models.

3.6.1. Survey Quality Control

Survey quality control incorporates many different activities throughout the survey lifecycle. Previous sections have addressed quality control procedures to support well planning, survey operations, and data management. The environmental corrections described in Section 3.5 (sag, depth, magnetic interference, IFR) are all examples of survey quality control because they are designed to enhance the quality of the survey data. The industry has developed specific quality control checks that are performed before, during, and after surveys are run.

Section 3.5 described the tool error models that mathematically quantify the uncertainty in wellbore position. The accurate representation of uncertainty, regardless of the actual size of the ellipse of uncertainty, is one of the most important factors contributing to directional drilling safety because of its use in anti-collision analysis. It is critical that the uncertainty measurements reflect the most realistic understanding of the physical conditions of the borehole, and not merely generate the smallest area of uncertainty. In order to assure the representativeness of the uncertainty calculations a rigorous quality control protocol is a prerequisite for validating the conditions of a tool error model.

For a tool error model to be valid it must meet certain threshold requirements including surveys were conducted in accordance with industry best practices, regular tool calibrations, and quality control checks (Williamson, 2000). If these requirements are not met, the tool error model is invalid and the resulting ellipse of uncertainty is unlikely to represent the actual conditions. In 2006 and 2007 two landmark journal articles by Roger Ekseth (Ekseth et al, 2006; Ekseth et al., 2007) set out specific quality control checks that should be conducted to demonstrate compliance with the tool error model prerequisites. The papers recommended Multi-Station Analysis as a method of estimating corrections to sensor readings that contribute to wellbore survey error. The most common use of MSA is to identify and correct sensor bias and scale factor error by comparing actual survey measurements with predictions based upon reference field components such as magnetic field strength.

Industry experts generally agree that the most powerful overall quality control procedure is to run two different survey tools over the same interval and analyze the variability. Ideally the tools would be based on different measurement physics, for example MWD and gyro. Many types of gross error can be identified with this method, especially those involving magnetic field references.

Human error is often responsible for data quality problems and inaccurate surveys, and may be the leading cause of collisions due to wells missing from the database (ISCWSA, 2016b). Misapplication of tool error models, miscalculation of corrections, transcription and format errors, and version control of corrected survey data files are common pitfalls due to human error. Many operators and service companies have instituted formal oversight and approval processes to address human error, but these are inherently human systems that are susceptible to human error, such as signing off without full review and understanding of the work.

In summary, quality control procedures occur throughout the survey lifecycle and must be implemented to ensure the uncertainty estimates are truly representative of the actual conditions. Because the uncertainty estimates are the basis for safely identifying and avoiding collision risks and maximizing the efficient recovery of resources quality control procedures are critical to the safety of directional drilling operations. Key aspects of the quality control lifecycle can be summarized:

- Planning the directional drilling program requires a complete an accurate inventory of all wells with the area of review. This is a function of the accuracy and integrity of the well database including the accuracy of the positional uncertainty of the surface and trajectory of each wellbore. Many data sets are incomplete and poorly documented which increases the risk of adverse outcomes.

- Survey operations require continuous quality control. Pre-survey checks should be performed for each survey run and results validated prior to collecting survey data. Quality control tests should be performed during survey operations, including check shots, rotational shots, repeat surveys. The data from these tests should be evaluated in real time to determine if the field acceptance criteria for each measurement is acceptable.
- The most powerful quality control tool for ensuring survey accuracy is repeating the survey measurements with different tool types at the same depth. Because this requires additional rig time some drillers and operators may be hesitant to invest in this quality control effort.
- Corrections should be applied, as needed, during the survey to ensure an accurate understanding of collision risk and target delivery. Many corrections can be made but the sag, magnetic reference, and magnetic interference from the drill string will have the most dramatic effect on data quality. Pipe stretch can be a significant factor in holes with tight drilling tolerances.
- Closely spaced survey station intervals are a method of ensuring accurate wellbore trajectory readings. Tool error models require readings no greater than 100 feet apart, and some industry experts believe that 60 feet is required to provide an acceptable error. Most regulations have more lax standards for acquisition of data. More frequent surveys require additional rig time, which must be considered in the survey plan.
- Some gross errors can be identified using quality control procedures that employ a repeat survey of hole sections with two different sensor types, but many gross errors go undetected until rigorous scrubbing of the database and survey data is performed.
- Database integrity is a critical part of the quality control process. The final and definitive survey archived by the operator and regulatory agency must represent the best quality survey data. It is critical that metadata, raw sensor readings and tool model error information be available as part of the database so that the full survey can be reconstructed from the information in the database.

The survey quality control literature does not specifically address issues related to high temperature surveys. To meet the general requirements of field acceptance criteria surveys made in high temperature environments must be performed with tools designed for, and calibrated at the temperatures in which they were run. Quality control procedures and survey plans for high temperature wells should specifically address this issue.

3.6.2. Survey Management

Survey management refers to a broad range of services to improve the usability and accuracy of wellbore survey data. There is not a universally accepted definition of the components but a recent paper (SPE-158064, by B Mat et al, 2012) defined it as follows:

The management, oversight, and development of wellbore surveying, survey planning procedures, survey data quality control, and the integrity management and custodianship of the directional planning survey database."

Larger service companies offer survey management services that cover all of these areas. Recently a number of smaller third party independent survey management service companies have been formed to provide onsite or remote survey monitoring as the surveys are being run. They apply necessary corrections and implement quality control procedures in real time, on behalf of the operator to ensure the survey data meet data usability standards. These firms also conduct post survey analysis of data quality to generate a definitive survey and reduce ellipses of uncertainty. The range of services provided will vary depending on the operator's needs and available resources.

The specific services offered as part of the survey management can include:

- Planning support including auditing existing databases, assessing the quality of legacy well data including verification of coordinate systems, units, survey datum and elevations, surface locations, in-field referencing, tie-in points, tool codes, and corrections.
- Survey quality control in real time and post processing of raw data for error model validation, scale/bias errors, magnetic reference values and gyro drift. The quality control procedures are those described in Section 3.6.1. This is a key component to survey management.
- Post-processing of surveys for reduced error ellipses by applying multi-station and IFR corrections.
- Database design and management.
- Education and training in quality control techniques for wellbore surveys.

The application of a comprehensive survey management program for all wellbore surveys is the best method to identify and address many causes of gross error. The structured and rigorous application of corrections as part of the quality control process within survey management activities is critical to identifying the internal and external errors that may be present in the wellbore survey data.

3.7. New Methods and Trends in the Survey Lifecycle

Industry has recognized the need to improve practices in each of the survey lifecycle areas and has responded by improving existing methods and developing several new methods and techniques. Additionally, industry is moving forward by improving technical resources and initiating a certification in Wellbore Surveying Competency. This study did not identify any truly new methods but we briefly summarize significant actions and trends in the wellbore survey industry that may have a material bearing on future survey operations. The information in this section is summarized from a Technical Memorandum on future technologies which is provided in Attachment B of this report.

3.7.1. Best Practices

The ISCWSA has initiated the preparation of a Recommended Practices (RP) for Wellbore Positioning to become a published practice of the American Petroleum Institute (API). ISCWSA states that the purpose of the document is to "provide a framework and minimum guidance for the planning, acquisition, quality assurance, storage, and use of wellbore position data for the well lifecycle. This includes the assessment of well objectives as they pertain to collision assessment and reserves targeting (ISCWSA 2016a)." The document designated API RP78 will contain recommended practices for many areas of directional surveys. A preliminary list of topic areas is presented in Table 13.

Table 13: Topics Potentially Included in API RP-78, Recommended Practices for Wellbore Positioning (ISCWSA, 2016a)

Topic	Content
Roles and Responsibilities	*Competence and minimum level of training, defined roles, bridging documents, API Q1*
Surface Location	*Staking procedure, elevation/vertical datum, actual/planned location, global vs. relative, coordinate system, uncertainty (methods)*
Survey Program	*Requirements for: frequency and interval, deployment method, tool type, steering, survey sequencing; magnetic north correction, toolface orientation, program by part*
Survey Mathematics	*Axial (short collar correction and limitations), SAG, MSA, IFR1 IFR2, formulas, limitations, dip*
Software	*Qualifications, vetting process, wellbore position calculation (minimum curve), standard well path*
Database	*Definitive survey and database, definitive rules/hierarchy, offset wells, trajectory tie-on, unique wellbore ID, database management, tool code assignment, ownership/ access controls and permissions, Archive and recovery, QA (missing data, course length, error model assignment)*
Position Uncertainty Models	*ISCWSA, OWSG set, survey frequency, validation, verification/Field Acquisition Criteria (FAC)*
Anti-Collision	*Clearance scan, major/minor (HSE versus non-HSE risk), Separation Factor*
QA/QC	*Revision control, quality of measurement assurance, completeness/quality of database, data integrity, QA (missing data, course length, error model assignment)*
Maps, Plots and Graphics	*Spider plots, north arrows, scales*
Planning	*Targeting requirements (drillers target, geologic target, lease requirements), fit for purpose well geometry (well life cycle and trajectory considerations, wireline, relief well considerations)*
Planning to Operations/Execution Handoffs	*Revision control, approval, distribution*
Operation/Execution	*Pre-operational checks, magnetic references, magnetic checks. scribe line confirmation, projecting ahead*
Post Survey Execution	*Data info archives, associated survey info (corrections applied, BHA), reporting (regulatory filings and requirements)*

ISCWSA is in the process of developing documents to support best practices in wellbore interception, collision avoidance several other areas independent of the APR Recommended Practice. A new version (V04.05.16) of the industry standard publication e-book "Introduction to Wellbore Positioning", compiled and co-written by Professor Angus Jamieson, of the University of the Highlands and Islands (UHI) has recently been released.

3.7.2. Training

Professor Angus Jamieson and UHI have developed a competency program in wellbore positioning in partnership with the Society of Petroleum Engineers (SPE) Technical Section for Wellbore Positioning (ISCWSA, 2016a). This is the first industry recognized program on the subject and was developed in response to an industry-wide need to promote good practice in this safety critical activity. The training is aimed at oil and gas professionals who collect, manage or use wellbore survey data and require to have a good understanding of the methods, the equipment and their applications and limitations. The course also is a standard, recognized credential in wellbore surveying and can be used to demonstrate competency in the subject.

3.7.3. Survey Management

Many operators and service companies have recently expanded their in-house organizations to address quality management of directional surveys for the planning through the final archiving of data. Additionally, several small third-party consultancies have opened to offer survey quality control services to both large and small operators. A broad range of services, referred to as survey management, are offered to reduce uncertainty in wellbore positioning. Typical services include:

- MWD survey quality analysis,
- Real-time survey and depth correction (at the rig site or in remote offices),
- Anti-collision monitoring and offset well detection,
- Survey database management,
- Well database scrubbing and verification,
- Well planning, and
- Educational consulting

The services provided by survey management organizations have been applied for many years, the bundling of these services as a separate product line is a somewhat new trend that appears to address an unmet need in wellbore survey quality control.

4. Best Practices and Regulations

4.1. Industry Standards and Best Practices

The wellbore survey industry is a relatively small and narrowly focused part of the oil and gas industry that became organized around the issues approximately 20 years ago (1995). Only two industry organizations, API and ISCWSA, have addressed the issues of wellbore survey best practices. Professional societies and industry organizations such as the Society of Petrophysicists and Well Log Analysts, and International Association of Drilling Contractors have not developed standards or best practices related to wellbore surveys.

4.1.1. American Petroleum Institute (API)

API is a national trade organization that represents all aspects of the United States oil and gas industry. API develops equipment and operating standards for the oil and natural gas industry and currently maintains over 600 standards and recommended practices to enhance safety operations, improve quality assurance, and promote the global acceptance of petroleum products and best practices. There are currently no active standards related to directional well surveys. In 1985, API issued a bulletin on directional drilling survey calculations that included recommendations to assist in the selection of the calculations method best suited for specific applications (API 1985). The bulletin is obsolete and no longer active, and has been withdrawn by API.

API is currently working with ISCWSA to develop a RP for Wellbore Surveying. In 2015 the Operators Wellbore Survey Group (OWSG) of ISCWSA formed a subcommittee to develop a consensus document for Wellbore Survey Procedures that would ultimately become an API Recommended Practice. In January 2016, API approved the formation of the Wellbore Surveying and Positioning Committee for API Recommended Practice RP 78. The Committee has developed an outline of subjects to be covered in the RP and is actively working on the content. The standard is expected to be complete in 2016.

4.1.2. Industry Steering Committee on Wellbore Survey Accuracy (ISCWSA)

ISCWSA is a voluntary industry organization formed in 1995 to improve the awareness and general understanding and application of survey data, associated methodology, and enabling technology. Their mission is to produce and maintain standards for the industry relating to wellbore survey accuracy, set standards for terminology and accuracy specifications, and, establish a standard framework for modelling and validation of tool performance. The Committee also raises awareness and understanding of wellbore survey accuracy issues across the industry. ISCWSA is affiliated with the SPE as the Wellbore Positioning Technical Section, and addresses wellbore positioning issues in onshore and offshore areas.

ISCWSA has developed several recommendations for practices related to wellbore positioning, and maintains and distributes tool error models for directional surveys. Table 14 shows the publications, recommendations, and models developed by ISCWSA.

Table 14: ISCWSA Documents Related to Wellbore Survey Best Practices

Document Name (date)	Content
Recommendations for Management of Inclination Only Survey Data (Rev. C, 2015)	*Describes good practice for uncertainty calculations, clearance scanning, target sizing and data management purposes when surveys include only inclination data and no azimuthal (direction) data. These surveys are common in legacy data sets. Provides recommendations for implementation.*
The Fundamentals of Successful Well Collision Avoidance Management (2014a)	*Describes a process, which, if properly executed, will help assure well placement integrity and thereby avoid well collisions. Eight requirements for successful collision avoidance management are described.*
Collision Avoidance Calculations - Current Common Practice (2013a)	*Explains the ways in which minimum allowable separation is commonly defined and calculated. Provides recommendations for clearance scan methods.*
Standard set of well paths for use in evaluating clearance calculations (2013b)	*Provides a standard set of well separation scenarios that will allow comparison between clearance scanning rules under a range of proximity conditions and also test agreement between implementations of the same rule in different software.*
Collision Avoidance Lexicon (2011)	*Definitions of commonly used collision avoidance terminology and position uncertainty terminology.*
Recommendation Against Minimum Allowable Separation Distance (MASD) Dispensation for HSE Risk Wells (2014b)	*Provides recommendation and rationale for why rules for minimum separation distance (collision avoidance rules) should not be granted exemption for wells with health, safety and environmental risk.*
Error Models (2014c)	*Includes mathematical formulae used to estimate multiple types of survey error for specific types of survey tools.*
Well Intercept good practice draft document (in progress)	*Under development by ISCWSA Intercept Committee, anticipated for release in mid-2016. Focuses on technologies for well intercept. Includes planning to avoid need for relief well intercept, and scenarios for implementing well intercepts. Relief wells, P&A, and SAGD twinning are covered.*
Introduction to Wellbore Positioning (2016, VO4.05.16)	*A comprehensive reference manual for all aspects of wellbore surveying offered as a free e-book by ISCWSA and published by the University of the Highlands and the Islands. It has been recently revised and expanded.*

4.1.3. Other Standards Organizations

ASTM International offers standards for testing oil and gas fluids, product specifications for refined products, and specifications for distribution systems piping. ASTM does not have any standards for upstream oil and gas operations or well survey methods. Neither the American National Standards Association (ANSI) nor the International Standards Organization (ISO) offer standards or specifications related to wellbore surveys.

4.2. Best Practices for Wellbore Surveys in Directional Drilling

This section describes the current best practices in wellbore surveying for directionally-drilled wells during the planning, operations, and data management phases of the survey. This section also describes the best practices for ensuring data quality.

The best practices described here generally reflect activities that have the potential to affect data quality, completeness, and overall accuracy issues, with a focus on improved safety and environmental performance. There are many other best practices among well planners, survey companies, and operators that improve the overall process or operations of wellbore surveys, however those are not considered here.

As discussed above, API Recommended Practice 78 for Wellbore Surveys is currently being developed, and is expected to be completed in late 2016. Representatives from the Committee indicate that many of the areas discussed below will be part of the practice. The recommendations below should be reviewed against these practices when the API standard is approved to identify the most appropriate recommendations and actions.

The best practices described here are generally much more detailed and specific than those defined in current BSEE regulations, as well as regulations in other jurisdictions (as described in Section 4.4.1). Section 5.1 includes discussion of what level of detail may be appropriate in regulations.

4.2.1. Planning

Wellbore survey planning is performed to design the wellbore trajectory and the survey programs that will be used to steer the bit along the planned trajectory safely and efficiently. The following conclusions can be drawn from the review of tools available for wellbore surveying under normal and high temperature conditions:

- For directional drilling and surveying under normal temperatures, the available tools and services are adequate for providing the data needed to steer and survey directional wells in real time.
- The available magnetic tools and services for directional drilling and surveying at elevated temperatures are adequate for providing the data needed to steer and survey directional wells in real time. Gyro-based MWD and survey tools are limited to temperatures of 150°C and below. They can be deployed at temperatures above 150°C for limited times, in dewars, so this is a limitation.

If elevated temperatures or other hostile conditions are considered likely, tool/service selection should include discussions and the exchange of information concerning tool performance, maximum operating times, means of assessing data quality and tool condition while downhole, and probability of failure, all at the expected temperatures and conditions. If downhole temperatures approaching the limits of tools being considered are possible, procedures such as limiting downhole time, the use of heat shields (or dewars), increasing circulation, and mud cooling should be explored well in advance. Finally, the possible need for back-up tools should be discussed and resolved before any commitments are made.

Rotary steerable systems (RSS). The acceptance and running of RSSs has enabled the well-drilling industry to make dramatic improvements in efficiency by keeping the bit on bottom and drilling ahead. RSSs make it possible to, in effect, change the BHA without tripping. So directional drillers can build or drop angle, turn left or right, or drill straight ahead with the same BHA. Typically, wells drilled with RSSs are more uniform and less tortuous than wells drilled with the typical combination of mud motors (with bent housings or bent subs) and rotary BHAs. While evaluation of the available RSSs is not within the scope of this project, the efficiency they offer suggests they should be considered for any drilling project where efficiency and reaching the target(s) quickly are high priorities, such as relief and intercept wells.

Tool selection. During the well planning process the performance of the survey tools should be evaluated with the BHA that is proposed to be used. To address directional accuracy and/or reducing location uncertainty while drilling, the selection processes for MWD and survey tools should include use of tool error models for the tools being considered. The models used should be developed consistent with the framework of the appropriate ISCWSA tool error models that characterize their performance throughout the anticipated well profile.

Tool selection should also consider the data types that will be generated (raw and final) and the format and data transmission/transfer capabilities of the tools. When LWD and MWD services are performed during drilling, transmission times and update frequency for survey data can be affected. Operators should identify and consider the data transmission times of the tools being considered and present the information in a survey plan.

The survey plan should reflect the purpose of the well, the casing plan, the risks associated with the well deviating from the planned trajectory, the directional measurement capabilities and limitations of the tools in the planned BHAs, the uniformity and stability of the local magnetic field, the survey station frequencies, the procedures and tools that will be used to confirm surveys and check data quality, and the procedures for decision-making. Issues that should be addressed under some of these topics include anticipated formation pressures, rates of curvature (dog-leg severity), anticipated borehole temperatures, the possible need for in-field magnetic references, and communication/reporting formats and procedures.

Collision avoidance. Collision avoidance is one of the most critical safety aspects of the directional drilling process and requires a rigorous performance standard. ISCWSA has developed a set of best practices for collision avoidance that address the issues necessary for management and execution of a comprehensive collision avoidance program (ISCWSA, 2014b). These practices incorporate a wide range of clear, rigorous, and effective requirements that cross cut other survey lifecycle activities including planning, data management, operations, and data quality. The application of these best practices for collision avoidance would also address best practices in other areas. The ISCWSA recommended practice includes the following statements[15]:

- Data Structure and Integrity – Optimally, there should be only one master database, containing all wellbores, accompanied by a written plan for use, maintenance and disaster recovery for the life of the field.
- Position Uncertainty – All wellpaths, planned and actual, should be associated with a valid position uncertainty estimate. The error models used to generate such estimates should include all significant error sources and/or err on the side of conservatism. Similarly, the selection of the most appropriate model from those available should err on the side of conservatism.
- Surface Location – The well location should be defined in the appropriate mapping system and converted to local drilling coordinates using the appropriate translation method. Locations should be surveyed to an approved accuracy standard and managed to allow updates as better position information becomes available during the well life cycle. The uncertainty associated with the location should be recorded as part of the well record. If the well reference point is on the seabed, the additional uncertainty between surface and seabed should be included. Revised surface locations should be distributed to all appropriate personnel and data archives.
- Survey Program Design – To ensure that the above objectives are met, survey programs should: a) Be based on the use of survey tools with valid error models (Instrument Performance Models [IPMs]), b) Specify running procedures and QC tests necessary to comply with error model assumptions, and c) Include survey redundancy to limit the presence of unobserved gross error.
- Collision Avoidance Procedures – Collision Avoidance procedures should define how safe separation is managed during planning and execution of the drilling program. They should include categorization of risk and the separation rules applied to each classification. Since HSE risk is associated with collision, the procedures should be jointly agreed between the Operating Company and the relevant contractors. Most contractors' internal policies require them to be active in managing HSE risk. Additionally:
    - Anti-Collision (AC) scans should be run against the master database.
    - The planning phase should result in a collision monitoring program to be followed by office and rig personnel during the execution phase.
    - Clearance data should be presented to users in a usable, meaningful, format, numerical and/or graphical. These should encourage correct interpretation and actions on the part of office and rig site personnel.
    - All personnel involved in wellbore construction activities should be trained in the collision management process and the detailed procedures appropriate to their role.

[15] These statements are taken from the ISCWSA 2014 document titled "Fundamentals of Successful Well Collision Avoidance Management." Some of the statements have been modified from their original form for editorial consistency with the overall document or for clarity and brevity.

- Survey programs should be executed in accordance with their design. Any changes should have proper management of change processes applied.
- The directional software, survey tool models and running procedures should be assessed and agreed with the Operator prior to their use.
- All software used should be auditable against appropriate safety critical software standards. Software outputs produced should contain references for safety critical calculations and appropriate versions e.g. software, engine, build etc.

- Collision Avoidance Management may also include:
  - Classification of offset wells in terms of cost of intersection
  - Minimum separation criteria per well classification
  - Requirement for anti-collision scan
  - Design approval prior to drilling
  - Presentation of safe separation tolerances for planning and execution
  - Verification of position relative to tolerances (timeliness while drilling)
  - Action in the event of failure to maintain safe separation
  - Identification of abandoned radioactive sources
- Quality Assurance – The quality assurance plan should define periodic assessment and audit of drilling and surveying tools and procedures:
  - Software used to prepare directional plans, collision scans and final survey calculations specifically: a) Safety Critical Software standards compliance, b) Consistency of algorithms and clear definition of limitations, and, c) Availability of redundant data (e.g., sub-surface, even though there is only one definitive database).
  - Instrument Performance Models (IPM's)
  - Calculation methods
  - Operations personnel training and frequency
  - Training systems that comply with tasks outlined in this document
- Communication – Personnel involved in the well planning, execution and archive process should be defined and engaged in a timely manner. Candidates include, but are not limited to: a) Sub-surface personnel, b) Drilling/Rig, Directional & Surveying contractors, c) Engineering personnel, d) Operations personnel, and e) Environmental, Permitting and Regulatory compliance personnel

Although not in the ISCWSA document presented above, the following statement regarding magnetic interference in collision avoidance is a best practice. In any drilling project where the presence of previously-drilled wells makes a collision possible, routine measurement of the total magnetic field and dip angle should not be ruled out without an exploration of the consequences. These measurements can be made and transmitted or stored by most – if not all – of the magnetic MWD and survey tools available today. In most situations, the added cost – mostly transmission time – is not significant.

Collision analysis. Tracking and analysis of wellbore collisions and near misses can be used to identify the most likely situations in which collisions may occur. Some operators have internal processes to review actual and near miss safety and environmental events and these have led to improved safety and environmental performance. Including near misses in wellbore collision safety analysis is a best practice.

Software and graphical representation of proposed well plan. The software package that is used to create the wellbore trajectory and analyze the survey program should be identified. The outcome of the well planning process should be represented in a figure, or figures that clearly show the trajectory of the well in plan and vertical section views.

4.2.2. Operations

During the operational phase, survey data are collected and interpreted in real time to steer the bit and avoid drilling obstacles. Best practices during operations generally ensure that the data are truly representative of the wellbore trajectory and will satisfy data quality criteria.

Tool calibration and checks. Only tools that are properly calibrated and pass initial calibration, operational checks, and field acceptance criteria should be used to generate data that will be used to steer drilling tools or create surveys. Evidence of the successful tool check should be obtained and managed for each tool used and retained as part of the survey data set (see Section 4.2.3 Data Management). Additional considerations for tool calibrations are presented below.

MWD and survey tools normally undergo a full calibration as one of the final tasks during their production, or following the replacement or repair of any of the directional sensors. Calibration verification must be done routinely relative to time, runtime, and exposure to extreme environments. Even transportation or handling incidents can warrant calibration checks. During this calibration the coefficients needed to characterize the performance of each sensor and the complete tool are determined and recorded. In most cases, these coefficients are those needed to describe the performance of the tool in accordance with an appropriate model that will typically have been developed by the ISCWSA. These coefficients may be stored in solid-state memory within the tool or downloaded into the tool before it is deployed. Tool history logs, indicating service and calibration activities for a particular tool, should be maintained and subject to auditing.

The equipment available in district or field offices of the tool suppliers and their procedures for checking the condition of their tools differ by supplier and by location. Some have test stands in magnetically-clean environments that can orient the tools in various fixed positions. These normally are used to confirm that the coefficients determined during the most recent, full calibration have not changed.

Roll tests, during which the directional sensor outputs are checked by rotating the tool to various fixed angular positions around its longitudinal axis, are the most-frequently used field tests. These normally are used to determine if the position or accuracy (bias and scale factor) of any accelerometer or gyroscope has changed, and if the tool is functioning normally. When done in a magnetically clean environment, roll tests also can detect if the position or accuracy of the magnetometers has changed. It should be recognized that roll tests do not provide meaningful calibrations; they are "checks" to minimize the likelihood that an out-of-calibration or malfunctioning tool will be deployed.

Survey station interval. In deviated boreholes, survey measurements should be collected at an interval that ensures an accurate wellbore trajectory is recorded. ISCWSA tool error models are valid only when survey stations are no more than 100 feet apart and this should drive the best practice of defining minimum survey station interval. Additionally, should a relief or intercept well be needed, frequent survey points will help reduce positional uncertainty and facilitate accurate targeting (see Section 4.3 Relief Well Operations). Modern tools and data transmission methods are not obstacles to this practice, although in some situations the memory limitations of battery powered systems may need to be addressed.

Survey calculations. The Minimum Curvature Method should be the standard calculation method for surveys. This method is recommended by ISCWSA and is the standard method required in some jurisdictions. Any deviation from this method should be described in the survey data set.

Survey concatenation. In the definitive survey, each survey station should have a unique and single set of survey data associated with it, and no interpolated, projected or estimated data should be included in the definitive survey. Tie in points for where two subsequent surveys are connected should be identified. Concatenated surveys should not include interpolated data. (Some operators request data to be regenerated at even depth increments, such as every 100 feet for simplifying analysis.) The appropriate tool code should be assigned to each section of the survey to facilitate tool error modeling.

Operations at high temperatures. Surveys made in high temperature environments must be performed with tools designed for, and calibrated at the expected operating temperatures. Tools should not be operated at high temperatures for durations that would degrade their performance or introduce errors in the measurements.

Depth accuracy. Accurate reporting of true vertical depth and measured depth is important to safety and overall survey quality. Wireline tools generally provide a more accurate estimate of depth. Calibrated measuring devices (measuring wheel), magnetic marking on the wireline, and stretch correction provide additional depth accuracy. Depth calculations from drill pipe should account for pipe stretch and other factors that may result in significant depth error. Physical measurements (strapping and pipe tally) should be checked for accuracy, if possible.

Response to unexpected magnetic conditions. Whenever there is reason to doubt the reliability or consistency of the local magnetic field, gyroMWD tools or other gyro-based surveys should be considered, as should the use of in-field referencing (static or dynamic).

Survey crew. Gross error (commonly caused by human or operator error) is the most common and often the largest error source in wellbore surveys. The qualifications and experience of the staff who will be responsible for transporting, assembling, testing, running, and maintaining the MWD and survey tools should be considered when selecting service providers. Procedures for transfer of responsibilities during crew changes should be reviewed and confirmed by responsible operating personnel.

4.2.3. Data Management

Data management activities are conducted throughout the planning, operations, and post survey phases of the survey lifecycle. Large amounts of data are collected during these phases and the proper collection and storage of the data are critical to current and future use of the data.

Database completeness. The ISCWSA collision avoidance recommended practice described above addresses the need and requirements for developing and maintaining a complete database. A related issue is the need to ensure that each drilled segment of the well is identified and the survey data associated with the segment is properly labeled and filed.

Unique well identifier. To ensure unambiguous well section references, a unique well designation should be provided to reflect the most accurate description of the section of the wellbore the survey data represents. This may include either a 14 digit API number or specific reference to the sidetrack and bypass numbers. Best practice would be to follow the latest numbering standard from the Professional Petroleum Data Management association (PPDM) (IHS, 2013), the new "owner" of the API numbering standard[16]. BSEE provides guidance for well naming and numbering in NTL No. 2009-G33.

Collection and management of raw data. Instrument sensors collect many different types of measurements from the downhole environment, and may selectively transmit and store only some of that data to be used in the actual survey calculations. Raw data, referring to a wide range of supporting measurements made during the survey, is a valuable asset that can be used for quality control and reconstruction of the survey at a later date. Best practice is to collect and maintain all raw data files available from the measurement systems. An example of the kind of data to be collected and stored is presented below (modified from Stolle, 2011 and Stolle, 2013).

1. Details of QC criteria
2. One Excel worksheet with the following
    - Information for each hole section or BHA: Date, Time, Measured Depth, G_X, G_Y, G_Z, B_X, B_Y, B_Z (where G represents gravity field and B represents magnetic field), uncorrected inclination, uncorrected azimuth, final corrected inclination, final corrected azimuth, N-S Display, E-W Display, and dogleg severity (DLS)
    - Note that G_X, G_Y, G_Z, B_X, B_Y, B_Z should be the original raw data from the tool with no corrections applied
3. A statement is required about:
    - The type of any correction applied to the azimuth (e.g., "single axis correction applied" etc.)
    - Inclination (Sag etc.)

[16] In 2013, the PDDM published a revised API numbering standard for the U.S. clarifying several aspects of the standard. In particular, the new standard states that all wellbores should be identified, even pilot holes and junked and mis-steered wellbores that do not reach the intended bottom-hole location. PPDM is now working to increase adoption of the new standard, given the importance that the oil and gas industry identify every wellbore for safety and conservation purposes.

- Any other information relevant to the wellbore positioning operations on this well to date

4. North reference Hole direction (True or Grid)
5. North reference Offset direction (True or Grid)
6. Grid Projection and Zone
7. Datum: NAD27 or NAD83 (it matters in some areas)
8. Survey contractor
9. Tool type
10. Surveys actually run - Correction angles (clearly stated, i.e. Survey corrected from Magnetic North to Grid North, (example: Zone 4203 using correction angle of 3.24 deg.)
11. If previous surveys were incorporated in this survey were those surveys already in or corrected to this survey's North reference. List depth intervals for other surveys included, and corrections applied to this North references
12. Survey calculation method
13. Plane of proposal
14. Survey start (if applicable) and survey end date
15. Tie-on point information and source of tie-on information, if utilized
16. Tool Correction Error Applied

Definitive surveys. A definitive survey should be generated and submitted to the regulatory agency for the permanent record. The source of the data for the survey should be easily identified. Best practice would suggest that no particular survey type (MWD or gyro) be universally accepted as the most accurate survey in all cases.

Data submittal requirements. Data submitted to regulators for the permanent record should include a comprehensive set of header information that clearly identifies all positional information and datum, along with other information that can be used to accurately recreate the well location and survey data. An example of the suggested header information is presented in Figure 18.

Figure 18: Example of Header Information on Survey Data Report

(Def Survey)

Report Date:	November 05, 2015 - 01:42 PM	**Survey / DLS Computation:**	Minimum Curvature / Lubinski
Client:	BP	**Vertical Section Azimuth:**	64.610 ° (Grid North)
Field:	Fall ATW Training Field	**Vertical Section Origin:**	3.361 m, 3.551 m
Structure / Slot:	A Structure / 9	**TVD Reference Datum:**	Rotary Table
Well:	A9 Well	**TVD Reference Elevation:**	68.300 m above MSL
Borehole:	A9 OH	**Seabed / Ground Elevation:**	100.000 m below MSL
UWI / API#:	Unknown / Unknown	**Magnetic Declination:**	-0.480 °
Survey Name:	A9 Keeper + MWD ft	**Total Gravity Field Strength:**	1000.9965mgn (9.80665 Based)
Survey Date:	April 10, 2012	**Gravity Model:**	DOX
Tort / AHD / DDI / ERD Ratio:	91.965 ° / 1493.290 m / 5.715 / 0.527	**Total Magnetic Field Strength:**	49951.532 nT
Coordinate Reference System:	UTM Zone 31N - WGS84, Meters	**Magnetic Dip Angle:**	70.120 °
Location Lat / Long:	N 56° 10' 40.52341", E 3° 27' 36.36214"	**Declination Date:**	April 10, 2012
Location Grid N/E Y/X:	N 6225977.520 m, E 528563.380 m	**Magnetic Declination Model:**	BGGM 2011
CRS Grid Convergence Angle:	0.3822 °	**North Reference:**	Grid North
Grid Scale Factor:	0.99961001	**Grid Convergence Used:**	0.3822 °
Version / Patch:	2.8.572.0	**Total Corr Mag North->Grid North:**	-0.8622 °
		Local Coord Referenced To:	Structure Reference Point

From Course Materials for SPE Well Placement and Intersection Best Practices workshop, November 2015

Re-submission of surveys. Operators should be encouraged to resubmit corrected well position and directional survey data to the regulatory agency to improve the overall data quality of the regulatory database. The resubmittal should include a brief explanation of why the re-submitted data are more representative of the actual wellbore conditions. Data sets that have been resubmitted and revised should be easily identifiable in the regulatory database.

Data transfer. A standard format should be used when transferring survey data to facilitate accurate transfer of information. This applies to handoff transfers (planning to operations teams, drilling to completion teams, completion to archive teams), and submittals to regulators or other operators. A process should be in place to ensure the complete, thorough, and accurate transfer of data.

4.2.4. Data Quality

Data quality is a crosscutting concept across the planning, operations, and data management phases of the wellbore survey lifecycle. The best practices for data quality that are described below address both broad concepts and specific activities.

In general, operators and their survey company partners who work in offshore areas have recognized and responded to the need for rigorous quality assurance programs to address safety, environmental performance, and resource management. The high cost of drilling offshore wells along with the greater consequences of using survey data of unknown or poor quality has encouraged offshore operators to develop formal programs to ensure data of known and documented quality are used in decision making.

Certification of survey accuracy. Operators in some jurisdictions are responsible for submitting definitive survey data to regulatory agencies to become part of the permanent well record, and therefore have the implied responsibility to ensure the survey data are accurate and complete. Many operators have internal processes to review and approve data prior to use and storage, and this best practice can be extended to submittal to regulatory agencies. Operators should provide written certification that the data they are submitting accurately represents the wellbore trajectory.

Certification of wellbore survey specialists. Ensuring survey data quality requires specialists well versed in the science and art of wellbore surveying. The major surveying companies require rigorous training of the survey crews and survey crew managers. Drilling engineering groups at some large operators offer training in wellbore surveying. The University of the Highlands and Islands (Inverness, Scotland) recently began to offer a certification course for wellbore surveyors; this is the only known formal certificate program. Given the importance of accurately representing the wellbore trajectory, it is a best practice for individuals with responsibilities in survey data collection, interpretation, and submittal to have specialized training in wellbore surveying.

Corrections. Significant errors can be accumulated in surveys if certain corrections are not applied to the survey data to address physical effects on the MWD tools. BHA sag, local magnetic fields, and magnetic interference from the BHA (short sub) are common corrections that are made to reduce the uncertainty of the borehole position. ISCWSA recommends that sections of the well with deviation above 45 degrees at any point should be sag corrected. Best practice would also suggest that data from regions with high susceptibility for geologic and diurnal magnetic interference and regions with low magnetic field vectors (e.g., Alaska) be corrected for magnetic fields. To reduce the uncertainty in survey measurements due to magnetic interference from short subs proper magnetic spacing should be preserved to ensure azimuthal accuracy.

Multi-station analysis. Many large service companies and offshore operators have adopted the Multi-Station Analysis (MSA) test to correct sensor bias and scale factor error. When properly applied, the correction can reduce wellbore position uncertainty. The methodology is broadly available in the industry and application of the MSA is a best practice for improving data quality.

Tool error models. The proper application of tool error models to survey data is critical to generate a data set that accurately represents the location and uncertainties of the wellbore position. The operating conditions of the survey must meet the minimum conditions for a valid error model set by ISCWSA, and the tool error model must be consistent with the framework for tool error models set by ISCWSA. Best practice would also suggest that the values used for development of the model be traceable and documented. The error model used should be identified on the data set for each section of a directional survey.

Quality control tests during survey operations. Quality control tests, including check shots, rotational shots, and repeat surveys, should be performed during survey operations. The data from these tests should be evaluated in real time to determine if the field acceptance criteria for each measurement has been satisfied.

Repeat survey points with different tools. The most powerful overall quality control procedure is to run two different survey tools over the same interval and analyze the variability of the resultant wellbore position. Ideally, the tools would be based on different measurement physics, for example MWD and gyro. Many types of gross error also can be identified with this method, especially those involving magnetic field references. Best practice is to run repeat surveys at critical points in the well including tie on points, significant changes in inclination and direction, and near geological and driller target entry points.

Survey management. The concept of survey management covers a broad area of data quality and data management activities that are designed to improve the overall accuracy of survey data. Survey management may be performed in-house or by a third party, in real time or post survey. The additional quality assurance offered by survey management is a value-added process improvement and is a best practice. The scope of survey management services is a function of the individual well conditions and the operator's needs.

4.3. Best Practices in Relief and Intercept Well Surveying

Relief wells and intercept wells incorporate the survey attributes and best practices of standard directionally-drilled wells in the upper part of the drilled section; that is, they rely on MWD and gyro surveys to drill efficiently, accurately, and safely along the predefined well trajectory. However, after locating the target, estimates of range and direction to the target provided by ranging tools drive the drilling decisions. Because each intercept and relief well will have a different set of challenges and drilling conditions, detailed best practices cannot be developed for each unique situation that might be encountered.

Relief well planning is a broad subject that covers many different technical areas. Developing the contingency plan includes consideration of surface location, directional strategy and approach, intercept strategy and survey plan (includes ranging), casing plan, and hydraulics/kill plan. Some of these areas can be considered in the initial planning stage, but the actual plan will require situation-specific information acquired at the time of the event-specific planning. Typically, targets for intercept and relief wells are much smaller than geologic targets for exploration and development wells, so the application of best practices to reduce uncertainty are more critical in relief and intercept wells. Therefore, the best practices described below focus on proper planning and data quality.

4.3.1. Planning

Available tools and services are adequate for providing the data needed to steer and survey relief wells in real time for normal temperature wells. Ranging tools and services, which are critical for interceptions, also are available and able to provide the needed data. The only significant limitation is there is one supplier of a commercial active ranging tool (and service).

For elevated temperatures, the available magnetic tools and services are adequate for providing the data needed to steer and survey directional wells in real time. Gyro-based MWD and survey tools are limited to temperatures of 150°C and below. They can be deployed at temperatures above 150°C for limited times, in dewars, so this is a limitation. Ranging tools and services also are available and able to provide the needed data. Scientific Drilling's MagTraC software-based service can accept data from any MWD tool for passive ranging projects, so there are many commercial suppliers. However, Halliburton is the only supplier of a commercial active ranging tool (and service). This might be considered a limitation.

Accuracy of the target well position. It is important to accurately represent the uncertainty of the location of the original (target) well to develop an accurate and effective intersection plan. The accuracy of the initial survey should be reevaluated during the planning using survey management techniques (surface position checks, environmental corrections, MSA, and tool error model improvements) to reduce the ellipses of uncertainty of target well. Survey station interval should be evaluated also because if the original survey is conducted at widely spaced intervals, such as every 500 feet, it is difficult to predict where the well is between survey stations and the kill plan could fail if doglegs create undetected deviations in the well path.

Tool selection. Many different ranging tools are available to address the multitude of needs during ranging. Access dependent and access independent tools are the initial considerations, but other issues such as proximity to the target; operating temperature and duration; potential interference from geologic and mud conditions; target casing weight, design and age; tool availability and mobilization; reading time and deployment method (Are trips required?) are a few of the other things to consider. Best practice is to thoroughly evaluate the types of conditions that may occur in the planned relief or intercept well, and plan for the range of contingencies that may occur. Considerations for tool selection should recognize and address a situation where the optimal tool may be from a supplier other than the contracted directional survey company.

Level of relief well planning. A basic level of planning, required in most jurisdictions, includes a generic approach and considerations for surface location selection and basic dynamic kill modeling. Generally these plans will meet the minimal regulatory compliance requirements, but do not include a survey/ranging plan and will need significant revision if there is a significant deviation from the original plan or a well control contingency occurs. Best practice is to provide a level of detail that describes the rationale and options for directional survey and ranging tool selection. In remote areas or areas with unique survey quality issues, such as the Alaska region where magnetic field strength is low and magnetic interference can be significant, more detailed planning is recommended. Detailed planning will improve the effectiveness of the relief well drilling and reduce the time necessary for preparing revised plans if an event requiring intervention occurs.

4.3.2. Operations

Relief well directional surveys and ranging operations follow the same general operating procedures as exploration and production wells.

Survey interval and accuracy (relief well). The relief well should never approach the target well with a separation factor less than one before ranging. This means that the survey plan for the relief well must reduce its positional uncertainty to the greatest extent possible. Once the relief well is within ranging distance and ranging is underway, the relative uncertainty of the combined wells takes over but prior to the first ranging run, there must be no danger of accidentally intersecting the target well.

Use of gyro surveys during ranging runs. As described above in Section 4.2.4, a best practice for quality control in directional surveying is to run two different tools over the same interval. Given the importance of wellbore accuracy during relief and intercept well drilling, there is justification for including gyro runs with ranging tools to minimize the uncertainty on the relief well. Gyros can be run in tandem with the ranging tools for additional data collection during in-runs and outruns that will provide multiple overlaps and reduce uncertainty.

4.3.3. Data Management

Relief well drilling often requires numerous survey runs with MWD, gyro, and ranging tools. While the primary use of the data is for near real-time interpretation and steering of the bit, the data represent a valuable resource for future reference and after-action reviews. Best practice is to manage the relief well survey data in a similar manner as that of the original well. Definitive surveys, metadata, and surface location information should be collected and stored using practices that apply to other well data.

4.3.4. Data Quality

As described above in the Section 4.3.1 (Planning), QC procedures are critically important during relief and well drilling. In the planning phase, the focus is on developing a realistic understanding of the target well trajectory and its associated uncertainty.

4.4. Regulations

4.4.1. Existing Regulations

Regulations on wellbore surveying, collision avoidance, survey accuracy, survey management, and relief well/well intersection operations from state and federal jurisdictions in the U.S., as well as international jurisdictions, were identified as possible candidates to inform current and possible best regulatory practices. Table 15 identifies the regulatory jurisdictions that were reviewed in this study.

The categories (and topics within the categories) of potential regulation for existing wellbore surveying regulations that were investigated include:

- Planning
  - Anti-collision analysis and minimum separation distances between wellbores
  - Actions considered when minimum separation distance is exceeded
  - Pre-drilling application submittals, diagrams and well trajectory figures, requirements for identifying surveying tools to be used
  - Wellbore identification and naming standards
  - Approvals required
  - Minimum Level of Training/Competency requirements
  - Penalties for false reports
  - Well Planning Software
- Operations
  - Minimum intervals for wellbore survey measurements in vertical wells and directional/horizontal wells
  - Calibration procedures
  - Coordinate system and reference points to be used for surveys
  - Check shot surveys and accuracy verification while surveying
  - Measurement while drilling
  - Magnetic spacing for azimuthal tools
- Data Management
  - Schedule for submission of well logs and surveys
  - Procedures for ensuring accurate tie-on depths if more than one survey is run
  - Format for survey submittal
  - Corrections to subject well or other wells if errors or omissions are identified
  - Master survey definition (also called the Definitive Survey)
  - Survey calculation method
  - Projecting ahead or at end of hole
  - Header and ancillary survey information requirements
  - Operator and survey company certification forms
  - Well planner identification

  - Data reporting for sidetracks, laterals and bypasses
  - Confidentiality of surveys/well logs
  - Raw data collection and archiving
- Errors and Uncertainty - Tool error models used
- Survey Quality Control - Independent QA/QC of survey data that is submitted
- Relief Well Operations
  - Well control plan, contingency plan, relief well plan, or oil spill contingency plan that includes multiple potential locations, equipment required equipment availability, mobilization time, lessons learned from past incidents and near-misses, and hazard assessment
  - Minimum time between incident and commencement of drilling a relief well

Table 15: Regulations Identified and Reviewed

Jurisdiction	Regulation/Rule
BSEE	*30 CFR 250* Oil and Gas and Sulphur Operations in the Outer Continental Shelf *NTL No. 2009-N10* Directional and Inclination Survey Data Submission Requirements*, NTL No. 2009-G33* Well Naming and Numbering Standards
BLM	*30 CFR 3160 Onshore Oil and Gas Operations*
New Mexico	*New Mexico Administrative Code* Chapter 15 Oil and Gas Part 16 Drilling and Production
North Dakota	*North Dakota Administrative Code* Chapter 43-02-03 Drilling
Texas	*Texas Administrative Code*, Texas Railroad Commission Rules 11, 12, and 86
Utah	*Utah Administrative Code* Rule R649-3 Drilling and Operations
Wyoming	*Wyoming Oil and Gas Commission Rules* Chapter 3 Operational Rules, Drilling Rules
Australia	*Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011*
Canada (National)	*Canada Oil and Gas Drilling and Production Regulations 2009*
Canada (Alberta)	*Oil and Gas Conservation Rules*
New Zealand	*Crown Minerals (Petroleum Regulations 2007* *Marine Protection Rules*
Norway	*Regulations Relating to Conducting Petroleum Activities (The Activities Regulations)*
United Kingdom	*The Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999* *The Merchant Shipping (Oil Pollution Preparedness Response and Co-operation Convention) Regulations 1998* *The Department of Energy & Climate Change Petroleum Operations Notice (PON) 9 Record and Sample Requirements for Seaward Surveys and Wells*

Other International Regulators Forum (IRF) member regulations were considered, but not examined in detail due to their current state: Brazil is in development stages for regulations in general; Mexico is reworking the bulk of its regulations as it moves from a PEMEX dominated approach to a more open market; and Denmark's regulations are not as developed as Norway and the United Kingdom.

4.4.1.1. Summary of Existing BSEE Regulations

BSEE regulates wellbore surveying in the areas of planning, operations, data management, and data quality. These regulations are covered in 30 CFR 250.418, 461, 466, 467, 468, and 1617, and Notice to Lessees 2009-N10 and 2009-G33. Many of these regulations are dated, and most are unchanged since their last revisions in 1999 to 2004.

Wellbore planning regulations require operators to submit a plot for all wells, including directionally-drilled wellbores, as part of the application to drill (APD) prior to any operations. In addition, BSEE has comprehensive guidance on wellbore identification and naming standards for managing digital data. BSEE defines minimal survey intervals for vertical and directional wells, 1,000 feet and 500 feet, respectively and 100 feet when changing angle, as well as requiring that surveys must be corrected to UTM grid north or Lambert grid north. Regulations also permit the use of MWD technology. A composite directional survey from the bottom of the conductor casing to total depth is required. Data management is regulated through survey format requirements and submittal schedules as directed by the region. Specifications for data collection, including inclination and azimuth are also defined.

The current BSEE wellbore survey regulations as well as the regulations in other jurisdictions (state and international) are summarized in Attachment C. The tables in Attachment C identify the most stringent, or comprehensive regulation within each topic area, and the jurisdiction from which it originates.

4.4.1.2. Summary of Other Existing Regulations

The regulatory approach of each jurisdiction reviewed is summarized in Table 16. The table provides an overall summary of the regulatory approach and overall scope of the regulations for each jurisdiction researched.

Table 16: Overview of Regulatory Approach

Jurisdiction	Approach	Last Update	Overall Scope
BLM	High Level	2015	General requirements for well control for drilling wells and very high level requirements on when operators should conduct surveys
New Mexico	High Level	2012	Specific requirements for when deviation tests are required, what defines excessive deviation and unorthodox locations, and directional survey requirements. Primarily focuses on approvals required.
North Dakota	High Level with Guidance	2012	Requirements for deviation test (minimum interval for recording results) and directional survey.
Texas	Comprehensive	2008	Specific requirements for horizontal drainhole wells including directional survey requirements. Also includes application and report submittal requirements.
Utah	High Level	2015	An example of general requirements for an application for directional drilling (a plot or sketch, reason for deviation, etc.)
Wyoming	Comprehensive	2015	Requirements for directional drilling including: approvals and certifications, survey intervals, and definitions of terms. Wyoming provides specific certification forms to allow for standardization of submittals.
Australia	High Level	2013	Requires operators to include coordinates of deviated wells in a completion report and develop a plan for dealing with well integrity hazards, but does not provide any additional details or guidance.
Canada (National)	High Level with Guidance	2009	General requirements for surveys and a contingency plan. Details on well control/relief wells (same season relief well) for this contingency plan laid out in the "National Energy Board Filing Requirements for Offshore Drilling in the Canadian Arctic".
Canada (Alberta)	High Level with Guidance	2012	Detailed filing requirements in Directive 059 guidance, but minimal detail in regulations.
New Zealand	High Level with Guidance	2015	Operators must provide a notice of intention for directional drilling and submit daily drilling reports, but regulations do not provide specific details. Guidance is available detailing specifics on the Well Control Contingency Plan that is mentioned in regulations.
Norway	High Level with Guidance	2013	Regulations refer to the NORSOK D-010 standards for guidance on well surveying and well control. Regulations do specify coordinate system to be used for surveys.
United Kingdom	High Level with Guidance	2015	Requires operators to prepare an Environmental Statement and Oil Pollution Emergency Plan, with DECC Guidance providing the details. Does not specify requirements for data acquisition nor require submittal of final survey data.

