Evaluating Barriers to Manage Drilling Costs and Risks

Prosper Aideyan, P.E., Prozzane LLC

14 April 2016
Houston, Texas

PROZZANE

Evaluating Barriers to Manage Drilling Costs and Risks

Prosper Aideyan, P.E.

Contents

- Risk Management
- Barriers and Types
- Barrier Evaluation
- Barrier Effectiveness
- Bow-ties and Example Risks and Barriers
- Impact of Barriers on Drilling Optimization
- Barrier Generation
- Barrier Design and Selection
- Inherently Safer Design/Practices
- Other Example Bow-ties and Barriers to Risks

Risk Management

- Risk Management: forecasting and evaluation of risks together with the development of barriers to avoid or minimize their impact
  - Identification
  - Assessment
  - Barriers generation
  - Barriers monitoring and review

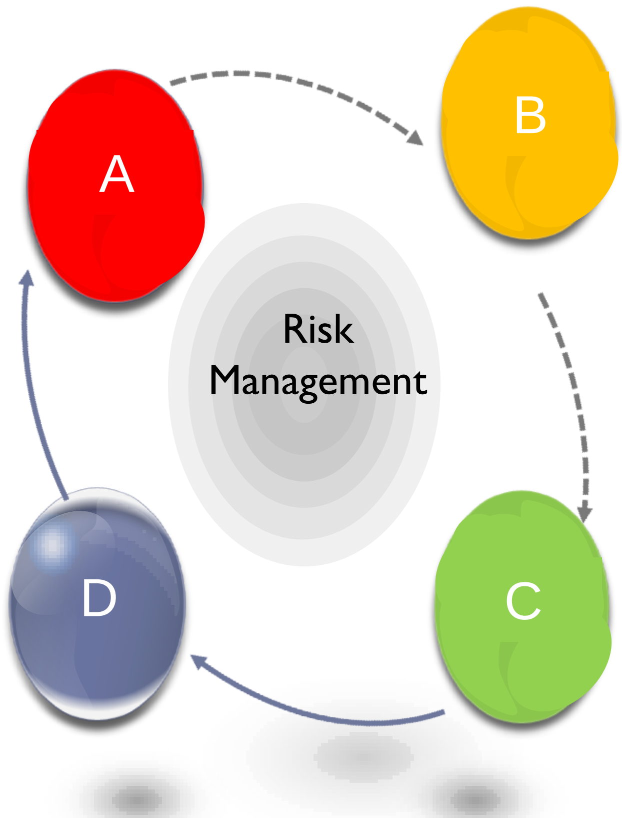
Risk Management Process

A- Risk Identification

- Review effect of deviation in measurable parameters
- Review possible change in energy in the system
- Energy – mechanical, hydraulic, heat, chemical etc.

B- Risk Assessment

- Assign probability and Impact
- Determine acceptable risk
- Cancel operations where risks cannot be accepted