Through our review of U.S. and international jurisdictions, we identified the following observations for wellbore surveying, collision avoidance, survey accuracy, survey management, and relief well/well intersection.

- All existing requirements reviewed (regulation and guidance) were oriented towards specific defined requirements (e.g., frequency of measurements) or specific data elements to be collected or reported. The requirements observed did not include risk-based or performance-based approaches.
- None of the regulations identified rely on industry standards for detailed practices.
- The more detailed approaches often include regulatory reference to more detailed guidance which then becomes *defacto* requirements as a result of the approvals process.
- None of the jurisdictions reviewed identify high temperature environments as a unique condition that requires separate treatment in regulation.
- Only one of the jurisdictions reviewed (Canada) addresses specific requirements for planning or operations in high latitude or arctic drilling conditions.
- Most of the regulations or the implementing guidance documents reviewed specify the survey frequency (survey station interval) or measure frequency, but there is wide variability among the specific frequency requirements.
- Many of the regulations reviewed focus on the requirements for submittal of final data sets, but do not address planning, survey quality, or certification of data.
- There were no noteworthy differences identified between regulations for onshore and offshore jurisdictions as they apply to the scope of this review.

4.4.2. Areas of Potential Regulatory Application

This section summarizes areas that BSEE regulations could address, based on regulations in other jurisdictions and understanding of the best practices for ensuring safety and environmental performance. Refer to Attachment C for details on all regulatory areas and jurisdictions discussed in this section. Section 5 of this report discusses recommendations for each of these areas.

4.4.2.1. Planning

Only by having a sufficient level of planning of wellbores prior to drilling activity can there be reasonable assurance that the well location will be understood and managed, and collisions will be avoided. Ensuring that collisions will be avoided relies not only on the ability to accurately control where a new well will be constructed, but also the degree of understanding of where already existing wells are located. Planning is dependent on current techniques and past efforts, data management, and data quality. Desirable plans (which must be approved) describe the full plot of where a wellbore is expected to be drilled, where that location will be relative to other existing or planned wells, the confidence level of that location, how that location will be assured, the means by which the level of accuracy needed to ensure a collision will be avoided will be accomplished, and the data management and reporting that will occur.

Wellbore survey planning can be regulated by requiring pre-drilling application submittals related to directional drilling or surveying, and requiring specific approvals or directional drilling permits prior to conducting these activities. While BSEE does require a directional plot to be submitted with an APD, other state and international jurisdictions, such as Texas and the United Kingdom, specify the exact data points that should be included on a directional plot (i.e., terminal depth, position of the well with respect to neighboring wells, plot with vertical section and horizontal plan).

Other areas for potential regulatory application include anti-collision analysis and actions to be considered when minimum separation distance is exceeded. Norway regulates both of these areas, including a minimum probability for the wellbore to be within calculated uncertainty ellipses (95%) and recommended actions for when a separation factor is below the acceptable ratio.

BSEE can address details of operation, data management, and data quality within wellbore APD requirements. Ensuring that plans address all areas of requirements prior to approval appears to be clear starting point to implement any additional requirements.

4.4.2.2. Operations

The interval and accuracy with which wellbore survey stations are recorded as drilling proceeds is intended to assure that a drill plan is followed, the location of the wellbore is understood so as to avoid collisions, and for future reference. Generating accurate data requires equipment capable of sufficient accuracy, that has been calibrated properly, and which is operated appropriately. Changes in direction require increased data points. Data needs to be collected in a standardized format.

Potential regulatory areas for survey operations include specific survey requirements (such as minimum survey intervals, coordinate systems and reference points, and check shot surveys and accuracy verifications), as well as tool requirements (including magnetic spacing for azimuthal tools and calibration procedures). While BSEE does specify minimum survey intervals, other jurisdictions define more stringent requirements. For example, Wyoming specifies directional survey intervals depending on the rate of change of the borehole angle (dogleg severity), with intervals ranging from 100 feet to 300 feet. Check shot surveys also are required by Wyoming when a wellbore is a highly deviated. When multiple surveys are run, regulations may define which one should be considered the master (or definitive) survey; Wyoming states that the gyro survey should be considered the master survey.

4.4.2.3. Data Management

Data management starts at planning, where the data points and format and methods for data capture, retention, and reporting are set before drilling is approved. All survey data (including if multiple surveys have been conducted) needs to be stored by the operator in an electronic format specified and submitted in that format to enable centralized storage and use as needed. Meta data (datum, magnetic field strength and dip angle, magnetic model, tool types, error codes, and survey computation methods) and raw data are important information to capture and record. Survey calculation needs to be via an approved method(s), which should have been part of an approved plan. Timeliness and frequency with which data is submitted is a part of the data submission requirements.

An area of potential regulatory application is general data management. Requirements have been developed in most jurisdictions, and consist of submission schedules, survey submittal formats, and data archiving requirements. Submittal formats can be as detailed as specifying whether the data should be submitted electronically or in hard copy and header and ancillary survey information requirements.

Another area for potential regulatory application includes specifying acceptable survey calculation methods. Wyoming, for example, states that the minimum curvature method with straight line extrapolation from the last data point in the survey to total measured depth should be used. Data reporting for sidetracks, laterals, and bypasses is also an area regulated by states, including Wyoming and Texas, with requirements for labeling laterals and sidetracks, defining survey tie-in points, and maintaining tabulations of maximum drift.

Setting data management and data submittal requirements may depend on whether BSEE will be the primary long term data holder for well survey data. Operators should also retain all data for at least the duration of a lease, but BSEE should not rely only on operator retention. Recent changes to the oil and gas regulations in the United Kingdom shift the records retention requirements from the government agency to the operator. A necessary part of submission of the survey data can be expected to be that detailed data submission formats be specified. BSEE will need to determine if it should require not just submissions but rather input into the master database.

4.4.2.4. Data Quality

"Quality data" (i.e., data which can be relied on with sufficient confidence), is fundamental to surveys. Data quality can be managed and regulated in a number of ways, including training and competency requirements for personnel and operator and survey company certifications. Norway, Wyoming, New Mexico, and Texas have a varying level of regulatory requirements under this topic; however Norway regulations are particularly detailed with training requirements for wellbore physics, well construction principles, and preparation of well construction principles. The Norwegian regulations state that certifications must be issued by an international recognized party (i.e., IWFC, IADC).

Data quality can also be managed with procedures for ensuring accurate tie-in depths, corrections to wells, and projecting ahead or at the end of the hole. Requiring the use and description of representative tool survey error models may also be defined in regulations to understand and minimize the ellipse of uncertainty. Independent QA/QC of survey data could be considered, however the regulatory review did not identify any jurisdictions that implement it.

4.4.2.5. Relief and Intercept Well Operations

A relief well should be subject to all normal well planning requirements, as well as additional requirements specific to its purpose. International regulatory bodies from Norway, Australia, Canada, and the United Kingdom regulate relief and intercept well operations primarily through the submittal requirements of well control or oil spill contingency plans. These plans are typically required to be filed and approved prior to any drilling activities. Relief well requirements within these plans include, but are not limited to, minimum number of rig locations for drilling relief wells, description of kill methods, technology to be used, secondary drilling unit strategies, and lessons learned from previous incidents or near misses. Norway also specifies the maximum amount of the time that can pass before relief well drilling begins (no more than 12 days after the decision to drill a relief well has been made).

Relief well regulations in the U.S. and internationally do not specifically address the role of directional surveying and ranging to ensure successful relief and intercept well operations. Requiring an increased level of planning that includes considerations for the selection and operation of directional survey and ranging tools is not identified in any jurisdictions, but may be valuable to facilitate efficient and effective operations, especially in hostile drilling environments (high temperature) and remote areas.

5. Recommendations for Improving Regulations and Guidance

5.1. Approach and Considerations to Evaluate Potential Improvements

Improvements to BSEE's regulations first and foremost need to improve short and long term safety and environmental protection, while not placing undue burden on industry. Any change in regulations should be consistent with BSEE management principles. These technical and regulatory considerations are discussed in the sections below.

5.1.1. Technical Considerations

Wellbore surveying and ranging is a specialized discipline that encompasses a wide range of technical issues affecting safety and environmental performance. The recommendations presented here were developed with recognition of certain technical considerations that were developed based on our research and understanding of the industry. These technical considerations are described below.

Equipment or product independent. Data developed in this study provided detailed assessments of regular and high temperature wellbore surveying and ranging tools available from many different service companies and suppliers. Although the industry segment is small, there are a number of potential suppliers for each service, with only a few exceptions for specialized services. Prescriptive use of a particular tool, service, measurement, or software in the regulations is not necessary given the broad availability of tools and services on the market. The preferred option for regulatory improvements should focus on practices and outcomes. Performance or risk-based requirements are most appropriate for the technical and operational requirements, because industry can respond with innovative ideas that will move the technology and practices forward.

Incorporates existing standards and industry practices. BSEE and other regulatory agencies often incorporate and reference industry standards in regulations. Incorporating established industry standards, if they are appropriate, facilitates industry compliance with new regulations and allows the challenges of developing detailed technical requirements to directly engage and capitalize on industry experts. ISCWSA practices are available for some of the survey lifecycle components, and have been accepted by the industry as a best practice. An API Recommended Practice for Wellbore Surveys (API RP 78) is under development and drafting of detailed content is in progress in 2016. These two references can form a foundation for many of the areas recommended for improving regulations.

Geographically applicable across BSEE jurisdictions. While most of the current BSEE regulated activity is in the Gulf of Mexico (GOM), the recommendations must consider future trends in activity in the Arctic, West Coast, and East Coast. The Arctic has some unique technical issues that affect wellbore surveys that are not found in the GOM. Activity includes exploration, production, and post-production (plug and abandonment) activities.

Enhances safety and improves efficiency and resource management. Safety can be enhanced through more accurate data collection, consistent and appropriate data processing, and proper reporting of key survey information (not just the definitive survey data points). Efficiency in operations is important during relief well situations where time is critical. From the operator's perspective, the regulations should reflect a balance of the time required to implement a new requirement, and the improvement in safety, environmental performance, and resource management, especially during drilling where the rig cost is high.

Best solution is applied. The best solution or option should be applied to a particular risk or work component without contractual or practical complications. For example, some industry experts believe that in certain high risk and emergency situations contractual agreements with a particular service company may not allow for use of another company's tool that might be more efficient or effective.

Practical application of regulations across all of industry. There is a wide range of sophistication and resources available in operating companies and directional services vendors. Technical recommendations are designed to improve industry performance yet be flexible enough for broad application across the industry. However, there may be operators and vendors who will not be able to meet proposed threshold standards to ensure safety and environmental protection.

5.1.2. Regulatory Considerations

Recommendations for improving the current regulations were developed to reflect the BSEE management principles of transparency, predictability, consistency, and accountability.

Additionally, the recommendations considered BSEE's strategic goals.

- Regulate, enforce, and respond to Outer Continental Shelf (OCS) and Deep Water development
  - Properly define, assess, and differentiate risks
  - Implement clear, consistent, comprehensive, and effective permitting processes
  - Refine and enhance offshore safety performance
  - Identify and adopt innovative ideas to enhance safety and environmental protection
- Build and sustain organizational, technical, and intellectual capacity
  - Innovate in regulation and enforcement
  - Keep pace with OCS industry technological improvements
  - Reduce risk through systemic assessment and regulatory and enforcement actions
  - Promote human capital transformation throughout the agency

Finally, the recommendations considered the four principal objectives of the Safety and Environmental Management System (SEMS) approach.

- Focus attention on the influences that human error and poor organization have on accidents;
- Continuous improvement in the offshore industry's safety and environmental records;

- Encourage the use of performance-based operating practices; and
- Collaborate with industry in efforts that promote the public interests of offshore worker safety and environmental protection.

5.1.3. General Regulatory Approach

Regulation of a highly technical field of activity is often not conducted via heavily prescriptive requirements, as the ability to innovate and apply better solutions tends to be limited. BSEE, on many similar regulatory fronts, is moving towards more risk-based and performance based requirements, which is applicable and relevant to the scope of wellbore surveys. Risk-based requirements drive better understanding of risk associated with complex activities, and as BSEE moves to more use of risk-based approaches in general, for example ALARP (as low as reasonably practicable) requirements for OCS activity, proponents will need to consider how their proposed wellbore survey activity supports and is consistent with ALARP. The specific recommendations presented in Section 5.2 do not discuss the broader application of risk management, rather they focus on performance requirements for the specific scope of wellbore survey activity.

BSEE uses an extensive application and technical review process in its permitting of OCS activity. This includes the APD process, where an applicant can be required to define the specific tools and techniques they will use, and how they will apply them. While a sufficiently defined plan is not a guarantee of success in of itself, a deficient plan greatly increases the likelihood of problems in execution. A sufficient plan is where a proponent is able to describe associated risks, the specific methods used to manage those risks, and also how they intend to meet any performance requirements. Execution requirements can be tied to plans and associated commitments made.

The ISCWSA-led API RP 78, when completed, is expected to include many recommended practices and will therefore not be a required API Standard, but rather a recommended practice (RP). An RP is based on the use of "should" statements as it is a recommended practice (not "shall" statements). As such, if API RP 78 (or components of it) were to be directly referenced in revision to a BSEE regulation, industry would not be compelled to follow it necessarily. Key elements of API RP 78 could be defined in regulation, or stipulated as review criteria in BSEE's review approach to drilling plan applications.

5.2. Specific Recommendations

The regulatory improvement recommendations provided in this section are based on and informed by:

- Already existing BSEE requirements,
- Technical and regulatory considerations including those summarized in Section 5.1 above,
- Regulatory approaches used in other jurisdictions, as they might apply in the context of the BSEE framework, and
- Industry best practices.

This section draws on the best practices for directional surveys in exploration/production wells and relief/intercept wells, and the potential areas for regulations to improve the safety and environmental performance of operators presented in previous sections. The specific recommendations apply the considerations above to the perceived gaps in the current BSEE regulations across the subject areas.

The tables below provide several types of recommendations and the rationale for each. Recommendations are identified as either a new or revised action[17], based on the current BSEE regulations, and are categorized as a possible requirement (a regulation) or guidance to indicate the level of priority and significance of the action. New actions are recommended in areas where either no regulation or guidance exist or in cases where the current action is very general. Improvements to existing regulations and guidance are recommended to improve, update, or expand the scope of the current action. Some recommendations represent actions for BSEE to consider that do not result in changes to regulations or guidance. The terms “must” and “shall” in the recommendations below indicate a higher priority action that is generally recommended for inclusion in a regulation, as opposed to guidance. “Must” is also used in some of the recommended guidance statements to indicate a required action (generally a technical method) if the guidance is followed. The term “should” is used to reflect a lower priority item, generally a best or preferred practice, intended for inclusion in a guidance document. The term “may” is used in a recommended regulation where BSEE determines if the action will be necessary.

The recommendations below recognize that there is an initiative to develop an industry practice for wellbore surveying (API RP 78) that will cover many of the technical areas identified here. Once the RP is available BSEE may want to compare the recommendations in this report against the API RP.

5.2.1. Planning

Wellbore planning includes the design of the drilling program for the wellbore, from surface to total depth. The objective of the wellbore design is to define a drilling plan that will reach the geologic target safely, accurately, and efficiently. Planning the wellbore and the directional survey program is a safety critical element in the well drilling process and is the basis for many of the operations that follow. Many of the recommendations presented in Table 17 address data quality and completeness as part of the planning process. Improving regulations in the planning stage will strengthen the performance through better organization.

[17] The term “action” in this context is a general reference to either a regulation or guidance document in a potential area of regulation.

Table 17: Recommendations for Wellbore Planning

Recommendations for Wellbore Planning		
Area/Subarea	**Recommendation**	**Rationale**
Directional Survey Program	The operator must develop a wellbore survey program that includes a written plan that identifies each directional survey tool or tool type to be used for each section of the wellbore, and the rationale for selection. The plan must address the specific conditions expected to be encountered in the proposed well(s), and identify how the operator will comply with the wellbore survey regulations. The plan must be submitted with the Application for Permit to Drill (APD), and be available for inspection at the well by BSEE, if requested.	**(New Requirement)** The existing requirement does not provide any detail on the content of the survey plan. This general planning requirement establishes a Directional Survey Program with a minimum level of performance to ensure that the proposed wellbore survey will provide usable data and address the regulatory requirements. The format is flexible and the minimum content is specified by a performance standard (rationale for selection) and references compliant with the supporting BSEE regulations. BSEE needs to have these plans so that there is documented commitment by the applicant as to the methods they intend to follow, the types of equipment, and the best practices they intend to use for the work. *This action is not likely to be addressed in the API RP.*
Survey Data Quality Checks	Quality control procedures for ensuring accurate measurement, such as taking check and rotational check surveys, should be included in the Directional Survey Program.	**(New Guidance)** Such procedures reduce the likelihood of gross errors and will improve confidence in the quality of directional data. *This action is likely to be addressed, at least in part, in the API RP.*

Recommendations for Wellbore Planning		
Area/Subarea	**Recommendation**	**Rationale**
Standby Tools	The need for standby tools should be assessed in light of tool performance specifications and the expected operating conditions. If standby tools are not to be available at the rig site, the procedures and transit times for obtaining them should be identified and documented. The standby tool policy should be included in the Directional Survey Program.	**(New Guidance)** The inability to replace a malfunctioning or failed tool increases the likelihood that poor-quality data from such tools will be used. This should be avoided. *This action is not likely to be addressed in the API RP.*
Elevated Borehole Temperatures	Expected borehole temperatures should be identified and considered in the selection of MWD and survey tools. If temperatures are expected to approach or exceed the operating temperatures of any tools, means of reducing borehole temperatures (circulating and/or cooling the mud) and/ or reducing the tools' exposure to elevated temperatures should be considered and documented in the well survey plan.	**(New Guidance)** Data quality and wellbore safety can be jeopardized if operating conditions cause survey tools to fail or miscalculate borehole position. Plans to avoid such easily-foreseen situations should be prepared, in advance, so the needed tools, equipment, and systems are in place when they are needed. *This action is not likely to be addressed in the API RP.*
Minimum Graphics Standard for Well Trajectory Plan	Operators must provide a legible copy of the graphical representation of the proposed well trajectory in the APD. The figure must show the well in plan and vertical section view and identify true north, map north and grid north, convergence and declination angles, and all datum and grid systems presented. The plot should identify any section of the well trajectory in which the dogleg severity is greater than 5 degrees.	**(Improvement of existing requirement)** Provides more specific guidance to standardize the visualization of the proposed trajectory and ensures the reference datum and correction angles are identified. Improves data quality because operators are required to document the values used in calculations, and highlight any sections where dogleg severity might affect data quality. *This action is likely to be addressed, at least in part, in the API RP.*

Recommendations for Wellbore Planning		
Area/Subarea	**Recommendation**	**Rationale**
Certification of Well Planner on Plan Submitted with APD	The APD must include a statement of certification from the well planner indicating that the plan was developed in accordance with best industry practices, includes a collision avoidance analysis, and reflects the safety and environmental conditions anticipated in the drilling of the well.	**(New Requirement)** Certification is commonly used in other jurisdictions to maintain a standard of quality and assurance that the well plan has been properly planned and reviewed. *This action is not likely to be addressed in the API RP.*
Anti-Collision Analysis	The operator must conduct an anti-collision scan for the proposed well consistent with best industry practices. The well database used for the scan must represent the best and most complete data available for all wells likely to be in the area of review. A summary of the results of the anti-collision analysis must be included in the wellbore survey plan.	**(New Requirement)** Provides performance requirement to ensure the collision avoidance analysis is based on a comprehensive data set. Forms the technical basis of the certification statement required above. *This action is likely to be addressed, at least in part, in the API RP, and is currently addressed in an ISCWSA RP.*
Anti-Collision Rules	The drilling plan in the APD must describe the rules that will be followed for collision avoidance during drilling, including well separation criteria and the associated actions to be taken during drilling for the proposed and offset wells.	**(New Requirement)** Similar to Norway, this requirement ensures that a logical and quantitative analysis is performed to address the risk of collision. *This action is likely to be addressed, at least in part, in the API RP, and is currently addressed in an ISCWSA RP.*
High Temperature Surveys	The operator should clearly identify if any part of the well will be drilled under high temperature conditions (350°F or greater) and incorporate the effects of high temperature into equipment selection for any data collection activity. The analysis should address the well plan as well as the contingency plan for relief wells.	**(New Guidance)** High temperature wells may require a different set of tools to ensure accurate data are collected. A complementary guidance on monitoring for temperature during operations in included below. *This action is not likely to be addressed in the API RP.*

Recommendations for Wellbore Planning		
Area/Subarea	**Recommendation**	**Rationale**
Well Planning Software	Software used for well planning must have functionality to produce required formats for reporting and database retention.	**(New Requirement)** The well planning software currently used by offshore operators appears to respond to the requirements to prepare a safe and efficient well plan, and provides documentation of the process. This requirement ensures that operators will be able to submit the required reports and data in an acceptable format. *The selection and use of software for well planning is likely to be addressed, at least in part, in the API RP.*

Planning for directional surveys and ranging activities in relief well drilling must consider a number of different factors that are often not known until the well drilling is in progress. The recommendations presented in Table 18 address the considerations for developing effective contingency plans for relief wells.

Table 18: Recommendations for Relief Well Survey Planning

Recommendations for Relief Well Survey Planning		
Area/Subarea	**Recommendation**	**Rationale**
Relief and Intercept Well Planning	The operator must prepare a wellbore survey and ranging plan for each relief well proposed, and include the survey plan in the contingency plan. The plan must identify each directional survey and ranging tool or tool type to be used for each section of the wellbore, and the expected availability of the tool and rationale for selection. The plan should address the expected conditions to be encountered in the proposed well (including temperature, difficult ranging conditions [i.e., salt] and magnetic interferences), recognizing that actual conditions may be different at the time of drilling the relief well. The plan must be submitted with the APD, and must be available for inspection at the drilling site by BSEE if requested.	**(New Requirement)** This general planning requirement for relief wells parallels the general well survey plan above and establishes a minimum level of performance to ensure that the relief well surveys will provide usable data efficiently. BSEE should have these plans on file and review them to ensure the operator has considered any difficult conditions for relief well drilling. *This action is not likely to be addressed in the API RP.*

5.2.2. Operations

Survey operations include the actions conducted at the well during the drilling process. The recommendations presented in Table 19 for survey operations address the calibration of tools and the type of data and survey interval for surveys. Methods for calculating the survey and preparing a final survey for the wellbore are also included.

Table 19: Recommendations for Survey Operations

Recommendations for Survey Operations		
Area/Subarea	**Recommendation**	**Rationale**
Survey Tool Functional Tests	Before a survey tool is added to the BHA or tripped downhole, the operator must ensure that all survey tools are calibrated in accordance to their standard calibration procedures. This may include passing the simple, functional tests (i.e., roll test) recommended by the manufacturer.	**(New Requirement)** Adding malfunctioning tools to a BHA may jeopardize data quality and is likely to cause unnecessary trips and reduce efficiency. It should be standard practice to verify the functionality of a tool prior to use. *This action is likely to be addressed, at least in part, in the API RP.*
Continuous Monitoring for Collision Risk	During drilling, the wellbore must be continuously monitored for collision risk using the approach described in the anti-collision portion of the directional survey plan. The monitoring approach may include a traveling cylinder, ladder plot, three-dimensional visualization, or other real-time analysis of downhole data to evaluate collision risk.	**(New Requirement)** This requirement for real-time monitoring of collision risk during drilling relies on the anti-collision program defined in the directional survey plan above. *This action is likely to be addressed in the API RP, and is currently part of the ISCWSA RPs.*
Monitoring Borehole Conditions While Surveying	During drilling and survey operations, any borehole condition that may affect the quality and accuracy of survey measurements must be monitored on a regular basis. This may include, but is not limited to, monitoring temperature, total magnetic field, dogleg severity, hole size and hole rugosity.	**(New Requirement)** This guidance statement will serve as a general quality assurance action for survey operations. It is the follow-on implementation check to the well planning requirements that consider temperature and other expected conditions in the tool selection. *This action is likely to be addressed, at least in part, in the API RP.*

Recommendations for Survey Operations		
Area/Subarea	**Recommendation**	**Rationale**
Survey Station Interval	In boreholes, directional survey measurements must be collected at an interval that ensures an accurate wellbore trajectory is recorded. The survey station interval shall be no greater than100 feet. In hole sections with dogleg severity greater than 5 degrees, the operator should establish a more frequent survey station interval that ensures accurate representation of the borehole.	**(Improvement of existing requirement)** Provides more stringent requirement for survey station intervals that is consistent with best industry practice. Any sections where high DLS might affect data quality should be evaluated and a shorter interval considered. *This action is likely to be addressed, at least in part, in the API RP.*
Survey Calculations	The standard for directional survey calculation shall be the Minimum Curvature Method with straight line extrapolation acceptable from last data point in survey to Total Measured Depth.	**(New Requirement)** The calculation method is not specified in the current regulations. The Minimum Curvature Method is recommended by ISCWSA and is the standard method required in some jurisdictions. *This action is likely to be addressed in the API RP, and is currently part of the ISCWSA RPs.*
Survey Concatenation	In the definitive survey, each depth point shall have a unique and single set of survey data associated with it, and no interpolated, projected, or estimated data shall be included in the definitive survey. Tie-in points for where two subsequent surveys are connected and methods for propagation and concatenation of ellipses shall be identified.	**(New Requirement)** Concatenated surveys should not include interpolated data. (Some operators request data to be regenerated at even depth increments, such as every 100 feet for simplifying analysis.) The appropriate tool code should be assigned to each section of the survey to facilitate tool error modeling. *This action is likely to be addressed, at least in part, in the API RP.*
Definitive Survey	Change the term “Composite Survey” or “Final Survey” to “Definitive Survey” in all BSEE regulations and guidance.	**(Improvement of existing requirements)** Definitive survey is the common industry term. *This action is likely to be addressed, at least in part, in the API RP.*

5.2.3. Data Management

Data management recommendations presented in Table 20 include activities related to the database used for well planning, and the storage, reporting, and transfer of directional survey data.

Table 20: Recommendations for Data Management

Recommendations for Data Management		
Area/Subarea	**Recommendation**	**Rationale**
Database Completeness	The master database used for collision avoidance should represent the best and most complete well data available. It should be checked for accuracy and thoroughness and stored in a manner that preserves the integrity of the data. The database should include all drilled segments of each well identified	**(New Guidance)** An accurate well database is critical to safety and overall survey quality. A new guidance for developing and using a comprehensive and accurate database will elevate the importance of database quality. *This action is likely to be addressed with rigor in the API RP.*

Recommendations for Data Management		
Area/Subarea	**Recommendation**	**Rationale**
Data Submittal Requirements (Header Information)	Data submitted to regulators for the permanent record must include a comprehensive set of header information that clearly identifies all positional information and datum, along with other information that can be used to accurately recreate the well location and survey data.	**(Improvement of existing guidance)** The current data submittal guidance requires a minimal amount of header data to be reported. This recommendation provides an updated list of information that must be included in the data file submitted to BSEE, potentially including: *Field, Structure and Slot, Well name, API# (14 digit), Survey Name, Survey Date, Coordinate Reference System, Location Lat/Long, Location Grid N/E and Y/X, Grid Convergence Angle, Grid Scale Factor, Survey Computation Method, TVD Reference Datum, TVD Reference Elevation, Seabed/Ground Elevation, Magnetic Declination, Total Gravity Field Strength, Gravity Model, Total Magnetic Field Strength, Magnetic Dip Angle, Declination Date, Magnetic Declination Model, North Reference, Grid Convergence Used, Total Correction Mag North to Grid North. This action is likely to be addressed, at least in part, in the API RP.*
Composite or Final Survey	None.	**No new or revised guidance or requirement recommended.** The current requirement for submission of the Definitive Survey currently required from offshore operators appears to be appropriate. *The preparation and submittal of the final, definitive, or composite survey is likely to be addressed, at least in part, in the API RP.*

Recommendations for Data Management		
Area/Subarea	**Recommendation**	**Rationale**
Re-submission of Surveys	Operators should be encouraged to resubmit corrected well position and directional survey data to BSEE to improve the overall data quality of the regulatory database. The resubmittal should include a brief explanation of why the re-submitted data are more accurate and representative than the existing BSEE data.	**(New Guidance)** Operators often re-evaluate and correct surveys as they conduct their database audits and well planning. To improve the quality and thoroughness of the BSEE survey database, a statement encouraging voluntary resubmittal of the improved data should be included in the guidance document. *This action is not likely to be addressed in the API RP.*
Data Transfer/Electronic Data Content	BSEE should consider the use of an existing standard data format instead of the current MMS format for reporting directional survey data. An example of such a format is UKOOA P7 Data Exchange.	**(Improvement of existing requirement/guidance)** The current mandatory data submittal requirement uses a BSEE-specific format that does not capture all the data fields commonly reported in modern directional surveys. Using an existing universally-accepted format, if it meets BSEE needs, will minimize errors that may occur when data are converted from one system to another. *This action is not likely to be addressed in the API RP.*

5.2.4. Data Quality

Data quality is a cross-cutting topic that is addressed during planning, operations, and data management activities. Operators and service companies have internal procedures for managing data quality, but the overall improvement on the data BSEE receives and stores can be improved as described in the recommendations presented in Table 21.

Table 21: Recommendations for Data Quality

Recommendations for Data Quality		
Area/Subarea	**Recommendation**	**Rationale**
Certification of Survey Accuracy and Qualifications of Wellbore Survey Specialists	Operators shall provide written certification that the directional survey data they are submitting accurately represents the wellbore trajectory and conforms to the calibration standards and operational procedures set forth by the MWD/directional survey company, and best industry practice. The person certifying the data must be an independent reviewer, such as a third party survey management organization from either within or outside the operating company. The certification must state the reviewer is authorized and qualified to review the data, calculations and report.	**(New Requirement)** A certification statement from the operator will provide added responsibility on the operator to ensure the survey data are accurate and complete. The requirement of a third party review helps ensure a thorough and independent review of the data. *This action is not likely to be addressed directly in the API RP, but may be addressed in the quality control procedures and documentation section.* Ensuring survey data quality requires specialists well versed in the science and art of wellbore surveying. Persons certifying the accuracy of the data should be qualified to do so. *This action (certification of qualifications) may be addressed in the API RP.*

Recommendations for Data Quality		
Area/Subarea	**Recommendation**	**Rationale**
Corrections Made to Magnetic Survey Station Data	The definitive survey must provide an accurate representation of the borehole trajectory and include corrections for physical effects on the MWD tools including sag, local magnetic field, and magnetic interference from the BHA where these effects are greater than the allowable error in the standard ISCWSA tool error model. All corrections applied must be noted in the meta data file submitted with the survey data.	**(New Requirement)** This new requirement will help ensure that the data submitted to BSEE for the permanent record will account for significant influences on the magnetic data, thus improving the overall quality and reliability of the BSEE database. It is best industry practice to apply these corrections, and most major operators regularly make these corrections to the data set. Since not all survey data will need to be corrected, the requirement applies a significance criteria based on the standard tool error model. The second requirement (corrections noted in the meta data) allows data users to easily identify the corrections made and gage data quality. *This action is likely to be addressed in the API RP.*
Depth Measurements	Depth measurements should be corrected to account for pipe stretch and other factors that may result in significant depth error (greater than 1 foot per 1,000 feet). Physical measurements (strapping and pipe tally) should be checked for accuracy, if possible.	**(New Guidance)** Accurate reporting of true vertical depth and measured depth is important to safety and overall survey quality. *This action is likely to be addressed, at least in part, in the API RP, and is partially addressed in ISCWSA best practices.*

Recommendations for Data Quality		
Area/Subarea	**Recommendation**	**Rationale**
Actions to Improve Accuracy and Reduce Uncertainty in Survey Data	Operators should apply the correct tool error model (instrument performance model) and other data quality improvement methods to accurately quantify the uncertainty of the borehole location at each survey point. Methods may include, but are not limited to, Multi-Station Analysis, and other methods generally accepted in the industry. Tool error models must be consistent with the framework for tool error models set by ISCWSA, and the operating conditions of the survey must meet the minimum conditions for a valid error model set by ISCWSA.	**(New Guidance)** Like the magnetic corrections described above, this new guidance will help ensure that the data submitted to BSEE for the permanent record accurately represents the borehole trajectory. There is much flexibility in the type and way an operator may make these corrections, so this is a guidance statement only. However, any models used must meet threshold requirements for validity and content set by ISCWSA. *This action is likely to be addressed in the API RP.*
Quality Control Tests During Survey Operations (Requirement)	BSEE may require specific quality control activities during the survey, including but limited to check shots, rotational shots, and repeat surveys at various depths, to ensure the data quality of surveys. BSEE may also require two different survey tools to be run over the same interval to evaluate the variability of the resultant wellbore position. Ideally, the tools would be based on different measurement physics. This requirement will be a stipulation on the approved APD on a case-by-case basis.	**(New Requirement)** This recommendation is modeled after Wyoming's requirement and allows BSEE to stipulate certain quality control checks, if necessary, after the agency reviews the survey plan and well trajectory diagrams in the APD. BSEE would only require these actions in wells where there was uncertainty or high risk based on existing knowledge. *The recommended practices for certain quality control procedures, such as those presented here, is likely to be addressed in the API RP.*

Recommendations for Data Quality		
Area/Subarea	**Recommendation**	**Rationale**
Survey Management	Operators should ensure the data used for decision making during drilling, and the data submitted to BSEE is an accurate representation of the trajectory of the borehole and accurately represents the uncertainty in the borehole location. Operators should follow the best practices for survey management to ensure the quality of the data.	**(New Guidance)** This general guidance encourages operators to apply survey management as a best practice to all survey data collected and submitted. The scope of survey management services is left to the operator based on the well conditions and risks, but relies on the best industry practices which will be well documented in the API RP.
Redundant Surveys	In situations where the precise location of a borehole is important, the use of redundant surveys with both magnetic and gyro-based tools should be considered. (i.e., where wells are present nearby and may create a collision hazard, high dogleg severity sections, obstacle avoidance, close proximity to lease lines, or small driller's target)	**(New Guidance)** This practice is the most effective means of preventing and detecting gross errors and will substantially reduce uncertainty in many situations. *This action is likely to be addressed, at least in part, in the API RP.*

5.2.5. Relief and Intercept Wells

Drilling relief and intercept wells requires a set of operational considerations that is different from exploration and development drilling. Planning is often performed at a relatively general level initially during APD stage, and then refined as the drilling and adjacent well conditions are better identified. Often, the survey and drilling decisions are made under tight time constraints and with significant implications for safety. The recommended regulatory improvements presented in Table 22 in this area recognize the broad range of issues and site specific conditions that may occur in relief and intercept well operations, and also recognizes the real-time decision making that may be necessary in time-critical drilling operations. In general, the API RP does not address relief and intercept well operations; however the Well Intercept Subcommittee of ISCWSA is developing best practices for relief and intercept well surveys.

Table 22: Recommendations for Relief and Intercept Wells

Recommendations for Relief and Intercept Wells		
Area/Subarea	**Recommendation**	**Rationale**
Relief and Intercept Well Planning	See Section 4.3.1 "Planning" and Table 3 for well planning recommendations for relief and intercept wells.	
Drilling Efficiency/ Measurements While Rotating	When selecting MWD tools, operators should consider the added efficiency that might result from obtaining directional measurements while drilling, but also be aware of the effect on uncertainty calculations. In the past, measurements made while drilling have not been as accurate as those made when tools were stationary, so the achievable accuracies also should be considered.	**(New Guidance)** In a time–critical drilling situation, the time required for directional measurements can be significant in deep wells. New methods are available for collecting directional measurements while rotating. Eliminating the need to stop drilling could reduce the time needed to complete a relief well. This guidance offers an alternative to traditional survey methods that relief well teams may find useful. *This action is not likely to be addressed in the API RP.*
Drilling Efficiency/Running a Mud Motor in Tandem with a Rotary-Steerable System (RSS)	When selecting drilling methods for relief wells, operators should consider adding a mud motor above an RSS, which will increase the power available to the bit and increase the rate of penetration.	**(New Guidance)** This guidance statement is also intended to improve the efficiency of drilling in a relief well situation. Increasing the horsepower to the bit is likely to reduce the time needed to complete a relief well. Although it is not directly related to directional surveys or ranging, the selection of drilling tools may influence the selection of survey and ranging tools. *This action is not likely to be addressed in the API RP.*

Recommendations for Relief and Intercept Wells		
Area/Subarea	**Recommendation**	**Rationale**
Survey Interval and Accuracy (Relief Well)	During relief well drilling operations directional survey data should be collected at an interval and level of accuracy such that the position of the well is accurately known at all times and will never approach the target well with a separation factor less than one (1) before ranging.	**(New Guidance)** This requirement sets a general performance standard that will reduce the likelihood of an unplanned intersection with the target well. The survey plan for the relief well should reflect this consideration in an effort to reduce uncertainty to the greatest extent possible. *This action is not likely to be addressed in the API RP.*
Data Management for Ranging Results	If ranging results indicate that the original (target) wellbore trajectory or surface location can be more accurately described than the existing data managed by BSEE, the operator must submit the updated definitive survey and revised surface location data to BSEE in accordance with data submittal requirements. The revised submittal must describe why the new data are considered more accurate than the existing data in the BSEE database.	**(New Requirement)** Currently there is no specific guidance or requirement related to ranging run data management. Data from ranging runs is used in real time to guide drilling and intersect decisions. The ranging data itself is of little use since it provides only relative proximity data not actual geodetic location data. During the ranging process a new target wellbore trajectory is calculated that may be significantly different from the original data, especially in older wells or wells with gross error. In an effort to improve the overall quality of the BSEE database, any improvement in wellbore data should be encouraged. *This action is not likely to be addressed in the API RP.*

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Obtaining the information needed to assess, describe, and compare the various tools, systems, and technologies that have been addressed in this report would not have been possible without the cooperation of many professionals for whom directional drilling, borehole surveying, and the drilling of relief wells has been a full-time occupation. The individuals listed below freely shared their time, experience, and knowledge with our team. Some provided technical papers and brochures that explicated the performance of their products, technologies, and systems. Others shared their knowledge concerning the history of their products and services, their capabilities and limitations. Still others

shared their experiences and knowledge gained in the field, while supervising the drilling of relief and/or directional wells. Without their kind assistance, concluding this project would not have been possible. We thank them all.

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SURCON: Shawn DeVerse

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Wild Well Control: John Wright

Attachments

Attachment A: Tool Descriptions and Lifecycle Components of Directional Surveys and Ranging

Wellbore Surveying Technology

Technical Memorandum for:

Task 2: Wellbore Surveying Tools and Technologies

Task 5: Ranging Technologies

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1. Introduction

1.1. Background

The mission of the Bureau of Safety and Environmental Enforcement (BSEE) is to promote safety, protect the environment, and conserve resources offshore through regulatory oversight and enforcement. Through its Technology Assessment Program (TAP), BSEE supports research related to operational safety and pollution prevention to provide engineering support to BSEE decision makers, to promote the use of Best Available and Safest Technologies (BAST), and to coordinate international research.

The Wellbore Survey Technology study will improve BSEE's ability to understand the operational performance capabilities and limitations of downhole surveying and ranging technology and operational practices. This knowledge will be used to enhance BSEE's regulations as related to wellbore surveying technology associated with surveying accuracy and survey management, as well as relief well/well intersection operations.

1.2. Task 2 and 5 Objectives

The objective of Task 2 is to evaluate and catalogue the various operational performance capabilities, characteristics, and limitations of downhole surveying technology/tools with a focus on 350 degrees Fahrenheit (° F) and greater, as well survey accuracy, survey management, and other properties which may limit wellbore surveying, steering, and ranging applications. Task 5 focuses on current ranging technologies, tools, techniques and applications. The tasks involve reviewing technical articles and product literature, and conducting outreach to tool and component suppliers, directional drilling and survey companies, and operating companies. Subsequent Technical Memoranda and the final report for this study will provide recommendations for the best methods, processes, procedures, and tools/technologies to use; for performing relief well and well intersection operations at 350° F and greater; to improve survey accuracy and survey management; and other properties which may limit ranging technology.

1.3. Methodology

The information presented in this report was gathered from several sources including publications, product literature, discussions with industry experts, and technical workshops attended by the report authors. Initial understanding of the subjects was obtained through professional papers primarily published through the Society of Petroleum Engineers (SPE) and affiliated organizations including the International Association of Drilling Contractors (IADC) and Society of Petrophysicists and Well Log Analysts (SPWLA). Introduction to Wellbore Surveying, a comprehensive resource on wellbore survey techniques published by the International Steering Committee on Wellbore Survey Accuracy (ISCWSA), now a technical section of SPE, also served as a basic reference. Additional technical resources include position papers and recommendations by ISCWSA, industry publications (World Oil, Schlumberger Oilfield Review, Oil & Gas Journal), technical presentations by industry experts, and technical specifications from published product literature.

After reviewing available literature, interviews were conducted with experts from service companies, tool and component manufacturers, and operating companies to obtain additional information and develop an understanding of deeper technical issues and the practical aspects of the tools and services described. Some of these interviews were conducted during technical workshops and meetings presented by ISCWSA.

ICF contacted or received information from the following firms on various aspects of this report: Abel Engineering, add Energy LLC, APS Technology, Baker Hughes, Bench Tree, BP, Copsegrove Developments Ltd., Devon Energy, Digital Graphics, Inc., Enteq Drilling (including XXT and KMS), GE Oil & Gas, Global QC Survey Management, Gyrodata, Halliburton/Sperry Drilling, MagVAR Inc., National Oilwell Varco, Noble Energy, Schlumberger, Scientific Drilling International, Superior QC, SURCON, Vector Magnetics LLC, Weatherford International, Inc., Applied Physics Systems, Honeywell, JAE, QDC Technology, Stephan Mayer Instruments, TIAX LLC, and Wild Well Control.

During the data collection we found that while there are many commonalities in understanding and procedures among the various service companies and operators, there are some areas where technical opinions diverged, which are presented in this report. In this report we provide a broad description of the technical topics, and recognize that some companies may operate differently globally or at a local level.

1.4. Report Organization

The report identifies the attributes and capabilities of wellbore survey and ranging tools (hardware) and also describes a wide range of operational and management practices applied during the wellbore survey process (herein referred to as the survey lifecycle). There are different sets of attributes to be assessed for the tools (hardware) and survey management/operational practices.

- **Section 1** is an introduction to the report and describes the purpose of the project, the approach, and a description of how the report is organized.
- **Section 2** discusses the hardware and measurements systems used in directional surveying and ranging. Tools are grouped by their primary use, directional survey (measurements while drilling) and ranging, and then by standard and high temperature tool categories. For each category, key aspects are summarized in a table.
- **Section 3** discusses the lifecycle components of directional and ranging surveys including planning, operations, data management, errors and corrections, and survey quality control. For each component of the survey lifecycle, key aspects are summarized in a table.
- **Section 4** provides bibliographic references for the cited documents.

The Attachment contains additional technical information and summaries of the tool attributes in Section 2.

2. Directional Survey and Ranging Tools

2.1. General Description of Survey and Ranging Tools

This section describes the following two types of tools within the scope of this project, their operating characteristics, key features, subsystems:

- **Directional Survey Tools** provide measurements used to determine the position of a bottom-hole assembly (BHA) or a location along a borehole with respect to the local gravitational and magnetic fields ("Magnetic") or the local gravitational field and true north. (True north, which coincides with the earth's spin axis, is directly sensed by tools using rate-sensing gyroscopes. Older generations of gyroscope-based directional tools employ free, vertical directional gyroscopes. These retain their initial orientation, with drift added or subtracted at an estimated rate, during a survey. Because they have been displaced by more accurate, rate-gyro-based tools, they are not within the scope of this report.) The measurements, or "surveys," made by Measurement-While-Drilling systems and survey tools are essentially the same. Magnetic MWD systems are usually called "MWD" systems, while Gyro-based Measurement-While-Drilling are known as "GMWD" tools or systems. ("GWD" is a trademark of Gyrodata and is in the name used for their GMWD tools and modules.) These directional tools measure only their orientation, which includes their azimuth, referenced to magnetic or true north, and inclination, which is referenced to the local gravitational field, with down equaling zero degrees. Thus, the azimuth of a tool at 0^o is indeterminate. Measured depth along the course of the borehole also is needed to determine position.
- **Ranging Tools** determine the direction and distance (range) from the tool, in an active borehole, and a target, which often is an already-drilled and cased borehole. Active ranging tools use a transmitter to induce an alternating current (AC) magnetic field in the casing, or other magnetic material, in the target borehole. By sensing the induced field from different locations, it is possible to locate the target with respect to the AC magnetometers in the ranging tool. Passive ranging tools determine the direction and distance to a target by determining how the magnetic materials in the target have distorted the earth's magnetic field. By "overlaying" multiple measurements along a known path, it is possible to construct a model of the target, since the distance between its magnetic poles is known. (Each joint will have a north and a south pole.) Passive ranging tools use the DC magnetometers that are used in magnetic directional tools to sense the local magnetic field and accelerometers to determine inclination.

Directional measurements normally are used to steer a borehole while it is being drilled, or plot the trajectory after it has been drilled. Usually, MWD systems are used to make such measurements while drilling to enable a directional driller to steer or direct the bit to specified targets, which requires the ability to determine the change in tool-face direction that is caused by reactive torque produced by the rotating bit. Surveys can also be conducted when drilling ceases using survey tools conveyed with wireline or through the drill pipe.

2.1.1. Development of Survey and Ranging Tools

During the last 50 years, the sensors and recording methods used for borehole directional measurements have changed dramatically. Early generations of directional tools employed mechanical compasses and inclinometers, whose orientations inside the tool were recorded on film. Single shot instruments took only a single picture, using a disk of film. Multi-shot tools took multiple pictures at timed intervals on a strip of film. Determining the measured inclinations and azimuths required retrieving these instruments, extracting the film, developing it, and "reading" the pictures using special viewers. Obviously, such measurements could not be made while drilling.

The concept of making directional measurements while drilling is not new. One of the early (unsuccessful) attempts was a battery-powered instrument that mechanically stamped inclination and magnetic azimuth onto a thin copper disk. The tool was designed to eject the stamped disks into the drilling fluid (mud), which carried them to the surface, where they could be recovered from the mud shaker screen.

Today's MWD tools use mud pulse or electromagnetic telemetry to transmit directional – and, often other – measurements to the surface in near-real-time. These tools rapidly penetrated most high-cost drilling projects (many of which are in offshore locations) during the 1980's. Their acceptance has been become even greater in recent years, as reliable rotary-steerable systems (RSS) were developed, brought to the market, and proven. Because of their nearly universal adoption for offshore oil- and gas-drilling projects, MWD systems are the primary focus of this project. But, before describing and assessing them, it will be useful to describe some other, legacy, directional measurement tools.

Modern multi-shot directional tools (aka "electronic multi-shots") use accelerometers and magnetic sensors, usually flux-gate magnetometers, and record their data in semiconductor ("solid state") memory. Rate-gyro based directional tools are available in both wireline and battery-powered versions. The former also are called surface-readout gyro tools. Like all rate-gyro-based tools, their azimuthal measurements are referenced to true north. Battery-powered, multi-shot tools often are operated in a "drop" mode, which means they are dropped inside the drill pipe to conduct directional surveys while the drill string is tripped to the surface.

The first commercially-successful, directional tools that were used to orient and guide a bit while drilling in real-time are called "steering tools." They are tripped into a borehole inside drill pipe on a wireline, which provides electrical power and real-time communications to the surface. They are used only with mud motors because the wireline in the hole precludes rotary drilling. This complication has resulted in the displacement of steering tools by MWD systems.

Other legacy systems include surface-readout gyro tools, which were – and still are – used to orient a BHA when kicking off or changing direction in locations where magnetic interference – usually from nearby, cased wells – precludes the use magnetic instruments. Because of their sensitivity to shock and vibration, gyro-based tools were not normally used while drilling, until recently. Advances in rate-gyro ruggedness and shock isolation methods have enabled several suppliers to offer rate-gyro-based measurement-while-drilling, or GMWD, systems. The development and use of error models, documented in IPM files, has enabled better understanding of the performance of GMWD tools and how they are likely to perform in specific applications

The evolution in rate-gyro sensors that has enabled the development of GMWD tools also has upgraded the performance of gyroscopic wireline and battery-powered tools. The higher bandwidth available to rate-gyro wireline tools provides better quality control ("QC") and facilitates multi-station correction. Such tools are now available in various configurations and operating modes, which will be described in the following section.

2.1.2. Operational Characteristics of Survey and Ranging Tools

In the vernacular of the directional-drilling and borehole-surveying industry, "wireline" usually means an armored, seven-conductor cable, which is used to lower and retrieve a (wireline) tool into and out of a borehole and provide electrical connections for power and communications. "Wireline" sometimes is used when referring to a non-conducting slickline (or "piano wire"), which is small-diameter, solid wire. (Larger, braided and die-formed, non-conducting wirelines also can be found on rig floors.) In this report, we use "wireline" when referring to the most commonly used, conducting armored cable. We use the term, "slickline," when referring to a non-conducting wire that is used to deploy and retrieve battery powered tools.