C-Barriers Generation

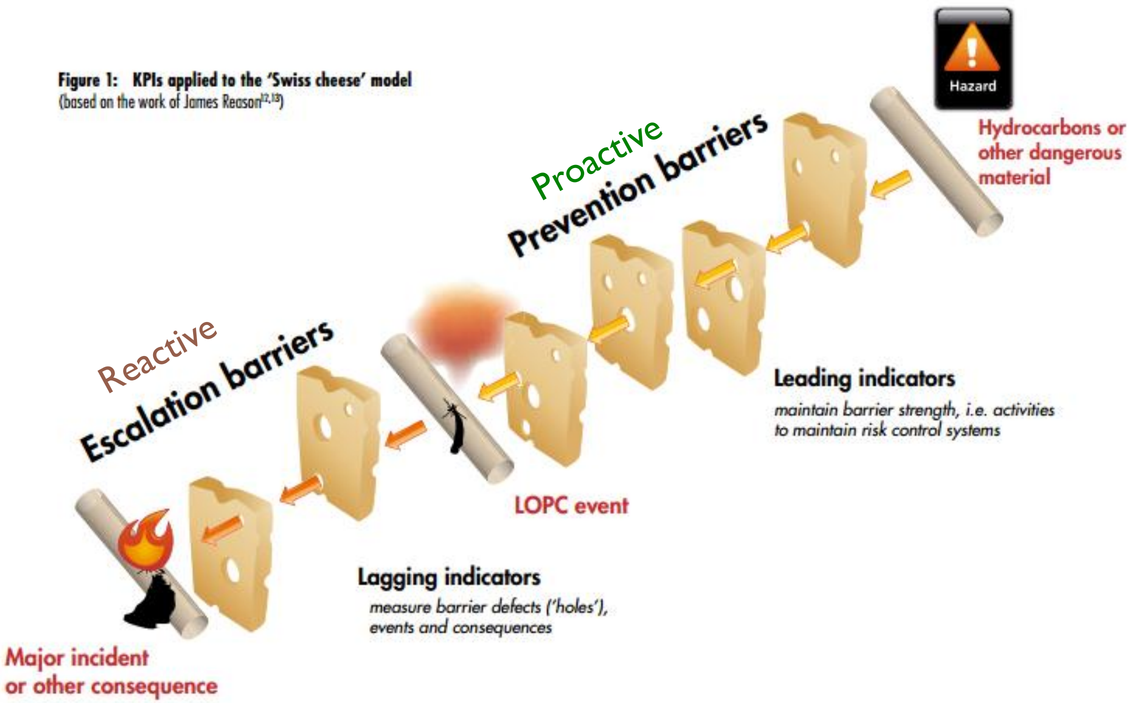
- Preventative, detection/control, mitigation barriers
- People, Process, Equipment
- Passive, Active, Procedural

D-Monitoring and Review

- Review risks and barriers at pre-defined frequency
- Evaluate effectiveness and reliability of barriers
- Testing and validation of barriers
- Consider upgrading procedural barriers to passive/active barriers
- Source new barriers due to better technology or government regulation
- Establishing KPIs

Barriers

- Barriers are simply “obstacle” to transfer/flow of energy
- Energy release “hazard” are contained by multiple barriers

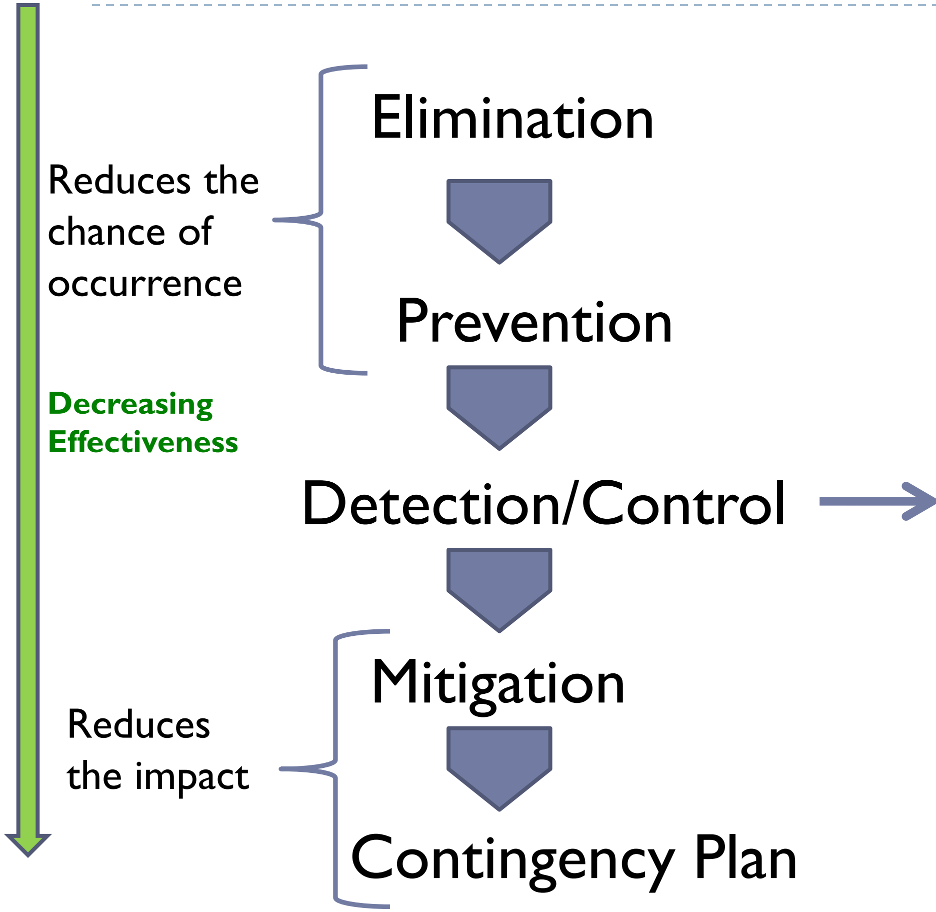


Source: Process Safety – Recommended Practice on Key Performance Indicators. Report No. 456, 2011

Types of Barriers

- Preventative Barriers: Reduce likelihood of occurrence
  - Elimination
  - Prevention
- Control/Detection Barriers: detection of risk events/control (indicators)
  - Parameters trending such as ROP, WOB, d-exponent, MSE, Vibration, Power etc.
  - Alarms
  - Can be use to determine the effectiveness of an action implemented to address a risk
  - It can be used to validate/update design (design vs. Actual)
- Mitigation Barriers: Minimize impact
  - Mitigations
  - Contingency plans

Barriers



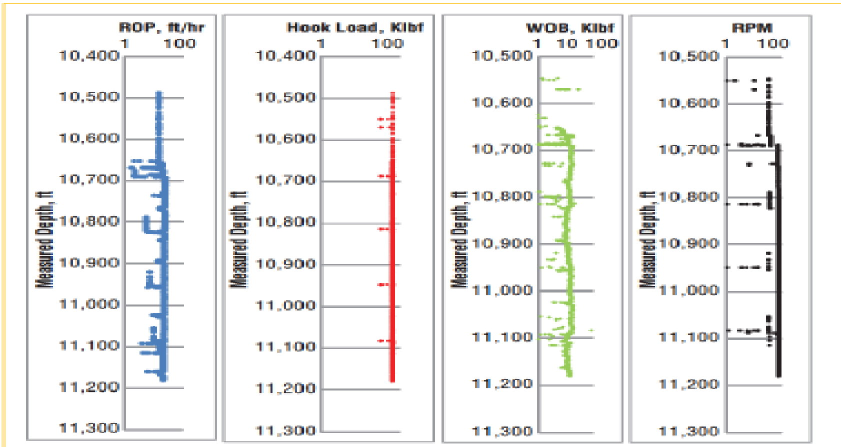
- Control/Detection "Listening" Barriers: This involves operational parameters trending or testing such as:
  - Torque and Drag
  - WOB, RPM, MW
  - Vibration/shocks
  - Mud properties
  - D-exponent
  - Positive and in-flow testing
- Operation limits should be defined with high and low alarms