Wireline tools are normally run into boreholes after the drill string has been removed ("tripped out"). The need to trip out and trip in (travel back into the hole) with the drill string adds substantially to the rig time needed to run wireline tools. Most wireline tools are logging tools that make measurements to evaluate the formations surrounding a borehole. Rate-gyro-based wireline tools, which often are called "surface-readout gyros," are considered to be among the most accurate survey tools presently available. The only commercially-available active ranging system is the one wireline tool within the scope of this study.

Battery-powered survey tools – both magnetic, which usually are called "multi-shots," and gyro-based, which normally are referred to as "gyro multi-shots" – have many operating modes. They can be tripped into and out of boreholes on a slickline or dropped inside the drill pipe in what is commonly called "drop mode."

Drop tools are dropped inside drill pipe, free fall through drilling mud, and come to rest at a predetermined location near the bottom of the hole, usually on a landing plate or in a Universal Bottom Hole Orientation (UBHO) sub. If the bottom end (nose) of the drop tool is equipped with a "mule shoe" the UBHO will orient it with respect to the toolface or BHA. For magnetic tools, the landing position will be in a non-magnetic collar within the BHA. Like all multi-shot tools, drop tools are programmed to take and store surveys at fixed time intervals. Normally, they are dropped before tripping out of the borehole and are used to obtain directional surveys while each stand of drill pipe is broken off and racked. Drop tools store data internally, so it is available only after the BHA has been brought to the surface.

High-accuracy rate-gyro-based tools are available in wireline and battery-powered configurations, which can be operated in a multi-shot drop mode or tripped on a slickline. In these configurations, they offer various operating modes, including continuous surveying, high angle, and conventional multi-shot (taking surveys at pre-determined intervals) modes. In many applications, these tools are significantly more accurate than GMWD tools. The performance of all rate-gyro-based tools is limited by the capabilities of rate gyros, which cannot withstand temperatures above 300°F (150°C) for very long. The two suppliers of wireline and battery-powered rate gyro tools offer heat shields (aka flasks or dewars), which can extend their operating time to six to twelve hours at elevated temperatures.

Table 1 highlights the key components of the directional and ranging tools described above, including how they store or transmit data, their power sources, and directional sensors.

Table 1: Key Components

		Directional Tools		Ranging Tools	
		Magnetic	Gyroscopic	Active	Passive
Data transmission/storage					
	Solid-state memory	D, M	D, M		M
	Wireline Telemetry	W	W	W	
	Mud Pulse telemetry	M	M		M
Power supply					
	Battery	D	D		
	Wireline		W	W	
	Turbine-Generator	M	M		M
Sensors					
	Accelerometers	D, W, M	D, W, M	W	M
	Rate-sensing Gyroscopes		D, W, M		
	Magnetometers-AC			W	
	Magnetometers-DC	D, W, M			M

Tool Types		
	Drop/Slickline	D
	Wireline	W
	MWD	M

Measurement-while-drilling (MWD) tools are run inside special, non-magnetic collars above the bit in the BHA or, if a mud motor or rotary-steerable system (RSS) is in the BHA, just above them as shown in Figure 1. Some MWD systems can be tripped in and out, inside the drill pipe. Others are permanently mounted in their non-magnetic collar. As with wireline tools, there are versions of MWD tools that also measure formation properties. They are usually created by adding logging sensors to directional MWD systems, and are called Logging-while-drilling (LWD) tools. LWD tools are outside the scope of this study.

MWD tools transmit their data and/or measurements to the surface through drilling fluid (mud), using pulses, or electromagnetically, through the earth. Electromagnetic MWD tools offer higher bandwidths, but are limited in range by the electrical impedances of the formations between the tool and the surface. MWD tools that transmit acoustically through mud are usually called "mud pulse" tools. This is an oversimplification, since there are three types of mud pulse telemetry:

- Positive mud pulse systems produce pressure pulses by restricting the flow of drilling mud, with a poppet or shear valve;
- Negative mud pulse systems produce pulses by venting mud from the inside (bore) of the tool into annulus, thereby lowering the pressure within the drill pipe; and
- Continuous-wave mud pulse systems (aka mud sirens) produce a continuous, low-frequency acoustic carrier and transmit data by changing its phase.

As mentioned above, wireline tools use conductors in the electrical cable to transmit their data to the surface. Because the bandwidth of typical logging cables is thousands of times greater that the bandwidth of mud-pulse systems, this transmission speed provides some compensation for the time lost while tripping the drill pipe and BHA out and back in to run a wireline tool.

Over the last 40+ years various borehole telemetry systems that use wired drill pipe have been developed, tested, and promoted. One supplier has such a system available today. Because it only recently has become a commercial product and has limited availability, it is not included in this study. However, MWD and GMWD tools that can be used with this system are included.

Figure 1: Typical BHA Configuration with MWD & GMWD (from: Gyrodata Inc. reproduced with permission)

2.2. MWD Tools

The tools described and analyzed in this study include "Standard" MWD and GMWD tools, which can be used when borehole temperatures are 350° F (176° C) or below, and "High Temperature" tools, which are capable of operating at borehole temperatures above 350°F (176° C) for extended periods of time.

2.2.1. Scope and Introduction

Suppliers of MWD tools that provide directional surveys and are compatible with marine environments were identified. A standard spreadsheet format was developed and submitted to appropriate contacts at each supplier, together with general information about the project and its objectives. Some of the data items listed in the spreadsheet are not normally provided by some of the suppliers. Discussions and iterations with many suppliers also were needed to reach agreement on units and qualifications (or limitations) that were needed to fully understand the capabilities and limitations of each tool.

To be considered for this study, each MWD system needed to provide directional surveys – inclination and azimuth, referenced to the earth's magnetic field or spin axis – and needed to transmit survey data from a BHA to the surface in an offshore environment. This latter criterion eliminated MWD tools that use electromagnetic telemetry. The range of electromagnetic telemetry is limited by high and low formation conductivity (or impedance) and salt water. A further consideration is that no supplier is currently offering an electromagnetic MWD system for marine applications.

The measurements provided by all the MWD systems documented in this report include:

- Inclination, measured by three orthogonally-mounted accelerometers;
- Azimuth, or direction in the horizontal plane, referenced to the earth's magnetic field (magnetic MWD) or the earth's spin axis (gyro-based MWD, or GMWD);
    - Magnetic MWD systems use three orthogonally mounted magnetometers to sense the three components of the earth's field.
    - Most GMWD systems use a single tuned-rotor, rate gyro to sense angular acceleration around the two axes ("X" and "Y") that are parallel to the tool's longitudinal axis ("Z"). One vendor recently has introduced a GMWD system that uses two rate gyros, so it is capable of sensing angular acceleration around all three axes, making it a full-inclination-range tool.
- Temperature inside the tool. The calibration of all directional sensors involves measuring bias, scale factor, and alignment errors at selected temperatures within the tool's operating range. Thus compensation for, repeatable, temperature-dependent sensor errors can be – and is – made in the field.

Many of the MWD and GMWD tools included in this report provide measurements in addition to those listed above. These normally fall into two groups: drilling dynamics and formation evaluation. Drilling dynamics measurements might include vibration, bit or mud motor RPM, torque, annular pressure and/or temperature, and caliper (borehole diameter). Gamma radiation (omnidirectional, focused, or azimuthal) is the most frequently offered formation evaluation measurement, since it is has been used to identify formation boundaries and, more recently, for geosteering. Other formation evaluation measurements offered include resistivity and porosity (typically sonic). The tables presented in this section list the other measurements offered by suppliers of the MWD and GMWD tools listed.

2.2.1.1. Tool Platforms, Power Supplies and Telemetry

There are two types of tool platforms employed by MWD and GMWD tools. The larger has the modules comprising the tool – sensors, data acquisition and control, pulser, and power – mounted inside cavities machined into a non-magnetic drill collar. The second platform has many or all the modules housed in a probe (or sonde) that is suspended inside a standard drill collar. There are variations to this second platform, where the power and/or pulser modules are permanently attached to a sub that is above or below the probe. One advantage to this approach is that some or all of the MWD or GMWD system can be brought to the surface on a slick line. This can enable the replacement of a failed module or a battery pack without tripping the BHA to the surface.

As with the tool platforms, there are two approaches to providing the power needed by MWD and GMWD systems. Most collar-mounted systems use a mud-driven turbine that drives an alternator to provide power. One disadvantage of this approach is there's no power to operate the tool when drilling fluid is not flowing, unless the tool also has a battery. Most probe-based tools use batteries for power, although some also offer an alternator option. Batteries have a finite life, which is a disadvantage. The lithium batteries normally used in downhole tools can operate for limited periods at temperatures above 180°C. The tables in this section show both the tool platform and power source for the listed tools.

All of the MWD and GMWD systems analyzed in this report use positive mud pulse telemetry to communicate to the surface from downhole. One supplier's tool also is available with negative mud pulse telemetry. Many of them also offer a downlink capability, which can be used to command the tool into different operating modes. There was no intentional process for eliminating systems using negative mud pulse telemetry. This study was primarily guided by information provided by suppliers, who selected the systems they thought best suited the application criteria. As mentioned above (in Section 2.2.1), the limitations of electromagnetic telemetry precluded considering systems using this data communications scheme.

One supplier has developed and now is offering a "wired-pipe" telemetry system. While this offers much higher bandwidths than can be provided by electromagnetic or mud pulse systems, it is not within the scope of this study due to its limited availability and limited field experience.

2.2.1.2. MWD and GMWD Tool Classes Analyzed

The following subsections document and analyze the key attributes of three classes of MWD and GMWD tools:

- Section 2.2.2 Available Standard MWD Tools
- Section 2.2.3 Available High-Temperature MWD Tools
- Section 2.2.4 Available GMWD Tools

The selection process for MWD and GMWD systems to include in this study began with companies whose products included at least one system that is capable of operating at temperatures above 350° F. This list was then expanded to include other established manufacturers whose products are well-known and who responded to a request for information. The individual systems or tools discussed below are those that meet – or come closest to meeting – the high-operating-temperature requirement. No effort was made to include all the models or configurations provided by each manufacturer.

For all tools, the information presented has been provided by the tool manufacturers (or suppliers). As is apparent from the blank cells in some of the tables, some manufactures and suppliers have been more willing to document the capabilities and limitations of their products than have others.

2.2.2. Available Standard MWD Tools

To facilitate comparisons between the tools, the key attributes have been allocated to the following groups: Platforms; Communications & Operating Modes; Environmental Limitations; Directional Measurements; Survey Times; Power Sources & LCM; and Gamma, Other Measurements & Maturity. Attachment A-1 provides a summary of the specifications of each tool for each of the standard MWD tool types discussed.

2.2.2.1. Platforms

Table 2 describes the external, mechanical configurations of the available, standard MWD tools. The "Nominal O.D. (min)" column lists only the smallest collar outside diameter that is available. Larger sizes are available from all the suppliers.

Table 2: Available Standard MWD Tools - Platforms

Supplier	Model	Description	Nom. O.D. (min)
APS Technology	SureShot MWD	Retrievable MWD/LWD in Std. collar	3.125"
Baker Hughes	OnTrak HT-175	Integrated MWD & LWD system	4.75"
Bench Tree	MWD Kit	Retrievable MWD probe, 1.875" diameter	3.5"
GE Oil & Gas	Tensor MWD	Retrievable MWD/LWD in Std. collar: 1.875" dia.	3.5"
Halliburton/SD	SOLAR MWD/LWD	Collar-based hostile-environment M/LWD system	4.75"
Schlumberger	HDS-1L	Fixed-collar directional service	4.75"
Scientific Drilling	Falcon MWD	Std. collar below Pulser Sub	3.125"
Weatherford	HyperPulse MWD	Probe-based MWD tool: 1.6875" dia.	3.0625"

Two of the MWD tools listed above, manufactured by Baker Hughes and Halliburton/Sperry Drilling, use a special, non-magnetic drill collar as their platform. Tools using this platform are transported and deployed as collars. They typically are not disassembled at field locations, and cannot be retrieved from the BHA without tripping out of the borehole.

Three of the tools, the SureShot MWD from APS Technology, the HDS-1L tool from Schlumberger, and the Falcon MWD from Scientific Drilling have their probes suspended in a drill collar, beneath the mud pulser, which is at the top of the tool. The APS Technology and Schlumberger tools are available in two configurations. In one, the tool is fixed in its collar. In the other, it is retrievable. Scientific Drilling's Falcon MWD is inserted and locked into its collar on the rig floor, and is not retrievable.

The probe-based tools from Bench Tree, GE Oil & Gas, and Weatherford have their mud pulsers at the bottom of the tools. They normally are inserted into standard non-magnetic collars at rig sites, and are retrievable and reinsertable (or reseatable) in vertical, or nearly-vertical, sections.

One significant difference between the eight manufacturers whose tools have been included is that three of them, APS Technology, Bench Tree, and GE Oil & Gas function largely as manufacturers and sell their systems to service providers.

2.2.2.2. Communications & Operating Modes

Table 3 captures the attributes of important interfaces of each MWD system. These include the type(s) of downhole-to-surface telemetry employed, the availability of a downlink, if the tool has a "Multi-Shot Mode," and if it can be run in tandem, as a host for a GMWD system.

Table 3: Available Standard MWD Tools - Communications & Operating Modes

Supplier	Model	Telemetry	Downlink	Multi-Shot Mode	Tandem w/ GWD
APS Technology	SureShot MWD	Positive mud pulse	Y	N	Y
Baker Hughes	OnTrak HT-175	Positive mud pulse	Y	N	Y
Bench Tree	MWD Kit	Positive mud pulse	Y		N
GE Oil & Gas	Tensor MWD	Positive mud pulse	Y	N	N
Halliburton/SD	SOLAR MWD/LWD	Pos. & Neg. mud pulse	Y		Y
Schlumberger	HDS-1L	Cont. Wave Pos. mud pulse	Y	N	Y
Scientific Drilling	Falcon MWD	Positive mud pulse	Y	Y	Y
Weatherford	HyperPulse MWD	Positive mud pulse	Y	N	

All of the listed systems employ positive mud pulse telemetry, although there are some differences. The APS Technology SureShot MWD and Baker Hughes' OnTrak HT-175 use rotary shear valves, which can adapt their pulse widths to conditions in the field. The Schlumberger HDS-1L uses a rotary valve, which has been called a "mud siren." It establishes a fixed-frequency, carrier wave, which is then phase modulated.

Halliburton has negative mud pulse MWD systems, but their maximum operating temperature is 150° C, so those systems have not been listed.

A downlink is used to communicate from the surface to an MWD tool while it is in the hole. The availability of a downlink may indicate that a tool can be commanded into a different mode to increase or reduce the number of data items that are captured during surveys and subsequently transmitted. It may also provide an ability to change the transmission or encoding modes to improve the reliability of data received on the surface or reduce the transmission time.

Suppliers were asked if their tools offered a "Multi-Shot Mode," meaning the ability to take and store directional surveys at a fixed (time) interval. This capability would enable the ability to record and store surveys while being tripped out of a hole, like a Drop Multi-Shot Tool.

The ability to run MWD and GMWD tools in tandem may offer advantage in situations where a well is being kicked off near other wells, where there is magnetic interference, but subsequently achieves sufficient horizontal displacement to switch over to magnetic measurements. There also are advantages in ranging applications, which are described below, in Sections 3.1.4 and 3.2.4.

2.2.2.3. Environmental Limitations

Table 4 shows specifications for the maximum operating temperatures and pressures the available, standard MWD tools will withstand, and the maximum operating times for tools at the specified temperatures. (Maximum operating times that are determined by battery life are shown in Table 7, below.)

Table 4: Available Standard MWD Tools - Environmental Limitations

Supplier	Model	Max. Operating		
		Temp. (°C)	Time (hrs.)	Max. Pressure (psi)
APS Technology	SureShot MWD	175	> 1000	25,000
Baker Hughes	OnTrak HT-175	175		30,000
Bench Tree	MWD Kit	175		20,000
GE Oil & Gas	Tensor MWD	175		20,000
Halliburton/SD	SOLAR MWD/LWD	175		25,000
Schlumberger	HDS-1L	175	300	25,000
Scientific Drilling	Falcon MWD	150	300+	30,000
Weatherford	HyperPulse MWD	150		15,000

While it might be fair to assume that the maximum operating times for tools for which no number has been provided are infinite, it would be prudent to confirm this with manufacturer. Better yet would be a review with the manufacturer of all the environmental conditions a tool is likely to encounter during a job while selecting a service provider and developing a plan.

2.2.2.4. Directional Measurements

The Accuracy and Resolution specifications for available, standard MWD tools are shown in Table 5. The Azimuth Accuracy figures assume a minimum horizontal magnetic field. For most suppliers this is on the order of 30 µTeslas, which is about what is found in the North Sea.

Table 5: Available Standard MWD Tools - Directional Measurements

Supplier	Model	Inclination		Azimuth		
		Acc'y	Resol'n	Acc'y	Resol'n	Incl. Min.
APS Technology	SureShot MWD	< ±0.1°	0.044°	±1.0°	0.088°	10°
Baker Hughes	OnTrak HT-175	±0.1°	0.09°	±1.0°	0.35°	5°
Bench Tree	MWD Kit	±0.1°		±0.35°		45°
GE Oil & Gas	Tensor MWD	±0.1°	0.1°	±1.0°	1.0°	3°
Halliburton/SD	SOLAR MWD/LWD	±0.1°	0.09°	±0.8°	0.17°	5°
Schlumberger	HDS-1L	±0.1°	0.1°	±1.0°	0.1°	6°
Scientific Drilling	Falcon MWD	±0.15°	0.15°	±0.25°	0.25°	3°
Weatherford	HyperPulse MWD	±0.2°	0.125°	±1.0°	0.25°	5°

The accuracy specifications in this table apply to surveys made when the tool is still and not rotating. All MWD systems are capable of also making directional measurements while drilling, although at reduced accuracy. (These are typically called “rotational azimuth” and “rotational inclination.”) In addition, the ability to determine tool face – either highside or magnetic - while the bit is actually turning is essential. It allows the directional driller to determine the change in tool-face direction due to reactive torque.

From the information provided, it appears that APS Technology may have a significant advantage in Inclination Resolution, and APS Technology and Schlumberger might have better Azimuth Resolution than the others.

However, before giving too much weight to these figures, it would be useful to obtain appropriate confidence figures – in Sigma's or Standard Deviations – for their Directional Accuracy and Resolution specifications from the manufacturers. These have not been included in Table 5 because comparable figures from many of the suppliers could not be obtained.

The error models of specific tools, which are based on the Instrument Performance Models (IPMs) developed by the Industry Steering Committee on Wellbore Survey Accuracy (ISCWSA), provide the best means of comparing the performance of MWD systems and other survey tools. Before selecting a tool for a specific job, the operator should have the service provider or survey management company run the error model (IPM) for the planned well's profile and environment for each tool that is being considered.

2.2.2.5. Survey Times

The tool manufacturers were asked to provide estimates of the amounts of time needed to conduct and transmit their standard short and long directional surveys from a "test well" meeting the following criteria: 15,000 feet vertical depth; no more than 20,000 feet measured depth; inclination of 20°; latitude of 30° north; magnetic dip of 60°; with mud properties and temperature within operating specifications. Table 6 shows the survey times provided by the manufacturers.

Typically, short surveys include azimuth, inclination, and toolface, and may include the magnitude of the magnetic field and/or another indicator of data quality. Long surveys usually include the compensated values from all six directional sensors in addition to other measured variables. However, there are no standards for the data types that are included in short or long surveys, Most suppliers offer many options and will customize the transmitted parameters and formats for specific jobs. So it is not possible to draw firm conclusions from the times specified by the manufacturers.

Table 6: Available Standard MWD Tools - Survey Times

Supplier	Model		Survey Times (sec)	
		No. Bits	Short	Long
APS Technology	SureShot MWD	12	192	255
Baker Hughes	OnTrak HT-175		105	139
Bench Tree	MWD Kit			
GE Oil & Gas	Tensor MWD	12	190	326
Halliburton/SD	SOLAR MWD/LWD	8/11-12	65	76
Schlumberger	HDS-1L			
Scientific Drilling	Falcon MWD		177	219
Weatherford	HyperPulse MWD			

The figures for number of bits shown for Halliburton/SD's SOLAR MWD/LWD tool indicates only eight bits are used for azimuth and inclination when it is transmitting short surveys. When transmitting long surveys, eleven bits are used for data from accelerometers, and twelve bits are available for data from magnetometers.

The time needed for any MWD system to take and transmit to the surface a directional survey with mud pulse telemetry can be divided into the following segments:

- Pumps Off Time – the time between stopping the mud pumps and restarting them, which will command the tool to initiate a survey;
- Settling Time – the time needed for the tool to be ready to conduct a survey after mud flow has started. During this segment voltage levels need to stabilize, accelerometers or a vibration sensor may be used to determine the tool is stationary, the data acquisition and control module is initialized, and the sensors have had the time needed to stabilize;
- Actual Survey Time – the time needed for the data acquisition and control module to scan and digitize (if needed) signals from the sensors, calculate the variables that are to be transmitted, and prepare the commands for the mud pulser;
- Transmit Time – the time needed to create the sequence of mud pulses needed to communicate the calculated, formatted, and encoded variables to the surface;
- Propagation Time – the time need for the last pulse transmitted to reach the receiving pressure sensor on the surface; and
- Computing Time – the time needed for the receiving system on the surface to filter and demodulate the mud pulses, reconstruct the transmitted information, and produce the needed displays and outputs.

Of these six segments, three – Survey Time, Propagation Time, and Computing Time – are quite short for MWD systems, on the order of a few seconds (or less), each. The three remaining time segments are usually programmed so the tool will perform as needed during each job. For example, the Pumps Off Time may need to be longer to accommodate BHA movement, fluids moving into or out of the formation, or noise in the mud system. For this example, the Pumps Off times used by the suppliers ranged from 20 seconds to one minute.

The Settling Time may be longer for tools that use a downhole turbine-driven alternator to provide electrical power than for tools using batteries. (Data in the Table 6 do not suggest this, but other differences may obscure this.) Settling Time also may be influenced by BHA movement, noise in the mud system, and tool and BHA orientation. Settling Times of the tools listed in Table 6 are estimated to range from zero to more than 80 seconds.

In addition to the quantity of data that is transmitted, Transmit Times are determined by pulse width, the encoding scheme used to generate the sequence of pulses that can be demodulated at the surface, the time needed to synchronize the downhole and surface systems, how the data are formatted and/or compressed, and the data items that are added to check or determine data quality and operating conditions within the MWD tool.

Pulse widths are normally set to the minimum needed to achieve reliable communications thorough the drilling fluid over the expected range (or depth). Pulse widths available in the selected MWD tools range from 240 msec to 1.2 sec. Pulse widths used to generate the Survey Times shown range from 240 to 750 msec.

There is a consensus that pulse position encoding is the most efficient scheme, when measured by the time needed to transmit a standard data set. Manchester encoding is more robust in most applications, however its transmission time can be almost ten times greater for the same data set.

Although this study has made a best effort to present fair and comparable survey times, the important conclusion to draw is that the acoustic properties of the drilling fluid (especially viscosity) and amount of noise in the mud system are likely to overwhelm any differences between tools. In a specific well, it is not unlikely that some systems will achieve shorter survey times than others, but general conclusions are risky, at best.

2.2.2.6. Power Sources & LCM

Table 7 shows the types of power sources used by the available, standard MWD tools, as well as specified maximum operating times for battery-powered tools, and the tools tolerance to lost circulation material (LCM). The operating times shown are those with the maximum number of battery packs available in the standard configurations. These operating times are, of course, largely determined by the number of surveys taken (or survey frequency) and format.

Table 7: Available Standard MWD Tools - Power Sources & LCM

Supplier	Model	Power Source	Oper'g Time (hrs.)	LCM Tol. (lbm/bbl)
APS Technology	SureShot MWD	Turb/Bat	200/battery	50
Baker Hughes	OnTrak HT-175	Turbine	N/A	40
Bench Tree	MWD Kit	Battery	800+	
GE Oil & Gas	Tensor MWD	Battery	180	40-50
Halliburton/SD	SOLAR MWD/LWD	Turbine	N/A	40
Schlumberger	HDS-1L	Battery	224-669	50
Scientific Drilling	Falcon MWD	Battery	300+	40
Weatherford	HyperPulse MWD	Battery		

The APS Technology SureShot MWD is available with either a battery or a turbine.

Because there are many types and concentrations of LCM and thorough blending of LCM into drilling fluid is essential, drawing conclusions from this specification may be difficult. However, it may not be a coincidence that two of the tools with the highest LCM tolerance (APS Technology SureShot MWD and Schlumberger HDS-1L) employ rotating or shear valves.

2.2.2.7. Gamma, Other Measurements & Maturity

Table 8 captures information for available, standard MWD tools describing other, formation evaluation, and drilling dynamics measurements that are available with their tools, and when the specific tools were first offered for commercial service. None of the suppliers whose tools have been included has been in the MWD business for less than 25 years.

Table 8: Available Standard MWD Tools - Gamma, Other Measurements & Maturity

Supplier	Model	Gamma	Other Measurements	First in Service
APS Technology	SureShot MWD	Azimuthal & Focused	Resistivity; weight, torque, bend; sonic; porosity, density & caliper	2002
Baker Hughes	OnTrak HT-175	Azimuthal	Multiple-propagation resistivity, Drilling dynamics	2014
Bench Tree	MWD Kit	Omni		
GE Oil & Gas	Tensor MWD	Omni	Propagation resistivity	mid-1990s
Halliburton/SD	SOLAR MWD/LWD	Omni & Azimuthal	Vibration, Pressure, Caliper, Resistivity, and other LWD Tools	2015
Schlumberger	HDS-1L	Omni	Vibration, Temperature	1995
Scientific Drilling	Falcon MWD	Azimuthal or Focused	Vibration, Temp, Pressure, and other LWD Tools	1999
Weatherford	HyperPulse MWD	Omni	Temperature	

Because gamma radiation measurements have been used for formation delineation for many years, gamma sensors were added to MWD systems soon after they became commercial. More recently, differential or azimuthal gamma measurements are used when MWD systems are operated in a geosteering mode. Thus, all suppliers offer at least one type of gamma radiation sensor. Other measurements offered can be sorted into other types of formation evaluation logs (resistivity, sonic, density, porosity) and drilling dynamics (vibration, pressure, weight, torque, bending, and caliper).

Mean-time-between-failure (MTBF) is the most useful indicator of the reliability of MWD systems or other tools that are deployed in field environments. However, failure rates of tools can improve (or worsen) for many reasons, only some of which correlate with the tool design or condition. As tools become more accepted, they are deployed to more remote regions where drilling conditions may be more severe and maintenance may be more difficult. The importance of having well-trained and highly motivated field technicians and tool operators cannot be overstated. For these reasons, most MWD suppliers are reluctant to share the MTBF history of their tools; drawing conclusions from it is difficult and what seems obvious may be misleading. Consequently, this study uses the number of years a tool has been in commercial service ("maturity") as a surrogate for MTBF data.

2.2.3. Available High-Temperature (HT) MWD Tools

There are fewer High-Temperature (HT) MWD systems available than Standard MWD Systems. However, the same groups of key attributes are used to facilitate comparisons between them (e.g., Platforms; Communications & Operating Modes; Environmental Limitations; Directional Measurements; Survey Times; Power Sources & LCM; and Gamma, Other Measurements & Maturity). Additional details and background information are provided where significant differences were found, and where such information has been provided by the suppliers. Attachment A-2 provides a summary of specifications of the available high temperature MWD tools.

2.2.3.1. Platforms

Table 9 describes the external, mechanical configurations of the available, HT MWD tools. The Nominal O.D. (min) column in the table lists only the smallest collar outside diameter that is available. Larger sizes, to 6.75" O.D are available from Halliburton and Schlumberger. Weatherford offers four sizes, and Scientific Drilling offers nine sizes to 9.5" O.D.

Table 9: Available HT MWD Tools - Platforms

Supplier	Model	Description	Nom. O.D. (min)
Halliburton/SD	Quasar Pulse M/LWD	Collar-based hostile-env. M/LWD system	4.75
Schlumberger	TeleScope ICE	Collar-based UltraHT MWD Service	4.75
Scientific Drilling	High Temp MWD	Std. collar below Pulser Sub	3.125
Weatherford	HEL MWD System	Collar-based hostile-env. MWD system	4.75

2.2.3.2. Communications & Operating Modes

Table 10 captures the attributes of important interfaces of each HT MWD system. These include the type(s) of downhole-to-surface telemetry employed, the availability of a downlink, if the tool has a "Multi-Shot Mode," and if it can be run in tandem, as a host for a GMWD system.

Table 10: Available HT MWD Tools - Communications & Operating Modes

Supplier	Model	Telemetry	Downlink	Multi-Shot Mode	Tandem w/ GWD
Halliburton/SD	Quasar Pulse M/LWD	Positive mud pulse	N	N	N
Schlumberger	TeleScope ICE	Cont. Wave Pos. mud pulse	N	N	Y
Scientific Drilling	High Temp MWD	Positive Mud pulse	Y	Y	N
Weatherford	HEL MWD System	Positive mud pulse	Y	N	Y

2.2.3.3. Environmental Limitations

Specifications in the Table 11 show the maximum operating temperatures and pressures HT MWD tools will withstand, and the maximum operating times for tools at the specified temperatures. Operating times determined by battery life are shown in Table 14, below.

Table 11: Available HT MWD Tools - Environmental Limitations

Supplier	Model	Max. Operating		
		Temp. (°C)	Time (hrs.)	Max. Pressure (psi)
Halliburton/SD	Quasar Pulse M/LWD	200		25,000
Schlumberger	TeleScope ICE	200	300	30,000
Scientific Drilling	High Temp MWD	177		30,000
Weatherford	HEL MWD System	180	200	30,000

Scientific Drilling's High Temp MWD and Weatherford's HEL MWD Systems are battery powered. The maximum operating time for Weatherford's tool reflects the temperature limitations of its battery, not the other components or subsystems.

2.2.3.4. Directional Measurements

Accuracy and Resolution specifications for available, HT MWD tools are shown in Table 12, as is the minimum inclination needed to achieve the specified azimuth accuracy.

Table 12: Available HT MWD Tools - Directional Measurements

Supplier	Model	Directional Measurements				
		Inclination		Azimuth		
		Acc'y	Resol'n	Acc'y	Resol'n	Incl. Min.
Halliburton/SD	Quasar Pulse M/LWD	±0.1°	0.09°	±0.8°	0.17°	5°
Schlumberger	TeleScope ICE	±0.1°	0.1°	±1.0°	0.1°	5°
Scientific Drilling	High Temp MWD	±0.15°	0.15°	±0.25°	0.25°	3°
Weatherford	HEL MWD System	±0.1°	0.08°	±0.5°	0.17°	5°

Azimuth accuracy of Scientific Drilling's High Temp MWD tool looks significantly better than the others'.

Principal among the caveats that accompany the accuracy figures provided is that the magnetic dip angle (inclination) is assumed to be no more than about 70°, which implies the horizontal component of the earth's field would be at least 30 µTeslas. As mentioned above, making meaningful comparisons of accuracy and/or resolution would require obtaining comparable confidence numbers for these specifications from the system manufacturers.

2.2.3.5. Survey Times

Table 13 shows the survey times for HT MWD tools provided by manufacturers for the same "test well" as was used for the standard MWD tools. The caveats described under the Survey Times table for Standard MWD tools (Section 2.2.2.5) apply here, as well.

Table 13: Available HT MWD Tools - Survey Times

Supplier	Model		Survey Times (sec)	
		No. Bits	Short	Long
Halliburton/SD	Quasar Pulse M/LWD	12	65	76
Schlumberger	TeleScope ICE		105	139
Scientific Drilling	High Temp MWD		177	219
Weatherford	HEL MWD System			

Schlumberger's Orion II Telemetry Platform, which is available for their TeleScope tools (and others) provides an intriguing combination of a downhole data compression utility, "new signal modulation methods," and improved noise cancellation and signal detection methods in their surface systems. They have claimed this new platform has extended the mud pulse range and provided higher data rates in many extended-reach wells.

2.2.3.6. Power Sources & LCM

Table 14 shows the types of power sources used by the available, HT MWD tools, as well as specified maximum operating times for battery-powered tools, and the tools tolerance to lost circulation material (LCM). The operating times shown are those with the maximum number of battery packs available in the standard configurations. These operating times are, of course, largely determined by the number of surveys taken (or survey frequency).

Table 14: Available HT MWD Tools - Power Sources & LCM

Supplier	Model	Power Source	Oper'g Time (hrs.)	LCM Tol. (lbm/bbl)
Halliburton/SD	Quasar Pulse M/LWD	Turbine	N/A	40
Schlumberger	TeleScope ICE	Turbine	N/A	50
Scientific Drilling	High Temp MWD	Battery	300+	40
Weatherford	HEL MWD System	Battery	348	50

Because the Halliburton and Schlumberger tools are turbine powered, their maximum operating times are determined by the ability of the downhole systems to continue functioning as exposure to elevated temperatures increases. From information provided by Halliburton, their Quasar Pulse tool has no limitation at temperatures as high as 200° C. The Schlumberger TeleScope ICE tool has an operating limit of 200 hours at 200° C.

The Scientific Drilling High Temp MWD and Weatherford HEL MWD tools are battery-powered, so the operating times shown above are determined by battery capacity. At its maximum operating temperature of 180° C, however, the Weatherford tool is no more than 200 hours.

2.2.3.7. Gamma, Other Measurements & Maturity

Table 15 captures information for available, HT MWD tools describing other, formation evaluation, and drilling dynamics measurements that are available with their tools, and when the tools were first offered for commercial service. As described in Section 2.2.2.7 above, the number of years a tool has been in commercial service ("maturity") is being used as a surrogate for MTBF data.

Table 15: Available HT MWD Tools - Gamma, Other Measurements & Maturity

Supplier	Model	Gamma	Other Measurements	First in Service
Halliburton/SD	Quasar Pulse M/LWD	Omni	Vibration, Annular & Bore Pressures	2015
Schlumberger	TeleScope ICE	Azimuthal	Shock, Vibration, Annular & Internal Pressures	2015
Scientific Drilling	High Temp MWD	Radial	Vibration, Temperature	1999
Weatherford	HEL MWD System	Azimuthal	Bit speed, Vibration, Bore & annular pressure, Annular temperature, Azimuthal density, Resistivity, Porosity & Sonic	

Because MWD systems often are used in a geosteering mode, all suppliers offer at least one type of gamma radiation sensor. Other measurements offered can be sorted into other types of formation evaluation logs (resistivity, sonic, density, porosity) and drilling dynamics (vibration, pressure, weight, torque, bending, and caliper).

2.2.4. Available Gyro-based MWD (GMWD) Tools

Rate-gyro-based surveying systems are inherently more complicated, with many more moving parts, than magnetic surveying systems. This complexity inhibited their use in downhole systems that were exposed to the shocks and vibration caused by operating bits and mud motors. As component suppliers and system developers gained experience, gyro-based systems became more rugged, and ultimately were proven in while-drilling applications. One consequence of the time lag between commercially-successful MWD systems and gyro-based systems that could operate in drilling environments is that today's commercially-available GMWD systems are configured so they can be added to the telemetry systems used in MWD systems; it was more cost-effective to add rate-gyro-based directional modules to existing telemetry systems. A further complication is that existing patents and licensing agreements limit suppliers' access to specific means of determining and compensating for drift.

Today, Gyrodata and Scientific Drilling are the major manufacturers and suppliers of rate-gyro-based directional modules that can be run with other manufacturers' data acquisition, control, and telemetry systems. They are likely to be available with positive and negative mud-pulse and electromagnetic MWD systems from other suppliers, whose systems will determine the capabilities of the integrated tool. Attachment A-3 provides a summary of specifications of the available GMWD tools.

Suppliers beyond those whose systems are listed in the following tables (Baker Hughes, Schlumberger, and Weatherford) advertise gyro-based MWD systems, but have not responded to requests for information.

To facilitate comparisons between these tools, key attributes are allocated to the following groups: Platforms; Communications & Operating Modes; Environmental Limitations; Directional Measurements; Survey Times; Power Sources & LCM; and Gamma, Other Measurements & Maturity.

2.2.4.1. Platforms

The Nominal O.D. (min) column in Table 16 lists only the smallest collar outside diameter that is available. Because Gyrodata provides modules that are integrated with the MWD systems of other manufacturers, they determine the available collar sizes.

Table 16: Available GMWD Tools - Platforms

Supplier	Model	Description	Nom. O.D. (min)
Gyrodata	Gyro-Guide GWD40	Probe-based tool: 1.875" O.D. X 18'	
Gyrodata	Gyro-Guide GWD70	Probe-based tool: 1.875" O.D. X 18'	
Gyrodata	Gyro-Guide GWD90	Probe-based tool: 1.875" O.D. X 18'	
Halliburton/SD	Evader MWD Gyro	Collar-based M/LWD system	4.75"
Scientific Drilling	gyroMWD	Module below Pulser Sub - 1.75" O.D.	3.125"
Scientific Drilling	gyroMWD Module	Module added to 3rd party MWD	3.125"

Both Gyrodata and Scientific Drilling manufacture and provide gyro-based probes (or modules) that are designed to interface with data acquisition, control, and telemetry systems produced by other service companies. In addition, Scientific Drilling has their own GMWD tool.

2.2.4.2. Communications & Operating Modes

Table 17 captures the attributes that describe the important interfaces of each GMWD system. These include the type of downhole-to-surface telemetry employed, the availability of a downlink, if the tool has a "Multi-Shot Mode," and if it can be run in tandem with an MWD system.

Table 17: Available GMWD Tools - Communications & Operating Modes

Supplier	Model	Telemetry	Downlink	Multi-Shot Mode	Tandem w/ MWD
Gyrodata	Gyro-Guide GWD40	Positive mud pulse			
Gyrodata	Gyro-Guide GWD70	Positive mud pulse			
Gyrodata	Gyro-Guide GWD90	Positive mud pulse			
Halliburton/SD	Evader MWD Gyro	Positive mud pulse	N	Y	Y
Scientific Drilling	gyroMWD	Positive mud pulse	Y	N	Y
Scientific Drilling	gyroMWD Module	Per MWD Host	Y	N	Y

Since the gyro-based modules manufactured by Gyrodata and Scientific Drilling are run with other manufacturers' MWD systems, it would be reasonable to assume they can be run in tandem with MWD modules, thereby providing both gyro-based and magnetic surveys.

2.2.4.3. Environmental Limitations

Table 18 shows specifications for the maximum operating temperatures and pressures the available GMWD tools will withstand. None of the suppliers provided specifications for the maximum operating time of their GMWD systems or modules at the specified maximum temperature. Maximum operating times that are determined by battery life are shown in Table 21, below.

Table 18: Available GMWD Tools - Environmental Limitations

Supplier	Model	Max. Operating		
		Temp. (°C)	Time (hrs.)	Max. Pressure (psi)
Gyrodata	Gyro-Guide GWD40	150		20000
Gyrodata	Gyro-Guide GWD70	150		20,000
Gyrodata	Gyro-Guide GWD90	150		20,000
Halliburton/SD	Evader MWD Gyro	150		20,000
Scientific Drilling	gyroMWD	150		30,000
Scientific Drilling	gyroMWD Module	150		30,000

Because gyroscopes generate significant heat, unlike magnetometers, the maximum operating temperature claimed by these tool suppliers is 150° C. However, it is possible to operate some gyro-based directional modules at higher temperatures by enclosing them in insulated dewars (or sondes). When protected by such dewars, Gyrodata's gyro-based modules will operate up to six hours at 170° C when configured as drop or wireline tools. However, no GMWD supplier has indicated their GMWD tools could operate at temperatures above 150° C.

2.2.4.4. Directional Measurements

The Accuracy and Resolution specifications for Inclination and Azimuth for available GMWD tools are shown in Table 19.

Table 19: Available GMWD Tools - Directional Measurements

Supplier	Model	Inclination		Azimuth		Max.
		Acc'y	Resol'n	Acc'y	Resol'n	Incl'n
Gyrodata	Gyro-Guide GWD40	±0.1°		±1.0°		40°
Gyrodata	Gyro-Guide GWD70	±0.1°		±1.0°		70°
Gyrodata	Gyro-Guide GWD90	±0.1°		±1.0°		none
Halliburton/SD	Evader MWD Gyro	±0.1°		±1.0°		none
Scientific Drilling	gyroMWD	±0.15°	0.088°	±0.15°	0.088°	105°
Scientific Drilling	gyroMWD Module	±0.15°	Per MWD Host	±0.15°	Per MWD Host	105°

The azimuth accuracy figures for Scientific Drilling's gyroMWD tool and module are significantly better than those claimed by the Gyrodata and Halliburton tools. They also are noticeably better than those claimed by all the standard and high-temperature MWD tools. Scientific Drilling's gyroMWD tools offer a low-inclination mode, which improves inclination resolution to 0.01°.

The maximum inclinations, as shown above, are for those tools that have two rate-sensing axes. Gyrodata's Gyro-Guide GWD90 is, to our knowledge, the only GMWD tool (or module) that has three rate-sensing axes, enabling it to provide azimuth measurements at all inclinations.

2.2.4.5. Survey Times

Table 20 shows times for both short and long surveys, as provided by the manufacturers of the available GMWD tools, for surveys in a "test well" meeting the following criteria: 15,000 feet vertical depth; no more than 20,000 feet measured depth; inclination of 20°; latitude of 30° north; magnetic dip of 60°; with mud properties and temperature within operating specifications.

Table 20: Available GMWD Tools - Survey Times

Supplier	Model		Survey Times (sec)	
		No. Bits	Gyro only	with MWD
Gyrodata	Gyro-Guide GWD40			
Gyrodata	Gyro-Guide GWD70			
Gyrodata	Gyro-Guide GWD90			
Halliburton/SD	Evader MWD Gyro	11-12	276	
Scientific Drilling	gyroMWD		375	453
Scientific Drilling	gyroMWD Module			

When the manufacturers have provided them, survey times are shown for gyro-only surveys and survey times that transmit both gyro- and magnetometer-based measurements. The caveats following the

Survey Times table for Standard MWD tools (Section 2.2.2.5) also apply to the numbers in Table 20. There is, however, an important difference.

The time needed to conduct a survey with these tools is much more than the “few seconds” needed for MWD tools that use magnetic measurements to determine azimuth. Rate gyros are very sensitive to vibration and movement while conducting a survey, and must begin each survey by indexing to remove drift. Thus, the survey times for gyro-based tools are about three minutes longer than those for magnetometer-based tools.

Halliburton/SD’s Evader MWD Gyro tool uses eleven bits for data from its accelerometers and twelve bits for gyroscopic data.

2.2.4.6. Power Sources & LCM

Table 21 shows the types of power sources used by the available GMWD tools, as well as specified maximum operating times for battery-powered tools, and the tools tolerance to lost circulation material (LCM). The operating times shown are those with the maximum number of battery packs available in the standard configurations.

Table 21: Available GMWD Tools - Power Sources & LCM

Supplier	Model	Power Source	Oper'g Time (hrs.)	LCM Tol. (lbm/bbl)
Gyrodata	Gyro-Guide GWD40	Battery		
Gyrodata	Gyro-Guide GWD70	Battery		
Gyrodata	Gyro-Guide GWD90	Battery		
Halliburton/SD	Evader MWD Gyro	Battery	60+	40
Scientific Drilling	gyroMWD	Battery	40 to 250	40
Scientific Drilling	gyroMWD Module	Battery	40+	Per Host

The need to index rate gyros before conducting a survey requires battery power because the movement caused by mud flow would introduce unacceptable errors. The operating time is, of course, influenced heavily by the frequency (or number) and data formats of surveys. For Halliburton/SD’s Evader MWD Gyro tool, the battery capacity is sufficient for 60 hours of continuous surveying.

2.2.4.7. Gamma, Other Measurements & Maturity

Table 22 captures information for available GMWD tools describing other, formation evaluation, and drilling dynamics measurements that are available with their tools, and when the tools were first offered for commercial service.

Table 22: Available GMWD Tools - Gamma, Other Measurements & Maturity

Supplier	Model	Gamma	Other Measurements	First in Service
Gyrodata	Gyro-Guide GWD40			2010
Gyrodata	Gyro-Guide GWD70			2010
Gyrodata	Gyro-Guide GWD90			2013
Halliburton/SD	Evader MWD Gyro			

Scientific Drilling	gyroMWD	Y	Vibration, Temp, Gamma, Pressure, and other LWD Tools	1999
Scientific Drilling	gyroMWD Module	Y	MWD Host Dependent (Compatible with all LWD and RSS tools)	2013

It would be reasonable to expect these GMWD tools would offer gamma and other formation-evaluation measurements that also are offered with their MWD tools.

2.3. Ranging Tools

2.3.1. Scope and Introduction

The ranging tools considered are used to measure the relative range and bearing to a cased, target borehole (or other ferrous object) from an active borehole, which is being drilled with the objective of intersecting the target borehole (or well). In other circumstances, a ranging tool may also be used to avoid intersecting the target well. The ranging systems included in the scope of this study all use magnetic or electromagnetic measurements to detect the position of the target. (An acoustic system that has been developed and tested has not been included. It is useful only when ranging in salt formations, and is not available commercially.) Attachment A-1 provides a summary of specifications of the available passive ranging tools and Attachment A-4 provides a summary of specifications of the active ranging tools.

2.3.2. Operating Considerations

From an operational perspective, it is useful to divide ranging systems into two groups. Ranging systems that require access to the target well are called “access dependent,” and are most often used to drill wells that are parallel to but displaced – horizontally or vertically – from previously drilled wells. Such systems induce an alternating magnetic field in the target well by connecting to it, electrically, or by insert a rotating permanent magnet or an electromagnet into it. This approach has been widely adopted for the production of heavy oil from the tar sands in Alberta, where steam is injected to reduce the viscosity of the oil in a process called steam-assisted gravity-drainage, or SAGD. Because such systems require access to the target well, they are not compatible with most relief well projects.

The second type of ranging systems, known as “access independent,” does not require access to the target well.

There are two types of access independent ranging systems: active and passive. Active systems use an electromagnetic transmitter and downhole electrode to induce a magnetic field in the casing (or other ferrous object) in the target well (shown in Figure 2). Because they transmit low frequency AC or pulsed DC to induce a magnetic field in the target, it would be more appropriate to call them “electromagnetic”

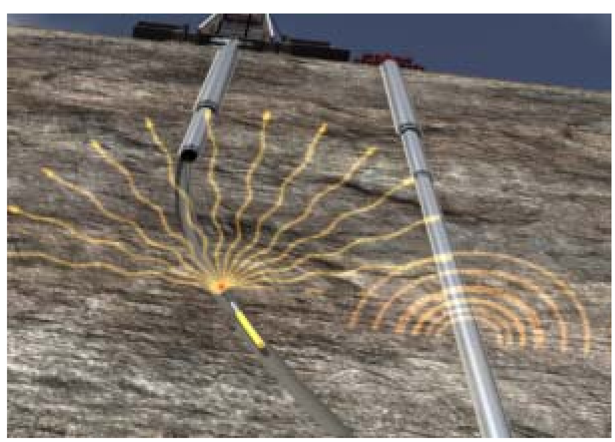


Figure 2: WellSpot Tool™ (from: Halliburton/Sperry Drilling, reproduced with permission)

ranging systems. The induced magnetic field is sensed by magnetometers and used to determine the range and bearing to the target from the tool in the active borehole. The only commercially-available active ranging system is configured as a wireline tool.

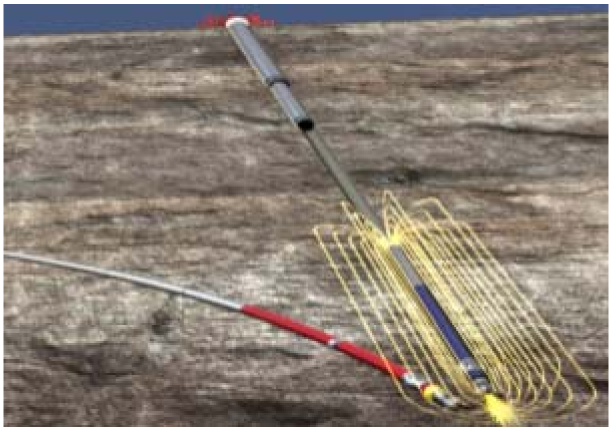


Figure 3: Passive Ranging (from: Halliburton/Sperry Drilling, reproduced with permission)

Passive ranging tools, which use precise and repeated measurements of the earth's magnetic field, comprise the second type of access independent ranging system (Figure 3). Standard or modified MWD tools are used for passive magnetic ranging, so they can be incorporated in most BHAs and used while drilling.

Thus one key difference between active, electromagnetic and passive, magnetic ranging systems is the former are open-hole tools, run into boreholes on typical logging (wireline) cables, while the latter are in BHAs and used while drilling.

Error sources in ranging tools. The two systems have somewhat different sources of errors. Active systems use their magnetometers to determine range and direction to the magnetic field that its transmitter has induced in the casing of the target well. Because the frequency and strength of the signal is controlled by the tool, the attenuation of the signal, its apparent direction, and its gradient can be used to estimate range and bearing to the target. Passive systems, however, measure only the earth's magnetic field, as it has been distorted by the residual magnetic poles of the casing in the target well. The calculations used by both tools assume the measurements are made – in the active borehole – along a known path. Passive systems use iterative measurements made along this known path to develop a model of the target, which is based primarily on the (known or estimated) distances between casing joints. Because the differences in the measured, DC field are small and can be distorted by magnetism in the drill string and BHA in the active well, the sensitivity and signal-to-noise ratio of the magnetometers used in passive systems are critical. Active ranging systems typically are sensing larger signals at known frequencies, so the signal-to-noise ratio of the magnetometers is less important.

All the available passive ranging systems use standard or slightly modified MWD tools to make the needed measurements. The ranging capability is achieved with special-purpose software to develop the model of the target borehole, using data from iterative long surveys conducted by MWD tools. Scientific Drilling was the first company to develop such a software package, which they call MagTraC MWD Ranging. They offer it as a service with their own MWD tools and with tools manufactured by others. To date, in addition to their own tools, it has been run with MWD tools provided by Baker Hughes, Halliburton, Schlumberger, and others.

Applications and use of ranging tools. Before addressing the subjects of range and accuracy of these two approaches to ranging, it is essential to consider the different situations in which a well is being drilled to intercept an existing well. As described in Section 3.1.4 relief wells are the most widely known type of interception, however, many more intercepting wells are drilled for the purpose of plugging a well before it is abandoned. Ranging systems also are used to guide sidetracks around boreholes that have become plugged with a broken tool or a twisted off BHA. In such circumstances, guiding the active well around the obstacle so that drilling can be continued in the formation below requires less accuracy than most interceptions.

Detection sensitivity. Promotional brochures and other publications from suppliers make many claims for the ranges that can be achieved with their tools. Based on interviews of many experienced relief-well specialists, the following observations are provided on range and accuracy of these two types of ranging tools, which should be considered consensus-based conclusions.

Active ranging tools usually provide acceptable range and bearing estimates at distances of 100-150 feet from the target. Ranging capabilities of 200 feet and more are claimed, but these are under ideal circumstances. When the distance is close to the maximum range claimed, the error is usually considered to be about 25% of the estimated range. At closer ranges, within 30 feet or less, the error is likely to be about 5%. Gradient measurements are even more accurate at close range.

The maximum ranging distance of passive systems is about half than what is normally achieved with active magnetic ranging systems. It should be recognized, however, that the ranging ability of passive systems is highly dependent on the weight (or mass) of the casing and the residual magnetism in the casing joints in the target well. The range of passive systems is significantly greater when there is a large approach angle between the target and active wells and the active well is near the bottom casing shoe. Thus, there could be situations where the ranging capabilities of a passive tool approach or even exceed those of an active tool. Conversely, passive ranging tools will have their ranging capability reduced if there is little residual magnetism in the target well's casing, if it has become corroded, or is light-weight.

In the following sections, the available ranging tools are presented in the following sequence: Available Standard Passive Ranging Tools; Available High-Temperature Passive Ranging Tools; and Available Active Ranging Tools. This sequencing was a consequence of: (1) all the passive ranging tools are the same MWD tools profiled above or, for one supplier, a slightly modified MWD tool based on the same platform; (2) only one commercially-available active ranging tool was identified; and (3) the available active ranging tool uses a different platform than do MWD tools.

2.3.3. Available Standard Passive Ranging Tools

Scientific Drilling's MagTraC software-based service for passive ranging can be used with any MWD system capable of providing long surveys that include the six axes (three magnetic and three gravity-based) of directional information. Baker Hughes' AccuTrak service adds similar ranging capabilities to their OnTrak MWD tools. The availability of these systems implies that all the MWD systems listed in prior sections are capable of providing passive ranging services. These systems are included in this segment for completeness, although they were discussed previously in the MWD section above. In addition, Scientific Drilling's Green Eye ranging MWD tool was added.

Following the same structure employed for MWD and GMWD tools, key attributes of the ranging tools have been sorted into the following groups: Platforms; Communications & Operating Modes; Environmental Limitations; Directional Measurements; Magnetic Measurements; Survey Times; Power Sources & LCM; and Gamma, Other Measurements & Maturity. The group, Magnetic Measurements, was added because of the important role played by magnetometers in passive ranging situations.

2.3.3.1. Platforms

Table 23 describes the external, mechanical configurations of the available, standard passive ranging/MWD tools. The Nominal O.D. (min) column in the table shows only the smallest collar outside diameter that is available. Larger sizes are available from all the suppliers.

Table 23: Available Standard Passive Ranging Tools – Platforms

Supplier	Model	Description	Nom. O.D. (min)
APS Technology	SureShot MWD	Retrievable MWD/LWD in Std. collar	3.125"
Baker Hughes	OnTrak HT-175	Integrated MWD & LWD system	4.75"
Bench Tree	MWD Kit	Retrievable MWD probe, 1.875" diameter	3.5"
GE Oil & Gas	Tensor MWD	Retrievable MWD/LWD in Std. collar: 1.875" dia.	3.5"
Halliburton/SD	SOLAR MWD/LWD	Collar-based hostile-environment M/LWD system	4.75"
Schlumberger	HDS-1L	Fixed-collar directional service	4.75"
Scientific Drilling	Falcon MWD	Std. collar below Pulser Sub	3.125"
Scientific Drilling	Green Eye Ranging MWD	Std. collar below Pulser Sub	3.125"
Weatherford	HyperPulse MWD	Probe-based MWD tool: 1.6875" dia.	3.0625"

Scientific Drilling's Green Eye Ranging MWD tool has been added to the table. It is identical to their Falcon MWD tool in almost all respects. The key difference is the range and resolution of its magnetometers.

2.3.3.2. Communications & Operating Modes

Table 24 shows the attributes of the important interfaces of the available, standard passive ranging/MWD systems. These include the type(s) of downhole-to-surface telemetry employed, the availability of a downlink, if the tool has a "Multi-Shot Mode," and if it can be run in tandem, as a host for a GMWD system.

Table 24: Available Standard Passive Ranging Tools - Communications & Operating Modes

Supplier	Model	Telemetry	Downlink	Multi-Shot Mode	Tandem w/ GWD
APS Technology	SureShot MWD	Positive mud pulse	Y	N	Y
Baker Hughes	OnTrak HT-175	Positive mud pulse	Y	N	Y
Bench Tree	MWD Kit	Positive mud pulse	Y		N
GE Oil & Gas	Tensor MWD	Positive mud pulse	Y	N	N
Halliburton/SD	SOLAR MWD/LWD	Positive mud pulse	Y		Y
Schlumberger	HDS-1L	Positive mud pulse	Y	N	Y
Scientific Drilling	Falcon MWD	Positive mud pulse	Y	Y	Y
Scientific Drilling	Green Eye Ranging MWD	Positive Mud Pulse	Y	Y	Y
Weatherford	HyperPulse MWD	Positive mud pulse	Y	N	

The ability to run MWD and GMWD tools in tandem offers an advantage when conducting passive ranging between the active borehole and a nearby, cased well. This process requires developing a model for the target well, which is based on the magnetic poles of each joint of casing, and obtaining measurements of the local magnetic along a known path. Having a gyro-based tool in the hole with a conventional MWD system reduces the time needed to determine the path along the active borehole.

2.3.3.3. Environmental Limitations

Table 25 shows specifications for the maximum operating temperatures and pressures the available, standard passive ranging/MWD tools will withstand, and the maximum operating times for tools at the specified temperatures. (Maximum operating times that are determined by battery life are shown in another table, below.)

Table 25: Available Standard Passive Ranging Tools – Environmental Limitations

Supplier	Model	Max. Operating		Max. Pressure (psi)
		Temp. (°C)	Time (hrs.)	
APS Technology	SureShot MWD	175	> 1000	25,000
Baker Hughes	OnTrak HT-175	175		30,000
Bench Tree	MWD Kit	175		20,000
GE Oil & Gas	Tensor MWD	175		20,000
Halliburton/SD	SOLAR MWD/LWD	175		25,000
Schlumberger	HDS-1L	175	300	25,000
Scientific Drilling	Falcon MWD	150	300+	30,000
Scientific Drilling	Green Eye Ranging MWD	150	300+	30,000
Weatherford	HyperPulse MWD	150		15,000

2.3.3.4. Directional Measurements

The Accuracy and Resolution specifications for available, standard passive ranging/MWD tools are shown in Table 26. The Azimuth Accuracy figures assume a minimum horizontal magnetic field magnitude. For most suppliers this is on the order of 30 µTeslas, which is about what is found in the North Sea.

Table 26: Available Standard Passive Ranging Tools – Directional Measurements

Supplier	Model	Inclination		Azimuth		
		Acc'y	Resol'n	Acc'y	Resol'n	Incl. Min.
APS Technology	SureShot MWD	< ±0.1°	0.044°	±1.0°	0.088°	10°
Baker Hughes	OnTrak HT-175	±0.1°	0.09°	±1.0°	0.35°	5°
Bench Tree	MWD Kit	±0.1°		±0.35°		45°
GE Oil & Gas	Tensor MWD	±0.1°	0.1°	±1.0°	1.0°	3°
Halliburton/SD	SOLAR MWD/LWD	±0.1°	0.09°	±0.8°	0.17°	5°
Schlumberger	HDS-1L	±0.1°	0.1°	±1.0°	0.1°	6°
Scientific Drilling	Falcon MWD	±0.15°	0.15°	±0.25°	0.25°	3°
Scientific Drilling	Green Eye Ranging MWD	±0.15°	0.15°	±0.25°	0.25°	3°
Weatherford	HyperPulse MWD	±0.2°	0.125°	±1.0°	0.25°	5°

Before giving too much weight to these figures, however, it would be useful to obtain appropriate confidence figures – in Sigma's or Standard Deviations – for Directional Accuracy and Resolution specifications from the manufacturers. These have not been included in Table 26 because comparable figures from many of the suppliers could not be obtained.

2.3.3.5. Magnetic Measurements

The specifications for range, accuracy, and resolution of the magnetic measurements made by the available, standard passive ranging/MWD tools provided by the manufacturers are listed in Table 27.

Table 27: Available Standard Passive Ranging Tools – Magnetic Measurements

Supplier	Model	Magnetic Field (µT)		
		Range	Accuracy	Resolution
APS Technology	SureShot MWD	±120	±0.3	0.6
Baker Hughes	OnTrak HT-175	0-100	±0.10	0.035
Bench Tree	MWD Kit		±0.075	
GE Oil & Gas	Tensor MWD	0-100	±0.075	0.01
Halliburton/SD	SOLAR MWD/LWD	±65		0.032
Schlumberger	HDS-1L	0-65	±0.110	0.035
Scientific Drilling	Falcon MWD	±75	±0.18	0.002
Scientific Drilling	Green Eye Ranging MWD	±150		0.0046
Weatherford	HyperPulse MWD			

When these MWD tools are used in passive ranging applications, the resolution of their magnetometers is particularly important. The only apparent difference between Scientific Drilling Falcon and Green Eye Ranging tools is the latter has been designed for ranging applications where it might be exposed to higher magnetic fields. This doubling of the range and resolution of their magnetometers suggests magnetic fields encountered while ranging may exceed normal earth's field magnitudes. If this is so, the smaller ranges of Halliburton/SD's SOLAR and Schlumberger's HDS-1L tools might be a disadvantage in ranging applications.

2.3.3.6. Survey Times

Table 28 shows times for both short and long surveys, as provided by the manufacturers of the available, standard passive ranging/MWD tools, for surveys in a "test well" meeting the following criteria: 15,000 feet vertical depth; no more than 20,000 feet measured depth; inclination of 20°; latitude of 30° north; magnetic dip of 60°; with mud properties and temperature within operating specifications.

Table 28: Available Standard Passive Ranging Tools – Survey Times

Supplier	Model		Survey Times (sec)	
		No. Bits	Short	Long
APS Technology	SureShot MWD	12	192	255
Baker Hughes	OnTrak HT-175		105	139
Bench Tree	MWD Kit			
GE Oil & Gas	Tensor MWD	12	190	326
Halliburton/SD	SOLAR MWD/LWD	8/11-12	65	76
Schlumberger	HDS-1L			
Scientific Drilling	Falcon MWD		177	219
Scientific Drilling	Green Eye Ranging MWD		177	219
Weatherford	HyperPulse MWD			

The figures for number of bits shown for Halliburton/SD's SOLAR MWD/LWD tool indicate only eight bits are used for azimuth and inclination when it is transmitting short surveys. When transmitting long surveys, eleven bits are used for data from accelerometers, and twelve bits are available for data from magnetometers.

It was not possible to test or confirm the transmit time provided by system suppliers, even though each provided data they feel would be "reasonable" for the test well that was described. Without actual tests in comparable environments, it is not possible to draw conclusions from the values in this table.

2.3.3.7. Power Sources & LCM

Table 29 shows the types of power sources used by the available, standard passive ranging/MWD tools, as well as specified maximum operating times for battery-powered tools, and the tools tolerance to lost circulation material (LCM). The operating times shown are those with the maximum number of battery packs available in the standard configurations. These operating times are, of course, largely determined by the number of surveys taken (or survey frequency).

Table 29: Available Passive Ranging Tools – Power Sources & LCM

Supplier	Model	Power Source	Oper'g Time (hrs.)	LCM Tol. (lbm/bbl)
APS Technology	SureShot MWD	Turb/Bat	200/battery	50
Baker Hughes	OnTrak HT-175	Turbine	N/A	40
Bench Tree	MWD Kit	Battery	800+	
GE Oil & Gas	Tensor MWD	Battery	180	40-50
Halliburton/SD	SOLAR MWD/LWD	Turbine	N/A	40
Schlumberger	HDS-1L	Battery	224-669	50
Scientific Drilling	Falcon MWD	Battery	300+	40
Scientific Drilling	Green Eye Ranging MWD	Battery	300+	40
Weatherford	HyperPulse MWD	Battery		

The APS Technology SureShot MWD is available with either a battery or a turbine.

It may not be a coincidence that two of the tools with the highest LCM tolerance (APS Technology SureShot MWD and Schlumberger HDS-1L) employ rotating or shear valves.

2.3.3.8. Gamma, Other Measurements & Maturity

Table 30 captures information for available, standard passive ranging/MWD tools describing other, formation evaluation, and drilling dynamics measurements that are available with their tools, and when the tools were first offered for commercial service. As described in Section 2.2.2.7 above, the number of years a tool has been in commercial service ("maturity") is used as a surrogate for MTBF data.

Table 30: Available Standard Passive Ranging Tools – Gamma, Other Measurements & Maturity

Supplier	Model	Gamma	Other Measurements	First in Service
APS Technology	SureShot MWD	Azimuthal & Focused	Resistivity; weight, torque, bending; sonic; porosity, density & caliper	2002
Baker Hughes	OnTrak HT-175	Azimuthal	Multiple-propagation resistivity, Drilling dynamics	2014
Bench Tree	MWD Kit	Omni		
GE Oil & Gas	Tensor MWD	Omni	Propagation resistivity	mid-1990s
Halliburton/SD	SOLAR MWD/LWD	Omni & Azimuthal	Vibration, Pressure, Caliper, Resistivity, and other LWD Tools	2015
Schlumberger	HDS-1L	Omni	Vibration, Temperature	1995
Scientific Drilling	Falcon MWD	Azimuthal or Focused	Battery voltage & draw, Vibration (axial & lateral), Tool RPM, Stick-Slip levels, Annulus & pipe pressures, Continuous & near-bit Inclination	1999
Scientific Drilling	Green Eye Ranging MWD			1999
Weatherford	HyperPulse MWD	Omni	Temperature	

Because MWD systems often are used in a geosteering mode, all suppliers offer at least one type of gamma radiation sensor. Other measurements offered can be sorted into other types of formation evaluation logs (resistivity, sonic, density, porosity) and drilling dynamics (vibration, pressure, weight, torque, bending, and caliper).

2.3.4. Available High-Temperature (HT) Passive Ranging Tools

The tables in this section are identical to those in the Section 2.2.3 (Available High-Temperature MWD Tools) above, except for the addition of a table addressing Magnetic Measurements. They are repeated here because the benefits of having the ranging tools in a separate section outweigh the disadvantages of the repetition.

2.3.4.1. Platforms

Table 31 describes the external, mechanical configurations of the available, HT passive ranging/MWD tools. The Nominal O.D. (min) column lists only the smallest collar outside diameter that is available.

Larger sizes, to 6.75" O.D are available from Halliburton and Schlumberger. Weatherford offers four sizes, and Scientific Drilling offers nine sizes to 9.5" O.D.

Table 31: Available HT Passive Ranging Tools – Platforms

Supplier	Model	Description	Nom. O.D. (min)
Halliburton/SD	Quasar Pulse M/LWD	Collar-based hostile-env. M/LWD system	4.75
Schlumberger	TeleScope ICE	Collar-based UltraHT MWD Service	4.75
Scientific Drilling	High Temp MWD	Std. collar below Pulser Sub	3.125
Weatherford	HEL MWD System	Collar-based hostile-env. MWD system	4.75

2.3.4.2. Communications & Operating Modes

Table 32 shows the attributes of the important interfaces of each HT passive ranging/MWD system. These include the type(s) of downhole-to-surface telemetry employed, the availability of a downlink, if the tool has a "Multi-Shot Mode," and if it can be run in tandem, as a host for a GMWD system.

Table 32: Available Passive Ranging Tools – Communications & Operating Modes

Supplier	Model	Telemetry	Downlink	Multi-Shot Mode	Tandem w/ GWD
Halliburton/SD	Quasar Pulse M/LWD	Positive mud pulse	N	N	N
Schlumberger	TeleScope ICE	Positive mud pulse	N	N	Y
Scientific Drilling	High Temp MWD	Positive Mud pulse	Y	Y	N
Weatherford	HEL MWD System	Positive mud pulse	Y	N	Y

There is no GMWD system or module that claims an operating temperature above 150° C. Thus using the two in tandem would reduce the maximum operating temperature for the entire system.

2.3.4.3. Environmental Limitations

Specifications in Table 33 show the maximum operating temperatures and pressures available, HT passive ranging/MWD tools will withstand, and the maximum operating times for tools at the specified temperatures.

Table 33: Available HT Passive Ranging Tools – Environmental Limitations

Supplier	Model	Max. Operating		
		Temp. (°C)	Time (hrs.)	Max. Pressure (psi)
Halliburton/SD	Quasar Pulse M/LWD	200		25,000
Schlumberger	TeleScope ICE	200	300	30,000
Scientific Drilling	High Temp MWD	177		30,000
Weatherford	HEL MWD System	180	200	30,000

Scientific Drilling's High Temp MWD and Weatherford's HEL MWD Systems are battery powered. The maximum operating time for Weatherford's tool reflects the temperature limitations of its battery, not the other components or subsystems.

2.3.4.4. Directional Measurements

Accuracy and Resolution specifications for available, HT passive ranging tools/MWD are shown in Table 34, as is the minimum inclination needed to achieve the specified azimuth accuracy.

Table 34: Available HT Passive Ranging Tools – Directional Measurements

Supplier	Model	Directional Measurements				
		Inclination		Azimuth		
		Acc'y	Resol'n	Acc'y	Resol'n	Incl. Min.
Halliburton/SD	Quasar Pulse M/LWD	±0.1°	0.09°	±0.8°	0.17°	5°
Schlumberger	TeleScope ICE	±0.1°	0.1°	±1.0°	0.1°	5°
Scientific Drilling	High Temp MWD	±0.15°	0.15°	±0.25°	0.25°	3°
Weatherford	HEL MWD System	±0.1°	0.08°	±0.5°	0.17°	5°

Azimuth accuracy of Scientific Drilling's High Temp MWD tool looks significantly better than the others'.

Principal among the caveats that accompany these accuracy figures is that the magnetic dip angle (inclination) is assumed to be no more than about 70°, which implies the horizontal component of the earth's field would be at least 30 µTeslas. As mentioned above, making meaningful comparisons of accuracy and/or resolution would require obtaining comparable confidence numbers for these specifications from the tool manufacturers.

2.3.4.5. Magnetic Measurements

The specifications for range, accuracy and resolution of the magnetic measurements made by the available, HT passive ranging/MWD tools provided by the manufacturers are listed in Table 35.

Table 35: Available HT Passive Ranging Tools – Magnetic Measurements

Supplier	Model	Magnetic Field (µT)		
		Range	Acc'y	Resol'n
Halliburton/SD	Quasar Pulse M/LWD			
Schlumberger	TeleScope ICE	0-65	±0.110	0.035
Scientific Drilling	High Temp MWD	±75		0.0023
Weatherford	HEL MWD System			

In ranging applications, the resolution of Scientific Drilling's High Temp MWD could be an advantage; however the range of its magnetometers is half that of their Green Eye ranging tool, which is rated for 150° C operating temperature.

2.3.4.6. Survey Times

Table 36 shows the survey times for available, HT passive ranging/MWD tools provided by manufacturers for the same "test well" as was used for the standard MWD tools. The caveats described under the Survey Times table for Standard MWD tools (Section 2.2.2.5) apply here, as well.

Table 36: Available HT Passive Ranging Tools – Survey Times

Supplier	Model		Survey Times (sec)	
		No. Bits	Short	Long
Halliburton/SD	Quasar Pulse M/LWD	12	192	255
Schlumberger	TeleScope ICE		105	139
Scientific Drilling	High Temp MWD		177	219
Weatherford	HEL MWD System			

2.3.4.7. Power Sources & LCM

Table 37 shows the types of power sources used by the available, HT passive ranging/MWD tools, as well as specified maximum operating times for battery-powered tools, and the tools tolerance to lost circulation material (LCM). The operating times shown are those with the maximum number of battery packs available in the standard configurations. These operating times are, of course, largely determined by the number of surveys taken (or survey frequency).

Table 37: Available HT Passive Ranging Tools – Power Sources & LCM

Supplier	Model	Power Source	Oper'g Time (hrs.)	LCM Tol. (lbm/bbl)
Halliburton/SD	Quasar Pulse M/LWD	Turbine	N/A	40
Schlumberger	TeleScope ICE	Turbine	N/A	50
Scientific Drilling	High Temp MWD	Battery	300+	40
Weatherford	HEL MWD System	Battery	348	50

Because the Halliburton and Schlumberger tools are turbine powered, their maximum operating times are determined by the ability of the downhole systems to continue functioning as exposure to elevated temperatures increases. From information provided by Halliburton, their Quasar Pulse tool has no limitation at temperatures as high as 200° C. The Schlumberger TeleScope ICE tool has an operating limit of 200 hours at 200° C.

The Scientific Drilling High Temp MWD and Weatherford HEL MWD tools are battery-powered, so the operating times shown above are determined by battery capacity. At its maximum operating temperature of 180° C, however, the Weatherford tool is no more than 200 hours.

2.3.4.8. Gamma, Other Measurements & Maturity

Table 38 captures information for available, HT passive ranging/ MWD tools describing other, formation evaluation and drilling dynamics measurements that are available with their tools, and when the tools were first offered for commercial service. As described in Section 2.2.2.7 above, the number of years a tool has been in commercial service ("maturity") is used as a surrogate for MTBF data.

Table 38: Available HT Passive Ranging Tools – Gamma, Other Measurements & Maturity

Supplier	Model	Gamma	Other Measurements	First in Service
Halliburton/SD	Quasar Pulse M/LWD	Omni	Vibration, Annular & Bore Pressures	2015
Schlumberger	TeleScope ICE	Azimuthal	Shock, Vibration, Annular & Internal Pressures	2015

Supplier	Model	Gamma	Other Measurements	First in Service
Scientific Drilling	High Temp MWD	Radial	Vibration, Temperature	1999
Weatherford	HEL MWD System	Azimuthal	Drilling dynamics, Bit speed, Bore & annular pressure, Annular temperature	

Because MWD systems often are used in a geosteering mode, all suppliers offer at least one type of gamma radiation sensor. Other measurements offered can be sorted into other types of formation evaluation logs (resistivity, sonic, density, porosity) and drilling dynamics (vibration, pressure, weight, torque, bending, and caliper).

2.3.5. Available Active Ranging Systems

At this moment, Halliburton/Sperry Drilling has the only commercially-available, access-independent, active ranging system suitable for borehole applications. It is, in fact, a family of products that share the WellSpot name. Initial development and commercialization of these products were started by Arthur Kuckes in 1980. In 1985, he founded Vector Magnetics, which manufactured the tools and offered ranging services. In 2010 Halliburton obtained commercial rights to these technologies and tools for all oil- and gas-related markets.

The primary tool, WellSpot RGR, comes in three versions that appear to reflect continuing improvements in their electronics and/or magnetometers. These tools are deployed on a conventional, 7-conductor wireline in open hole. Above the tool is a bridle that incorporates an electrode to transmit a low-frequency electromagnetic AC signal into the surrounding formation. One set of three magnetometers measures all three axes of the local fields, both induced AC and earth's (DC) field. The acronym, RGR, stands for radial-gradient ranging. The tool has two pairs of magnetometers that measure the gradient of the induced AC field in the two directions orthogonal to the tool's longitudinal axis (X and Y). Gradient measurements provide more precise range information when the active and target wells are close.

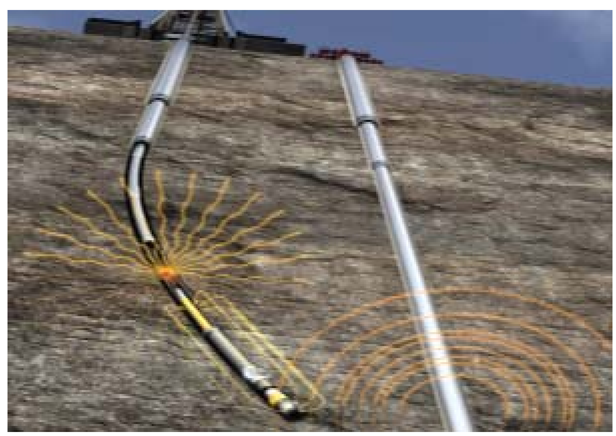


Figure 4: WellSpot Tool™ with WSAB Sub
(from: Halliburton/Sperry Drilling, reproduced with permission)

An alternative configuration of the WellSpot tool uses the WSAB Sub (Figure 4), which is normally placed between the bit and mud motor or RSS. It uses short-hop telemetry to communicate to its receiver, which is tripped in on 7-conductor wireline, inside drill pipe or open hole to a location above the BHA, within 75 feet of the WSAB Sub.

The WSAB Sub is battery-powered and is activated after rotation has stopped for a set interval. After turning on, it averages the readings of the AC field from its magnetometers for a minute-or-so and, if it finds a signal, activates the short-hop telemetry link to its receiver, which them sends the readings to the surface. This configuration eliminates the need to trip the BHA to make ranging measurements. The disadvantage of this configuration is the need to have a wireline inside the drill pipe (unless the tool is used in open hole).

Most of the systems and some of the components in the WellSpot family are covered by an extensive array of patents. Thus information on the performance and limitations of these products is limited. The information provided in the sections below captures what has been provided by Halliburton/Sperry Drilling. Key attributes of the active ranging, WellSpot family are sorted into the following groups: Platforms; Communications & Operating Modes; Environmental Limitations; and Ranging Measurements.

2.3.5.1. Platforms

Table 39 describes the external, mechanical configurations of the available active ranging tools. The Nominal O.D. (min) column lists only the smallest collar outside diameter that is available.

Table 39: Available Active Ranging Tools – Platforms

Supplier	Model	Description	Nom. O.D.
Halliburton/SD	WellSpot RGR I	Wireline AMR Tool w/ bridle	4.5"
Halliburton/SD	WellSpot RGR II	Wireline AMR Tool w/ bridle	2"
Halliburton/SD	WellSpot RGR III	Wireline AMR Tool w/ bridle	2"
Halliburton/SD	WSAB Sub	WellSpot At-Bit Sub	7"
Halliburton/SD	WSAB Sub	WellSpot At-Bit Sub	8.5"
Halliburton/SD	WSAB Receiver/CML	Receiver for WSAB and Continuous Logging Tool	2"

The progression of sizes and capabilities of the WellSpot RGR tool – from I to II to III – suggests continuing improvements in performance and reductions in size. The WellSpot At-Bit Sub is available in just the two sizes shown. The receiver is designed to be run inside drill pipe, but also has been run in open hole.

2.3.5.2. Communications & Operating Modes

Table 40 shows the attributes of the important interfaces of each active ranging system. These include the type(s) of downhole-to-surface telemetry employed and if it can be run in tandem, as a host for a GMWD system.

Table 40: Available Active Ranging Tools – Communications & Operating Modes

Supplier	Model	Telemetry	Tandem w/ GWD
Halliburton/SD	WellSpot RGR I	7-Conductor Wireline	Y
Halliburton/SD	WellSpot RGR II	7-Conductor Wireline	Y
Halliburton/SD	WellSpot RGR III	7-Conductor Wireline	Y
Halliburton/SD	WSAB Sub	Wireless to WSAB Receiver	N
Halliburton/SD	WSAB Sub	Wireless to WSAB Receiver	N
Halliburton/SD	WSAB Receiver/CML	7-Conductor Wireline	N

The wireline that is used to connect these tools to the surface provides high-bandwidth communications for data as well as a downlink, which enable control and reconfiguring the tool from the surface.

2.3.5.3. Environmental Limitations

Table 41 shows specifications for the maximum operating temperatures and pressures the available active ranging tools will withstand.

Table 41: Available Active Ranging Tools - Environmental Limitations

Supplier	Model	Max. Oper'g Temp. (°C)	Max. Pressure (psi)
Halliburton/SD	WellSpot RGR I	177	25,000
Halliburton/SD	WellSpot RGR II	177	20,000
Halliburton/SD	WellSpot RGR III	204	25,000
Halliburton/SD	WSAB Sub	127	15,000
Halliburton/SD	WSAB Sub	127	15,000
Halliburton/SD	WSAB Receiver/CML	127	25,000

The operating temperatures of the WellSpot RGR tools could be increased by running them inside insulating dewars. The lower temperature limits of the WSAB system reflect the anticipated conditions for which it was developed (relatively shallow water in the Gulf of Mexico).

2.3.5.4. Ranging Measurements

Table 41 shows the maximum ranges the available active magnetic ranging tools are capable of in their two modes and the tolerances for these measurements and for direction to the target.

Table 42: Available Active Ranging Tools – Ranging Measurements

Supplier	Model	Distance Detection		Gradient Detection		Direction
		Range	Tolerance	Range	Tolerance	Tolerance
Halliburton/SD	WellSpot RGR I	150 ft.	±20%	10 ft.	±5%	±3°
Halliburton/SD	WellSpot RGR II	150 ft.	±20%	25 ft.	±5%	±3°
Halliburton/SD	WellSpot RGR III	150 ft.	±20%	10 ft.	±5%	±3°
Halliburton/SD	WSAB Sub	20 ft.	±25%	7 ft.	±5%	±3°
Halliburton/SD	WSAB Sub	40 ft.	±25%	7 ft.	±5%	±3°
Halliburton/SD	WSAB Receiver/CML	75 ft.				

In their normal mode, they sense the magnitude of the induced magnetic field; in their gradient mode, they sense the gradient of the induced field. The important role played by gradient measurements can be inferred from the large differences in tolerances between the two modes.

3. Survey Lifecycle Elements

3.1. Wellbore Planning

Wellbore planning includes design of the drilling program for the wellbore from surface to total depth. The objective of the wellbore design is to define a drilling plan that will reach the geologic target safely, accurately, and efficiently. Comprehensive wellbore planning includes a wide range of considerations that may affect the directional survey including drilling tool selection (BHA), torque and drag analysis, wellbore tortuosity and doglegs, hydraulics (mud and pressure control), casing, and formation evaluation. Directional surveys are an integral part of the drilling plan. Well designers document the types of survey tools that will be used to record wellbore position and steer the drill bit throughout the drilling process, and consider the uncertainty in the survey data when planning the wellbore.

The following discussion provides the basic principles of directional well design with a focus on survey planning for exploration and production wells, and describes the special situation of relief well planning. Because wells are planned and graphically represented using specialized wellbore planning software, the section contains a brief discussion on wellbore planning software. As with most technical subjects covered in this document, the concepts presented are general in nature. Individual operators or regional requirements may necessitate different approaches.

3.1.1. Well Design and Directional Survey Planning

Planning exploration and production wells requires consideration of many factors to ensure a safe and useful completed well. Some examples of the factors considered during well planning are shown in Table 43.

Table 43: Factors Considered in Wellbore Planning

Factor	Consideration
Geologic Target	Reach depth and xy location of targeted zone.
Legal Requirements	Maintain lease line setbacks and other legal requirements for surface hole location and wellbore trajectory.
Collision Avoidance	Maintain a safe distance from other wellbores.
Drilling Conditions and Geologic Obstacles	Avoid or optimize drilling through difficult geologic materials. Considers pore pressure, fracture gradient, hole geometry to minimize torque and drag, mud plan, bit and drill string program, drill time projection, and cost estimation. Considers ability to collect reliable directional measurements during drilling, and formation evaluation data during or after drilling.
Final hole conditions	Prepare a clean and smooth borehole that is suitable for completion and production. Avoid severe doglegs that limit equipment selection or cause excessive equipment wear.

The wellbore planning process starts with the operator defining a set of target coordinates for the surface location and bottom hole position. Well planners or drilling engineers design an initial well path, and work with geologic and engineering teams to integrate subsurface geologic models and make sure well designs are technically or economically viable by applying the considerations described above. Multiple well designs are prepared and evaluated, and a final selection is made based on the operator's selection criteria.

Well planning may be performed by the operator, or more commonly is contracted to a directional drilling company. The advantage of well planning by the directional drilling company is that the selection of BHA and survey tools is based on the tool capabilities that will be supplied by the directional driller. Operating companies often have internal guidance documents and standard procedures to manage well planning. Final well plans are reviewed and approved by both the directional driller/well planner, and the operating company. As shown in Figure 5, the final well plan includes a graphical representation of the well in plan and profile views.

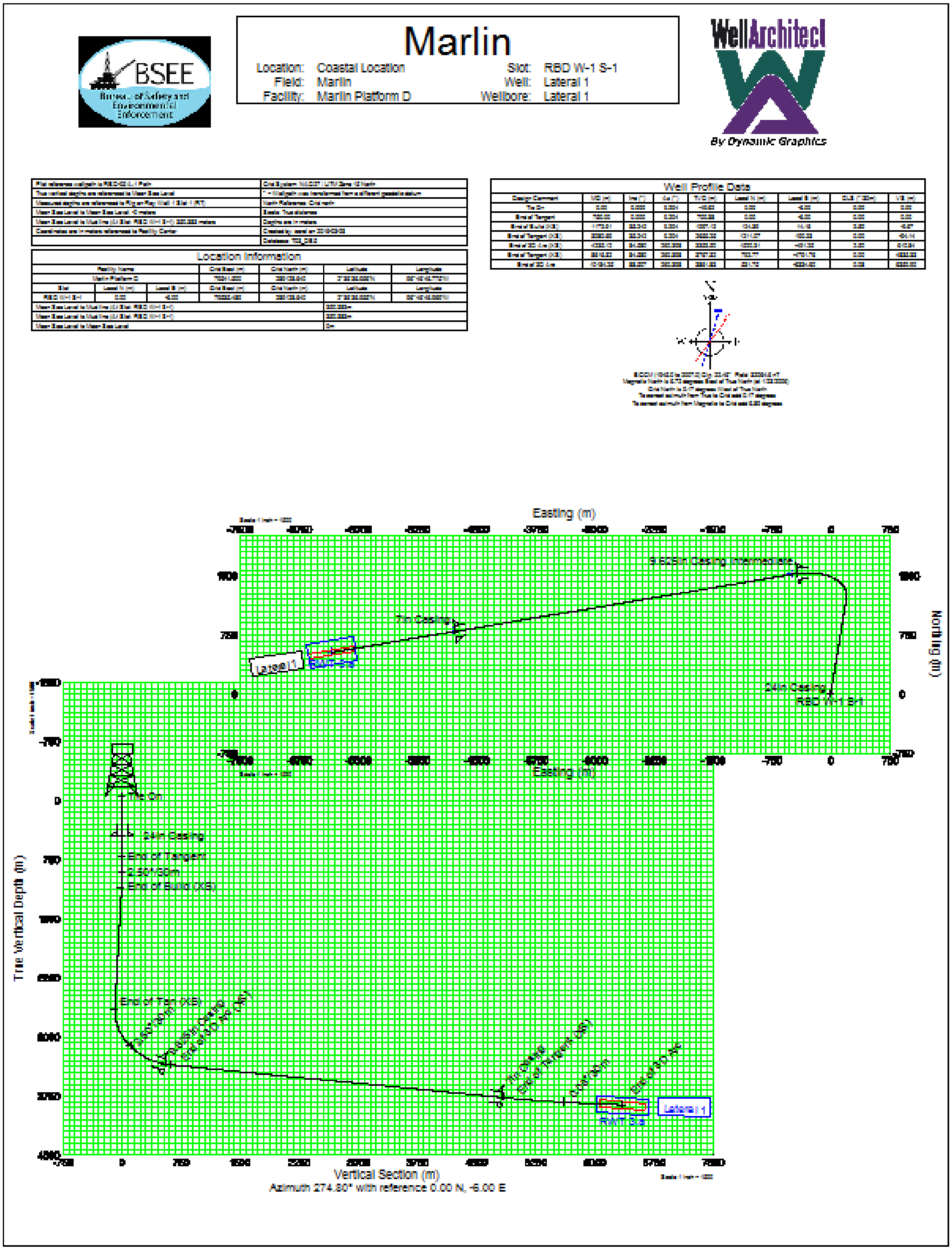
A Safety Critical Element (SCE) is a component or activity whose failure could lead to, or whose purpose is to prevent or limit the consequences of a major accident event[1]. An out of control well, or accidental intercept of an adjacent well would be considered a major accident event (MAE). Wells with elevated risk of MAE occurrence with environmental or safety consequences are classified as Health Safety and Environment (HSE) risk wells. Many offshore operators consider wellbore planning to be an SCE because a major part of the planning activity is to avoid hazards such as adjacent wells. The development of a wellbore surveying plan (defining the tools used and quality assurance to be implemented) and the adherence to collision avoidance rules established by operators (discussed below in Section 3.1.3) are the tools used to manage HSE wells. The well survey plan must also minimize the risk of drilling an unsuccessful relief well by accurately representing and minimizing the uncertainty in wellbore positon so that the relief well has a well-defined target.

While safety is a primary consideration in wellbore planning, there are also economic and resource conservation considerations. A properly designed wellbore will maximize the resource recovery within the reservoir and allow for economic recovery of the resource from the planned well, as well as subsequent wells drilled in the field. Recent studies (Stockhausen, 2016) have shown that significant volume of reserves can be lost or underestimated if wellbore position is inaccurate. For example, Stockhausen demonstrated that a one-foot error in true vertical depth (TVD) can equate to 10,000 to 100,000 barrels of reserves; wellbore uncertainty is often in the range of tens of feet. Considering that some surveys may have uncertainties of tens to hundreds of feet at total depth (TD), enormous volumes of reserves can be unrealized. Wellbores that appear to penetrate unproductive geologic targets may actually be mislocated in the subsurface. Poorly designed wells may require frequent maintenance and shut downs to repair or replace failed components caused by excessive wear in wells with high angle doglegs and spiraled casings. Unplanned well intersections can incur significant economic and reputation cost and cause the operator to lose the right to drill.

Offshore rig time is an important consideration in the development of a well survey plan. Collecting measurements with MWD tools generally requires the drill string to be stationary for several minutes. Collecting frequent measurements in a deep offshore well (20,000 to 30,000 feet) may add considerable rig time to the drilling program. Additionally, singleshot and multishot tools require the drill string to be stable during tripping, which increases rig time. Well survey plans must balance the time required to take survey measurements against the rig time. Likewise, quality control procedures while tripping in and out, and during drilling also add to rig time.

[1] Adapted from : API RP 2FB, Recommended Practice for the Design of Offshore Facilities Against Fire and Blast Loading, First Edition, April 2006, and The Offshore Installations (Safety Case) Regulations 2005, UK S.I. 2005/3117, 2005

Figure 5: Graphical Representation of Well Plan showing Plan and Profile Views



Well Plan courtesy of Dynamic Graphics Inc. reproduced with permission.

Using unnecessarily large uncertainty estimates (resulting from incorrect tool error models and unapplied corrections) can add to drilling cost by creating drilling restrictions that affect penetration rate. Restrictive drilling tolerances may necessitate more frequent survey measurements to ensure adherence to the drilling plan, and may be more likely to result in sidetracks and corrections. Operators consider these factors in developing well survey plans.

A wellbore survey plan is a part of the wellbore planning process and provides a set of instructions for collecting information to locate the wellbore trajectory. It includes a description of the proposed survey tools, the depth interval the tool will be used and the frequency of measurements. Survey plans may also contain a contingency plan for data collection in the event of a tool failure or unacceptable data quality. Drillers and survey operators are responsible for implementing the plan and using the data to safely and effectively drill to TD.

When planning and evaluating the survey program, it is useful to consider the effect of tool selection on the final accuracy. Comparing tool specifications for accuracy and measurement resolution provides a first step, but the tool specifications are normally given in measurement units such as degrees, or micro Teslas, which may not provide a realistic representation of the impact of the measurement on the final x, y location. Industry often uses the "1=2" rule of thumb to evaluate the effect of measurement accuracy on the final location. The rule represents the mathematical relationship that one degree of angle is equal to a 2 percent change in the distance (1° = 2%). For example, a small inclination error of 0.25 degrees will produce 0.5% of step out as an error in TVD. If the step out to a reservoir entry point is 3,000 feet, the TVD error would be + or – 15 feet for only a quarter of 1 degree of inclination error (example from ISCWSA, 2012). For long boreholes, small declination errors can lead to substantial uncertainty at the target location.

No specific planning procedures are required for wells that are expected to encounter high temperature conditions. However, tools selected for inclusion in the survey plan must be rated for the environments for which they will operate, and operated in accordance with all quality control (QC) or the readings and error models will not be valid. To ensure proper operation of the survey equipment, the expected bottom hole temperatures should be identified, and running procedures should consider the length of time tools are operating at elevated temperature to avoid adverse effects on sensors and battery life. Likewise, some gyro tools have limitations on the maximum inclination angle in which they will operate and the maximum latitude in which they can obtain accurate readings[2].

The final wellbore survey plan submitted to BSEE in the Application for Permit to Drill (APD) is often a general description of the directional survey program and may include only plan and profile view of the well trajectory with annotation of the type of survey to be performed (MWD or gyro).

3.1.2. Well Planning Software

Well planning software is universally used to plan and document well trajectories for offshore wells. It is normally part of a larger software package used during directional drilling and may also function as a

[2] At high latitude (the Arctic Circle) the earths spin rate is very low and gyro tools may be unable to obtain necessary resolution in spin rate to make accurate readings.

survey management system for large well data sets. This section provides a brief introduction to the general attributes and uses of well planning software, as it relates to wellbore survey data. Additional discussion of the use of these programs during drilling is provided in Section 3.2 Survey Operations and Section 3.3 Data Management.

Two major vendor licensed software products, Compass™ (by Landmark, a Haliburton company) and WellArchitect™ (Dynamic Graphics Inc.), are the most commonly used licensed well planning software for offshore applications. DrillingOffice™ is a proprietary well planning and drilling engineering software package developed and used by Schlumberger for well planning and directional drilling. It is generally not licensed for external use. A number of smaller vendor-supplied software products are also available for wellbore planning. With respect to wellbore planning, each of the major software products provide:

- A database function to store and manage a set of well survey data,
- A selection of error models to be applied to the well survey data to generate cones of uncertainty,
- A well planning module to select well path and BHA components,
- A collision avoidance scan with choices for scanning methodologies,
- Report outputs for well plans and collision scans, and
- Integration with real time data collection during drilling.

The outputs from the planning module of the software include plan and profile views of the well trajectory, various anti-collision plots (travelling cylinder, ladder and spider plots, described in Section 3.1.3) and a wide range of reports of anti-collision scans, and well survey plans. The well survey plan provides a listing of the tools and vendors to be used, the start and end depth for each tool, survey frequency, and other information such as QC requirements and specific tool codes.

3.1.3. Collision Avoidance Analysis

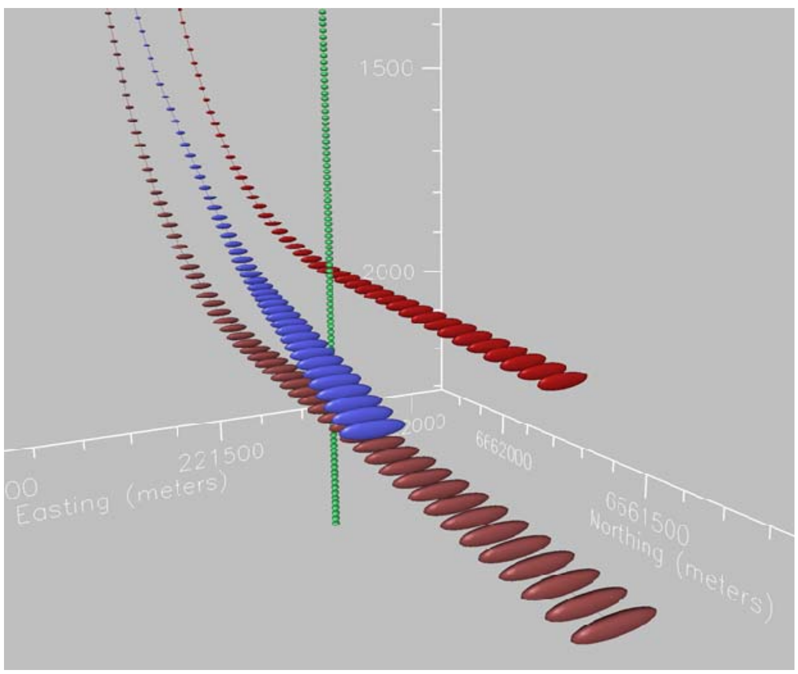
Anti-collision analysis (also called collision avoidance) is a key part of the well planning process and one of the most important safety considerations related to wellbore surveying. Because of the significance of the topic the subject is addressed in detail.

Operating companies and directional drilling companies have established rules to ensure the risks from unplanned well intersections are properly identified and evaluated during the wellbore planning process. The procedures described in this section address the planning process. After the planning phase, the execution of the recommended drilling plan adheres to strict collision avoidance procedures during drilling to avoid collision. Actions taken to avoid wellbore collision during drilling are part of a comprehensive collision avoidance policy and are addressed in Section 3.2 Survey Operations.

Platforms for offshore fields contain drilling slots for several dozen or more wells located in close proximity to each other at the surface. In the subsurface the wells often have complex trajectories and include bypasses and sidetracks. Operators are increasing the number of available slots on a platform to avoid the expense of major additions to infrastructure. The large number of existing wells and the need to add new ones to extend platform life creates a congested drilling environment and very challenging collision-avoidance scenarios. Collision avoidance policies are statements that define the limits of risk, and the management approach that the business will adopt to mitigate the risk. Successful collision avoidance policies define roles for operators and directional drilling company staff at multiple levels.

The general procedure for conducting collision avoidance analysis is to assemble the well construction and survey data from all nearby wells and conduct a proximity analysis along the proposed wellbore to determine if any adjacent wells are within a specified distance from the proposed well using a geometrical spacing approach. The well trajectory for the proposed well incorporates the uncertainty in the wellbore position of the actual well due to the survey accuracy, and therefore is represented by a volume (ellipsoid) around the wellbore[3] at a single point. When the ellipses are connected along the wellbore they form a three-dimensional surface represented by a cone. Likewise, the trajectories of adjacent wells incorporate their positional uncertainty, represented by an ellipse around the wellbore (Figure 6). The operator or directional driller defines the minimum acceptable allowable distance between the two ellipses of uncertainty, and the proximity analysis is conducted using a collision avoidance software package[4]. If an unacceptable risk of collision is identified the wellbore trajectory is revised. For most operators, the collision avoidance policy requires that results of the collision avoidance analysis are documented and auditable, reviewed, and approved by authorized senior staff.

Figure 6: Ellipsoids of Uncertainty Around Planned and Target Wells



Anti-collision analysis example courtesy of Dynamic Graphics Inc., reproduced with permission.

[3] The concept of wellbore position uncertainty and the calculation of ellipses of uncertainty is covered more thoroughly in Section 3.4 - Errors and Corrections.

[4] Collision avoidance analysis can be conducted manually, but due to the large amount of data required it is generally conducted using specialized automated software. Collision avoidance analysis modules are included in the major well planning software products described in Section 3.1.3 – Well Planning Software, or as standalone software products.

Specific rules for collision avoidance are established by the operators and directional drillers and documented in a corporate Collision Avoidance Policy or Rules. These policies are normally part of the company Risk Management procedures. An example of collision avoidance rules from a major international operator is shown in Figure 7. Prior to preparing the well plan, the operator and directional driller must agree on the rules to be applied to the collision avoidance analysis. To ensure an appropriate margin of safety, operators may have different rules and mitigations for well planning and drilling.

Figure 7: Example of Major International Operator Collision Avoidance Rules

Well Proximity Category	Well to Well Separation Criteria as Defined by Proximity Rates	Drilling Well Operational Constraints	Offset Well Operational Constraints
Category 1: Wells are not close	**Proximity Ratio** ≥ 1.75	No special precautions necessary.	No special precautions necessary.
Category 2: Wells are close	1.75 > **Proximity Ratio** ≥ 1.5	Use most accurate surveying methods, including use of independent confirmation checks. Survey as required to prevent unacceptable deviation from the well plan.	Each producing offset well must be shut-in and lift gas bled down from its casing x tubing annulus. No special precautions for well injectors.
Category 3: Wells are very close	1.0 < **Proximity Ratio** < 1.5	Use most accurate survey methods, surveying to allow maximum 30% decline in separation distance per survey interval. Observers, with earphones, must be paced at offsetting well(s) to detect well-to-well contact. Provide additional Directional supervision on the rig.	Each producing object well must be shut-in and lift gas bled down from its annulus. A Wireline plug must be set in the tailpipe to isolate the formation. Water injectors must be shut-in and plugged as above.
Category 4: Wells are within uncertainty limits	**Proximity Ratio** ≤ 1.0	Drilling can only continue with Drilling Manager's approval. If approval is given, survey and monitor as in category 3 above. In addition, log well with ultra-long spaced electrode log or magnetic proximity device to determine distance to object well. Maximum course length between logging runs to set such that well-to-well separation distance does not decrease more than 50% over the drilled course.	Object well(s) shut-in as described in category 3.