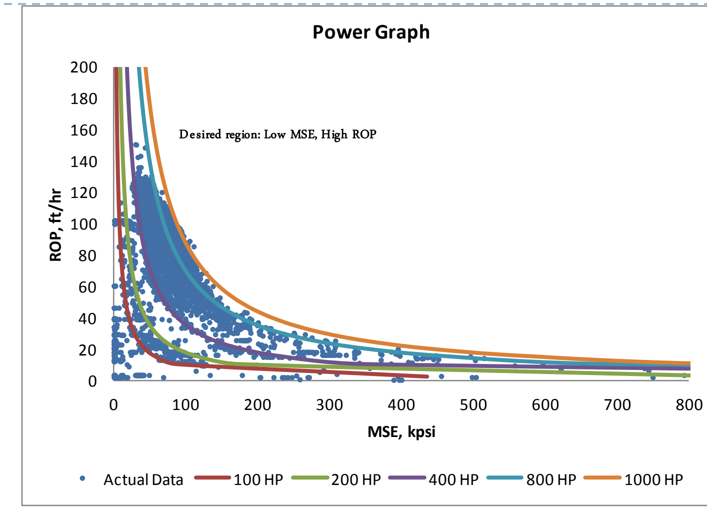
Comparison of Preventative and Mitigation Barriers

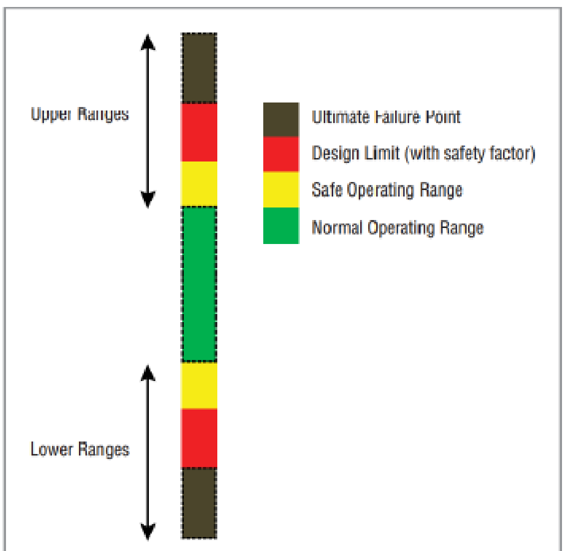
	Preventative Barriers	Mitigation Barriers
1	Proactive	Reactive
2	Reduce the likelihood of an event occurring	Reduce the impact of an event
3	Involve elimination, prevention and control	Involve mitigation and a recovery plan
4	Usually engineering design (well trajectory design, BHA design, mud design), administrative actions (e.g., enforcement of buffer zones) and/or procedural (e.g., ensuring pipe movement to prevent differentially stuck pipe)	Personal and environmental protection, personal protective equipment (PPE) and Contingency plans/procedures. Can also be engineering actions (e.g., construction of berms for spill containment), or administrative actions (e.g., restricting access to only essential personnel during a well control event)

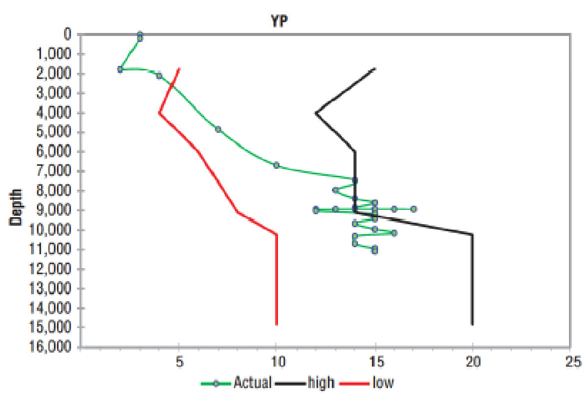
Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