From Burton 1991, SPE 22546, (reproduced with permission, re-typed for readability)

As shown in Table 44, an effective anti-collision analysis relies on several factors including having a complete and accurate database of all wells (including sidetracks and bypasses) in the area of review. On land, there are many undocumented wells that create potential risks to directional drilling. Many of these wells were drilled before comprehensive regulations for well spacing and permitting were in place. While undocumented wells are less of a problem for offshore areas, incomplete databases due to data loss can be a significant issue, especially in fields where the operator has changed several times over the life of the field. Industry sources familiar with this issue have noted that in some cases up to 60 percent of wells in offshore fields have incomplete or no data suitable for use in collision avoidance analysis. When well data are incomplete a conservative risk factor is often used to calculate the positional uncertainty, which can lead to inefficient production of the resource.

Table 44: Considerations for a Valid Anti-Collision Analysis

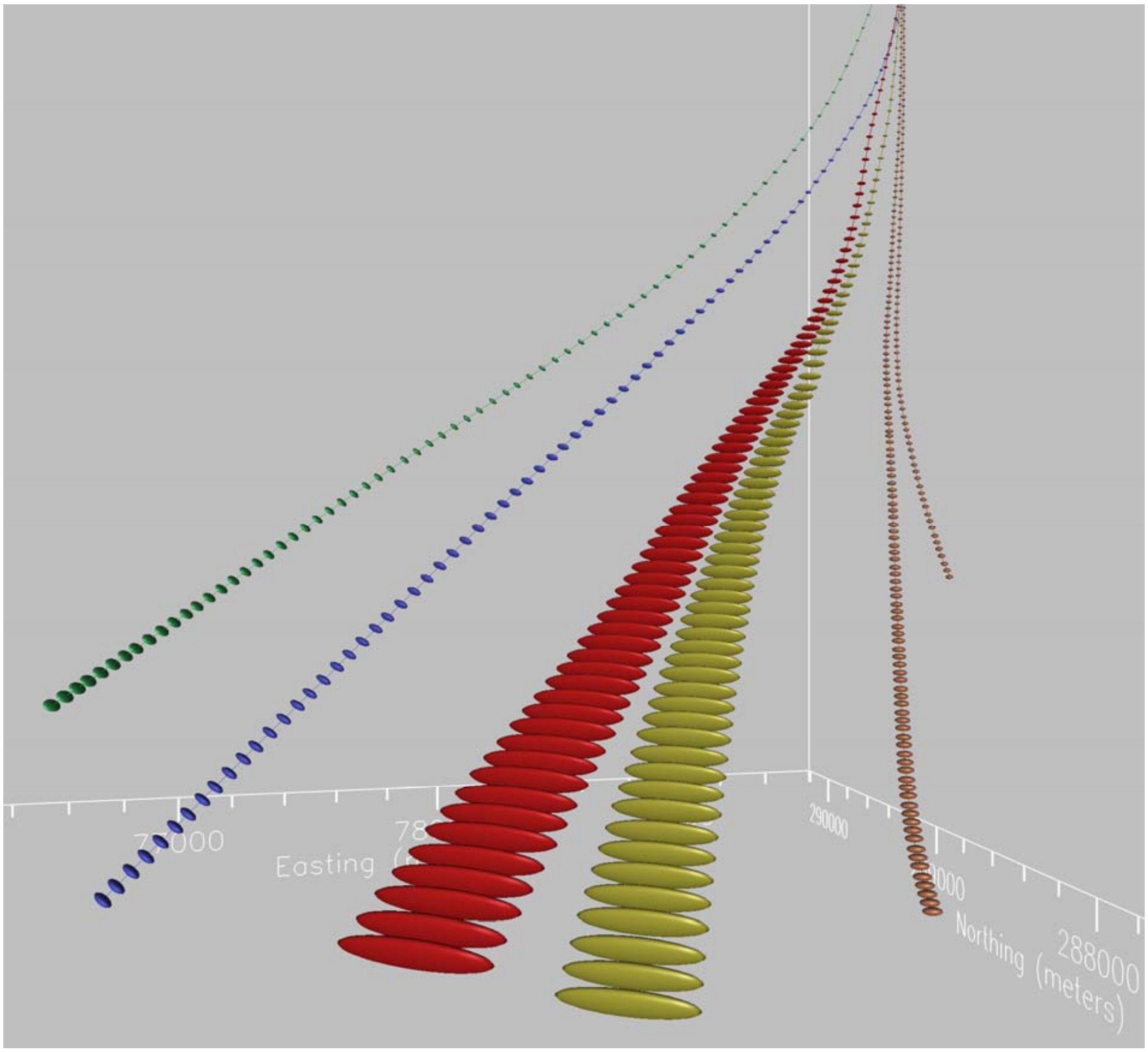
Consideration	Information Required
Completeness of the well database	What assurance is there that the well database is complete and includes all potential collision risks? How does the collision avoidance policy address the risk of "ghost wells" or incomplete data?
Accurate representation of the positional uncertainty of adjacent wells	Do the locations of the adjacent wells accurately depict the uncertainty around each wellbore, taking into consideration the survey tools run, and the error models and corrections applied to the surveys? How does the collision avoidance policy and subsequent risk assessment address the uncertainty of known adjacent well locations? Is there survey redundancy to limit the presence of unobserved gross error?
Separation Distance Rules (for geometric method)	What mathematical rules are used to calculate the separation distance? How was the separation distance factor selected? Are there separate anti-collision rules for surface versus deep portions of the wellbore?
Completeness of scan	What method was used to search for adjacent wells – horizontal plane, normal plane, or 3-dimensional least distance, or closest distance (not necessarily at survey points)? Do survey frequencies allow for the closest point to be identified in high angle dogleg sections?

The accuracy of the ellipses of uncertainty for both the planned well and the adjacent wells, and the method of calculating and applying the minimum acceptable separation distance (MASD) between wells, also affect the effectiveness of the collision avoidance analysis. The calculation of error[5] and ellipses of uncertainty is discussed in Section 3.3. An overview of methods for MASD calculations is presented below. For a more thorough discussion of the topics the reader is referred to the ISCWSA documents *Current Common Practice in Collision Avoidance Calculations* (ISCWSA, 2013), *The Fundamentals of Successful Well Collision Avoidance Management* (ISCWSA, 2014) and *Introduction to Wellbore Surveying* (ISCWSA 2012). Uncertainty in survey measurements, described in Section 3.4, stems from the effect of the environment on the measurement sensors, and to a lesser extent the accuracy and precision of the

[5] The use of the term "error" in this context refers to the mathematical difference between the actual value and the measured value, and does not necessarily represent a mistake. Error values in wellbore survey work are derived through rigorous mathematical models and statistical analysis. Tool error models are discussed in Section 3.4.

sensors. The magnitude of the uncertainty of measurements can be calculated mathematically and used to generate an estimate of the error in the wellbore position. Uncertainty estimates (error models) are specific to the survey tool and BHA configuration used so the well planner must consider the type of survey tools and BHA to be used on the proposed well, and select the proper error model to accurately calculate the uncertainty in wellbore position. The well planner must consider the tools and BHA used on adjacent wells also in order to generate an accurate representation of the uncertainty of their wellbore position. Figure 8 shows the ellipses of uncertainty around a planned well and an adjacent well.

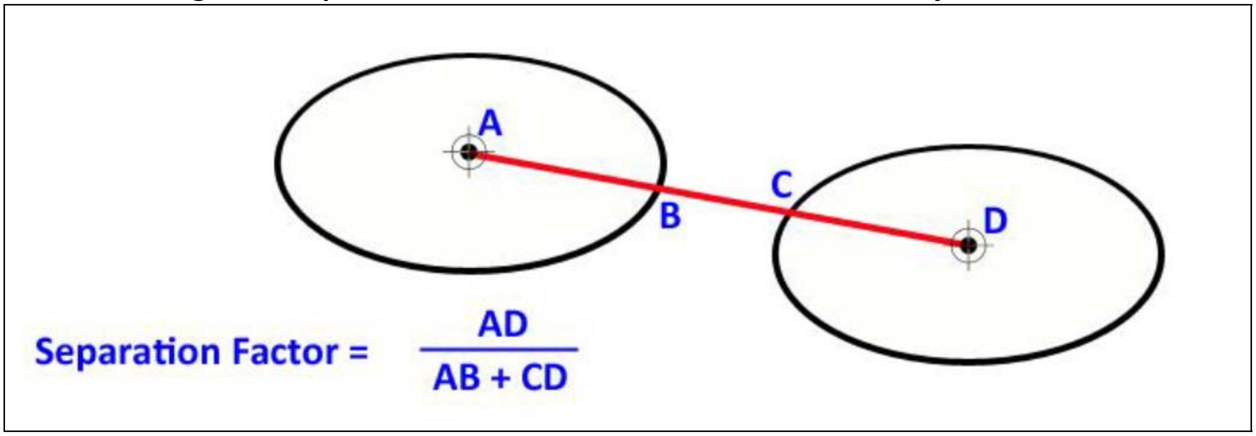
Figure 8: Ellipsoids of Uncertainty around Planned Well and Adjacent Well



Ellipses of Uncertainty example courtesy of Dynamic Graphics Inc., reproduced with permission.

The major axis radius of the ellipse and the distance between the outside edges of the ellipses is used to calculate a separation factor (SF) from the calculated values shown in Figure 8. Separation factor is the ratio of the planned or surveyed center to center distance of the wells divided by the uncertainty of their actual locations (major axis of ellipse of uncertainty) as shown on Figure 9.

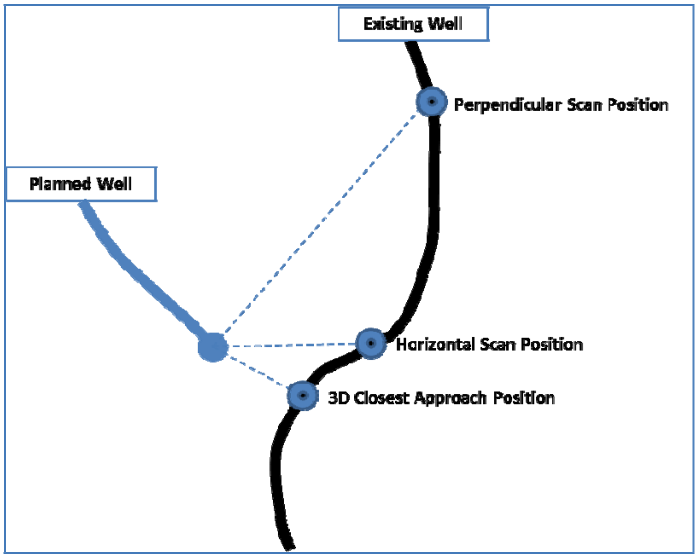
Figure 9: Separation Factor between Planned Well and Adjacent Well



From: Introduction to Wellbore Surveying (ISCWSA 2012)

Collision avoidance software may allow for other methods for calculating separation factors that account for various geometries and mathematical relationships (pedal curve method, scalar expansion method, etc.). The reader is referred to *Introduction to Wellbore Surveying* (ISCWSA 2012) for more information on these methods. The most conservative method, recommended by ISCWSA, is the 3-dimensional closest approach which scans for wells in three dimensions around the proposed wellbore to identify the minimum distance to the closest well (Figure 10). Older software may scan only perpendicular or horizontal to the wellbore which may lead to missed collision risk. Once the acceptable separation factors are determined the MASD rule is applied and the entire wellbore is scanned for potential collision risk.

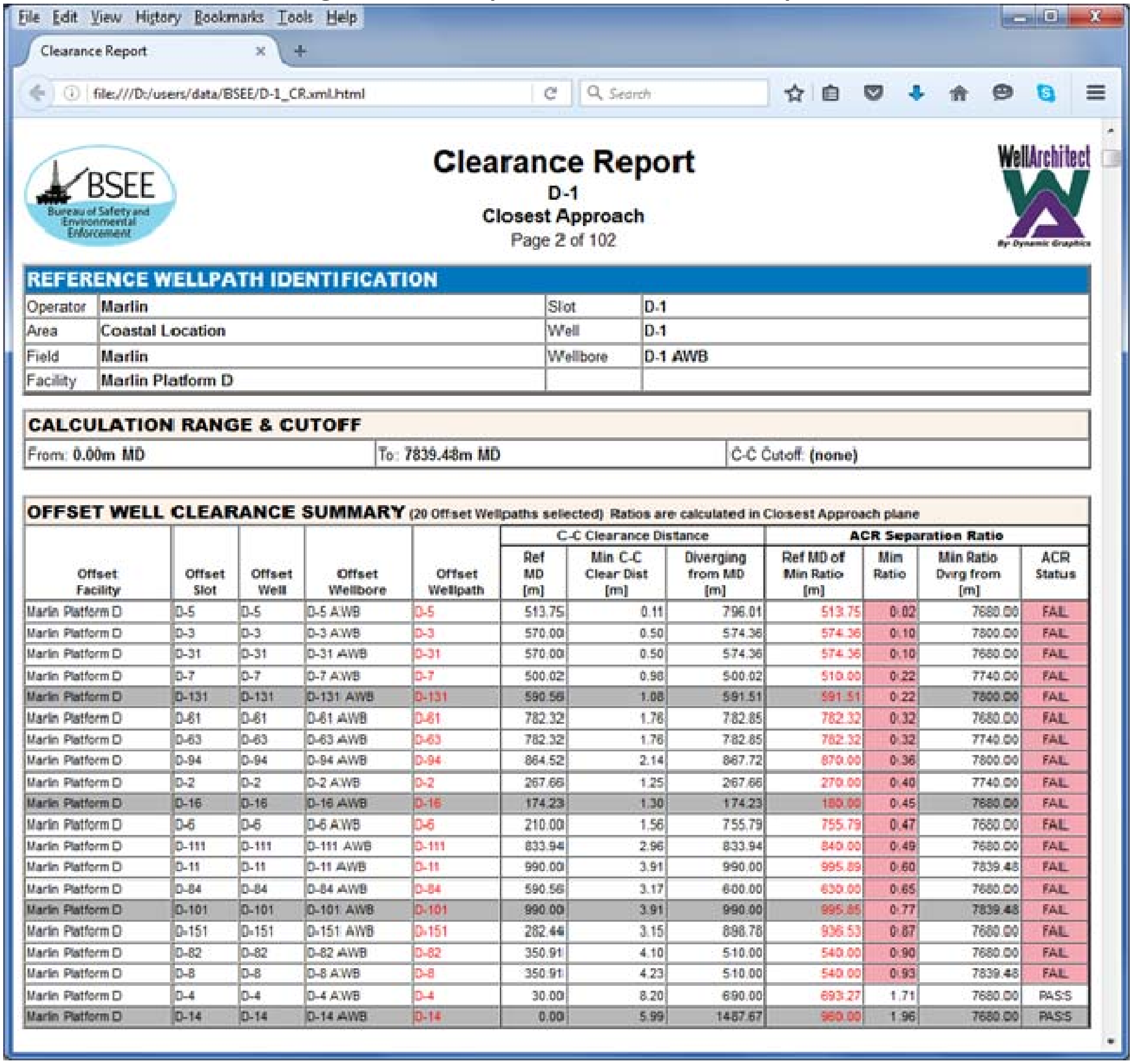
Figure 10: Anti-collision Scanning Methods



Modified from: Introduction to Wellbore Surveying (ISCWSA 2012)

An example of the anti-collision scan report is shown in Figure 11. If the planned trajectory violates the planning rules and separation factors are outside acceptable risk limits (see Table 45) the well trajectory may need to be revised. Most software performs clearance scans at predefined intervals along the well path, usually based on the survey points in the offset well or at a regular depth interval (typically 100 feet) for planned wells. Some software will insert additional interpolated survey point stations where it can identify intermediate closest points between successive scanned stations. Software used for anti-collision scanning should be auditable against appropriate safety critical software standards and outputs produced should contain references for safety critical calculations (ISCWSA, 2014).

Figure 11: Example Anti Collison Scan Report



File Edit View History Bookmarks Tools Help

Clearance Report

file:///D:/users/data/BSEE/D-1_CR.xml.html

BSEE Bureau of Safety and Environmental Enforcement

Clearance Report

D-1

Closest Approach

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WellArchitect By Dynamic Graphics

REFERENCE WELLPATH IDENTIFICATION

Operator	Marlin	Slot	D-1
Area	Coastal Location	Well	D-1
Field	Marlin	Wellbore	D-1 AWB
Facility	Marlin Platform D		

CALCULATION RANGE & CUTOFF

From: 0.00m MD	To: 7839.48m MD	C-C Cutoff: (none)

OFFSET WELL CLEARANCE SUMMARY (20 Offset Wellpaths selected) Ratios are calculated in Closest Approach plane

					C-C Clearance Distance			ACR Separation Ratio			
Offset Facility	Offset Slot	Offset Well	Offset Wellbore	Offset Wellpath	Ref MD [m]	Min C-C Clear Dist [m]	Diverging from MD [m]	Ref MD of Min Ratio [m]	Min Ratio	Min Ratio Dvrg from [m]	ACR Status
Marlin Platform D	D-5	D-5	D-5 AWB	D-5	513.75	0.11	796.01	513.75	0.02	7680.00	FAIL
Marlin Platform D	D-3	D-3	D-3 AWB	D-3	570.00	0.50	574.36	574.36	0.10	7800.00	FAIL
Marlin Platform D	D-31	D-31	D-31 AWB	D-31	570.00	0.50	574.36	574.36	0.10	7680.00	FAIL
Marlin Platform D	D-7	D-7	D-7 AWB	D-7	500.02	0.98	500.02	510.00	0.22	7740.00	FAIL
Marlin Platform D	D-131	D-131	D-131 AWB	D-131	590.56	1.08	591.51	591.51	0.22	7800.00	FAIL
Marlin Platform D	D-61	D-61	D-61 AWB	D-61	782.32	1.76	782.85	782.32	0.32	7680.00	FAIL
Marlin Platform D	D-63	D-63	D-63 AWB	D-63	782.32	1.76	782.85	782.32	0.32	7740.00	FAIL
Marlin Platform D	D-94	D-94	D-94 AWB	D-94	864.52	2.14	867.72	870.00	0.36	7800.00	FAIL
Marlin Platform D	D-2	D-2	D-2 AWB	D-2	267.66	1.25	267.66	270.00	0.40	7740.00	FAIL
Marlin Platform D	D-16	D-16	D-16 AWB	D-16	174.23	1.30	174.23	180.00	0.45	7680.00	FAIL
Marlin Platform D	D-6	D-6	D-6 AWB	D-6	210.00	1.56	755.79	755.79	0.47	7680.00	FAIL
Marlin Platform D	D-111	D-111	D-111 AWB	D-111	833.94	2.96	833.94	840.00	0.49	7680.00	FAIL
Marlin Platform D	D-11	D-11	D-11 AWB	D-11	990.00	3.91	990.00	995.89	0.60	7839.48	FAIL
Marlin Platform D	D-84	D-84	D-84 AWB	D-84	590.56	3.17	600.00	630.00	0.65	7680.00	FAIL
Marlin Platform D	D-101	D-101	D-101 AWB	D-101	990.00	3.91	990.00	995.85	0.77	7839.48	FAIL
Marlin Platform D	D-151	D-151	D-151 AWB	D-151	282.44	3.15	898.78	936.53	0.87	7680.00	FAIL
Marlin Platform D	D-82	D-82	D-82 AWB	D-82	350.91	4.10	510.00	540.00	0.90	7680.00	FAIL
Marlin Platform D	D-8	D-8	D-8 AWB	D-8	350.91	4.23	510.00	540.00	0.93	7839.48	FAIL
Marlin Platform D	D-4	D-4	D-4 AWB	D-4	30.00	8.20	690.00	693.27	1.71	7680.00	PASS
Marlin Platform D	D-14	D-14	D-14 AWB	D-14	0.00	5.99	1487.67	960.00	1.96	7680.00	PASS

Anti-collision scan output example courtesy of Dynamic Graphics Inc., reproduced with permission.

Results of the clearance scan are classified by risk level to prioritize sections of the well trajectory that have higher risk of intersection. The classification of risk is often a function of the separation factor ratio with lower separation ratios representing higher risk of collision. For example, a company may identify the following action levels for well planning.

Table 45: Example Action Levels for Anti-collision Well Planning

Separation Factor Ratio (SF) or Center to Center (C-C) Distance	Rule	Action
SF greater than 5, or C-C <100 feet	Include in Collision Scan	Routine directional drilling survey and monitoring.
Between 1.5 and 5	Acceptable for well planning purposes	Continuously monitor separation factor form both onshore and offshore locations. Review action plans for SF < 1.5.
SF between 1 and 1.5	Not permitted during planning phase, but may be present during operations.	Corrective actions required during drilling to change direction or improve survey accuracy. Shut in offset wellbores to reduce HSE risk.
SF less than 1	Not permitted during planning phase, but may be present during operations. Only acceptable when planning relief or intended intercept wells.	Stop drilling. Take corrective actions to immediately increase SF, including plug back to safe point, improve survey accuracy.

An assumption of the collision avoidance scan is that the error models are appropriately applied and accurately depict the uncertainty around the wellbore. If directional survey tools are run outside of their operating range readings may be unstable and not reflect the true conditions. Results of error models are considered valid only if the survey is run in accordance with all calibration and operating requirements. If tools are run in high temperature environments outside the calibration and operating ranges the tool error model and associated uncertainty is invalid.

Recently, some operators and service companies have applied a probability and risk assessment approach to collision analysis. In this approach a probability density function along the line normal to the two well paths is derived from survey data that describes the combined survey uncertainties between the wells. The survey uncertainties are based on the error model tool codes. Adjacent wells are classified according to risk by evaluating the probability of collision and the consequence of the resultant collision (risk = likelihood x consequence). Risk based probability analyses has been proposed in cases with poor offset survey data or close approach issues within allowed clearance factors. The ISCWSA *Current Common Practice in Collision Avoidance Calculations* (ISCWSA, 2013) describes the use of probability of collision approach.

Operators have identified a higher level of risk (likelihood and consequences) for near surface well intersections due to the proximity of drilling slots, and consequences of near surface release of gas and oil. To account for the higher risk scenario a different set of collision avoidance rules are often prepared for the surface casing section of the hole.

3.1.4. Relief and Intercept Well Planning

Relief wells and intercept wells have unique planning requirements because they are designed to purposely intersect a target well at a specific depth. Additionally, the well trajectory details are generally developed and revised in near real-time to address time critical activities. Basic elements of the survey tools used for relief and intercept well surveys were presented in Section 2.3 Ranging Tools.

Because of the publicity that usually surrounds relief wells, they are certainly the most widely known. And because the target well is typically out-of-control, the formation and pressure environment around the planned location of the interception are critical. Most often, the interception is made by milling into the casing of the target well, some distance above the last coupling. However, many more intercepting wells are drilled for the purpose of plugging a well before it is abandoned (so-called "P&A" projects) or for re-entering previously drilled wells ("re-entries"). Under these circumstances, the location of the interception is usually less critical, and perforating guns may be used to establish communication between the two wells. Ranging systems also are used to guide sidetracks around boreholes that have become plugged with a broken tool or a twisted off BHA. In such circumstances, guiding the active well around the obstacle so that drilling can be continued in the formation below requires less accuracy than most interceptions. So the starting point in any discussion of accuracy should be the purpose of the intercepting well or sidetrack, and the type "completion" the situation requires.

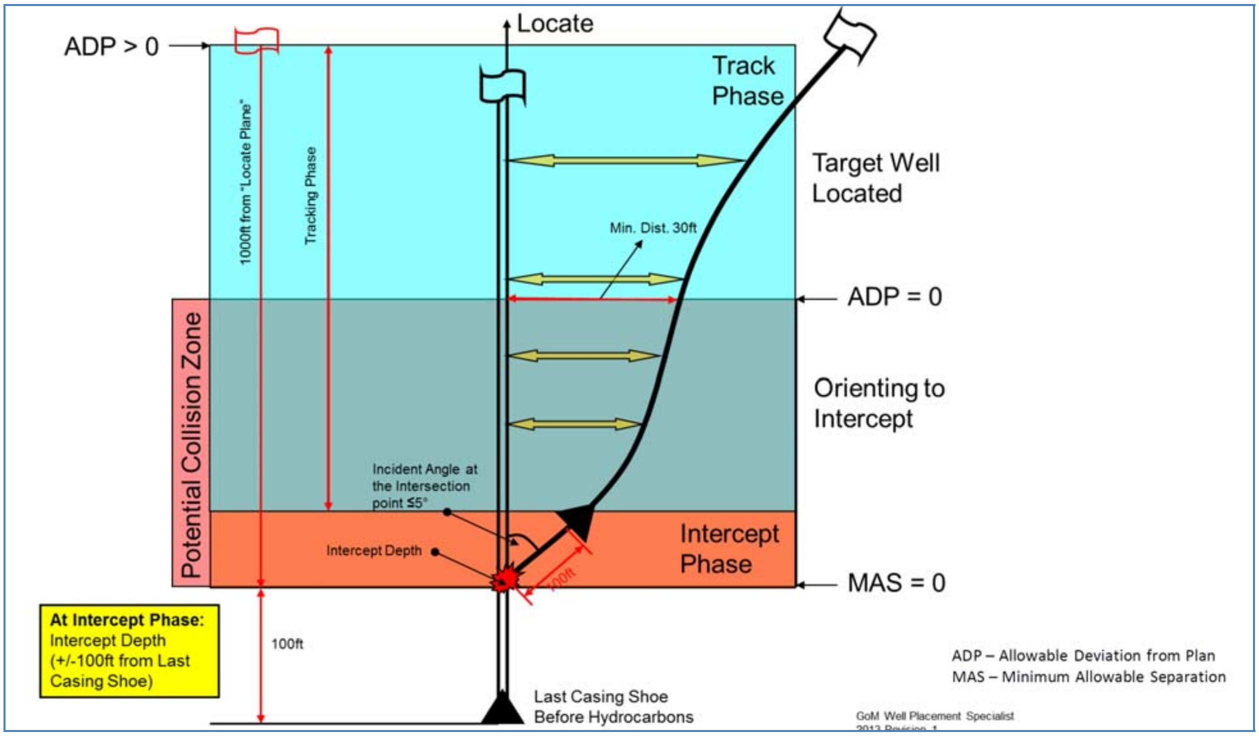
The ranging strategy for a relief well is only one of several elements of a relief-well plan. Other important elements are:

- Relief well objectives and constraints;
- Casing plan, including geology, pressures, etc.
- Directional plan, including trajectory, attack angle, survey program & uncertainty;
- Kill plan, including kill point, intersection & communication strategy, hydraulics; and
- Required services, equipment, and materials

The general sequence of activity for both relief and intercept wells includes five stages, each employing some aspect of ranging strategy (Goobie, 2015). Figure 12 illustrates the details of the conceptual design for the track and intercept phases.

- **Data Gathering** – Collecting known information on the wells and subsurface conditions to identify the best approach for intercept. In this stage the accuracy of the well path (ellipses of uncertainty) are reviewed and refined if possible. Precise definition of the position of both wells improves the level of confidence in locating, tracking and intercepting the blow out well (Goobie, 2015).
- **Drilling** – Accurately drill along proposed well path at a distance from the surface to a point at which the target well can be located using ranging techniques. Use MWD or gyro survey to accurately determine positon of well at all times.
- **Locate** – Establish the presence of the target well using ranging technology and continue drilling alongside the target well.
- **Track** – Continue drilling while maintaining a known and safe distance from the target well using sensitive ranging technology. Decrease distance to target well and maintain an appropriate angle for intercept.
- **Intercept** – Make physical connection and communication with the target well, or its immediate environment (cement).

Figure 12: Conceptual Design of the Track and Intercept Phases of a Relief Well

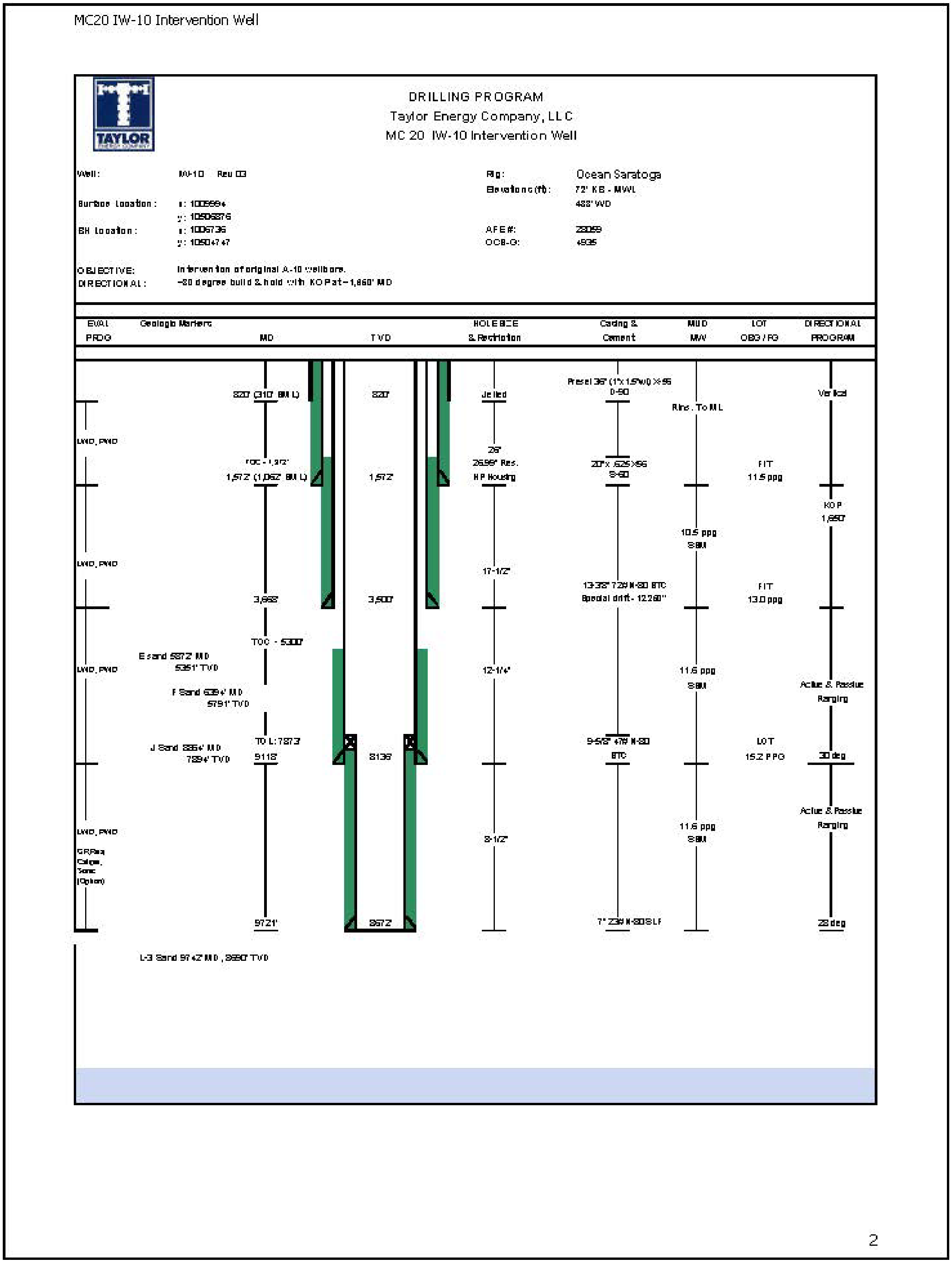


From Goobie, 2015 SPE/IADC-173097-MS, reproduced with permission

The maximum ranging distance of the tools selected for use is an important consideration for relief well planning. This is normally a situation-specific decision that is affected by many environmental and drilling factors, and is likely to change as the relief or intercept target is approached. See Section 2.3.1 for more detailed information on the factors affecting passive systems range of detection. Generally active ranging tools are effective at distances of 100-150 feet from the target, and passive ranging tools are effective when the target is less than 40 feet.

When a relief well plan is required as part of the permitting process the plans are often general and provide minimal information on the selection of wellbore survey tools. Figure 13Figure 13 is an example of an approved relief well plan for a well in the Gulf of Mexico that shows the very general description of survey tools (active or passive). Once well conditions are known the plan is revised and approved in near-real time to provide specific tool types and depths of use. This is normally performed in a collaborative setting with operators, drillers, service companies and regulatory agencies.

Figure 13: Example of a Relief Well Plan for a Well in the Gulf of Mexico



Well Plan provided by BSEE.

3.2. Survey Operations

Real-time wellbore position data are collected during drilling and used to avoid intersecting adjacent wellbores and to accurately reach the geologic target. These measurements also form the basis of the permanent well trajectory record that will be submitted to the regulatory agency and used by others to ensure safety in subsequent operations.

This section describes the common operational practices and considerations used during execution of the wellbore survey program under normal operations and in ranging operations. The focus of the discussion is those aspects of wellbore survey that affect safety and data quality. The descriptions are general and may not reflect all activities conducted by a particular service company.

3.2.1. Surveying Under Normal Operating Operations

The execution of the well survey plan is conducted as part of the normal directional drilling process. Before drilling begins the directional drilling company and survey company conduct pre-spud meetings to review all plans and contingencies, then mobilize the drilling and survey tools to the offshore rig or platform.

Essentially all offshore directional drilling in the U.S. is performed using MWD tools as the primary source of well survey and position data. MWD tools transmit azimuth and inclination position data uphole as the well is being drilled. In some cases gyro tools or other surveys may be run during or after a drilling run to provide QC or tie-in data from previous surveys.

3.2.1.1. Pre-survey Operations

Prior to placing a tool in service downhole the tool is checked for operational functionality. Although this step is often referred to as “calibration” this step is actually a calibration check because the tools are not adjusted to change the sensor outputs[6]. Service companies have developed Field Acceptance Criteria (FAC) for tool checks to ensure tools are functioning within an expected range. Examples of tool checks conducted at the rig, and the associated FAC may include the following components. Note that the FAC presented is a general reference and operators or survey companies may use different values.

- Measuring total gravitational field and comparing to the known gravitational field at the location to test inclination sensors. Field Acceptance Criteria example: tool reading is within 2.5 milligals (mG) of reference value.
- Rotation and inclination of the tool in a test stand to verify all sensors are functional, and to test rotational bias of tool sensors. Field Acceptance criteria example: tool readings in all orientations are within 3 degrees.
- Measuring the Earth's magnetic field strength, and dip angle and comparing the results against known local values to test magnetic sensors. Field Acceptance Criteria example: tool

[6] Calibration, as used in this document, refers to procedures at the manufacturing facility and shop to test tool performance under controlled simulated field conditions, and make adjustments to the outputs so that tools meet specified performance and measurement standards.

reading is within 300 nano Teslas (nT) of total magnetic field reference value and 0.45 degrees of reference magnetic dip angle.

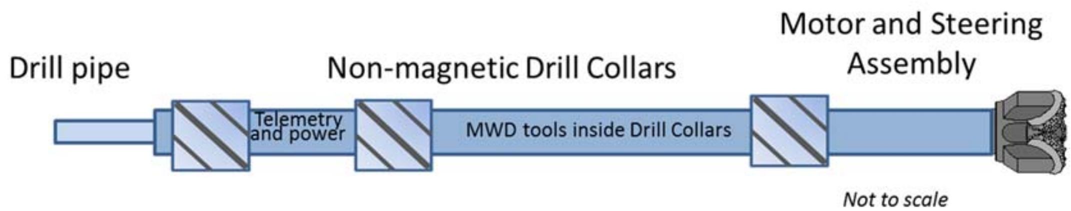
- Inspecting non-magnetic drill collars and drilling tools for magnetic hotspots.

Other checks are made to ensure the reference points the tool will use are accurate and minimize the risk of gross error. These include:

- **Well tie-on location.** For surveys that are run over a deeper interval than the previous survey and not run to surface, a tie-on point is defined.
- **Surface hole location.** The latitude and longitude, or UTM coordinate of surface hole location is verified, and the accuracy of that location (and reference points) are documented. The surface hole location is important for absolute positioning, and is critical to the survey quality assurance program for comparing to local magnetic field strength and earth rotation.
- **The magnetic declination** (the angle between True North and Magnetic North as measured from True). The date and time when the declination was determined (magnetic north varies over time) is recorded and the sign of the declination measurement is checked (easterly declination (clockwise) is positive and westerly declination (anticlockwise) is negative).
- **Map reference and grid convergence** (the angle between True North and Grid North as measured from True North). The map projection is identified (Lambert, Universal Transverse Mercator) and the convergence value checked to ensure is applied accurately (easterly convergence (clockwise) is positive and westerly convergence (anticlockwise) is negative). The datum to be used (NAD27, NAD84) is also verified.
- **Toolface offset.** The angle (in the X-Y plane) needed to align the MWD tool with the toolface of the BHA.
- **Elevation reference** and other relevant data are collected and verified. Elevation reference is particularly important on deep water wells drilled from a drill ship or rig which is removed before production. Depths need to be referenced to permanent datum such as MSL or the mud line. The distances from the drilling/survey reference (Kelly Bushing or drill floor, etc.) to the water (MSL) and the water depth are needed for future reference.

MWD tools are placed in non-magnetic drill collars of sufficient length to allow the measurement of the earth's magnetic field without magnetic interference. Non-magnetic drill collars were developed to allow magnetic surveying of the well trajectory, and were originally made of Monel (a nickel-copper alloy with high tensile strength and resistance to corrosion) but, due to cost have been replaced by stainless steel. Figure 14 shows the placement of the MWD and non-magnetic drill collars in the BHA. Directional survey tools are often located more than 30 feet above the drill bit to allow for drill motors and other steering assemblies, and to avoid magnetic interference from the lower BHA. When making up the BHA the MWD tool must be aligned and oriented properly with the other BHA components to ensure it accurately reflects the orientation of the bit face. Misalignment of MWD tools can be a source of error in directional measurements.

Figure 14: Bottom Hole Assembly showing location of MWD Tools



3.2.2. MWD Survey Frequency

During drilling, the MWD tools transmit measurements at predefined intervals or times, usually every stand (three drill pipe sections, or 90 to 96 feet), or at some other intervals depending on the project and regulatory requirements. In some sections of relatively vertical holes, directional measurements are taken at less frequent intervals, for example every 300 to 500 feet; and at some critical points, such as high build angles (doglegs), data are collected every pipe joint (30 feet). The ISCWSA error model documentation recommends that the survey interval be no greater than 100 feet (30 m) (ISCWSA, 2012). Industry studies suggest that collecting measurements every 60 feet in high dogleg sections reduces depth error significantly. Well survey plans must balance the need for directional data, and the additional rig time required for taking readings with some tools. Battery powered survey systems take surveys when the pumps turn off then transmit when the pumps come back on, and no additional rig time used.

In most deep-water offshore locations, MWD tools are used in upper sections because their inclination readings are useful for determining if the well should be “nudged” to retain separation from nearby wells and the readings of the magnetic field magnitude and dip angle can be used to determine when magnetic measurements can be relied on (when the readings are no longer affected by interference from nearby wells and equipment). If there’s any doubt or reason for concern, a wireline or drop gyro tool can be run inside the drill pipe.

The initiation of a stationary MWD survey reading is triggered by the temporary shut off of mud pumps. Once the pumps have been off for a period of time the tool acquires the readings and performs simple quality check of the readings. If readings are within specifications the data are stored and transmitted uphole. If sensor readings are not within specified criteria another measurement is made. After the measurement is collected it is transmitted to the surface and drilling resumes.

The frequency of MWD survey stations (survey measurement points) can affect the quality of the directional survey data when widely spaced survey points are collected and used to calculate curvature between survey points. Widely spaced data may result in a wellbore trajectory that is significantly different from the actual trajectory between points. When a bent-housing mud motor (or bent sub) is used the bit changes trajectory during slide mode, then resumes drilling straight ahead when rotating. This often creates a sinuous pattern in the wellbore and can degrade the definition of the well path. Likewise for rotary steerable systems, widely spaced directional measurements may not accurately reflect the wellbore trajectory where rapid changes in direction occur. Because positional errors are propagated downhole the uncertainty of bottom hole location can be significantly affected by MWD survey frequency.

MWD tools can also be run in a continuous mode, however not all service companies offer this alternative. In the continuous mode measurements are made in the same manner as in the stationary survey mode but are taken at specified time intervals during drilling and periodically transmitted uphole. In order to acquire reliable continuous survey measurements the tool must compensate or correct for the effects of shock, vibration and drill string rotation.

3.2.2.1. MWD Survey Analysis

Wellbore survey data is used during drilling to avoid obstacles (anti-collision) and steer the bit along the planned well trajectory. Once received uphole, data are stored, corrected if necessary, and analyzed to determine the current location of the drill bit. In offshore operations wellbore positioning data analysis and corrections are performed using directional drilling software, typically the same program used for well planning (refer to Section 3.1.2 for a discussion of well planning software). For many operators concurrent data analysis is performed onshore or at remote locations for quality assurance and safety management.

Directional survey measurement data is often corrected for environmental effects prior to use in steering and anti-collision analysis. Most commonly readings are corrected for BHA sag, and many are further corrected for variations in the local magnetic field, and pipe or wireline stretch. Sag and local magnetic field corrections are often the largest source of error in survey readings. These corrections are described in greater detail in Section 3.4. Uncorrected survey data results in larger uncertainties in the position of the wellbore.

During drilling quality control procedures are conducted to ensure the tools are operating properly and measurements accurately represent the wellbore position. These quality control checks sometimes require re-occupying a previous survey station or collecting repeat readings at new stations, and are described in greater detail in Section 3.5. Survey data are often sent simultaneously to the rig and an on-shore facility for quality control and decision analysis support.

After corrections are made with the software, directional survey data are reported in a table format and reviewed by the driller for steering and anti-collision analysis (Figure 15). The driller analyzes the positional data to determine if any changes need to be made to correct or maintain the trajectory. Most directional drilling programs provide an estimate of the amount of deviation between the plan and actual position, and an estimate of the uncertainty in position, expressed in feet, as well as a plot showing the planned and actual trajectories, similar to the one shown in Figure 15. As part of the analysis the driller may consider the magnitude of the deviation from plan, and the ability of the existing BHA to correct the deviation. Drilling programs can also provide a “look ahead” calculation to extrapolate the bit location at the next survey point.

Figure 15: Example of Directional Survey Data Report

(Def Survey)

Report Date:	November 05, 2015 - 01:42 PM	**Survey / DLS Computation:**	Minimum Curvature / Lubinski
Client:	BP	**Vertical Section Azimuth:**	64.610 ° (Grid North)
Field:	Fall ATW Training Field	**Vertical Section Origin:**	3.361 m, 3.551 m
Structure / Slot:	A Structure / 9	**TVD Reference Datum:**	Rotary Table
Well:	A9 Well	**TVD Reference Elevation:**	68.300 m above MSL
Borehole:	A9 OH	**Seabed / Ground Elevation:**	100.000 m below MSL
UWI / API#:	Unknown / Unknown	**Magnetic Declination:**	-0.480 °
Survey Name:	A9 Keeper + MWD ft	**Total Gravity Field Strength:**	1000.9965mgn (9.80665 Based)
Survey Date:	April 10, 2012	**Gravity Model:**	DOX
Tort / AHD / DDI / ERD Ratio:	91.965 ° / 1493.290 m / 5.715 / 0.527	**Total Magnetic Field Strength:**	49951.532 nT
Coordinate Reference System:	UTM Zone 31N - WGS84, Meters	**Magnetic Dip Angle:**	70.120 °
Location Lat / Long:	N 56° 10' 40.52341", E 3° 27' 36.36214"	**Declination Date:**	April 10, 2012
Location Grid N/E Y/X:	N 6225977.520 m, E 528563.380 m	**Magnetic Declination Model:**	BGGM 2011
CRS Grid Convergence Angle:	0.3822 °	**North Reference:**	Grid North
Grid Scale Factor:	0.99961001	**Grid Convergence Used:**	0.3822 °
Version / Patch:	2.8.572.0	**Total Corr Mag North->Grid North:**	-0.8622 °
		Local Coord Referenced To:	Structure Reference Point

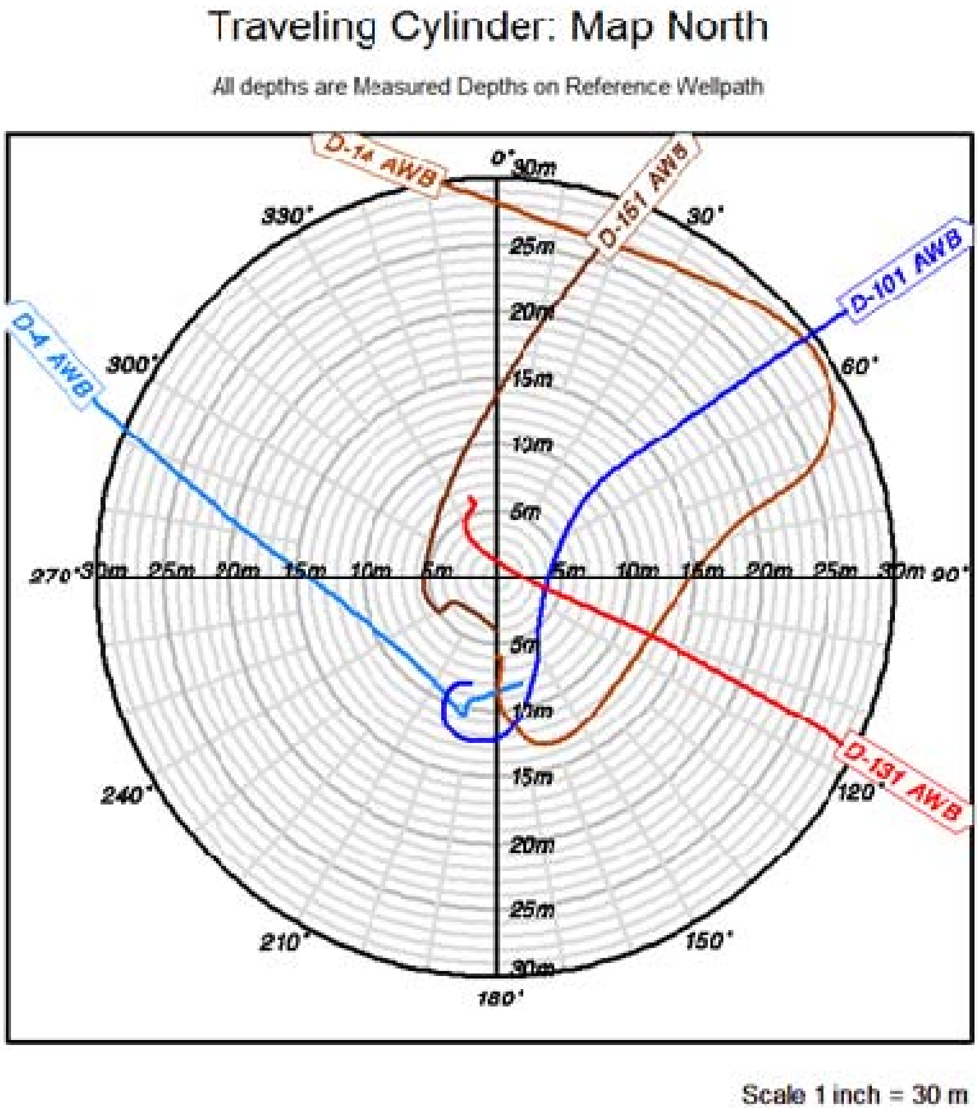
Comments	MD (m)	Incl (°)	Azim Grid (°)	TVD (m)	VSEC (m)	NS (m)	EW (m)	DLS (°/30m)	Northing (m)	Easting (m)	Latitude (N/S ° ' ")	Longitude (E/W ° ' ")
	3048.00	16.46	60.11	2629.79	1428.17	613.47	1294.85	0.52	6226587.39	529854.18	N 56 10 59.96	E 3 28 51.46
	3077.00	16.88	60.32	2657.57	1436.47	617.60	1302.07	0.44	6226591.52	529861.39	N 56 11 0.10	E 3 28 51.88
	3105.00	16.46	60.40	2684.39	1444.48	621.57	1309.05	0.45	6226595.49	529868.37	N 56 11 0.22	E 3 28 52.28
	3134.00	15.28	59.14	2712.29	1452.38	625.56	1315.90	1.27	6226599.48	529875.22	N 56 11 0.35	E 3 28 52.68
	3171.00	15.78	58.76	2747.94	1462.24	630.67	1324.39	0.41	6226604.59	529883.70	N 56 11 0.51	E 3 28 53.18
	3189.00	16.67	59.33	2765.22	1467.24	633.26	1328.70	1.51	6226607.17	529888.02	N 56 11 0.60	E 3 28 53.43
	3216.00	17.32	58.20	2791.04	1475.09	637.35	1335.45	0.81	6226611.26	529894.76	N 56 11 0.73	E 3 28 53.82
	3244.00	17.71	57.64	2817.74	1483.46	641.83	1342.59	0.46	6226615.74	529901.90	N 56 11 0.87	E 3 28 54.24
	3261.00	17.98	58.20	2833.92	1488.64	644.60	1347.01	0.56	6226618.50	529906.31	N 56 11 0.96	E 3 28 54.49
Interpolation	3194.00	16.79	59.11	2770.01	1468.68	634.00	1329.94	0.81	6226607.91	529889.25	N 56 11 0.62	E 3 28 53.50
												E 3 27 41.81

From Course Materials for SPE Well Placement and Intersection Best Practices workshop, November 2015

For anti-collision analysis, the software program provides an estimate of the wellbore position uncertainty, based on the corrections and tool error models selected in the software. If there are wells nearby the software will calculate the separation distance and separation factor. Some software programs compare separation distance to company anti-collision rules (minimum distance and acceptable separation factors) and generate a warning if rules are violated. For visualization of the anti-collision potential, the Traveling Cylinder plot is commonly used. The travelling cylinder is a radial projection showing the current location as a point at the center of a disk onto which the paths of nearby offset wells are plotted (Figure 16). It is a view looking down the wellbore along the proposed trajectory at a specific depth. A point on a travelling cylinder is specified by the radial distance from the center of the plot, and the angular direction to a point on the offset well. Traveling cylinder plots are generally referenced with north at top (twelve o'clock) position. In Figure 16, five offset wells located within 30 meters of the planned wellbore are shown along the drill path, and well D-131 is within a few feet of the current well path. Travelling cylinder presentations often present the depth of the nearby wells along their well paths.