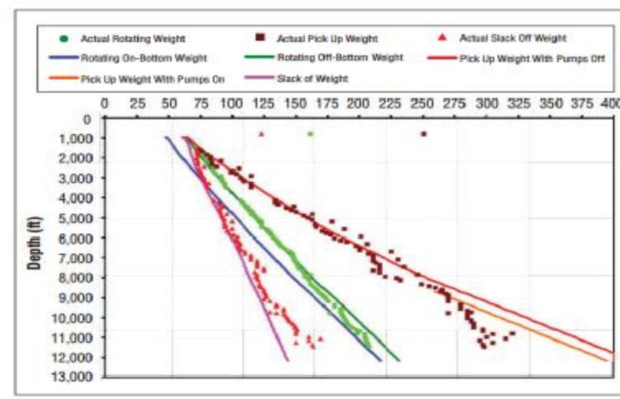
Detection/Control Barriers











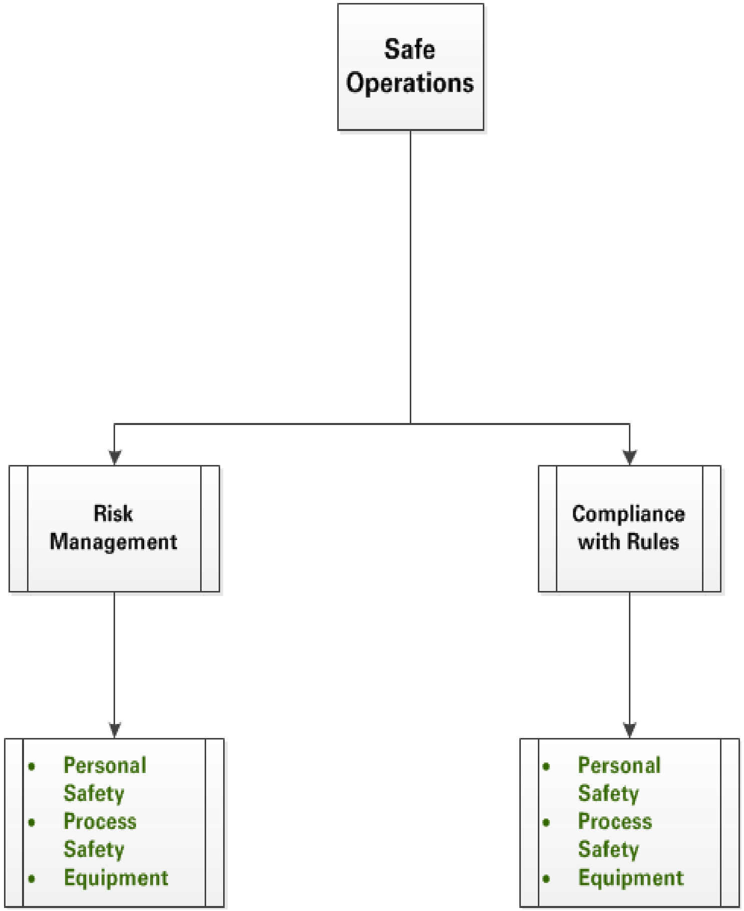
Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Evaluation of Barriers (1)

- Passive Barriers:
  - No human action or control logic required e.g. Blast walls, casing, cement, mechanical plugs, etc.
- Active Barriers:
  - Requires some form of human intervention or control logic e.g. BOP activation, alarms etc.
- Administrative/Procedural Barriers:
  - Full human action required – someone has to take action e.g. Procedure to pump sweeps at defined intervals, procedure to ensure pipe movement etc.
  - In most cases this should not form a basis of long term risk reduction plan. It should be a temporary solution until an active or passive barrier can be implemented

Evaluation of Barriers (2)

- People:
  - Competency
  - Behavior (speak up, STOP)
  - Follow approved procedure or MOC to change
- Process/Procedures:
  - Company/industry standards
  - Procedures for interpreting and responding to upsets e.g. Ballooning
  - Adequate procedure for tasks
- Equipment:
  - Fit for purpose design/reliability
  - Inspection, testing, maintenance



Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Barriers Effectiveness

- Barriers are more effective if they require less human action and/or communication interface because of the reduce probability of error and/or communication failure

Passive Barriers

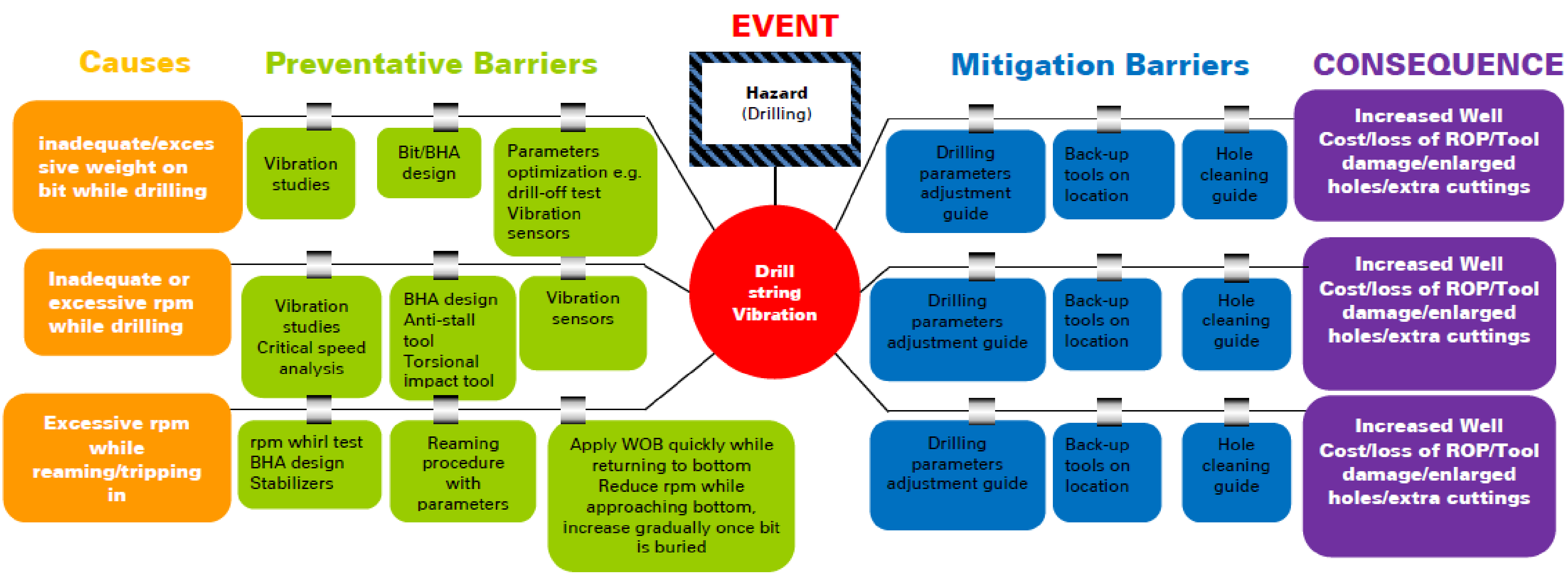
Active Barriers

Administrative/Procedural Barriers

Bow-ties and Example Risk Barriers

- Bow-tie is a useful tool for building a framework of barriers for any particular identified risk
- It is a diagrammatic representation of barriers to a risk event with preventative barriers on one end and mitigation barriers on the opposite end of the risk event
- Bow-tie makes it easier to spot barriers that need to be strengthened for example presence of too many procedural barriers