In practice on offshore rigs, the well positon data is often plotted on a centrally located traveling cylinder plot by hand. This practice encourages communication between the survey team and the drilling team and is believed to improve the visualization and recognition of drilling obstacles.

Figure 16: Traveling Cylinder Plot

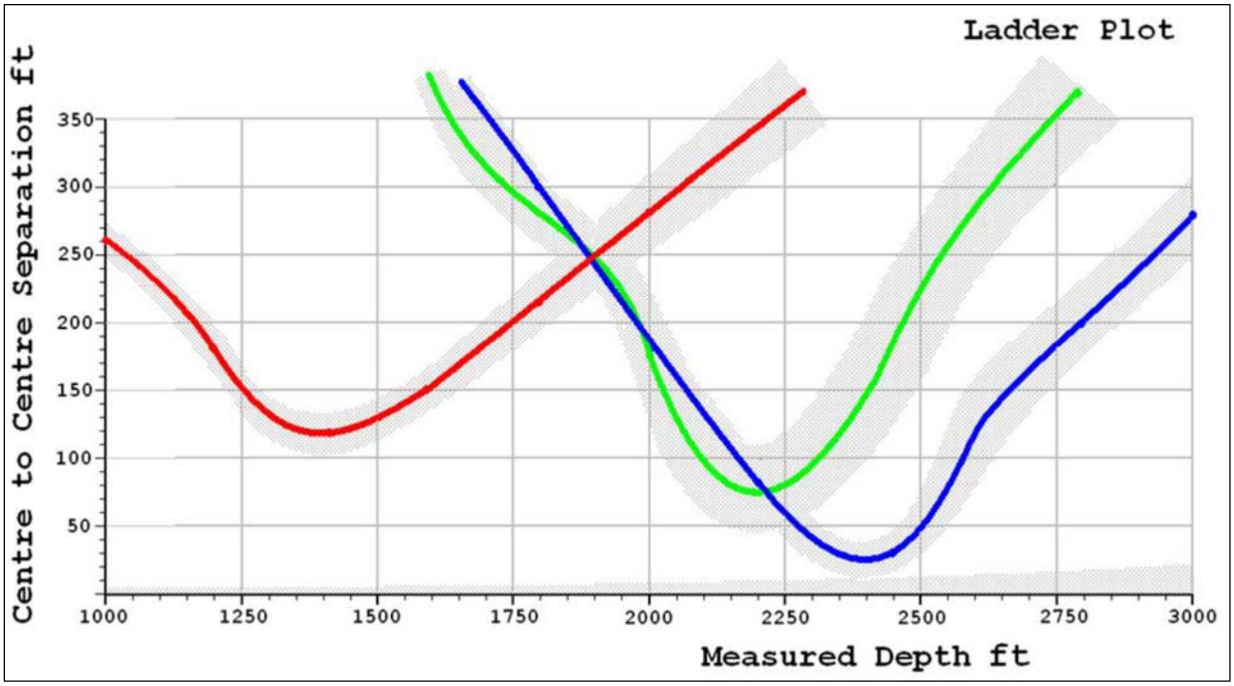


Traveling Cylinder example courtesy of Dynamic Graphics Inc., reproduced with permission.

Another common plot for anti-collision analysis is the ladder plot, showing the separation to target wells against the measured depth of the well being drilled. Ladder plots are most useful when the uncertainty of the well positions is included, as shown in Figure 17. Most directional drilling software allows for many other types of visualizations including three-dimensional renderings of all nearby well trajectories (Figure 18).

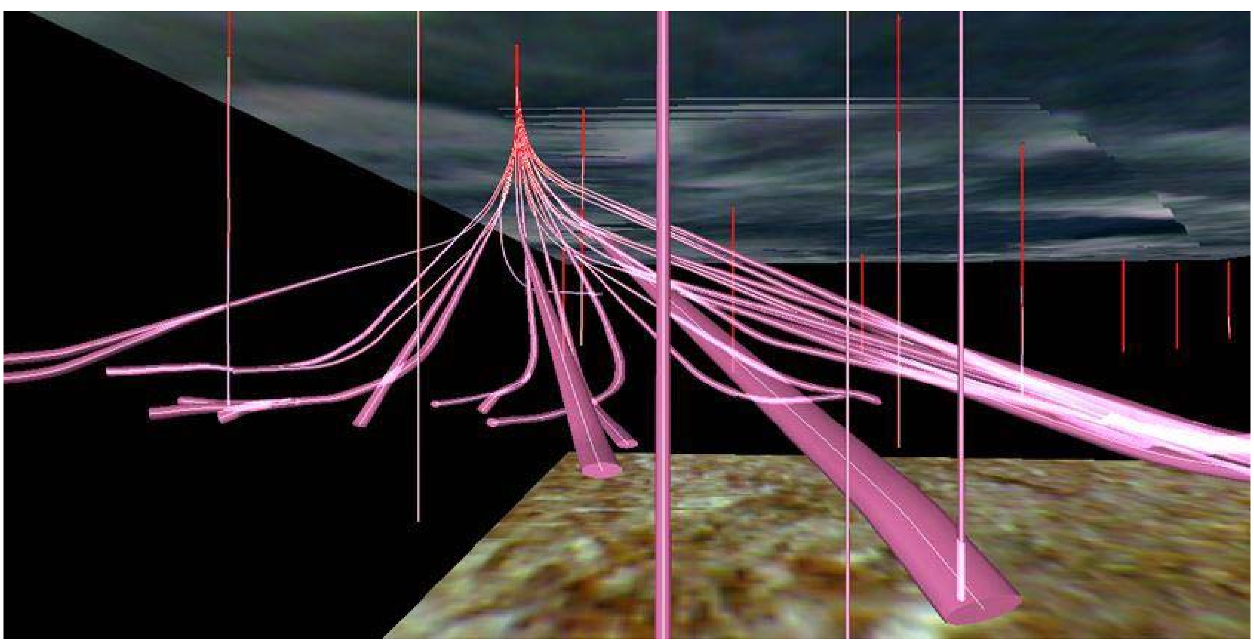
Figure 17: Ladder Plot with Uncertainty Ranges

From



From Introduction to Wellbore Surveying ISCWSA, 2012

Figure 18: Three Dimensional Spider Plot showing Multiple Wells from the Same Platform



From Introduction to Wellbore Surveying ISCWSA, 2012

3.2.2.2. Survey Concatenation

Multiple runs of the same tool combination with different BHAs are often run. Additionally, gyro surveys are sometimes run over sections that have already been surveyed with MWD tools. Concatenation is the process of integrating and stacking the surveys to create a final comprehensive survey of the wellbore. A critical aspect of the concatenation process is assigning the correct tool code to the survey section to facilitate tool error modeling. Operators and service companies have jointly developed specific requirements for combining surveys, but generally all require that each depth point has a unique and single set of survey data associated with it, and that no interpolated, projected or estimated data be included in the definitive (also referred to as the final survey). Tie in points for where two subsequent surveys are connected are required to be identified. Concatenated surveys do not include interpolated data (some operators request data to be regenerated at even depth increments, such as every 100 feet).

3.2.3. Gyro Surveys

Gyro surveys[7] can be run to provide an interim or final directional survey of the wellbore trajectory. The advantage of using a gyro survey is that it is not affected by magnetic interference and can be run in cased hole. The reader is referred to Section 2.2.4 for a discussion of the various gyro tools available. Gyro surveys are most commonly run on wireline or as drop tools, but may also be included in some newer MWD systems.

In MWD systems gyro readings are more likely to be affected by shock and vibration than magnetometers and accelerometers, so rough drilling conditions may affect the accuracy of gyro readings. Historically the industry has considered gyro surveys to provide a more reliable and accurate description of the wellbore position. While this may be true for older surveys, some industry experts believe that modern MWD tools combined with a better understanding of the error sources and corrections provide MWD data that is of comparable or better quality as gyro tools. When determining whether a magnetic or gyro-based tool should be considered more accurate in a specific situation – or which of the two types of surveys should be given more weight – the issues to be considered fall into the following four subject areas:

- The local environment, including latitude, consistency of the magnetic field, borehole temperature, and depth;
- Tool orientation, or expected range of orientations, which can influence the accuracy of both magnetic and gyro-based measurements and the need for sag corrections;
- Tool performance, meaning the expected operating life, available data types, accuracy, survey time, data quality and other housekeeping sensors, and memory capacity; and
- Data management, which includes the use of proper datums, instrument performance models (IPMs), survey frequency, data QC procedures, tie-in points, and multi-station analysis.

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[7] Unless otherwise specified the description of gyro surveys refers to the use of north seeking rate gyros, which have been the standard in the industry for many years. Occasionally legacy survey data may include free gyros used in near surface single shot applications.

Surface sections of wells are normally surveyed with gyro tools because the high magnetic interference from other wells and equipment make magnetic surveys ineffective. It is commonly assumed that surface conductor casings are driven straight and plumb, but this is not always the case. It is not uncommon for driven conductors to cross two rows of slots from their original surface position (ISCWSA 2102), therefore accurate surveys are required in conductor casings.

Gyro tools are often run as a quality check after a section of hole is drilled with MWD (see Section 3.5.2 for a discussion of quality control procedures for surveys). Other common uses for gyro surveys include:

- In sections with high dogleg severities (exceeding 6°/100ft) and MWD survey points are every stand (90 feet) or more. Gyro surveys can provide a higher resolution using very small station intervals (commonly 25 feet).
- In collision risk sections of the wellbore where the separation factor requirements cannot be met using MWD alone.
- In side-tracks where the original hole contains a fish, or casing and the accuracy requirements demand an adequate survey during the side-track section close to the original hole.
- Anywhere the survey accuracy cannot be met with MWD surveys, including lease lines, geologic hazards, fault blocks, and tight reservoir targets.

When gyro surveys are run over an interval previously surveyed by MWD, the ellipse of uncertainty for the MWD section is reduced due to the more accurate nature of gyro readings[8]. If drilling with MWD resumes below the gyro survey, the ellipse of uncertainty for the new MWD section will be smaller than if the gyro were not run. For this reason, gyro surveys are often used to decrease uncertainty in critical sections of the hole, such as when approaching the geological target. When switching between gyro and MWD surveys, a survey station where both data are collected is identified as a reference point to compare and transition the results of the surveys. This survey station is called a tie-in point (also called a tie-on point) and is a critical part of survey quality control procedures, and required to be identified in submittals to some regulatory agencies.

High temperature environments are a challenge for gyro tools, and as described in Section 2.2.4. This study identified no tools available for high temperature applications (operating at 350°F (176° C) for extended periods of time).

During drilling quality control checks are conducted to ensure the tools are operating properly and measurements accurately represent the wellbore position. The most common check is to collect gyro survey data at the same location while tripping/running in and out of the hole. These quality control checks are described in greater detail in Section 3.5.

3.2.4. Surveying for Ranging Applications

Each relief well and intercept well operation will have unique conditions that require site-specific analysis and decisions. One relief-well drilling strategy that has been found to have wide support is to

[8] This assumes that the gyro is within calibration, and is operated in accordance with all specifications and parameters that are contained in the gyro tool error model.

use an active ranging tool first, to obtain an initial range and bearing to the target before the two ellipses of uncertainty overlap (the "Locate" phase). Then drill ahead with a passive MWD-based ranging tool until it provides an acceptable range and bearing, or until the ellipses overlap (the "Track" phase). If an unintentional interception is not acceptable, additional runs of an active tool should be considered if the ellipses overlap and the passive tool has not provided an acceptable range or bearing. This sequence should normally be repeated until the range and bearing from the passive tool are acceptable, after which it can be used to guide the bit until the time comes for the interception.

Passive ranging tools have two disadvantages in interception situations. First, their magnetic sensors are typically at least 30 feet above the bit, so the actual position of the bit is based on an extrapolation. Secondly, the ability of a passive tool to accurately determine range and bearing to a casing diminishes as the range decreases. Conversely, the accuracy of an active tool increases when it is close enough to use gradient measurements. During operations the tool selection and operational conditions must be considered.

It is generally believed that an active ranging tool should be used to guide the actual interception, especially if the plan calls for milling a window in the casing of the target well. If communication between the two wells is to be established by perforating or in open hole by breaking down the formation, the accuracy requirements are less, and the use of a passive ranging tool during this phase may be acceptable. This choice should be made considering the consequences of intercepting the target well above the planned location, the consequences of drilling past the planned interception point, and the time and cost associated with running an active ranging tool.

Ranging operations may require many ranging runs to provide the level of accuracy for proximity information required to intercept a wellbore. Industry experts have noted examples where in some cases multiple ranging runs have been made after advancing the bit one joint (about 30 feet). The intercept team must balance the time required to collect additional survey measurements, which may require tripping out of the hole and adds one to two days on a deep well, against the likelihood of intercepting the well. Failure of intercept could require the hole to be plugged back to a safe depth and re-drilling a sidetrack which could take considerably longer than collecting the additional data for determining accurate bit location. In HSE wells the decision becomes critical.

3.3. Data Management

Data management occurs across the survey lifecycle and is a key component to ensuring the safe and efficient drilling of offshore wells. Because data management is integrally related to planning, operation, error and uncertainty modeling, and survey quality, certain aspects of the applications of data management are covered in other parts of this document. The purpose of this section is to take a more comprehensive view of the concepts of data management across the survey lifecycle.

In this section, two general categories of data are discussed– completed survey data reports and survey data components. A completed survey data report includes the final or definitive data on wellbore position (x, y, and z coordinates), along with header information that represent the location and survey conditions. This is generally the data set provided to regulatory agencies for the permanent record. Survey data components include all the information that are used to generate the final wellbore position including the raw data (if available), operating conditions, tool error codes used, survey corrections applied, calibration and QC data, signoffs and approvals, and any ancillary data that was used to generate the final survey.

3.3.1. Planning

The data management procedures required for wellbore planning are one of the most critical components for ensuring safety in offshore drilling. During the planning process the universe of risks that may be encountered during drilling is identified and addressed. The data set used to identify and quantify the potential risks must be thorough and accurate so that well planners and those responsible for review and approval address all potential risks. This section address data management associated with the risks related to the wellbore trajectory planning (primarily related to use of databases to conduct collision avoidance screening); however, there are many other safety considerations of overall well planning that must be considered, which are outside the scope of this study.

As described in Section 3.1.1, wellbore planners rely on a database to identify all potential wells with risk of collision. This database is developed and maintained by the operator, directional service company or third party software service that specializes in oil and gas data management. Databases for offshore fields can be very large and commonly use a sophisticated database software system such as Oracle or SQL Server. These databases are used for many activities including regulatory reporting and asset inventory, wellbore planning and future field development, collision avoidance, reservoir modeling, hydraulic fracturing analysis and P&A planning.

Data sets contained in the databases are available from a number of different sources including databases managed by the regulatory agencies (BSEE, TRC, and other state agencies), commercially available data sets from oil and gas data suppliers[9] (TGS, DrilingInfo, EGI, LEXCO, and others), and organic data sets prepared and maintained by operators (data assets of the operator and partners). Well planning is most commonly conducted using data that has been thoroughly evaluated for completeness and quality, and is part of an auditable data management system. Operators invest significant resources into developing reliable and auditable data sets that become the "definitive database" for all well and field planning. ISCWSA anti-collision best practice (ISCWSA, 2014) states that there should be only one Master Database that is free from errors and remains free from errors as new data are added over the life of the field.

Errors and incomplete data in regulatory databases are not uncommon. One industry expert contacted for this study noted that in a recent database integrity study of 10,000 wells in a regulatory database, the mean difference in the accuracy of surface location was 67 feet, with the 3-sigma standard deviation more than 200 feet. A recent presentation from a data management company estimated that 15 to 20 percent of the drilled wellbores are missing in regulatory databases (Stolle, 2013). The nature of the error can be incorrect surface locations, which displaces location of the entire wellbore, or incorrect and missing wellbore survey data which may affect all or only portions of the wellbore. Some examples of database errors include:

[9] The source of data for commercial database is often based on regulatory submissions that have been subjected to rigorous quality control procedures.

- Incorrect or missing reference information, including north reference (true, magnetic or grid), map projection, and UTM zone, which affect the surface location and the corrections made to raw survey data. The direction of magnetic north and grid correction (negative or positive) is a common source of error.
- Incorrect surface location information. When latitude and longitude are used the longitude value must include a negative sign to reflect west of prime meridian. Relative reference locations to slots on drilling platform are often incorrect, and some platforms have been incorrectly surveyed or readings rotated 180 degrees. Depth references and datum are not standardized within a field or incorrectly applied (MSL, KB, and mudline).
- Units of measure. Some international operators have mixed U.S. feet with International feet.
- Numeric rounding of digital lat/long or x and y coordinates. Some data transfer tools truncate or round values without notifying the user.
- Incorrect or missing magnetic references and supporting information including total field strength, declination and dip amount and direction, magnetic model used (BGGM, HDGM), and the date of the magnetic model. Magnetic reference information is necessary to conduct quality control checks and reconstruct the survey by reapplying survey corrections.
- The corrections and tool error models applied to the survey data are not specified, incorrectly identified, or improperly applied. Corrections made to survey data increase the accuracy of the readings and error models establish the uncertainty in the wellbore trajectory.
- Incorrect or non-specific API number. Offshore wellbores commonly have multiple sidetracks and bypasses that result in different wellbore trajectories. Each wellbore should be represented by a unique wellbore identifier (UWI). Databases that use API-10 (10 digit API numbers) do not capture all wellbores, and API-12 are not always provided. Databases that tie wellbores to permit numbers or well names often include only the latest or deepest wellbore, and may fail to provide data for other wellbores drilled under the same permit (sidetracks, laterals, redrills, bypasses).

Offshore operators have recognized the importance and value of accurate well databases. The data represents a valuable company asset and the database is commonly considered safety critical software which is subject to stringent quality control and security policies. Wells drilled recently tend to have better quality data, as do fields currently under development. Generally these databases have been scrubbed and checked. Offshore fields that have undergone change in ownership present a challenge, especially if those fields are older and have had multiple operators. During the asset transfer data and information can be lost or corrupted.

Database integrity and security during planning are important aspects of the data lifecycle. During planning multiple iterations of a well plan may be generated and stored in the working database. Some companies retain the working files to document the workflow and support audit requirements. Changes are sometimes made to wellbore trajectories after approval and company signoff or submission to regulatory agencies. These changes should be reflected in the final wellbore plan. At some point the well plan is locked for editing and a final version of the plan is entered into the definitive database for later use.

3.3.2. Operations

During survey operations, real time position data are collected, transmitted to the surface and onshore offices for analysis, and stored in a database. Generally, the data sent to the surface includes a computed inclination and azimuth value and other supporting information. Data may include a set of inclination and azimuth readings from each of the sensors[10]. Other quality control and operating condition information is collected and transmitted, although not all companies choose to retain the "raw" readings and information. Raw data is a valuable asset for quality control and provides the ability to reconstruct the final survey readings.

Some service companies can modify the type of data collected and transmitted to the surface and offer a comprehensive suite of information for the user to manage. The amount of data that can be sent to the surface through mud pulse systems is limited by the data pulse size and complexity (see description of mud pulse transmission systems in Section 2.2.2). Wireline platforms are not restricted by pulse size and allow for a large amount of data to be transmitted to the surface rapidly. Battery powered systems use onboard data storage memory and may limit to the amount of data collected and stored especially in long survey sections.

Log header information provides critical data to perform corrections and conduct quality control checks. Historically the header information submitted with a directional survey contained survey company information, well name and general location and reference data, but did not provide any insight to the map or magnetic references used, or the various tool error models applied to the data. Newer survey data files provide a thorough understanding of the conditions under which the data was acquired and presented. Header data is part of the permanent well file and should be verified at the time of the survey.

3.3.3. Final Survey and Data Archiving

Upon completion of all surveys, a final or definitive survey data set is established for permanent record and submittal to regulatory agencies. The definitive survey may include position data that is a combination of more than one survey, but in no case includes duplicate data points, except where required for tie-in accuracy demonstration. For example, if MWD data is initially collected during drilling to support steering and anti-collision, and subsequently a higher quality gyro survey is run over the same interval, the operator may choose to retain the gyro survey as the final definitive survey for that portion of the hole. After operators perform quality control and audit checks the final survey data are approved by a supervisor and are locked for editing and become part of the permanent well record.

[10] Most MWD and survey tools determine their orientation by sensing two sets of data along the three axes of the tool (X, Y, and Z, which is the longitudinal axis). Thus the raw data will contain six sensor values, three from accelerometers (for gravity), three from magnetometers (for the magnetic field) or three from two rate-sensing gyros (for earth's spin rate), plus data-quality and other house-keeping values. Some gyro-based survey and MWD tools have only one rate-sensing gyro, so they measure and can store only two axes for the earth's rate (X and Y).

When more than one survey run is used to generate the definitive survey, a survey reading from each run at a common depth is made to demonstrate accuracy between two surveys. The point at which the two surveys are linked is the tie-in (or tie-on) point. Tie-ins are based on actual readings and do not use projections or interpolations of values between measurement points. Retention of all data sets may be necessary to provide demonstration that the overlapping surveys and tie-ins match.

The key elements in a definitive survey file are dependent on company polices and regulatory requirements and may differ within regions. Regardless, each definitive survey should represent the most accurate data for the wellbore preserved in a manner to ensure integrity and maximize future use.

Policies for the permanent storage or archive of well data are a company specific decision, and may be included in regulatory requirements[11]. Some international offshore operators consider data an asset and have developed survey data management plans and procedures for database development and maintenance that include requirements for access, user read/write permissions, workflows, accountability and auditing procedures. The intent of these procedures is to ensure data integrity.

Correcting data once it is archived or submitted is the subject of ongoing discussion in the industry. Operators conducting regular checks and audits on wellbore survey data often identify and correct mistakes and missing information in existing data. Changes to the operator's database are documented and become part of the permanent audit record. Discussions with operators indicate that once data are submitted to the regulatory agencies, it is generally not revised or resubmitted voluntarily by the operator, even if errors are discovered. Some operators felt that resubmission could create version control concerns or complicate the regulatory archive with multiple versions of the same data with only minor differences. Other operators felt that resubmittal might require extensive explanations and lead to additional data review and corrections.

3.3.4. Data Transfer

Well survey data is often transferred between many different teams during the asset life. Handoffs between the planning and execution team, and between the completion and asset management team may require data to be re-formatted to support the new user's needs. Regulatory agencies, such as BSEE and other state agencies, may also have a specified electronic format for well survey data. There is currently no single data standard for well survey data. Most software programs used for well planning and survey analysis offer a wide range of output options for transfer. Major directional drilling software packages (Compass™, WellArchitect™, DrillingOffice™) have indicated that the format of the data output is not a significant challenge, and that all major outputs are, or can be supported. Examples of commonly used outputs are shown in Table 46.

[11] As an example, the U.K. (DECC PON-9) requires that operators retain all data for the term of the license and must provide it if requested. The discussion of regulatory requirements for well data is included in a subsequent report completed for this study.

Table 46: Common Output Formats used in Well Survey Data Transfer

Output	Description
MMS/BSEE	ASCII file format compliant with BSEE requirements in NTL-2009-N10.
NPD	Data requirements from the Norwegian Petroleum Directorate.
Openworks®	Oil and gas project data management system that supports multi user collaborations and cross-domain workflow across asset teams and asset life. Developed and sold through Landmark (Halliburton).
UKOOA P7/2000	ASCII file format designed to support data exchange format for well deviation data as recommended by UK Offshore Operators Association. The format is widely used and generally regarded in the industry as good practice.
WITSML™ (maintained by Energistics)	Wellsite Information Transfer Standard Markup Language (WITSML) is a web-based XML technology for data transfer, which is both platform- and language-independent. It is broadly used in the transfer of survey data from the rig to communicate data to the operators. Some survey systems use WITSML to acquire the data from the MWD tools for real time data analysis.

3.4. Corrections and Tool Error Models

This section addresses three different, but related, concepts related to wellbore survey accuracy – the corrections made to compensate for the environmental effects inherent in the wellbore, tool error models, which are used to calculate the mathematical uncertainty of the tool readings and the method of survey calculations. Neither error models nor corrections address unmodellable errors caused by human error (referred to as blunders or gross error). Gross errors may include wrong datum, incorrect reference data, missing data, misapplication of error models, transcription error and may other random error types. Gross errors are discussed in Section 3.5.1 Survey Quality Control.

Error modeling is a complex and highly specialized aspect of wellbore survey management. This section will provide a high level summary of the key aspects of error modeling that are necessary to understand their application in accuracy and survey management. The reader will be referred to more detailed texts and professional papers for detailed discussions of the error models.

Technically, the application of magnetic declination and grid convergence to azimuth readings is a mapping correction, not an environmental correction. Improvement of the declination value (via IFR) is an environmental correction of the same type discussed below. Referencing the survey information to the mapping coordinate system is an important aspect of well survey accuracy that was briefly addressed in previous sections. The reader is referred to ISCWSA Introduction to Wellbore Surveying (ISCWSA, 2012) for a more thorough description of maps and reference corrections.

3.4.1. Environmental Corrections

Corrections are applied to survey data to correct for physical effects on MWD tools. These corrections commonly include:

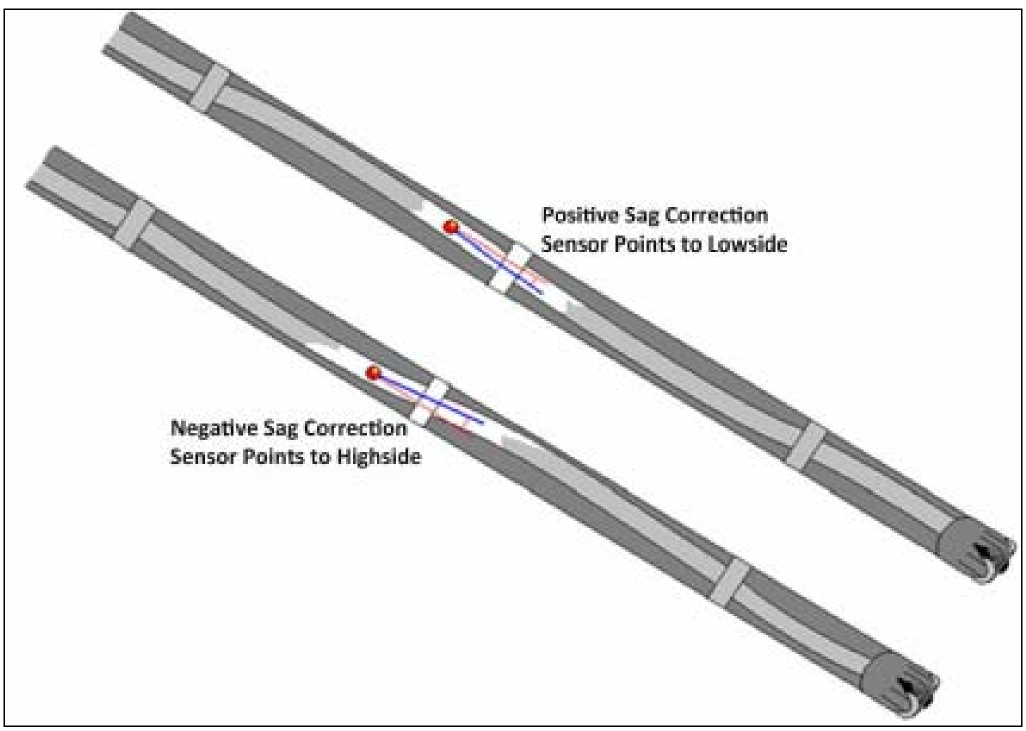
- Sag
- Magnetic field
- Short sub/short collar

3.4.1.1. Sag Correction

The length and diameter dimensions of drill collars is such that they will bend when traversing curved sections of boreholes, and will sag when not uniformly supported at higher inclinations. Collar-based MWD tools will sag between support points (typically stabilizers). Probe-based tools are subject to two types of sagging. The first comes from the sag of the collar between stabilizers. The second is caused by less-than-perfect centralization of the probe (or sonde) inside the collar. Gyro surveys conducted inside drillpipe also will experience sag. The effect is illustrated in Figure 19. The amount of sag is negligible at low inclinations but increases as inclination increases. It is one of the most important corrections made in wellbores with high angles and can have a significant effect on TVD accuracy. To determine the effect of sag on the accuracy of directional measurements, it is necessary to know the locations of the support points, the stiffness of the collar and the probe (for probe-based tools), the locations of the directional sensors, and the inclination.

ISCWSA recommends that sections of the well with deviation above 45 degrees at any point should be sag corrected. The sag correction is most commonly applied using software that models the performance of BHA, or specifically designed for sag correction. To make the correction the survey operator must obtain information on the BHA that is in use including the size (ID and OD) and position of stabilizers, drill collars and subs present in the BHA, the bend for any steerable elements in the BHA, the mud weight, and expected survey angles. If the BHA changes a new sag correction calculation must be determined and applied to that hole section. Calculations can also be made manually.

Figure 19: Misalignment Due to Drill String Sag



From Introduction to Wellbore Positioning (ISCWSA 2012)

3.4.1.2. Local Magnetic Field Correction

The azimuth measurements made by magnetic sensors rely on referencing to the earth's magnetic north pole. The magnetic pole is normally thought of as a fixed and stable reference, but in reality it changes in both strength and location over time. In addition, the magnetic pole is buried deep within the earth and not at the geographic north. Readings from the magnetometers must be adjusted to reflect the correct north reference.

The strength of the earth's magnetic field is made up of three component fields. Each field has some variability that can be identified and corrected to improve the accuracy of magnetic azimuth readings.

Main Field. Approximately 95 percent of the earth's magnetic field is created by movement of fluids within the outer core. The strength of the main magnetic field has been modeled with accuracy, using magnetic models maintained and updated regularly by the British Geological Survey (the British Geological Survey Global Geomagnetic Model or BGGM) and the National Oceanic and Atmospheric Administration High Definition Geomagnetic Model (HDGM). Using these models instead of static maps available from public agencies provides a more accurate resolution of the main magnetic field near the wellsite.

Crustal Variations. Magnetic rocks create local magnetic anomalies that distort the magnitude and direction of the earth's field over a short distance. These anomalies do not vary much over time, but can have a very significant effect on the local magnetic field. The strength and direction of the local magnetic field can be mapped prior to drilling to provide a site-specific value for magnetic field. Crustal variation is the largest source of error in magnetic measurements. In Field Referencing (IFR) refers to correction of the magnetic field using local data. A study in south Texas with long lateral wells showed that the uncertainty of MWD survey can be reduced by about 15-30% using IFR (Maus and DeVerse, 2015).

Diurnal Variations. Rapid daily variations in magnetic field can be caused by solar wind and earth rotation. In the Gulf of Mexico these variation are generally small, unless there is a significant solar storm. In northern regions solar storms can create significant variation in the magnetic field for several hours to several days and change the magnetic field by 1,000 nano Teslas (approximately) which represents 2 percent of the magnetic field (Buchanan et al, 2013). Interpolated In Field Referencing (a different model and technique from IFR) and real time magnetic station corrections can be made to correct for diurnal variation, however corrections are not commonly made unless drilling in an area highly susceptible to large diurnal variation.

3.4.1.3. Magnetic Interference (Short Collar) Correction

Non-magnetic drill collars that house magnetic field sensors must be long enough to effectively isolate magnetic components (drill string and BHA) from the magnetic interference caused by the components. In some cases non-magnetic drill collars are not long enough to isolate the magnetic sensors from the magnetic interference of the drill string. The effect of the "short collar" will be reflected in the axial component (along the drill string) of the total magnetic field. The magnitude of the interference can be calculated manually or with software programs. The most common and simplest method for correcting for short collar is the single station analysis or rotational shot analysis and requires collecting multiple magnetic sensor readings at the same depth while rotating the drill string. If the total magnetic field is accurately known (from IFR) and the x and y components of the field are measured, the z, or axial component can be identified and corrected. Other methods, such as multi station analysis, addressed in Section 3.5, can also be used for short collar corrections.

Some industry experts favor an aggressive program to remove the magnetism from all BHA components prior to drilling in order to reduce the likelihood of magnetic interference. The process, called "de-gaussing" is performed by passing the pipe or collar slowly through an AC coil. DC methods can be used, but tend to be less effective as they leave strong internal fields which cannot be measured, and may re-activate. De-gaussing can reduce the magnetic interference, but may be impractical to deploy on a regular basis. Normal drilling activities generate heat and shock which can re-magnetize downhole components. Common methods to reduce magnetic interference include adding more non- magnetic subs to increase the distance to the sensors, using non-magnetic components (drilling subs, stabilizers, floats, etc.) and the requesting new drill collars that have not been exposed to extensive heat and shock.

Corrections for magnetic interferences of the drill string are sensitive to high inclination, latitude and azimuth of the wellbore. At high latitudes, such as Alaska[12], the horizontal component of the magnetic field is small so the effect of magnetic interference has a large effect on the accuracy of the magnetic reading. Likewise, when drilling at a high angle in the east-west direction the axial component of the magnetic field is small and uncertainty in the total field may be greater than the effect of the drill string interference.

3.4.2. Depth Errors

Direction and inclination measurements are tied to a depth. Depth errors add to positional uncertainty and if not addressed will misrepresent the actual ellipse of uncertainty or proximity to a downhole hazard. The depth of a borehole, both during directional drilling and as a permanent reference, is a critical safety data point to ensure safe drilling. Knowing the correct depth of a well at all points along the trajectory helps avoid well collisions during drilling, and provides accurate steering of the drill bit to the target depth and location.

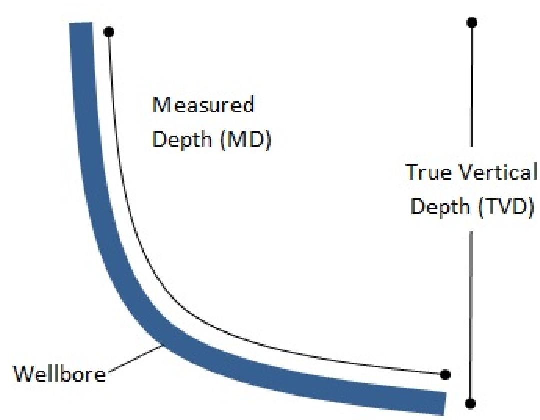


Figure 20: TVD versus MD

During drilling, depth measurements are calculated based on the length of the drill pipe and wireline depth measurement methods. True Vertical Depth (TVD) is the vertical distance from a point in the well to a point on the surface (Figure 20). TVD is independent of the directional path of the wellbore. TVD is important in determining bottomhole pressures, which are dependent on hydrostatic head of the fluid in the wellbore. Measured Depth (MD) is the length of the path of the

[12] SPE paper 173047-MS presents a discuss of Anti-Collision Considerations for Arctic and Other High Latitude Locations

wellbore, which will only be equal to TVD for vertical wells (Figure 20). When no designation is given by drilling crews, depth typically refers to the MD. However it is important for a designation to be given to allow for a complete understanding of the wellbore. MD is always longer than TVD, due to intentional or unintentional curvature in the wellbore.

Driller's depth is a measurement based on the depth of pipe going into the hole. This depth is determined from the pipe tally, measuring each pipe or collar at the surface and adding up the measurements. There are, however, several factors that can cause the driller's depth to be inaccurate (Table 47). The measurement of the pipe itself is a significant source of error, and human error in both the measurement (strapping or mechanical measurement system) and the tally can also affect accuracy.

Table 47: Factors Contributing to Drill Pipe Depth Error

	Potential error for a depth of 10,000 ft.	
Factor	**(m)**	**(ft.)**
Drill pipe stretch	5 to 10	16 to 33
Thermal expansion	3 to 4	10 to 13
Pressure effects	1 to 2	3 to 6
Ballooning effects	2	6
Other effects	1	3

From Theys, 1999

- There may be errors in depth measurements as a result of stretch due to pipe weight. Total length change can be adjusting the original pipe length by the weight on the joints and elasticity and area of the pipe. This is the largest contributor to depth error.
- Due to the elevated temperatures in wellbores, thermal expansion of pipes will occur. Average elongation is 0.86 inches per 100 feet of pipe per 100 °F increase.
- Due to buoyancy of the pipe, stretch due to hydraulics and buoyancy, must be taken into consideration when correcting survey depth.
- A correction factor for axial misalignment of the pipe in the wellbore can be utilized to accurately represent the radius of curvature of the wellbore.

The allowance for depth measurement error for drill pipe depth in the ISCWSA error model is 1 foot of error per 1,000 feet of pipe.

In wireline survey operations, the cable lowered into the well is used as the depth measuring device, while the logging tool gathers other properties which can be related to the well depth. The cable is typically lowered into the well and drawn down using gravity, which can cause difficulties in highly deviated wells. In some cases, roller and power tractor subassemblies have been used to assist the cable in reaching the end of the borehole. Magnetic marks places on the wireline cable (typically spaced every 10 to 100 feet) are used to help calibrate the raw depth, resulting in the Calibrated Depth. Calibrated depth that is corrected for cable stretch, temperature, and tension is called Corrected Depth. Corrected depth represents the best estimate of the true depth of the wellbore. Wireline depth corrections are often made during logging by the service company and depth errors are included in most MWD and gyro tool error models.

3.4.3. Tool Error Models

The accuracy of wellbore survey measurements can be affected by many factors. The effect of the major environmental effects, discussed above, can be quantified and corrected, but there are other conditions that create uncertainty in the readings, that are more difficult to correct. The uncertainty of the wellbore location is a critical safety factor used during wellbore planning and drilling to ensure there is safe working distance between wellbores. Tool error models, also referred to as an Instrument Performance Model (IPM), provide a mathematical estimate of the uncertainty of the wellbore location in the x, y and z direction based on the average operational conditions of survey tools. The mathematical estimate is translated into distances from the wellbore in the x, y and z directions to generate an ellipsoid[13]. The actual location of the wellbore could be anywhere within the ellipsoid.

ISCWSA is a voluntary group of industry professional whose goal is "to produce and maintain standards for the industry relating to wellbore survey accuracy" and "(E)stablish a standard framework for modelling and validation of tool performance. (ISCWSA, 2016)" They have developed and maintain tool error models which have become the standard for the industry. The group's work focused initially on MWD systems because they provide a large proportion of the total directional survey data and there are many similarities between the various suppliers' tools, and have also developed tool error models for gyro surveys. The details of the models and their development are presented in two SPE papers; SPE-67616 and SPE-90408. ISCWSA members have published many other technical articles that describe the models, and have made available worksheets and examples to support use of the error models. These materials are available through the ISCWSA website at http://www.iscwsa.net/. The ISCWSA is affiliated to the SPE as the Wellbore Positioning Technical Section and has a web site with the SPE at: www.spe.org.

The ISCWSA has specified a generic MWD tool error model. It comes in eight different arrangements to address common operating conditions and corrections including standard MWD or short collar corrected surveys, surveys made from a fixed or floating platform, and surveys with or without sag correction. The error codes are generic and make several assumptions about tool specifications, running procedures and processing standards that must be met for the model to be valid. Tool suppliers may offer more specific error information for specific tool models if users wish to modify the generic error model.

Gyro error models are somewhat different from MWD error models in that common environmental errors are not as dominant as with MWD. Use of gyro models require tool-specific information on the particular tool configuration from the suppliers because gyro tools vary greatly in design and specifications, and may be run in different operational modes (stationary, continuous, gyroMWD, drop). Some industry experts have noted the misapplication of gyro models that result in underestimation of uncertainty.

The Operators Survey Work Group (OWSG) is a subcommittee of the ISCWSA and has developed a more complete set of tool error models that address a wider range of wellbore survey situations than ISCWSA

[13] The ellipsoidal shape occurs because the azimuthal error is normally larger than either the inclination or depth errors. Inclination errors tend to be small.

models. These are based on the same mathematical framework defined by the ISCWSA Error Model, but offer a wider range of applications. The OWSG models are compliant with the ISCWSA framework.

In the ISCWSA/University of the Highlands e-book "Introduction to Wellbore Surveying" Andrew McGregor provides the following description of an error model:

> *"The error model identifies a number of physical phenomena which contribute to borehole survey errors and provides a mathematical framework for determining in numeric terms the uncertainty region around a particular survey. Typically this error model will be implemented in directional drilling software. The user will select the appropriate tool model for the survey tool that has been run and the error results will be used in anti-collision or target sizing calculations."*

Error models, despite their complex mathematical derivations, are designed to be relatively simple to implement using common software programs, and apply to a wide range of tools and operational conditions. Models require that the surveys were conducted in accordance with industry best practices including regular tool calibrations, survey intervals less than 100 foot, field quality control checks, appropriate magnetic spacing, and no magnetic interference from adjacent wells[14]. Components of an error model include:

- **Error source** – a physical phenomenon that contributes to the overall position measurement error. These may include (for MWD) the sensitivity and precision of the sensors, borehole/tool misalignments, magnetic field uncertainties, or drill pipe or wireline stretch.
- **Magnitude of the error**– the standard deviation of the range of values expected for each error source under normal operating conditions. A tool that is run with IFR will have a lower magnitude declination error than a tool run without IFR. The magnitude of the error is specified to be 1 standard deviation in the model, however users can modify the value to create error ellipses at 2 or 3 standard deviations.
- **Weighting function** – the relationship between the error source and the survey measurement. This relationship allows the sensor reading to be converted into degrees or feet of uncertainty.
- **Propagation error** – defines how the error is correlated to sum up the errors. Some errors may apply equally globally, such as magnetic reference, and others propagate from survey station to survey station.

An example of the application of error models is provided below (Table 48, from Maus and DeVerse, 2015) to show the effect of various models on the ellipse of uncertainty. In this example from a deep horizontal onshore well in South Texas, the author summarizes the resulting uncertainties at TD for eastward, southeastward and southward wellbore orientations by applying three different tool models to the wellbore survey data. In the first tool model, the basic MWD model, the lateral uncertainty (semi-major axis of the ellipse) ranges from 259 to 439 feet. Performing an IFR survey and adding that

[14] Tools must also be run within their calibration and operating ranges. This includes the temperature ranges established by the tool manufacturers. If tools are run outside the specified temperature range the error is not predictable and the model is invalid.

correction to the tool model reduces the ellipse by 11 to 38 percent. Further reductions in the ellipse can be achieved if the data are corrected using a Multi Station Analysis technique to remove the effects of magnetic interference. The authors also performed a study to evaluate the effect of these same corrections on depth which resulted in reducing depth error from 119 to 71 feet, a reduction of 40 percent.

Table 48: Lateral Uncertainties for Three Wells using Different Error Models

Well Orientation	Lateral Length	MWD	MWD+IFR1	MWD+IFR1+MS
	(ft)	(ft)	(ft)	(ft)
Eastward	11000	± 439	± 390 (-11%)	± 173 (-61%)*
Southeastward	11000	± 387	± 329 (-15%)	± 160 (-59%)
Southward	11000	± 259	± 161 (-38%)	± 129 (-50%)

*With limitations

From Table 1 in Maus and DeVerse, 2015, SPE-175539-MS, reproduced with permission

The use of error models is a specialized skill that is best left to experienced individuals. The improper application of tool error models can underestimate the risk of collision if the model is too optimistic, or unnecessarily restrict the wellbore trajectory plan if the model is too conservative.

3.4.4. Surface Position Uncertainty

The positon of wellbore at the surface is assumed to be accurate, but is often a considerable source of error. As well spacing becomes smaller and platforms become more crowded, an accurate surface position is necessary to properly evaluate collision risk with nearby wells and maximize resource access and recovery. The role and general causes of surface position error were introduced in Section 3.1 as part of the discussion of wellbore planning and collision avoidance, and also discussed in Section 3.3, as an element of Data Management. This section summarizes the main causes of surface position uncertainty and provides an understanding of the significance of the error.

The location of a well at the surface is normally tied to a reference point on the platform that was initially surveyed using differential global positioning system (DGPS) and is accurate to less than 0.1 meter. At this level of accuracy instrument error is generally not a major contributor to surface well positon error. Some error is introduced if the drilling template on the floating platform or drill ship is not positioned exactly over the well entry point in the mudline. Offsets can occur due to ocean currents, tilting, and surface casing placement errors. In shallow water the effect of the offset is minimal, however in deeper water the offsets can be large. Uncertainties and errors in surface well locations most often occur as the original survey point is translated into different coordinate systems or measured off secondary reference points. These errors fall under the category of blunders or gross errors, which cannot be modeled mathematically, and can be difficult to recognize without specific quality control checks.

Industry experts who work with operators to certify databases have found that surface position errors due to gross error are common in regulatory databases, commercial databases, and operator databases. The problem is exacerbated in fields where the asset has been transferred multiple times and data is subjected to multiple transformations to align the reference datum with company standards. Common sources of errors are:

- Using the wrong map reference datum (NAD27, NAD83, WGS84)
- Using the wrong map projection type or UTM Zone
- North reference not correct (True North, Grid North or Magnetic North) or inconsistent with other data sets
- Magnetic declination value incorrect, has wrong sign (- or +), or is applied for the wrong year
- Grid convergence (Grid North to True North angle) incorrect or has wrong sign (- or +)
- Northing and easting coordinates not tied into local datum (based on 0.0 starting point)
- Mixed or incorrect units, or unit conversions (U.S. feet, meters, international feet)
- Rounding or truncating latitude/longitude or x, y coordinates due to software
- Incorrect or inconsistent reference point for depth measurement (mean sea level, kelly bushing, rig floor, other)
- Surface position based on incorrect platform slot, or slot locations transposed

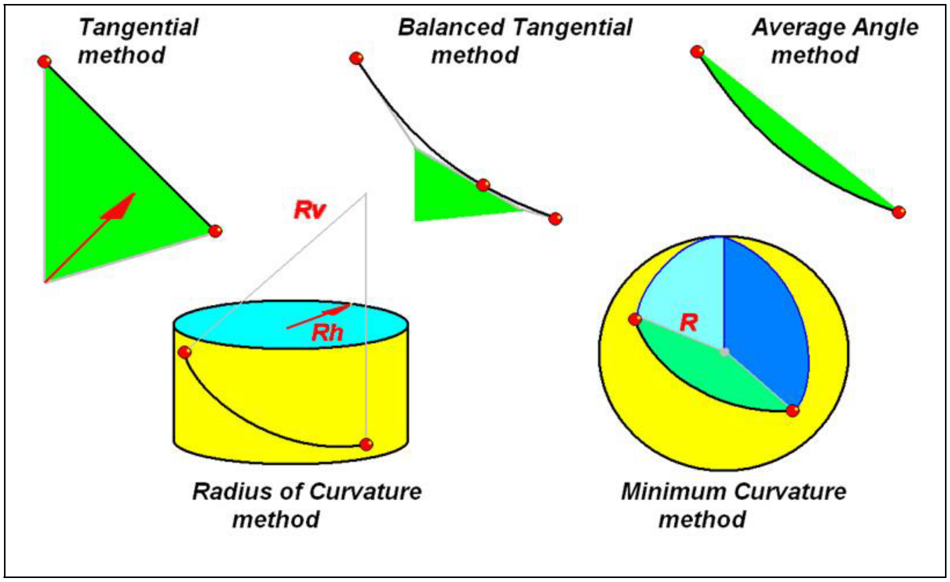
These and other surface location errors are more common in older surveys, but persist in newer surveys where quality control procedures have not been effectively implemented.

3.4.5. Survey Calculations

Wellbore direction and inclination measurements are not continuous, but are made at discrete intervals (often hundreds of feet apart) while advancing the bit or moving the drill pipe or wireline tool. The wellbore path between two adjacent points must be extrapolated using a model. Early models applied simple straight line estimation (Tangential Method, and Balanced Tangential Method) but modern complex wellbore geometries are not accurately represented by a series of straight lines, and will create significant uncertainty in location that propagates downhole.

Several mathematical models are available to calculate the distance between two points in a non-linear borehole (Figure 22). The Minimum Curvature method assumes that the hole is a spherical arc with a minimum curvature or a maximum radius of curvature between stations and the wellbore follows a smooth circular arc between stations. Although the calculations are complex and must be performed with a computer it has become the standard method for calculating wellbore trajectory, and recommended by ISCWSA. However, because it is a mathematical approximation of a mechanical process it may not accurately represent the actual borehole in all situations, especially in areas where rotary steerable drilling switches between slide and rotate modes.

Figure 21: Methods of Calculating Well Path in a Curved Borehole



From Introduction to Wellbore Positioning (ISCWSA 2012)

3.5. Survey Quality Control and Survey Management

Wellbore survey data is susceptible to many factors that affect the accuracy of the data. The directional survey industry has developed many techniques, such as error models and corrections, to help the data user improve and assess the accuracy of the survey data. However, before these techniques can be used the integrity and soundness of the data needs to be verified. Quality control procedures are a critical part of ensuring the directional survey will meet the user needs and can meet the specific conditions for use in tool error models.

3.5.1. Survey Quality Control

Survey quality control incorporates many different activities throughout the survey lifecycle. Previous sections of this memorandum addressed quality control procedures to support well planning, survey operations, and data management. The environmental corrections described in Section 3.4 (sag, depth, magnetic interference, IFR) are all examples of survey quality control because they are designed to enhance the quality of the survey data. The industry has developed specific quality control checks that are performed before, during, and after surveys are run.

Section 3.4 described the tool error models that mathematically quantify the uncertainty in wellbore position. The accurate representation of uncertainty, regardless of the actual size of the ellipse of uncertainty, is one of the most important factors contributing to directional drilling safety because of its use in anti-collision analysis. It is critical that the uncertainty measurements reflect the most realistic understanding of the physical conditions of the borehole, and not merely generate the smallest area of uncertainty. In order to assure the representativeness of the uncertainty calculations a rigorous quality control protocol is a prerequisite for validating the conditions of a tool error model.

For a tool error model to be valid it must meet certain threshold requirements including surveys were conducted in accordance with industry best practices, regular tool calibrations, and quality control checks (Williamson, 2000). If these requirements are not met, the tool error model is invalid and the resulting ellipse of uncertainty is unlikely to represent the actual conditions. As tool error models improved, and the ellipses of uncertainty were reduced through better understanding of tool error, industry experts noticed that the threshold requirements for quality control and calibration were commonly violated. In 2006 and 2007 two landmark journal articles were published that set out specific quality control checks that should be conducted to demonstrate compliance with the tool error model prerequisites. The 2006 paper (Ekseth et al, 2006) recommended “internal” quality control checks, including specific downhole sensor tests for MWD and gyro tools to demonstrate the tool was functioning properly, and quality control tests using multiple readings taken at the same depth (rotation and check shots). The most powerful quality control test proposed, which has been adopted by many large service companies and offshore operators, is the Multi-Station Analysis test. The 2007 paper (Ekseth et al., 2007) addressed “external” quality control checks and recommended conducting overlapping verification surveys (in-run and out-run repeat surveys, also known as benchmark surveys) and other independent observations and statistical tests.

Multi-Station Analysis is a method of estimating corrections to sensor readings that contribute to wellbore survey error. The most common use of MSA is to identify and correct sensor bias and scale factor error by comparing actual survey measurements with predictions based upon reference field components such as magnetic field strength. There are several methods for conducting MSA for error correction and many survey experts believe that it can provide more powerful survey quality control than the standard single station analysis. Recent analysis of the MSA technique by Hanak et al. (2015) showed that it is not always the case and if not properly conducted results may not produce accurate corrections and lead to unfounded accuracy estimates.

Industry experts generally agree that the most powerful overall quality control procedure is to run two different survey tools over the same interval and analyze the variability. Ideally the tools would be based on different measurement physics, for example MWD and gyro. Many types of gross error can be identified with this method, especially those involving magnetic field references.

Tool calibration procedures and frequency are a threshold and critical aspect of quality control. As described in Section 2 calibration at the manufacturing facility, office, or shop under controlled conditions is the basis for defining and validating instrument error. Calibration is generally not performed at the wellsite, as the conditions do not allow for a controlled environment, such as testing under high temperature and pressure. Normally tests performed at the wellsite are calibration checks and functionality test to ensure the sensors respond appropriately to various ordinations while in a tool stand. Documentation of the most recent calibration should be provided for all tools (including backup tools) involved in wellbore survey operations at a wellsite.

Human error is often responsible for data quality problems and inaccurate surveys, and may be the leading cause of collisions due to wells missing from the database (ISCWSA 2012). Misapplication of tool error models, miscalculation of corrections, transcription and format errors, and version control of corrected survey data files are common pitfalls due to human error. Many operators and service companies have instituted formal oversight and approval processes to address human error, but these are inherently human systems that are susceptible to human error, such as signing off without full review and understanding of the work.

In summary, quality control procedures occur throughout the survey lifecycle and must be implemented to ensure the uncertainty estimates are truly representative of the actual conditions. Because the uncertainty estimates are the basis for safely identifying and avoiding collision risks and maximizing the efficient recovery of resources quality control procedures are critical to the safety of directional drilling operations. Key aspects of the quality control lifecycle can be summarized:

- Planning the directional drilling program requires a complete an accurate inventory of all wells with the area of review. This is a function of the accuracy and integrity of the well database including the accuracy of the positional uncertainty of the surface and trajectory of each wellbore. Many data sets are incomplete and poorly documented which increases the risk of adverse outcomes.
- Survey operations require continuous quality control. Pre-survey checks should be performed for each survey run and results validated prior to collecting survey data. Quality control tests should be performed during survey operations, including check shots, rotational shots, repeat surveys. The data from these tests should be evaluated in real time to determine if the field acceptance criteria for each measurement is acceptable.
- The most powerful quality control tool for ensuring survey accuracy is repeating the survey measurements with different tool types at the same depth. Because this requires additional rig time some drillers and operators may be hesitant to invest in this quality control effort.
- Corrections should be applied, as needed, during the survey to ensure an accurate understanding of collision risk and target delivery. Many corrections can be made but the sag, magnetic reference, and magnetic interference from the drill string will have the most dramatic effect on data quality. Pipe stretch can be a significant factor in holes with tight drilling tolerances.
- Survey point frequency is a method of ensuring accurate wellbore trajectory readings. Tool error models require readings at a minimum of 100 feet apart, and some industry experts believe that 60 feet is required to provide an acceptable error. Most regulations have more lax standards for acquisition of data. More frequent surveys require additional rig time, which must be considered in the survey plan.
- Some gross errors can be identified using quality control procedures that employ repeat survey of hole sections with two different sensor types, but may gross errors go undetected until rigorous scrubbing of the database and survey data is performed.
- Database integrity is a critical part of the quality control process. The final and definitive survey archived by the operator and regulatory agency must represent the best quality survey data. It is critical that metadata, raw sensor readings and tool model error information be available as part of the database so that the full survey can be reconstructed from the information in the database.

The survey quality control literature does not specifically address issues related to high temperature surveys. To meet the general requirements of field acceptance criteria surveys made in high temperature environments must be performed with tools designed for, and calibrated at the temperatures in which they were run. Quality control procedures and survey plans for high temperature wells should specifically address this issue.

3.5.2. Survey Management

Survey management refers to a broad range of services to improve the usability and accuracy of wellbore survey data. There is not a universally accepted definition of the components but a recent paper (SPE-158064, by B Mat et al, 2012) defined it as follows:

> *The management, oversight, and development of wellbore surveying, survey planning procedures, survey data quality control, and the integrity management and custodianship of the directional planning survey database."*

Larger service companies offer survey management services that cover all of these areas. Recently a number of smaller third party independent survey management service companies have been formed to provide onsite or remote survey monitoring as the surveys are being run. They apply necessary corrections and implement quality control procedures in real time, on behalf of the operator to ensure the survey data meet data usability standards. These firms also conduct post survey analysis of data quality to generate a definitive survey and reduce ellipses of uncertainty. The range of services provided will vary depending on the operator's needs and available resources.

The specific services offered as part of the survey management can include:

- Planning support including auditing existing databases, assessing the quality of legacy well data including verification of coordinate systems, units, survey datum and elevations, surface locations, north referencing, tie-in points, tool codes, and corrections.
- Survey quality control in real time and post processing of raw data for error model validation, scale/bias errors, magnetic reference values and gyro drift. The quality control procedures are those described in Section 3.5.1. This is a key component to survey management.
- Post-processing of surveys for reduced error ellipses by applying multi-station and IFR corrections.
- Database design and management.
- Education and training in quality control techniques for wellbore surveys.

The application of a comprehensive survey management program for all wellbore surveys is the best method to identify and address many causes of gross error. The structured and rigorous application of corrections as part of the quality control process within survey management activities is critical to identifying the internal and external errors that may be present in the wellbore survey data.

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Attachments

Table A-1. Specifications for Standard MWD and Ranging Tools

								Max. Oper'g		Max.	Inclination		Azimuth			Magnetic (µT)				Survey							
Supplier	**Model**	**Description**	**Nom. O.D. (min,")**	**Telemetry**	**Downlink**	**Multi-Shot Mode**	**Tandem w/ MWD**	**Temp. (°C)**	**Time (hrs)**	**Pressure (psi)**	**Acc'y**	**Resol'n**	**Acc'y**	**Resol'n**	**Incl. Max.**	**Range**	**Acc'y**	**Resol'n**	**No. Bits**	**Short**	**Long**	**Power Source**	**Operating Time (hrs)**	**LCM Tol. (lbm/bbl)**	**Gamma**	**Other Measurements**	**First in Service**
APS Technology	SureShot MWD	Retrievable MWD/LWD in Std. collar	3.125"	Positive mud pulse	Y	N	Y	175	> 1000	25,000	< ±0.1°	0.044°	±1.0°	0.088°	10°	±120	±0.3	0.6	12	192	255	Turbine/ Battery	200/battery	50	Azimuthal & Focused	Resistivity; weight, torque, bending; sonic; porosity, density & caliber	2002
Baker Hughes	OnTrak HT-175	Integrated MWD & LWD system	4.75"	Positive mud pulse	Y	N	Y	175		30,000	±0.1°	0.09°	±1.0°	0.35°	5°	0-100	±0.10	0.035		105	139	Turbine	N/A	40	Azimuthal	Multiple-propogation resisity, Drilling dynamics	2014
Bench Tree	MWD Kit	Retrievable MWD probe, 1.875" diameter	3.5"	Positive mud pulse	Y		N	175		20,000	±0.1°		±0.35°		45°		±0.075					Battery	800+		Omni		
GE Oil & Gas	Tensor MWD	Retrievable MWD/LWD in Std. collar: 1.875" diameter	3.5"	Positive mud pulse	Y	N	N	175		20,000	±0.1°	0.1°	±1.0°	1.0°	3°	0-100	±0.075	0.01	12	190	326	Battery	180	40-50	Omni	Propogation resistivity	mid-1990s
Halliburton SD	SOLAR MWD/LWD	Collar-based hostile-environment M/LWD system	4.75"	Pos. & Neg. mud pulse	Y		Y	175		25,000	±0.1°	0.09°	±0.8°	0.17°	5°	±65		0.032	8/11-12	65	76	Turbine	N/A	40	Omni & Azimuthal	Vibration, Pressure, Caliper, Resistivity, and other LWD Tools	2015
Schlumberger	HDS-1L	Fixed-collar directional service	4.75"	Cont. Wave Pos. mud pulse	Y	N	Y	175	300	25,000	±0.1°	0.1°	±1.0°	0.1°	6°	0-65	±0.110	0.035				Battery	224-669	50	Omni	Vibration, Temperature	1995
Scientific Drilling	Falcon MWD	Std.collar below Pulser Sub	3.125"	Positive mud pulse	Y	Y	Y	150	300+	30,000	±0.15°	0.15°	±0.25°	0.25°	3°	±75	±0.18	0.002		177	219	Battery	300+	40	Azimuthal or Focused	Battery voltage & draw, Vibration (axial & lateral), Tool RPM, Stick-Slip levels, Annulus & pipe pressures, Continuous & near-bit Inclination	1999
Scientific Drilling	Green Eye Ranging MWD	Std.collar below Pulser Sub	3.125"	Positive Mud Pulse	Y	Y	Y	150	300+	30,000	±0.15°	0.15°	±0.25°	0.25°	3°	±150		0.0046		177	219	Battery	300+	40	Radial or Focused	Battery voltage & draw, Vibration (axial & lateral), Tool RPM, Stick-Slip levels, Annulus & pipe pressures, Continuous & near-bit Inclination	1999
Weatherford	HyperPulse MWD	Probe-based MWD tool: 1.6875" diameter	3.0625"	Positive mud pulse	Y	N		150		15,000	±0.2°	0.125°	±1.0°	0.25°	5°							Battery			Omni	Temperature	

Table A-2. Specifications for High Temperature MWD Tools

Supplier	Model	Description	Nom. O.D. (min,")	Telemetry	Downlink	Multi-Shot Mode	Tandem w/ MWD	Max. Oper'g Temp. (°C)	Max. Oper'g Time (hrs)	Max. Pressure (psi)	Inclination Acc'y	Inclination Resol'n	Azimuth Acc'y	Azimuth Resol'n	Incl. Max.	Magnetic (µT) Range	Magnetic (µT) Acc'y	Magnetic (µT) Resol'n	No. Bits	Survey Short	Survey Long	Power Source	Operating Time (hrs)	LCM Tol. (lbm/bbl)	Gamma	Other Measurements	First in Service
Halliburton/ SD	Quasar Pulse M/LWD	Collar-based hostile-environment M/LWD system	4.75	Positive mud pulse	N		N	200		25,000	±0.1°	0.09°	±0.8°	0.17°	5°	±65		0.008	12	65	76	Turbine	N/A	40	Omni	Vibration, Annular & Bore Pressures	2015
Schlumberger	TeleScope ICE	UltraHT MWD Service	4.75	Cont. Wave Pos. mud pulse	Y/N	Y/N	Y	200	300	30,000	±0.1°	0.1°	±1.0°	0.1°	5°	0-65	±0.110	0.035		105	139	Turbine	N/A	50	Azimuthal	Shock, Vibration, Annular & Intyernal Pressures	2015
Scientific Drilling	High Temp MWD	Std.collar below Pulser Sub	2.75	Positive Mud pulse	Y	Y	N	177	300+	30,000	±0.15°	0.15°	±0.25°	0.25°	3°	±75		0.0023		177	219	Battery	300+	40	Radial	Vibration, Temperature	1999
Weatherford	HEL MWD System	Collar-based hostile-environment MWD system	4.75	Positive mud pulse	Yes	?	Y	180	200	30,000	±0.1°	0.08°	±0.5°	0.17°	5°	?	?	?				Battery	348 hrs	50	Azimuthal	Bit speed, Vibration, Bore & annular pressure, Annular temperature, Azimuthal density, Resistivity, Porosity & Sonic	

Table A-3. Specifications for Gyroscopic Tools

								Max. Oper'g		Max.	Inclination		Azimuth				Survey Times (sec)							
Supplier	Model	Description	Nom. O.D. (min,")	Telemetry	Downlink	Multi-Shot Mode	Tandem w/ MWD	Temp. (°C)	Time (hrs)	Pressure (psi)	Acc'y	Resol'n	Acc'y	Resol'n	Incl. Max.	No. Bits	Gyro only	with MWD	Power Source	Operating Time (hrs)	LCM Tol. (lbm/bbl)	Gamma	Other Measurements	First in Service
Gyrodata	Gyro-Guide GWD40	Probe-based tool: 1.875" X 18 feet		Positive mud pulse				150		20,000	±0.1°		±1.0°		40°				Battery					2010
Gyrodata	Gyro-Guide GWD70	Probe-based tool: 1.875" X 18 feet		Positive mud pulse				150		20,000	±0.1°		±1.0°		70°				Battery					2010
Gyrodata	Gyro-Guide GWD90	Probe-based tool: 1.875" X 18 feet		Positive mud pulse				150		20,000	±0.1°		±1.0°		none				Battery					2013
Halliburton/ SD	Evader MWD Gyro Service	Collar-based M/LWD system	4.75	Positive mud pulse	N	Y	Y	150		20,000	±0.1°		±1.0°		none	11-12	276		Battery	60+				
Scientific Drilling	gyroMWD	Directional Module below Pulser Sub - 1.75" O.D.	3.125	Positive mud pulse	Y	N	Y	150		30,000	±0.15°	0.088	±0.15°	0.088°	105°		375	453	Battery	40 to 250	40	Y	Vibration, Temp, Gamma, Pressure, and other LWD Tools	1999
Scientific Drilling	gyroMWD Module	Directional Module added to 3rd party MWD	3.125	Per MWD Host	Y	N	Y	150		30,000	±0.15°	Per MWD Host	±0.15°	Per MWD Host	105				Battery	40+	Per Host	Y	MWD Host Dependent (Compatible with all LWD and RSS tools)	2013
Baker Hughes	GyroTrak	Integrated GWD & LWD system	3.125	Positive mud pulse			Y	150		20,000									Battery	150				
Schlumberger	GyroPulse	Collar-based GWD/MWD system	9.5	Positive mud pulse			Y	150		20,000	±0.1°		±1.0°		20°				Turbine & Battery			Y		
Weatherford	TrendLine Gyro-while-Drilling Service	Probe-based tool: 1.875" X 23.2 feet	4.75	Positive mud pulse				150		20,000	±0.1°		±1.0°						Battery					

Table A-4. Specifications for Active Ranging Tools

								Distance Detection Range				
Supplier	Model	Description	Nom. O.D. (min)	Telemetry	Tandem w/ GWD	Max Oper'g Temp. (°C)	Max Pressure (psi)	Distance	Tolerance	Gradient Distance	Tolerance	Direction Tolerance
Halliburton/ SD	WellSpot RGR I	Wireline AMR Tool w/ bridle	4.5"	7-Conductor Wireline	N	177	25,000	150 ft.	±20%	10 ft.	±5%	±3°
Halliburton/ SD	WellSpot RGR II	Wireline AMR Tool w/ bridle	2"	7-Conductor Wireline	N	177	20,000	150 ft.	±20%	25 ft.	±5%	±3°
Halliburton/ SD	WellSpot RGR III	Wireline AMR Tool w/ bridle	2"	7-Conductor Wireline	N	204	25,000	150 ft.	±20%	10 ft.	±5%	±3°
Halliburton/ SD	WSAB Sub	WellSpot At-Bit Sub	7"	Wireless to WSAB Receiver	N	127	15,000	20 ft.	±25%	7 ft.	±5%	±3°
Halliburton/ SD	WSAB Sub	WellSpot At-Bit Sub	8.5"	Wireless to WSAB Receiver	N	127	15,000	40 ft.	±25%	7 ft.	±5%	±3°
Halliburton/ SD	WSAB Receiver/CML	Recever for WSAB and Continuous Logging Tool	2"	7-Conductor Wireline	N	127	25,000	75 ft.				

Attachment B: Future Technologies for Tools and Lifecycle Components of Directional Surveys and Ranging

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Wellbore Surveying Technology

Technical Memorandum for:
Task 7: Future Technologies

BPA No. E13PA00010
Call Order No. E15PB00084

July 21, 2016

Prepared for
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1. Introduction

1.1. Background

The mission of the Bureau of Safety and Environmental Enforcement (BSEE) is to promote safety, protect the environment, and conserve offshore resources through regulatory oversight and enforcement. Through its Technology Assessment Program (TAP), BSEE supports research related to operational safety and pollution prevention to provide engineering support to BSEE decision makers, to promote the use of Best Available and Safest Technologies (BAST), and to coordinate international research.

The Wellbore Survey Technology study will provide recommendations to improve BSEE's regulations as they relate to wellbore surveying technology associated with surveying accuracy and survey management, as well as relief well/well intervention operations.

1.2. Task 7 Objectives

The oil and gas market has grown significantly in recent years, and the drilling and completion technologies that drove the growth continue to evolve as exploration and production move into more challenging areas. Electronics and materials technology markets are evolving to address some of the issues faced by highly deviated and hostile environment drilling. The improvements in drilling, wellbore survey and ranging technologies, procedures and services are an important consideration when developing regulations and guidance. Understanding the emerging tools for wellbore survey and ranging, and new methods will help ensure that the best available technologies are considered in the decision-making process.

Previous technical memoranda for this project (under Tasks 2 and 5) have identified and analyzed the current technologies, practices, and standards related to wellbore surveys. The objective of this task is to identify new and emerging technologies that are likely to (a) improve the performance, reliability, and/or ability to operate at elevated temperatures of tools used for downhole ranging or directional measurements, and (b) become commercially-available within the next 3 to 5 years. Because several years often are needed to evaluate and qualify components and subsystems for use in borehole applications, the technologies considered need to be "visible" today, meaning they exist as tested models or prototypes. As such, this memorandum does not assess potential technologies that exist only as concepts or untested models.

While the focus of this memorandum is on tools and technology, we also offer some observations on new developments and trends in survey lifecycle methods, best practices, and quality control.

1.3. Methodology

The information presented in this technical memorandum was gathered from many sources including publications, product literature, discussions with industry experts, and technical workshops attended by the report authors. During communications with measurement while drilling (MWD) and ranging tool suppliers and while reviewing and analyzing the available information on such systems, the project team identified the essential components, modules, and sub-systems and sought to identify unmet needs.

Information provided by those suppliers enabled the team to assess the extent to which existing components, modules, and subsystems provide the performance needed for MWD and ranging tools to meet the needs and expectations of their customers. In many cases we were able to identify and communicate directly with the third-party suppliers (manufacturers that do not provide surveying, MWD, or ranging services) that provide the components, modules, and/or subsystems that are integrated into complete tools by the service companies. Information from these suppliers and their customers enabled the project team to identify several new technologies – prototypes or non-commercial tools – that, in our opinion, will improve the efficiency and safety of directional drilling projects.

1.4. Report Organization

The memorandum summarizes new and emerging technologies and practices for wellbore survey and ranging.

- **Section 1** is an introduction to the memorandum and describes the purpose of the project, the approach, and a description of how the memorandum is organized.
- **Section 2** presents summaries of the new and emerging technologies and practices in directional surveys and ranging. The chapter describes future developments and the implications of components, modules and systems, data quality, and survey management.
- **Section 3** provides bibliographic references for the cited documents.

2. Description of Future Technologies and Practices in Directional Surveys and Relief Well Operations

2.1. Improving Performance at Elevated Temperatures

The elevated temperatures experienced by borehole tools and instruments (often exceeding 125°C) are well above the temperatures found in almost all other environments where modern, solid-state electronics are used. Electronic components designed and manufactured for military and aerospace applications normally are tested and expected to perform at temperatures of 125°C and below.

For about the last 50 years, the manufacturers of the tools and instruments used in boreholes have needed to carefully select and test the components they use. This process usually begins with direct communications between the design and manufacturing staff of the component manufacturer and the tool manufacturer. Information concerning the sources of heat within the component, how the heat can be minimized and dissipated, and how the component should be employed to achieve the needed functionality while minimizing heat generation, usually is of greatest interest. After several iterations of such discussions with component manufacturers, the tool manufacturer will usually obtain some components to test. Components usually are subjected to both thermal shock and to “baking” at elevated temperatures while they operated in a test fixture that simulates how the component will be operated. Details concerning their component selection and test procedures, and the results, which indicate how components will perform at elevated temperatures, are considered to be proprietary information by most tool manufacturers.

The design and production of high-temperature tools involves more than component selection. Subassemblies (or modules) must survive the environmental extremes to which such tools are subjected, including shock, vibration, rapid cycling between temperature extremes, as well as long-term exposure to elevated temperatures. The need to maximize thermal conductivity can prompt the use of exotic materials. Solders that provide the needed electrical and mechanical properties are difficult to find. Elastomers and organic materials degrade in high-temperature environments. Production volumes are small, so the advantages typically realized with automation in electronics assembly are modest. In summary, the design, production, and maintenance of borehole tools and instruments capable of performing at elevated temperatures is technically challenging, time consuming, and expensive.

Although resolving the technical issues needed to field high-temperature tools is challenging, resolving the associated economic issues is even more difficult. The cost of a high-temperature survey or MWD tool, capable of performing at temperatures significantly above 175°C, can be many times the cost of a standard tool. However, the market for high-temperature tools is much smaller than that for standard tools, and tool manufacturers normally cannot charge the premium prices needed to yield a fair return, when including development and production costs, and amortization of their investment.

An important consequence of the limited financial returns for high-temperature tools is that the markets for components, such as sensors, processors, solid-state memory, and other circuits, and batteries are not large enough to provide the financial incentives needed for many suppliers to expand their product offerings. In other words, substantial and predictable markets for the components and materials needed for high-temperature tools would, over time, improve the capabilities and performance of the available tools and services.

Whether there is a role for a government agency, like BSEE, to provide the guidance and/or incentives needed to improve this market is an open question. However, any recommended best practices or new regulations should reflect the technical and economic realities of the situation.

2.1.1. Components

Suppliers of directional sensors, including accelerometers, gyroscopes, and magnetometers, have been aware of the directional drilling and borehole surveying market for more than 40 years. The design of and materials used in these types of components normally determine the extent to which they can tolerate the extreme conditions – shocks, vibration, and temperatures – to which tools in this market are exposed. The business models of many component manufacturers are based on manufacturing large quantities of components that usually are sold into markets where price is more important than performance or reliability. In most directional drilling, and borehole surveying and ranging markets, the reverse holds: performance and reliability are more important than price. Consequently, a few component suppliers have developed or adapted their products for this market. Many have not.

There are several manufacturers of accelerometers and magnetometers that are able to perform at elevated temperatures – to 200°C – so there do not appear to be any unmet needs for these components. However, rate-sensing gyros are another matter.

The spinning-mass, tuned-rotor gyros that are used in most gyro-based survey and MWD tools are capable of performing at temperatures above 150°C for limited periods of time. The fundamental problem is a consequence of their generating heat and requiring a lubricant for their bearings. At elevated temperatures, the lubricant degrades, which ultimately will cause the bearings to fail.

Ring laser and fiber optic gyros, which can provide excellent performance, cannot easily be adapted for high-temperature applications. The lifetime of their optical sources is limited at temperatures above 125°C. Some of the fabrication methods used in ring laser gyros are not compatible with high temperatures. The current limitations of both types of sensors are such that our team believes other, micro-electromechanical systems (MEMS)-based sensors are more likely to meet the needs of borehole guidance and surveying in the near-to mid-term (4 to 8 years).

Gyroscopes using MEMS technology have been available and produced for many years. The first to sense the earth's rotational rate was produced in 1988. These are known as Coriolis Vibratory Gyros (CVGs) because they use a measurement principle that is fundamentally different from other gyroscopic sensors. Two (or two pairs of) proof masses are driven so they oscillate linearly, in the same plane, but in opposite directions ("antiparallel"). The sensing axis is orthogonal to and in the same plane as the driving forces. A Coriolis force, which is induced by the relative motion of each proof mass on the spinning earth, acts orthogonally to the motion and sense plane, and causes proof masses to move in opposite directions. This differential motion is sensed – typically capacitively – and is proportional to the rotational velocity. Three such sensors are capable of defining the rotational axis of the earth.

Most of the CVGs being developed and/or manufactured today are based on three designs: vibrating beams (or tuning forks), vibrating plates, or ring resonators. Of these three, the vibrating plate gyro initially developed by Draper Laboratory (which has been licensed to Honeywell Aerospace) and is also known as a double-ended tuning-fork gyro, seems at the moment to come closest to offering performance that would be comparable to that provided by tuned-rotor gyros used for borehole applications today. MEMS-based gyros (and accelerometers) are much smaller than the conventional (electromechanical) sensors they may ultimately displace. (Typically they are less than 3 mm on each side, with thickness less than 1 mm.) Because of their operating principles and small size, they use much less power than other types of gyroscopes (and accelerometers). Thus, the design and power requirements of a MEMS-based directional module that could be indexed within the space that is available inside a survey or MWD tool should be less challenging.

Initially, the advantages of such sensors would be their smaller size, better reliability, and reduced power requirements. Ultimately, they also may provide improved accuracy and reduced cost.

Although an analysis of the performance and limitations of MEMS-based gyros is outside the scope of this project, a summary of recent progress and a snapshot of the performance of currently-available gyros will serve as the basis for our conclusion. Bias and scale-factor stability dominate the error budgets of MEMS-based rate gyros. Averaging over time and indexing can substantially reduce these types of errors. (Indexing involves rotating a gyro in the plane of its sensitive axis between two known orientations, typically 180° apart, which is called “Magtagging,” or rotating it continuously so its output is a sine wave, which is known as carouseling. Both methods are now covered by U.S. Patents for MWD applications.) Generally speaking, gyro drift (or bias instability) of 0.01°/hr is considered adequate for navigational applications, including borehole guidance and surveying.

Today, at least one manufacturer of a MEMS-based rate gyro claims bias instability that is less than 0.02°/hr, averaged over a period of one hour, and an accuracy of ±0.0365° with a four-minute integration period. These figures are at least 50% better than the performance claimed by the same manufacturer in 2010, so significant progress toward sensors suitable for navigation continues to be made (Johnson et al., 2010; Johnson et al. 2015).

Unfortunately (for the operating and service companies involved in drilling for oil and gas), many of the military and aerospace applications that are being pursued by the manufacturers of MEMS-based sensors call for maximum operating temperatures of 80°C. Until more tests are conducted at higher temperatures, it is not possible to predict how much time and effort will be needed to produce MEMS-based gyros that would be capable of operating at temperatures of 150°C and higher. However, MEMS-based sensors are manufactured with the processes and techniques that are used to fabricate integrated circuits and other semiconductors, so experience gained while producing semiconductors should facilitate the development of high-temperature MEMS-based sensors.

2.1.2. Electronic Modules and Systems

The testing and qualification of semiconductors, integrated circuits, and modules is typically conducted at temperatures of 125°C and below. For military and aerospace applications, the operating limits for components typically are -55° to +125°C. The potential market for high-temperature components capable of performing at 175°C and above is not considered to be large enough for most manufacturers to make the investments needed to adapt and test their products at higher operating temperatures. Honeywell Aerospace is an exception.

Components using the silicon-on-insulator (SOI) complementary metal oxide semiconductor (CMOS) technology developed by Honeywell are capable of operating continuously at 225°C. Honeywell has produced SOI integrated circuits since about 1995, and produced SOI multi-chip modules (MCMs) for at least 10 years. Thus it's difficult to describe SOI-based components as a "new technology." However, two issues have limited their penetration of borehole-related markets:

1. The range of available circuits is limited, so providing the functionality needed in today's survey, MWD, and ranging tools is difficult, and often forces tradeoffs between the desired functions and number of circuits needed to implement the design.
2. Because they use a unique process and are manufactured in limited quantities, SOI components and MCMs are expensive.

Should the markets for steering and survey tools capable of operating at higher temperatures be expanded by the perceived needs of operators, suitable tools would, in all likelihood, be developed and be available in sufficient quantities to meet the market needs. Most of the essential "technologies" are available.

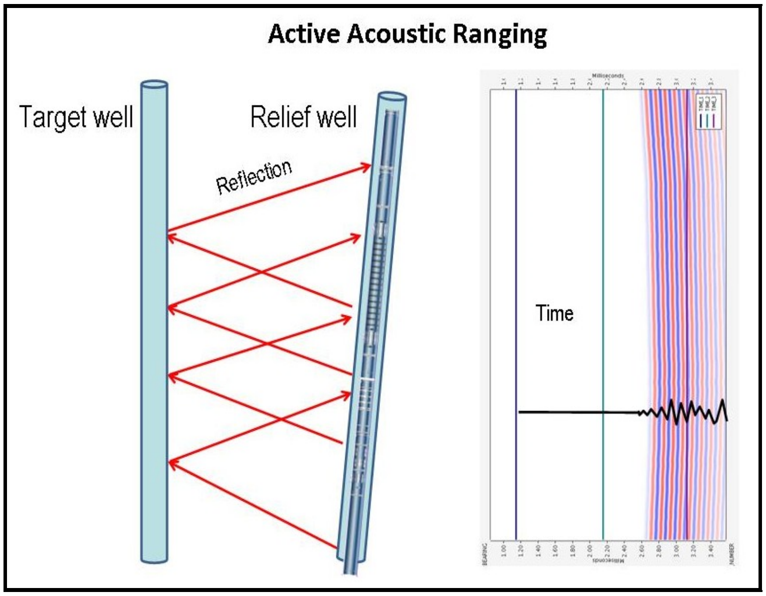
2.2. Emerging Tools

During the project, the team learned about one new tool, the adaptation of an acoustic logging tool to ranging applications, and a new approach to passive magnetic ranging. Each of these has completed some field tests, but are not considered by their manufacturers to be "commercial" products. We have included them here because the field tests have been encouraging, and each expands the methods and/or tools now used for ranging.

2.2.1. Acoustic Ranging Tool

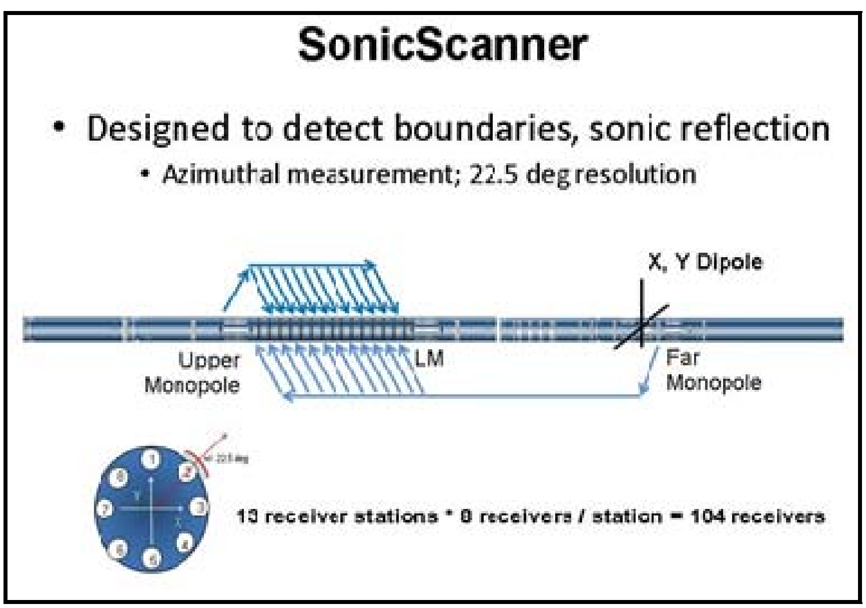
Schlumberger has adapted an acoustic wireline tool that was first developed to evaluate formations around boreholes and the quality of cement bonds to ranging applications. With a data acquisition and processing system designed for ranging, it has been successfully tested in an active ranging application. This ranging technique is effective primarily in salt formations, where conductivity inhibits the use of active electromagnetic ranging tools. The basic principle of operation is illustrated in Figure 1. Acoustic waves are transmitted into the surrounding formation from the tool. Reflections from the target are received by the tool and analyzed to determine the range and direction to the target.

Figure 1: Active Acoustic Ranging, Principle of Operation (from: Schlumberger reproduced with permission)



The Sonic Scanner tool, shown in Figure 2, utilizes monopole and dipole transmitters, which generate compression (p), and shear (s) waves. The acoustic receivers are arranged in azimuthal arrays that vary in direction and distance from the transmitters. The reflected signals are transmitted up-hole by wireline to a processing center, which resolves the distances and directions to target wellbores. The Sonic Scanner tool is 41.3 ft. long, with an outer diameter of 3.625 inches. It can withstand pressure to 27,000 psi and temperatures to 350°F (177°C).

Figure 2: SonicScanner Tool (from: Schlumberger reproduced with permission)



Modeling is highly recommended to optimize the estimated location and trajectory of the target wellbore, prior to starting drilling. In addition, the acoustic images can provide estimates of the salt quality, which can be used to select the interception location for hydraulic kills. The maximum ranging distance is dependent on the velocity and attenuation of the transmitted acoustic signals in the traversed formations. Salt typically has higher velocities that will enable ranging at greater distances than other formations.

2.2.2. BlackShark Active Ranging System

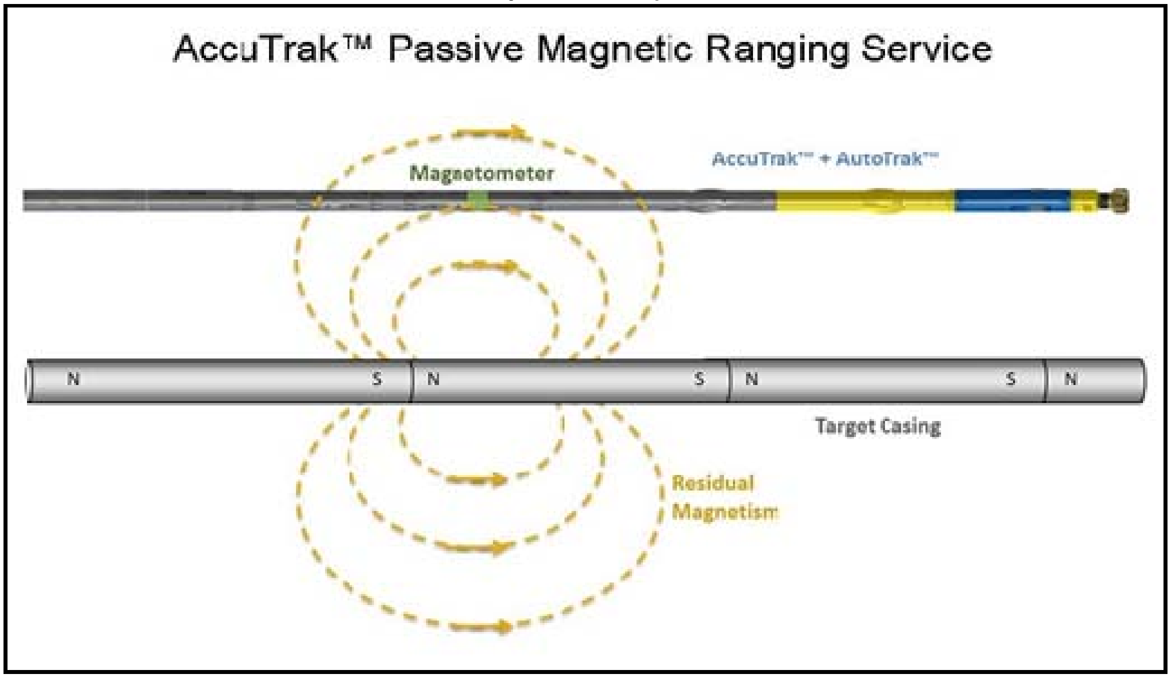
The BlackShark active ranging system, which is shown in Figure 3, was developed by Scientific Drilling International and completed its first field test in February 2016. It is a wireline tool that, in concept, is similar to Halliburton's WellSpot tool. An electromagnetic signal is radiated from a bridle, which is above the tool and has at least one radiating electrode. Isolation subs provide electrical isolation of the radiating electrode(s) from the tool, below, and the wireline, above. The tool contains magnetometers and accelerometers, which are located at the Sensor Point, and a data acquisition and telemetry module ("Downhole Processor") that gathers data from the sensors and transmits it to the surface with a Wireline Modem. The tool is 10 feet long and 4.5 inches in diameter, and can be run in tandem with a gyro-based tool. It will withstand borehole pressures to 25,000 psi and is available in a high-temperature version, which can operate at temperatures to 250°C when contained in a dewar. 200 feet is the maximum claimed range.

Figure 3: BlackShark Active Ranging Tool, (from: Scientific Drilling International reproduced with permission)

2.2.3. AccuTrac™ Passive Magnetic Ranging

Baker Hughes has developed and tested a new method of Passive Magnetic Ranging for well twinning applications that is based on aerospace navigation technology. The AccuTrak™ PMR Service uses measurements made by their OnTrak™ MWD tools and an adaptive Kalman filter technique. The basic principle, as shown in Figure 4, is to develop and refine a model for the target well that is based on the residual magnetic fields in its casing.

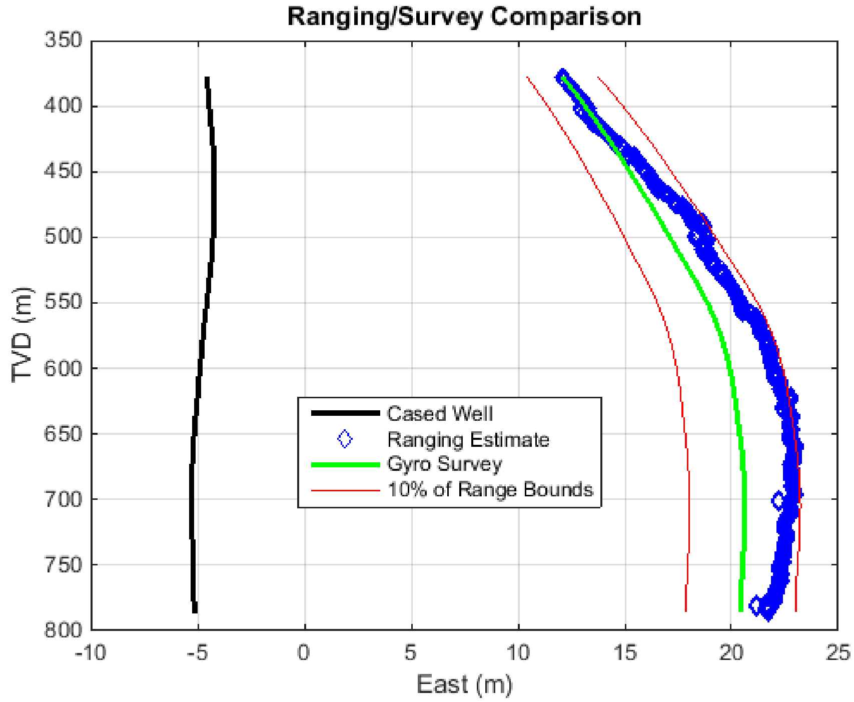
Figure 4: Passive Magnetic Ranging, Basic Principle (from: Baker Hughes, reproduced with permission)



With repeated measurements which can be acquired while rotating and drilling ahead, an initial magnetic model of the target well is improved and ultimately converges to an accurate model from which range and bearing can be calculated in real-time. The driller's display includes a compass rose depicting the location of the target well, the planned well, and the actual well path, along with range, bearing and confidence factors. Although this modeling technique was developed with SAGD well twinning applications in mind, it also can be applied to collision avoidance and relief well projects.

Figure 5 documents the performance of Baker Hughes' passive ranging system in a test well, and compares its ranging accuracy to measurements taken with a wireline rate-gyro-based survey tool.

Figure 5: Passive Magnetic Ranging, Basic Test Results (from: Baker Hughes, reproduced with permission)



2.3. New Methods and Trends in the Survey Lifecycle

The survey lifecycle includes wellbore and directional survey planning, field operations, data management, tool error models and corrections, and survey management/quality control. Industry has recognized the need to improve practices in each of these areas and has responded by improving existing methods and developing several new methods and techniques. Additionally, industry is moving forward by improving technical resources and initiating a certification in Wellbore Surveying Competency. The sections below identify new methods and trends in the wellbore survey industry that may have a material bearing on future survey operations. The information in this section was obtained through review of Industry Steering Committee for Wellbore Survey Accuracy (ISCWSA) meeting minutes, journal papers, and discussions with experts from service companies, consultancies, and operating companies.

2.3.1. Best Practices

The ISCWSA has initiated the preparation of a Recommended Practices (RP) for Wellbore Positioning to become a published practice of the American Petroleum Institute (API). ISCWSA states that the purpose of the document is to “provide a framework and minimum guidance for the planning, acquisition, quality assurance, storage, and use of wellbore position data for the well lifecycle. This includes the assessment of well objectives as they pertain to collision assessment and reserves targeting (ISCWSA 2016a).” The document designated API RP78 will contain recommended practices for many areas of directional surveys. A preliminary list of topic areas is presented in Table 1.

Table 1: Topics Potentially Included in API RP-78, Recommended Practices for Wellbore Positioning (ISCWSA, 2016a)

Topic	Content
Roles and Responsibilities	*Competence and minimum level of training, defined roles, bridging documents, API Q1*
Surface Location	*Staking procedure, elevation/vertical datum, actual/planned location, global vs. relative, coordinate system, uncertainty (methods)*
Survey Program	*Requirements for: frequency and interval, deployment method, tool type, steering, survey sequencing; magnetic north correction, tool face orientation, program by part*
Survey Mathematics	*Axial (short collar correction and limitations), SAG, MSA, IFR1 IFR2, formulas, limitations, dip*
Software	*Qualifications, vetting process, wellbore position calculation (minimum curve), standard well path*
Database	*Definitive survey and database, definitive rules/hierarchy, offset wells, trajectory tie-on, unique wellbore ID, database management, tool code assignment, ownership/ access controls and permissions, Archive and recovery, QA (missing data, course length, error model assignment)*
Position Uncertainty Models	*ISCWSA, OWSG set, survey frequency, validation, verification/Field Acquisition Criteria (FAC)*
Anti-Collision	*Clearance scan, major/minor (HSE versus non-HSE risk), Separation Factor*
QA/QC	*Revision control, quality of measurement assurance, completeness/quality of database, data integrity, QA (missing data, course length, error model assignment)*
Maps, Plots and Graphics	*Spider plots, north arrows, scales*
Planning	*Targeting requirements (drillers target, geologic target, lease requirements), fit for purpose well geometry (well life cycle and trajectory considerations, wireline, relief well considerations)*
Planning to Operations/Execution Handoffs	*Revision control, approval, distribution*
Operation/Execution	*Pre-operational checks, magnetic references, magnetic checks. scribe line confirmation, projecting ahead*
Post Survey Execution	*Data info archives, associated survey info (corrections applied, BHA), reporting (regulatory filings and requirements)*

The Well Intercept Work Group of the ISCWSA is in the process of developing documents to support best practices for wellbore interception (ISCWSA, 2016b, 2016c). The documents will include a lexicon, bibliography, and a guidance document that includes a discussion of the current ranging technologies (active, passive and acoustic), relief well ranging operations, and well intercept design considerations.

The guidance will be based on Roger Goobie's SPE paper 173097, A Guide to Relief Well Trajectory Design using Multidisciplinary Collaborative Well Planning Technology (Goobie, 2015), and Halliburton's Introduction to Relief Well Ranging & Interception (Halliburton, 2015). The guidance is planned for release as an e-book by ISCWSA in 2017. These recommended practices are important because API RP78 is currently not intended to address proximity surveys (ranging) for relief wells or interception applications.

The Collision Avoidance Work Group of the ISCWSA has started work on a set of best practice documents on collision avoidance procedures. The objective of the document is to present a clear and concise description of the structure, purpose and recommended practice for well collision avoidance. Notes from the March 2016 committee presentation (ISCWSA, 2016d) indicate that the adopted method will distinguish between HSE and non-HSE collisions and include provisions for both planning and operational applications. The document will include a recommended equation for calculating separation factor and is planned for release by ISCWSA in 2017.

In June 2016, ISCWSA announced the release of a new version (V04.05.16) of the industry standard publication e-book "Introduction to Wellbore Positioning", compiled and co-written by Professor Angus Jamison, of the University of the Highlands and Islands (UHI). The document is accepted by the ISCWSA board and is published through the UHI Research Office (ISCWSA, 2016e). The new version includes a revised chapter on Survey Frequency, a new chapter on Depth Measurements, and a new chapter on Combined Surveys. The revision is significant because it addresses the need for instruction and best practice for depth measurements and the value of performing combined surveys (magnetic and gyro, for example) to reduce uncertainty.

2.3.2. Training

Professor Angus Jamison and UHI, have developed a competency program in wellbore positioning in partnership with the Society of Petroleum Engineers (SPE) Technical Section for Wellbore Positioning (ISCWSA, 2016b). This is the first industry recognized program on the subject and was developed in response to an industry-wide need to promote good practice in this safety critical activity. The training is aimed at oil and gas professionals who collect, manage or use wellbore survey data and require to have a good understanding of the methods, the equipment and their applications and limitations. The course also is a standard, recognized credential in wellbore surveying and can be used to demonstrate competency in the subject.

The course can be taken in-house or online. The new online course had its first class starting in January 2016 with 25 students. Courses will be offered approximately four times per year.

2.3.3. Survey Management

Many operators and service companies have recently expanded their in-house organizations to address quality management of directional surveys for the planning through the final archiving of data. Additionally, several small third-party consultancies have opened to offer survey quality control services to both large and small operators. A broad range of services, referred to as survey management, are offered to reduce uncertainty in wellbore positioning. Typical services include:

- MWD survey quality analysis,
- Real-time survey and depth correction (at the rig site or in remote offices),
- Anti-collision monitoring and offset well detection,
- Survey database management,
- Well database scrubbing and verification,
- Well planning, and
- Educational consulting

The services provided by survey management organizations have been applied for many years, the bundling of these services as a separate product line is a somewhat new trend that appears to address an unmet need in wellbore survey quality control.

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Attachment C: Summary of Regulations in State, Federal, and Selected International Jurisdictions

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Table C-1. Overview of Wellbore Surveying Regulations and Guidance

Jurisdiction	Regulation or Guidance	Scope	Last Update
Federal			
BSEE	30 CFR 250.461 What are the requirements for directional and inclination surveys?	Vertical well, directional well, and composite survey requirements. Provides minimum intervals for recording results and specifies coordinate systems to use	Current as of 12/3/2015
BSEE	30 CFR 250.466 What records must I keep?	Must keep records of well logs and surveys run in the wellbore	Current as of 12/3/2015
BSEE	30 CFR 250.467 How long must I keep records?	Storage requirements for drilling records and casing and liner pressure tests, diverter tests, and BOP tests.	Current as of 12/3/2015
BSEE	30 CFR 250.468 What well records am I required to submit?	Lists the types of records that need to be submitted to BSEE	Current as of 12/3/2015
BSEE	30 CFR 250.418 What additional information must I submit with my APD?	Must submit a directional plot in APD if conducting directional drilling. No details provided.	August 2012
BSEE	Notice to Lessees (NTL) No. 2009-N10	Details directional and inclination survey data submission requirements	October 7, 2009
BSEE	Notice to Lessees (NTL) No. 2009-G33	Details well naming and number standards.	November 4, 2009
BLM	30 CFR 3162.4-2 Samples, tests, and surveys	Provides very general requirements when operators will conduct surveys ("when required by the authorized officer")	May 1988
BLM	30 CFR 3162.5-2 Control of Wells	General requirements for well control for drilling wells, vertical drilling, high pressure or loss of circulation, and protection of useable water and other materials. Includes definition of significant deviation. Minimal requirements without much detail.	March 2015
State			
New Mexico	NMAC 19.15.16.14 Deviation Tests; Deviated, Directional and Horizontal Wells	Specific requirements for when deviation tests are required, what qualifies for excessive deviation and unorthodox locations, and directional survey requirements. Primarily focuses on approvals required.	February 2012
New Mexico	NMAC 19.15.16.15 Special Rules for Horizontal Wells	Stipulates that consent must be received prior to commencing horizontal or directional drilling	February 2012
North Dakota	NDAC 43-02-03-25 Deviation Tests and Directional Surveys	Requirements for deviation test (minimum distance for recording results) and directional survey. Minimal requirements without much detail (guidance provides much more detail than regulations)	April 2012
Texas	TXAC Title 16 Part 1 Chapter 3 Rule 3.11 Inclination and Directional Surveys Required	Detailed for when inclination and directional surveys are required, reporting requirements, survey filing requirements, and associated penalties.	June 2001
Texas	TXAC Title 16 Part 1 Chapter 3 Rule 3.12 Directional Survey Company Report	Requires the surveying company to file a directional survey report and includes the required components.	October 2008

Table C-1. Overview of Wellbore Surveying Regulations and Guidance

Jurisdiction	Regulation or Guidance	Scope	Last Update
Texas	TXAC Title 16 Part 1 Chapter 3 Rule 3.4 Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms	General well ID requirements.	January 1976
Utah	UTAC R649-3-10 Tolerances for Vertical Drilling	States that deviation from vertical for short distances is permitted without special approval.	Current as of 10/1/2015
Utah	UTAC R649-3-11 Directional Drilling	Details requirements for application for directional drilling (a plat or sketch, reason for deviation, etc.).	Current as of 10/1/2015
Utah	UTAC R649-3-21 Well Completion and Filing of Well Logs	Survey filing requirements (within 30 days of being run).	Current as of 10/1/2015
Wyoming	Wyoming Oil and Gas Conservation Commission Rules Chapter 3 Section 21 Filing of Wells Logs	General filing requirements for directional surveys, including submittal format, specific surveys to be submitted (deviation, measurement-while-drilling), and length of time the surveys will remain confidential.	April 2008
Wyoming	Wyoming Oil and Gas Conservation Commission Rules Chapter 3 Section 25 Directional Drilling	Fairly in depth requirements for directional drilling including: approval requirements, required certifications, and definitions of terms.	April 2008
International			
Australia	Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 Part 7 Division 3 Regulation 7.14 Requirement for final well completion report and data	If a well is deviated or horizontal, the surveyed path of the well and well coordinates must be included in the well completion report.	November 2013
Australia	Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 Part 9 Division 3 Regulation 9.13 Requirement for initial well completion report and data	If a well is deviated or horizontal, the surveyed path of the well and well coordinates must be included in the well completion report.	November 2013
Australia	Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 Part 5 Division 3 Regulation 5.09 Contents of well operations management plan	Requires operators to include a plan for dealing with well integrity hazards.	November 2013
Australia	Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 Part 5 Division 8 Regulation 5.26 Requirement to control well integrity hazard or risk	Penalty for titleholder committing a well integrity hazard offense.	November 2013
Australia	Guidelines for Reporting and Submission of Offshore Petroleum Data	Guidelines on reporting offshore petroleum data, including submission addresses, transmittals, and example data requirements.	November 2013

Table C-1. Overview of Wellbore Surveying Regulations and Guidance

Jurisdiction	Regulation or Guidance	Scope	Last Update
Canada	Canada Oil and Gas Drilling and Production Regulations Section 77 Records	Very general requirements of records that must be kept. Does not specifically call out survey data.	December 2009
Canada	Canada Oil and Gas Drilling and Production Regulations Section 32 Directional and Deviation Surveys	Very high level, stating that "surveys are taken at intervals that allow the position of the well-bore to be determined accurately….and except in the case of a relief well, a well is drilled in a manner that does not intersect an existing well"	December 2009
Canada	Canada Oil and Gas Drilling and Production Regulations Section 6 Application for Authorization	Application requires a contingency plan to be submitted. Details on well control/relief wells (same season relief well) for this contingency plan laid out in the "National Energy Board Filing Requirements for Offshore Drilling in the Canadian Arctic". Also discusses drilling program filing requirements for application for authorization.	December 2009
Canada	National Energy Board Filing Requirements for Offshore Drilling in the Canadian Arctic Sections 4.17 and 4.18	Details requirements for contingency plans for releases of reservoir fluids and spills. Includes specific filing requirements, including same season relief well requirements.	2015
Canada	National Energy Board Filing Requirements for Offshore Drilling in the Canadian Arctic Section 5.7	Details filing requirements for well description in a well approval application.	2015
Canada	CAPP The Canadian Unique Well Identifier	Industry guidance on the Unique Well Identifier (UWI) utilized in Canada.	December 2000
Canada (Alberta)	Oil and Gas Conservation Rules Section 2.020 Application for License	An application for license must include a plan including the location for the well tied by bearings and distance to a monument and by the additional requirements laid out in the rules.	2013
Canada (Alberta)	Oil and Gas Conservation Rules Section 6.030 Deviation and Directional Surveys	The licensee must send a an electronic copy of the survey to the ERCB if a well deviates from the vertical or within 30 days of completion of drilling.	2013
Canada (Alberta)	Oil and Gas Conservation Rules Section 11.005 Well Data	Surveys must be submitted to the Regulator within the time specified by the regulator.	2013
Canada (Alberta)	Oil and Gas Conservation Rules Section 11.110 Analyses, Tests, Surveys, and Logs	Calibration and certification requirements for survey equipment.	2013
Canada (Alberta)	Oil and Gas Conservation Rules Section 11.140 Analyses, Tests, Surveys, and Logs	Surveys must "be in a format acceptable to the Regulator"	2013
Canada (Alberta)	Alberta Energy Regulator Directive 80 Well Logging	Provides well logging requirements, including submission and reporting of well log requirements.	March 23, 2016
New Zealand	Crown Minerals (Petroleum) Regulations 2007 32 Notice of intention to carry out well-drilling operations	Details of directional drilling must be reported in a notice of intention and must include kick-off depth, angle build-up, and average and maximum deviation. Notice of intention must also include proposed types of intervals of electric logs and surveys. Very high level regulations.	May 2013
New Zealand	Crown Minerals (Petroleum) Regulations 2007 45 Daily well-drilling report	Daily well drilling reports must be submitted including direction and inclination of any deviation in the well	May 2013

Table C-1. Overview of Wellbore Surveying Regulations and Guidance

Jurisdiction	Regulation or Guidance	Scope	Last Update
New Zealand	Marine Protection Rules Part 131: Offshore Installations - Oil Spill Contingency Plans and Oil Pollution Prevention Certification	Provides detailed administrative requirements for an Oil Spill Contingency Plan (which must include Well Control Contingency Plan), including submittal requirements, trainings, approvals, and general content requirements. Well Control Contingency Plan guidance is available for more detail.	October 2015
Norway	PSA Guidelines Regarding the Activities Regulations Section 82 Well location and Wellbore	References NORSOK D-010 standard, Chapters 4.3 and 5.7.4, with the following addition: the well's location and wellbore should be stated in Universal Transverse of Mercator (UTM) coordinates.	August 2004
Norway	PSA Guidelines Regarding the Activities Regulations Section 86 Well control	States that an action plan for drilling a relief well must be prepared and References NORSOK D-010 standard, Chapters 4.8 and 10.4.2.	August 2004
Norway	NORSOK D-010 Guidance version 4	Detailed guidance document on well integrity in drilling and well operations. Covers drilling, well testing, completion, production, and abandonment activities.	June 2013
Norway	NPD guidelines for designation of wells and wellbores	Defines well naming conventions for wells and wellbores.	September 1, 2014
United Kingdom	The Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999	Requires the preparation of an Environmental Statement, but does provide detail on what to include regarding well control. Guidance documents provide all the detail.	1999
United Kingdom	The Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998	Requires the preparation of an Oil Pollution Emergency Plan, but does provide detail on what to include regarding well control. Guidance documents provide all the detail.	2015
United Kingdom	Well Intervention and Well Abandonment Operations and the Petroleum Operations Notice (PON) 9 Record and Sample Requirements for Seaward Surveys and Wells	Provides well and survey record header information and lists license data to be submitted to DECC and to be made for publication.	5/13/2014
United Kingdom	A guide to the Offshore Installations (Safety Case) Regulations 2005	Additional guidelines and clarifications to the safety case regulations.	2006

Table C-2. Summary and Range of Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		RANGE OF REQUIREMENTS	
Category	**Topic**	**Least**	**Most**
Planning	Anti-collision analysis and minimum separation distances between wellbores	*Only one requirement identified*	The probability for the wellbore to be within the calculated uncertainty ellipses should exceed 95%. Minimum acceptable distance between wellbores and risk reducing actions shall be defined. [36] **(Norway)**
	Actions considered when minimum separation distance is exceed	If the results of the directional survey indicate that the producing interval is more than 50 feet from the approved surface location and closer than the minimum setback requirements to the applicable unit's outer boundaries, then the well is considered unorthodox. The operator shall file an application with the director to obtain approval of the unorthodox location [8] **(New Mexico)**	For a point of potential contact of casing with no well barrier element (WBE) function, the cuttings from the reference well should be analyzed to determine to determine cement and/or metal content prior to the separation becoming less than minimum acceptable separation. The annuli in an adjacent well should be pressurized and monitored for changes in pressure to detect penetration. If not possible, noise detection should be utilized. For a point of potential contact of casing with a well barrier element function or production liner, the production/injection in the adjacent well should cease and be secured by closing of the downhole safety valve/annulus safety valve, or setting tubing plugs, bridge plugs, or cement plugs. Installation of a well barrier below the point of contact shall be assessed. [36] **(Norway)**
	Pre-drilling application submittals (plan detailing location of proposed wellbore, location of other wellbores, proposed depth and deviation), Diagrams and well trajectory figures, requirements for identifying surveying tools to be used	Applying for a Permit to Drill (APD) must include a proposed directional plot if the well is to be directionally drilled [5] **(BSEE)**; An application for license must include a plan (including the location for the well tied by bearings and distance to a monument) [26] **(Canada (Alberta))**	Wells that will be directionally drilled must specify on the application to drill both the surface location for the well and the projected bottom hole location. The plat must include: two perpendicular lines providing the distance in feet from the projected bottomhole location to the nearest point on the lease or tract line; a line providing the distance in feet from the projected bottomhole location to the nearest point on the lease line or tract line; a line providing the distance in feet from the projected bottomhole location to the nearest oil, gas, or oil and gas well; perpendicular lines providing the distance in feet from the near nearest non-parallel survey/section lines to the projected bottomhole location [11] **(Texas)**
	Wellbore identification and naming standards	Gas well identification numbers will be assigned by the commission. [46] **(Texas)**	API well number and producing interval codes should be used to manage digital data. In addition, outer continental shelf (OCS) lease number, well or well completion name, and well name suffix should be defined. Specific details regarding the naming conventions for these identifiers is identified in the NTL. [45] **(BSEE)**

Table C-2. Summary and Range of Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		RANGE OF REQUIREMENTS	
Category	**Topic**	**Least**	**Most**
	Approvals required	Upon the director's request, the operator will conduct a directional survey. They must inform the director of the time of the survey and may not be assigned an allowable to the well until the surveys are filed [8] **(New Mexico)**	Prior to directionally drilling activities, a notice of intent must be filed with the Supervisor and approval obtained. Approval is valid for one year from the date it is granted. Approval must be given if an alternate method of survey calculation is used (other than minimum curvature method with straight line extrapolation) [16] **(Wyoming)**; Health and Safety Executive (HSE) acceptance (requires satisfaction with the approach to identify and meet health and safety needs) is required for all safety cases. The safety case is a document that gives confidence to the operator and HSE that the operator has the ability and means to control major accident risks effectively. [44] **(United Kingdom)**
	Minimum Level of Training/Competency requirements	Directional surveys must be conducted by competent surveying companies that are approved by the director [8] **(New Mexico)**	Training programs should be formulated to fill knowledge gaps for personnel working with well integrity. Knowledge areas include wellbore physics, well construction principles, preparation of well handover documentation, testing, monitoring, and maintenance. Personnel should hold a well control certificate issued by international recognized party (IWFC, IADC). All training should be documented [36] **(Norway)**
	Penalties for false reports	*Only one requirement identified*	The penalties for submitting a false report include cancellation of well permit or pipeline severance of the lease [11] **(Texas)**
	Well Planning Software	*No requirements identified*	*No requirements identified*
Operations	Minimum intervals for wellbore survey measurements in vertical wells and directional/horizontal wells -Vertical holes -low angle hole sections -high angle/build sections	Directional and deviation surveys will be taken at intervals that will allow the wellbore to be located accurately. Except in the case of relief well, a well should be drilled in a manner to not intersect another well. [22] **(Canada)**	In a vertical hole, directional surveys should be conducted at no more than 200 ft intervals and at the terminus of the vertical section. When deviation is less than 5 degrees dogleg rate, directional surveys will be taken at intervals no greater than 300 ft. When deviation is 5 degrees or greater dogleg rates, directional surveys will be taken at intervals no greater than 100 ft. In the build section, directional surveys will be taken at intervals no greater than 100 ft in the lateral portion of the wellbore while rotating. [16] **(Wyoming)**
Operations	Calibration procedures	*Only one requirement identified*	The survey or MWD contractor is responsible for ensuring MWD tools are calibrated in accordance to their standard calibration procedures [16] **(Wyoming)**

Table C-2. Summary and Range of Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		RANGE OF REQUIREMENTS	
Category	**Topic**	**Least**	**Most**
	Coordinate system and reference points to be used for surveys	Bottom hole location should be tied back to well surface location using the most recent government survey, such as NAD 83. All surveys must be corrected to True North. [16] **(Wyoming)**	All surveys must be corrected to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north after making the magnetic-to-true-north correction [1] **(BSEE)**; Regulations state that well location shall be known at all times, with guidelines specifying that the location shall be specified in Universal Transverse of Mercator (UTM) coordinates. [34] Survey plots must be referenced to grid north. [36] **(Norway)**
	Check shot surveys and accuracy verification while surveying	*Only one requirement identified*	A change out of the directional survey tools is required if the Operator has to trip out of the hole during the build section or while steering the well in the event of failure of MWD itself or failure of direction survey tool; however, the Operator will be allowed to proceed as long as the surveys are replaced with MWD check shots or gyro survey. If wells are highly deviated, the Commission may require check shots at various depths [16] **(Wyoming)**
	Measurement while drilling	*Only one requirement identified*	Measurement while drilling technology is allowed if meets the requirements in 30 CFR Part 250.461 [1] **(BSEE)**
	Magnetic spacing for azimuthal tools	*Only one requirement identified*	Proper magnetic spacing must be preserved in order to ensure azimuth accuracy [16] **(Wyoming)**
	Schedule for submission of well logs and surveys (daily, weekly, 30 days after completion, etc.)	Surveys will be conducted when required by the authorized officer. Results will be provided to the authorized officer without cost to the lessor [6] **(BLM)**; Deviation data must be made upon request in a specified format [41] **(United Kingdom)**	Directional and vertical well surveys must be submitted. In the GOM OCS Region, BSEE-0133 Well Activity Report must be submitted weekly. In the Pacific or Alaska OCS Regions, BSEE-0133 must be submitted daily [4] **(BSEE)**
	Procedures for ensuring accurate tie-on depths if more than one survey is run (including concatenation and how ellipses are tied together)	*Only one requirement identified*	Original laterals and any sidetracks shall be kept separately appropriately labeled as to what they depict and filed from the tie-in point to a projection to total measured depth of each leg or sidetrack. [16] **(Wyoming)**
	Format for survey submittal -hard copy v. electronic submittal of survey - electronic data submission format (ASCI, special format) - Actual versus planned trajectory plot	Electronic versions of the surveys (in a form approved by the director) must be submitted within 30 days of attaining total depth [9] **(North Dakota)**	Logs must be submitted to the Alberta Energy Regulator in Microsoft Excel Format along with all Log ASCII Standard and raster logs (TIFF or PDF) on a CD or DVD. Each log must be submitted as a separate file, but may be included on a single CD or DVD. The CD or DVD must be labelled with ICF Data Collection, licensee name, contact name, contact phone number, and contact email. [48] **(Canada (Alberta))**

Table C-2. Summary and Range of Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		RANGE OF REQUIREMENTS	
Category	**Topic**	**Least**	**Most**
Data Management	Corrections to subject well or other wells if errors or omissions are identified	Should a survey be missed, the Owner or Operator must take a survey at the next possible opportunity and an explanation of the reason for the missing survey shall be included on the Directional Survey Report [16] **(Wyoming)**	Surveys must show magnetic and grid corrections and include a listing of the directionally computed inclinations and azimuths [1] **(BSEE)**
	Master survey definition - what if more than 1 survey is run (MWD/gyro)	Composite surveys must show the interval from the bottom of the conductor casing to the total depth [1] **(BSEE)**	In the event that a gyro survey is run after the well has been drilled with an MWD tool, all surveys must be submitted and the “master survey” will be considered the gyro survey [16] **(Wyoming)**
	Survey calculation method	The minimum angle of curvature method or other equivalent models should be used. [36] **(Norway)**	The accepted standard for directional survey calculation shall be the minimum curvature method with straight line extrapolation acceptable from last data point in survey to Total Measured Depth. If another method is used, it must be specified on the APD. [16] **(Wyoming)**
	Projecting ahead or at end of hole	*Only one requirement identified*	Operators shall provide on their Certification form the method of bottom hole location projection used from the last surveyed point to total measured depth (TMD) [16] **(Wyoming)**
	Header and ancillary survey information requirements (BHA, rig, driller, survey operator)	Header data includes log name, complete UWI, license number, log run data, logged intervals, and ground elevation, as well as other data fields (which vary depending on the log submission type). [48] **(Canada (Alberta))**	Must include all headers and data types specified in the NTL (Geodetic datum, elevation, operator, tiein measured depth, etc.). [42] **(BSEE)**
	Operator and survey company certification forms	All training should be documented [36] **(Norway)**	Operation certification forms shall be attached to the completion form and include the operator name and address, well name and API number, well surface location, producing interval lop location, producing interval bottom location, and bottom hole location (lat/long, datum 1/4 1/4 section, etc.), specified certification language as provided by the Commission, and operator name. [16] **(Wyoming)**
	Well planner identification	*No requirements identified*	*No requirements identified*
	Data reporting for sidetracks, laterals and bypasses	Submitted reports must include a tabulation of the maximum drifts which could occur between the surface and the first shot point, and each two successive shot points [11] **(Texas)**	Laterals and sidetracks shall be kept separately, appropriately labeled, and filed from the tie-in point to a projection to TMD of each leg or sidetrack. When additional laterals and/or sidetracks are surveyed, the tie-in point should be listed as the first survey. Do not include any surveys prior to the tie-in as they are required to be filed with the previous lateral or sidetrack. The survey point used for the tie-in should be the last survey run immediately above the sidetrack depth. [16] **(Wyoming)**
	Confidentiality of surveys/well logs	*Only one requirement identified*	Well logs and surveys shall be kept confidential for 6 months after the filing date [15] **(Wyoming)**

Table C-2. Summary and Range of Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		RANGE OF REQUIREMENTS	
Category	**Topic**	**Least**	**Most**
	Raw data collection and archiving	Data records will be kept for incidents, near-misses, daily maintenance and operation activities, and the calibration of meters or instruments [21] **(Canada)**	Direction survey results must be recorded digitally. [1] Complete, legible, and accurate records must be kept for all wells onsite during drilling activities (in a location of their choice). Records include well logs and surveys in the wellbore [2] Drilling logs must be kept for 90 days after completion of activities [3] **(BSEE)**
Errors and Uncertainty	Tool survey error models used (ISCWSA, OWSG, etc., and number of standard deviations expressed)	*Only one requirement identified*	In general, a survey plan should be established to minimize the ellipses of uncertainty. The ellipses of uncertainty should be based on survey tool error models. The probability for the wellbore to be within the calculated uncertainty ellipses should exceed 95%.[36] **(Norway)**
Survey Quality Control	Independent QA/QC of survey data that is submitted	*No requirements identified*	*No requirements identified*
Relief Well Operations	Well control plan, contingency plan, relief well plan, or oil spill contingency plan that includes multiple potential locations, equipment required (including surveying and ranging), equipment availability, mobilization time, lessons learned from past incidents and near-misses, and hazard assessment	Requires that operator take all necessary precautions to keep wells under control, utilizing materials and equipment necessary to insure safety of operations. Operator shall take immediate steps and utilize all necessary resources to maintain or restore well control. Useable water and other mineral bearing formations must be protected from contamination [7] **(BLM)**	Relief wells may be drilled from two alternative locations. [34] [35] Drilling activities that will require more than one relief well shall be verified by another party no more later than 3 months prior to commencement of the activities. Per regulations, plans for regaining well control need to be prepared. [35] A relief plan must include a minimum of 2 rig locations (including an anchoring assessment and up-wind/up-current of wellbore location), shallow gas assessments for each location, simplified relief well points, overview of suitable rigs/vessels, description of primary killing method, and updates reflecting current conditions. Well control action drills should be conducted at the frequency specified in the guidance [36] **(Norway)**
	Minimum time between incident and commencement of drilling a relief well	*Only one requirement identified*	Drilling should commence no more than 12 days after the decision to drill a relief well has been made [36] **(Norway)**

Table C-3. Summary of U.S. Federal Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		U.S. FEDERAL	
Category	Topic	BSEE	BLM
Planning	Anti-collision analysis and minimum separation distances between wellbores		
	Actions considered when minimum separation distance is exceed		
	Pre-drilling application submittals (plan detailing location of proposed wellbore, location of other wellbores, proposed depth and deviation), Diagrams and well trajectory figures, requirements for identifying surveying tools to be used	Applying for a Permit to Drill (APD) must include a proposed directional plot if the well is to be directionally drilled [5]	
	Wellbore identification and naming standards	API well number and producing interval codes should be used to manage digital data. In addition, outer continental shelf (OCS) lease number, well or well completion name, and well name suffix should be defined. Specific details regarding the naming conventions for these identifiers is identified in the NTL. [45]	
	Approvals required		
	Minimum Level of Training/Competency requirements		
	Penalties for false reports		
	Well Planning Software		
Operations	Minimum intervals for wellbore survey measurements in vertical wells and directional/horizontal wells -Vertical holes -low angle hole sections -high angle/build sections	Survey intervals may not exceed 1,000 ft during normal course of drilling for vertical well. Directional surveys must be conducted (providing azimuth and inclination) within 500 ft of setting surface, 500 ft of setting a liner, or when reach total depth. Directional survey intervals must not exceed 500 ft during normal course of drilling, must not exceed 100 ft during angle-changing portions [1]	
	Calibration procedures		
	Coordinate system and reference points to be used for surveys	All surveys must be corrected to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north after making the magnetic-to-true-north correction [1]	
	Check shot surveys and accuracy verification while surveying		

Table C-3. Summary of U.S. Federal Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		U.S. FEDERAL	
Category	Topic	BSEE	BLM
	Measurement while drilling	Measurement while drilling technology is allowed if meets the requirements in 30 CFR Part 250.461 [1]	
	Magnetic spacing for azimuthal tools		
Data Management	Schedule for submission of well logs and surveys (daily, weekly, 30 days after completion, etc.)	Directional and vertical well surveys must be submitted. In the GOM OCS Region, BSEE-0133 Well Activity Report must be submitted weekly. In the Pacific or Alaska OCS Regions, BSEE-0133 must be submitted daily [4]	Surveys will be conducted when required by the authorized officer. Results will be provided to the authorized officer without cost to the lessor [6]
	Procedures for ensuring accurate tie-on depths if more than one survey is run (including concatenation and how ellipses are tied together)		
	Format for survey submittal -hard copy v. electronic submittal of survey - electronic data submission format (ASCI, special format) - Actual versus planned trajectory plot	Directional surveys must be submitted electronically using the MMS ASCII format [42]	
	Corrections to subject well or other wells if errors or omissions are identified	Surveys must show magnetic and grid corrections and include a listing of the directionally computed inclinations and azimuths [1]	
	Master survey definition - what if more than 1 survey is run (MWD/gyro)	Composite surveys must show the interval from the bottom of the conductor casing to the total depth [1]	
	Survey calculation method		
	Projecting ahead or at end of hole		
	Header and ancillary survey information requirements (BHA, rig, driller, survey operator)	Must include all headers and data types specified in the NTL (Geodetic datum, elevation, operator, tiein measured depth, etc.). [42]	
	Operator and survey company certification forms		
	Well planner identification		
	Data reporting for sidetracks, laterals and bypasses		
	Confidentiality of surveys/well logs		

Table C-3. Summary of U.S. Federal Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		U.S. FEDERAL	
Category	**Topic**	**BSEE**	**BLM**
	Raw data collection and archiving	Direction survey results must be recorded digitally. [1] Complete, legible, and accurate records must be kept for all wells onsite during drilling activities (in a location of their choice). Records include well logs and surveys in the wellbore [2] Drilling logs must be kept for 90 days after completion of activities [3]	
Errors and Uncertainty	Tool survey error models used (ISCWSA, OWSG, etc., and number of standard deviations expressed)		
Survey Quality Control	Independent QA/QC of survey data that is submitted		
Relief Well Operations	Well control plan, contingency plan, relief well plan, or oil spill contingency plan that includes multiple potential locations, equipment required (including surveying and ranging), equipment availability, mobilization time, lessons learned from past incidents and near-misses, and hazard assessment		Requires that operator take all necessary precautions to keep wells under control, utilizing materials and equipment necessary to insure safety of operations. Operator shall take immediate steps and utilize all necessary resources to maintain or restore well control. Useable water and other mineral bearing formations must be protected from contamination [7]
	Minimum time between incident and commencement of drilling a relief well		

Table C-4. Summary of U.S. State Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		STATE				
Category	Topic	New Mexico	North Dakota	Texas	Utah	Wyoming
Planning	Anti-collision analysis and minimum separation distances between wellbores					
	Actions considered when minimum separation distance is exceed	If the results of the directional survey indicate that the producing interval is more than 50 feet from the approved surface location and closer than the minimum setback requirements to the applicable unit's outer boundaries, then the well is considered unorthodox. The operator shall file an application with the director to obtain approval of the unorthodox location [8]				
	Pre-drilling application submittals (plan detailing location of proposed wellbore, location of other wellbores, proposed depth and deviation), Diagrams and well trajectory figures, requirements for identifying surveying tools to be used			Wells that will be directionally drilled must specify on the application to drill both the surface location for the well and the projected bottom hole location. The plat must include: two perpendicular lines providing the distance in feet from the projected bottomhole location to the nearest point on the lease or tract line; a line providing the distance in feet from the projected bottomhole location to the nearest point on the lease line or tract line; a line providing the distance in feet from the projected bottomhole location to the nearest oil, gas, or oil and gas well; perpendicular lines providing the distance in feet from the near nearest non-parallel survey/section lines to the projected bottomhole location [11]	An application for directional drilling may be included in initial APD for a proposed well. The application must include the name and address of the operator, the well identification details (lease, well number, field and reservoir names, etc.), a plat or sketch showing the distance from the surface location to lease lines, target location within the producing interval, and any point along the proposed wellbore outside the 460 ft radius for which consent of the owner has been obtained. It must also include the reason for intentional deviation. [13]	Notice of intent must include depth, exact surface location, proposed direction of deviation, and proposed horizontal distance between surface location and bottom of the wellbore. [16]
	Wellbore identification and naming standards	The director will maintain a record of official well names, which include the name and location of the well and the well file number. The official name of the well will be the last name assigned to a well in the well-name register. [47]	The director will maintain a record of official well names, which include the name and location of the well and the well file number. The official name of the well will be the last name assigned to a well in the well-name register. [47]	Gas well identification numbers will be assigned by the commission. [46]		Wells will be identified by state well number and API number. A horizontal well's number will be appended with an "H" suffix. [16]
	Approvals required	Upon the director's request, the operator will conduct a directional survey. They must inform the director of the time of the survey and may not be assigned an allowable to the well until the surveys are filed [8]	Special permits must be attained to drill directionally. Directional surveys may be waived If the wellbore is deviated to sidetrack junk in the hole, straighten a crooked hole, control a blowout, or if the necessity can be demonstrated [9]	If the need to drill directionally comes up after drilling has begun, the operator will give written notice to the district and commission offices and wait for approval before proceeding [11]	Deviation from the vertical is permitted without special approval to straighten the hole, sidetrack junk, or correct mechanical difficulties. [12] Otherwise, no well may be intentionally deviated without filing an application and receiving approval prior to deviation. [13]	Prior to directionally drilling activities, a notice of intent must be filed with the Supervisor and approval obtained. Approval is valid for one year from the date it is granted. Approval must be given if an alternate method of survey calculation is used (other than minimum curvature method with straight line extrapolation) [16]
	Minimum Level of Training/Competency requirements	Directional surveys must be conducted by competent surveying companies that are approved by the director [8]		Directional surveys must be run by competent surveying companies, approved by the commission, and signed and certified by a person having knowledge of the facts [11]		

Table C-4. Summary of U.S. State Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		STATE				
Category	Topic	New Mexico	North Dakota	Texas	Utah	Wyoming
	Penalties for false reports			The penalties for submitting a false report include cancellation of well permit or pipeline severance of the lease [11]		
	Well Planning Software					
Operations	Minimum intervals for wellbore survey measurements in vertical wells and directional/horizontal wells -Vertical holes -low angle hole sections -high angle/build sections	Directional survey shot points must be no more than 200 ft apart. Deviation tests will be at least every 500 ft. [8]		The first shot of an inclination survey must be made at 500 ft depth. They must be made every 500 ft or when a drill bit requires changing, but cannot exceed 1,000 ft. Directional surveys must be single shot surveys or multi-shot surveys with shot points no more than 200 ft apart, beginning with 200 ft below the surface. If more than 200 ft of casing has already been run, the directional survey may begin directly below the surface casing depth [11]		In a vertical hole, directional surveys should be conducted at no more than 200 ft intervals and at the terminus of the vertical section. When deviation is less than 5 degrees dogleg rate, directional surveys will be taken at intervals no greater than 300 ft. When deviation is 5 degrees or greater dogleg rates, directional surveys will be taken at intervals no greater than 100 ft. In the build section, directional surveys will be taken at intervals no greater than 100 ft in the lateral portion of the wellbore while rotating. [16]
Operations	Calibration procedures					The survey or MWD contractor is responsible for ensuring MWD tools are calibrated in accordance to their standard calibration procedures [16]
Operations	Coordinate system and reference points to be used for surveys					Bottom hole location should be tied back to well surface location using the most recent government survey, such as NAD 83. All surveys must be corrected to True North. [16]
Operations	Check shot surveys and accuracy verification while surveying					A change out of the directional survey tools is required if the Operator has to trip out of the hole during the build section or while steering the well in the event of failure of MWD itself or failure of direction survey tool; however, the Operator will be allowed to proceed as long as the surveys are replaced with MWD check shots or gyro survey. If wells are highly deviated, the Commission may require check shots at various depths [16]
Operations	Measurement while drilling					
Operations	Magnetic spacing for azimuthal tools					Proper magnetic spacing must be preserved in order to ensure azimuth accuracy [16]
	Schedule for submission of well logs and surveys (daily, weekly, 30 days after completion, etc.)				The deviation survey and/or MWD measurements must be submitted within 30 days of completion of the directionally drilled well [13] [14]	Within 30 days after logs are run on a well or within 30 days of completion, the operator must submit a well log. A 30 day extension may be granted if requested by the operator. Directionally surveys that portray bottomhole location and/or MWD surveys must also be submitted within 30 days of completion. [15] [16]

Table C-4. Summary of U.S. State Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		STATE				
Category	**Topic**	**New Mexico**	**North Dakota**	**Texas**	**Utah**	**Wyoming**
Data Management	Procedures for ensuring accurate tie-on depths if more than one survey is run (including concatenation and how ellipses are tied together)					Original laterals and any sidetracks shall be kept separately appropriately labeled as to what they depict and filed from the tie-in point to a projection to total measured depth of each leg or sidetrack. [16]
Data Management	Format for survey submittal -hard copy v. electronic submittal of survey - electronic data submission format (ASCI, special format) - Actual versus planned trajectory plot		Electronic versions of the surveys (in a form approved by the director) must be submitted within 30 days of attaining total depth [9]	Surveys must be submitted regardless of the reason the survey was run. If calculations are made from dipmeter surveys to determine the wellbore course, a report of computations must be submitted [11]		Well logs should be submitted on Commission's Form 2. Logs should be submitted electronically in LAS, Log ASCII standard, or in a format approved by the Supervisor. [15] [16] Directional surveys must include a plan vs. actual plot with all dimensions marked. It may be submitted electronically in .pdf format, but must be complete and signed. All surveys must be submitted and no portion of the survey should be deleted. Directional survey certification form must include company name, survey job identifiers, well name and API number, operator/client name, well location (lat/long, county, etc.), report date, survey run date, survey depth range, survey tool type and relation to bit, rig identifiers, surveyor name, and specific certification language as provided by the Commission [16]
Data Management	Corrections to subject well or other wells if errors or omissions are identified					Should a survey be missed, the Owner or Operator must take a survey at the next possible opportunity and an explanation of the reason for the missing survey shall be included on the Directional Survey Report [16]
Data Management	Master survey definition - what if more than 1 survey is run (MWD/gyro)					In the event that a gyro survey is run after the well has been drilled with an MWD tool, all surveys must be submitted and the “master survey” will be considered the gyro survey [16]
Data Management	Survey calculation method					The accepted standard for directional survey calculation shall be the minimum curvature method with straight line extrapolation acceptable from last data point in survey to Total Measured Depth. If another method is used, it must be specified on the APD. [16]
Data Management	Projecting ahead or at end of hole					Operators shall provide on their Certification form the method of bottom hole location projection used from the last surveyed point to total measured depth (TMD) [16]

Table C-4. Summary of U.S. State Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		STATE				
Category	Topic	New Mexico	North Dakota	Texas	Utah	Wyoming
	Header and ancillary survey information requirements (BHA, rig, driller, survey operator)					
	Operator and survey company certification forms			When a directional survey report is required, a Directional Survey Company Report must be submitted to the commission. Must include: name of the surveying company, name of individual conducting the survey, title or position that individual holds, the date of the survey, the type of survey or if it is a multishot survey, identification of the well, and depth of the well. The report may be filed electronically if able [10]		Operation certification forms shall be attached to the completion form and include the operator name and address, well name and API number, well surface location, producing interval lop location, producing interval bottom location, and bottom hole location (lat/long, datum 1/4 1/4 section, etc.), specified certification language as provided by the Commission, and operator name. [16]
	Well planner identification					
	Data reporting for sidetracks, laterals and bypasses			Submitted reports must include a tabulation of the maximum drifts which could occur between the surface and the first shot point, and each two successive shot points [11]		Laterals and sidetracks shall be kept separately, appropriately labeled, and filed from the tie-in point to a projection to TMD of each leg or sidetrack. When additional laterals and/or sidetracks are surveyed, the tie-in point should be listed as the first survey. Do not include any surveys prior to the tie-in as they are required to be filed with the previous lateral or sidetrack. The survey point used for the tie-in should be the last survey run immediately above the sidetrack depth. [16]
	Confidentiality of surveys/well logs					Well logs and surveys shall be kept confidential for 6 months after the filing date [15]
	Raw data collection and archiving					
Errors and Uncertainty	Tool survey error models used (ISCWSA, OWSG, etc., and number of standard deviations expressed)					
Survey Quality Control	Independent QA/QC of survey data that is submitted					
Relief Well Operations	Well control plan, contingency plan, relief well plan, or oil spill contingency plan that includes multiple potential locations, equipment required (including surveying and ranging), equipment availability, mobilization time, lessons learned from past incidents and near-misses, and hazard assessment					
	Minimum time between incident and commencement of drilling a relief well					

Table C-5. Summary of International Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		INTERNATIONAL					
Category	Topic	Australia	Canada	Canada (Alberta)	New Zealand	Norway	United Kingdom
Planning	Anti-collision analysis and minimum separation distances between wellbores					The probability for the wellbore to be within the calculated uncertainty ellipses should exceed 95%. Minimum acceptable distance between wellbores and risk reducing actions shall be defined. [36]	
	Actions considered when minimum separation distance is exceed					For a point of potential contact of casing with no well barrier element (WBE) function, the cuttings from the reference well should be analyzed to determine to determine cement and/or metal content prior to the separation becoming less than minimum acceptable separation. The annuli in an adjacent well should be pressurized and monitored for changes in pressure to detect penetration. If not possible, noise detection should be utilized. For a point of potential contact of casing with a well barrier element function or production liner, the production/injection in the adjacent well should cease and be secured by closing of the downhole safety valve/annulus safety valve, or setting tubing plugs, bridge plugs, or cement plugs. Installation of a well barrier below the point of contact shall be assessed. [36]	
	Pre-drilling application submittals (plan detailing location of proposed wellbore, location of other wellbores, proposed depth and deviation), Diagrams and well trajectory figures, requirements for identifying surveying tools to be used		Application for authorization should include a description of the drilling and well control equipment. [23] Per filing requirements, an application should include a directional plan. [25]	An application for license must include a plan (including the location for the well tied by bearings and distance to a monument) [26]	Notice of intention to drill must be given at least 15 days before drilling commences. It must include the proposed depth, details of any proposed directional drilling (kick-off depth, angle build up, average and maximum deviation), drilling forecast with schematic, and proposed type and intervals of electric logs and surveys [31]		Notification of well operations must include particulars (including diagrams) of the location of the top of the well, the directional path of the wellbore, its terminal depth an location, its position and that of nearby wells relative to each other. The diagram of the directional path should include a plot with vertical section and horizontal plan. The notification must also include the procedures for effectively monitoring the direction of the wellbore and for minimizing the likelihood and effects of intersecting nearby wells. [44]

Table C-5. Summary of International Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		INTERNATIONAL					
Category	Topic	Australia	Canada	Canada (Alberta)	New Zealand	Norway	United Kingdom
	Wellbore identification and naming standards			In log submittals, wells will be identified using the Unique Well Identifier (UWI). [48] The UWI is made up of 16 characters that identify the legal survey location and three additional codes. It defines an approximate geographical location of the well and may define a significant drilling or producing event. [50]		Well and wellbores are identified using quadrant number, block number, identification of the wellbore, well number, identifying letter for well (exploration wellbore planned to be deviated, side tracks, etc.), count of re-entried or well tracks, whether sub-sea is complete, and detailed status identifiers provided by operator. [49]	
	Approvals required						Health and Safety Executive (HSE) acceptance (requires satisfaction with the approach to identify and meet health and safety needs) is required for all safety cases. The safety case is a document that gives confidence to the operator and HSE that the operator has the ability and means to control major accident risks effectively. [44]
	Minimum Level of Training/Competency requirements					Training programs should be formulated to fill knowledge gaps for personnel working with well integrity. Knowledge areas include wellbore physics, well construction principles, preparation of well handover documentation, testing, monitoring, and maintenance. Personnel should hold a well control certificate issued by international recognized party (IWFC, IADC). All training should be documented [36]	
	Penalties for false reports						
	Well Planning Software						
Operations	Minimum intervals for wellbore survey measurements in vertical wells and directional/horizontal wells -Vertical holes -low angle hole sections -high angle/build sections		Directional and deviation surveys will be taken at intervals that will allow the wellbore to be located accurately. Except in the case of relief well, a well should be drilled in a manner to not intersect another well. [22]	Unless approval is given otherwise, shots shall be taken at depth intervals not exceeding 150 meters [27]		When drilling a new well, inclination and direction must be obtained at least every 100 meters MD [36]	DECC expects that competent operators will acquire all data and samples necessary to carry out safe and efficient drilling operations and properly evaluate formations encountered in a well. DECC does not specify a minimum data acquisition program although it reserves the right to enforce changes or enhancements to a planned program through well consents process. [41]
	Calibration procedures						

Table C-5. Summary of International Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		INTERNATIONAL					
Category	**Topic**	**Australia**	**Canada**	**Canada (Alberta)**	**New Zealand**	**Norway**	**United Kingdom**
	Coordinate system and reference points to be used for surveys					Regulations state that well location shall be known at all times, with guidelines specifying that the location shall be specified in Universal Transverse of Mercator (UTM) coordinates. [34] Survey plots must be referenced to grid north. [36]	
	Check shot surveys and accuracy verification while surveying						
	Measurement while drilling						
	Magnetic spacing for azimuthal tools						
Data Management	Schedule for submission of well logs and surveys (daily, weekly, 30 days after completion, etc.)	Raw data, edited field data, and processed data for all wireline logs, MWD, or LWD tools needs to be submitted within 6 months after rig release date. Initial well completion reports must submitted within 6 months after rig release date and final completion reports must be submitted within 18 months after rig release date. [43]		Licensee shall, immediately upon making a directional survey, send the regulator a copy. [27] In general for well logs and surveys, the licensee will report the results within the time specified by the regulator. [28] Within one month of rig release date, submit to the Regulator a copy of each log, survey, or chart taken. [30]	Daily reports must be submitted, including direction and inclination of any well and details of operations [32]		Deviation data must be made upon request in a specified format. Well log data available within 12 months of Well Completion Date. [41]
Data Management	Procedures for ensuring accurate tie-on depths if more than one survey is run (including concatenation and how ellipses are tied together)						
Data Management	Format for survey submittal -hard copy v. electronic submittal of survey - electronic data submission format (ASCI, special format) - Actual versus planned trajectory plot	Initial and final well completion reports must include contractor names for wireline logging, MWD, and LWD, MWD or LWD tools used, MD, TVD. If the well is deviated, it must also include the surveyed path of the well, coordinates of the bottom of the wellbore, and if applicable, the coordinates and true vertical depth of the intersection of the well with the reservoir horizon. [17] [18] Completion reports must be submitted as pdf via a CD/DVD or portable hard drive. Raw data must be submitted as LIS, DLIS, or LAS via a CD/DVD or portable hard drive. [43]		Logs must be submitted to the Alberta Energy Regulator in Microsoft Excel Format along with all Log ASCII Standard and raster logs (TIFF or PDF) on a CD or DVD. Each log must be submitted as a separate file, but may be included on a single CD or DVD. The CD or DVD must be labelled with ICF Data Collection, licensee name, contact name, contact phone number, and contact email. [48]			
Data Management	Corrections to subject well or other wells if errors or omissions are identified						

Table C-5. Summary of International Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		INTERNATIONAL					
Category	**Topic**	**Australia**	**Canada**	**Canada (Alberta)**	**New Zealand**	**Norway**	**United Kingdom**
	Master survey definition - what if more than 1 survey is run (MWD/gyro)						
	Survey calculation method					The minimum angle of curvature method or other equivalent models should be used. [36]	
	Projecting ahead or at end of hole						
	Header and ancillary survey information requirements (BHA, rig, driller, survey operator)			Header data includes log name, complete UWI, license number, log run data, logged intervals, and ground elevation, as well as other data fields (which vary depending on the log submission type). [48]			
	Operator and survey company certification forms					All training should be documented [36]	
	Well planner identification						
	Data reporting for sidetracks, laterals and bypasses						
	Confidentiality of surveys/well logs						
	Raw data collection and archiving		Data records will be kept for incidents, near-misses, daily maintenance and operation activities, and the calibration of meters or instruments [21]				
Errors and Uncertainty	Tool survey error models used (ISCWSA, OWSG, etc., and number of standard deviations expressed)					In general, a survey plan should be established to minimize the ellipses of uncertainty. The ellipses of uncertainty should be based on survey tool error models. The probability for the wellbore to be within the calculated uncertainty ellipses should exceed 95%.[36]	
Survey Quality Control	Independent QA/QC of survey data that is submitted						

Table C-5. Summary of International Wellbore Surveying Regulatory Requirements

REQUIREMENT TYPE		INTERNATIONAL					
Category	Topic	Australia	Canada	Canada (Alberta)	New Zealand	Norway	United Kingdom
Relief Well Operations	Well control plan, contingency plan, relief well plan, or oil spill contingency plan that includes multiple potential locations, equipment required (including surveying and ranging), equipment availability, mobilization time, lessons learned from past incidents and near-misses, and hazard assessment	A well operations management plan must include an explanation of how to deal with a well integrity hazard or a significant increase in an existing risk for the well. Plan must also include how the titleholder will notify the Regulator and give reports on well integrity hazards and risks. [19] Penalties will be issued if titleholders do not control well integrity or risk. [20]	Application for authorization should include a contingency plan that includes emergency response activities including coordination with other regional response plans and oil spill countermeasures. [23] Specifically, filing requirements state that contingency plans should include a description of the worst case scenario (flow rate, total volume of fluids, etc.), describe criteria to select the appropriate contingency measures, describe measures available to regain well control through same-well intervention and by drilling a relief well, and lessons learned from previous incidents and near misses. The plan must also include capping and containment measures as well as same season relief well capability (describe relief well plans, procedures, technology and competencies, time to drill relief well, and strategies for drilling a relief well using a second drilling unit. Guidance also detail spill contingency plan requirements [24]		Has detailed administrative requirements for an Oil Spill Contingency Plan including submittal requirements, trainings, approvals, and general content requirements. All installations must have an International Oil Pollution Prevention Certificate. [33]	Relief wells may be drilled from two alternative locations. [34] [35] Drilling activities that will require more than one relief well shall be verified by another party no more later than 3 months prior to commencement of the activities. Per regulations, plans for regaining well control need to be prepared. [35] A relief plan must include a minimum of 2 rig locations (including an anchoring assessment and up-wind/up-current of wellbore location), shallow gas assessments for each location, simplified relief well points, overview of suitable rigs/vessels, description of primary killing method, and updates reflecting current conditions. Well control action drills should be conducted at the frequency specified in the guidance [36]	An Environmental Statement and an Oil Pollution Emergency Plan are required. [38] [39] Operators must provide details on plans to manage a relief well operation. A contractor must be selected for these operations, however a contract does not need to be in place. Operators must demonstrate that they could drill a relief well in a timely manner. [40]
	Minimum time between incident and commencement of drilling a relief well					Drilling should commence no more than 12 days after the decision to drill a relief well has been made [36]	

References

[1] 30 CFR 250.461 What are the requirements for directional and inclination surveys?
[2] 30 CFR 250.466 What records must I keep?
[3] 30 CFR 250.467 How long must I keep records?
[4] 30 CFR 250.468 What well records am I required to submit?
[5] 30 CFR 250.418 What additional information must I submit with my APD?
[6] 30 CFR 3162.4-2 Samples, tests, and surveys
[7] 30 CFR 3162.5-2 Control of Wells
[8] NMAC 19.15.16.14 Deviation Tests; Deviated, Directional and Horizontal Wells
[9] NDAC 43-02-03-25 Deviation Tests and Directional Surveys
[10] TXAC Title 16 Part 1 Chapter 3 Rule 3.12 Directional Survey Company Report
[11] TXAC Title 16 Part 1 Chapter 3 Rule 3.11 Inclination and Directional Surveys Required
[12] UTAC R649-3-10 Tolerances for Vertical Drilling
[13] UTAC R649-3-11 Directional Drilling
[14] UTAC R649-3-21 Well Completion and Filing of Well Logs
[15] Wyoming Oil and Gas Conservation Commission Rules Chapter 3 Section 21 Filing of Wells Logs
[16] Wyoming Oil and Gas Conservation Commission Rules Chapter 3 Section 25 Directional Drilling
[17] Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 Part 7 Division 3 Regulation 7.14 Requirement for final well completion report and data
[18] Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 Part 9 Division 3 Regulation 9.13 Requirement for initial well completion report and data
[19] Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 Part 5 Division 3 Regulation 5.09 Contents of well operations management plan
[20] Offshore Petroleum and Greenhouse Gas Storage (Resource Management and Administration) Regulations 2011 Part 5 Division 8 Regulation 5.26 Requirement to control well integrity hazard or risk
[21] Canada Oil and Gas Drilling and Production Regulations Section 77 Records
[22] Canada Oil and Gas Drilling and Production Regulations Section 32 Directional and Deviation Surveys
[23] Canada Oil and Gas Drilling and Production Regulations Section 6 Application for Authorization
[24] National Energy Board Filing Requirements for Offshore Drilling in the Canadian Arctic Sections 4.17 and 4.18
[25] National Energy Board Filing Requirements for Offshore Drilling in the Canadian Arctic Section 5.7
[26] Oil and Gas Conservation Rules Section 2.020 Application for License
[27] Oil and Gas Conservation Rules Section 6.030 Deviation and Directional Surveys
[28] Oil and Gas Conservation Rules Section 11.005 Well Data
[29] Oil and Gas Conservation Rules Section 11.110 Analyses, Tests, Surveys, and Logs
[30] Oil and Gas Conservation Rules Section 11.140 Analyses, Tests, Surveys, and Logs

[31] Crown Minerals (Petroleum) Regulations 2007 32 Notice of intention to carry out well-drilling operations
[32] Crown Minerals (Petroleum) Regulations 2007 45 Daily well-drilling report
[33] Marine Protection Rules Part 131: Offshore Installations - Oil Spill Contingency Plans and Oil Pollution Prevention Certification
[34] PSA Guidelines Regarding the Activities Regulations Section 82 Well location and Wellbore
[35] PSA Guidelines Regarding the Activities Regulations Section 86 Well control
[36] NORSOK D-010 Guidance version 4
[37] The Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999
[38] The Offshore Petroleum Production and Pipe-lines (Assessment of Environmental Effects) Regulations 1999
[39] The Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998
[40] Clarification of DECC Guidance Relating to Environmental Aspects of Drilling
[41] Well Intervention and Well Abandonment Operations and the Petroleum Operations Notice (PON) 9 Record and Sample Requirements for Seaward Surveys and Wells
[42] Notice to Lessees (NTL) No. 2009-N10
[43] Guidelines for Reporting and Submission of Offshore Petroleum Data
[44] A guide to the Offshore Installations (Safety Case) Regulations 2005
[45] Notice to Lessees (NTL) No. 2009-G33
[46] TXAC Title 16 Part 1 Chapter 3 Rule 3.4 Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms
[47] NDAC 43-02-03-13 Record of Wells
[48] Alberta Energy Regulator Directive 80 Well Logging
[49] NPD guidelines for designation of wells and wellbores
[50] CAPP The Canadian Unique Well Identifier