Example Risks and Barriers - Vibration



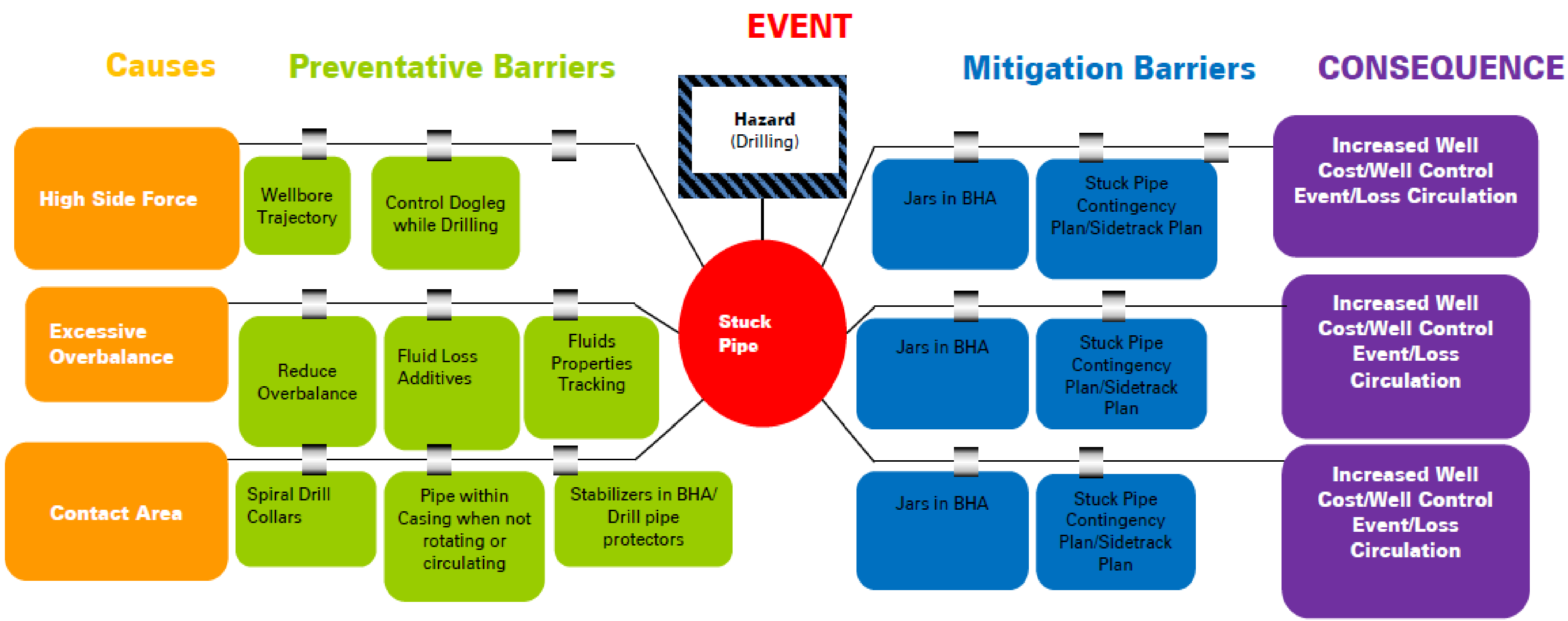
Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Example Risks and Barriers – Vibration

Elimination	• Wellbore trajectory to minimize side force/dogleg severity/tortuosity.
Prevention	• BHA design for vibration– stabilizers, drill collars to make BHA stiffer. • Selection of bit with long gauge, tapered length or undercut to minimize vibration from side cutting action. • Reduce bit aggressiveness to enable application of higher weight on bit to prevent lateral vibration especially in low compressive strength rock if ROP is not limited by bit performance. • Run oversize bit sub or some large OD drill collars in pendulum assembly. • Offset well analysis to determine the optimum drilling parameters. • Use of drill pipe rubber/drill pipe protectors in high angle well to reduce friction and also prevent buckling. • Select the right mud motor for formation to be drilled.
	• Plan to use roller reamer if excessive torque from reaming off-bottom is anticipated. • Consider running an under-gauge near bit stabilizer. Usually about 1/8″ to 1/4″ under-gauge. Near gauge may cause angle to build. • If under-reamer is used, stabilize BHA between bit and under-reamer. • If reaming is required, consider under-reaming while drilling rather than a dedicated reaming run. There is less weight transfer to the bit during dedicated reaming run leading to lateral vibration.
Control	• Run vibration and downhole parameters monitoring tool to track vibration, MSE, torque, and drag (e.g., Baker Oil Tool's Co-Pilot® and NOV's Blackbox®). • Conduct drill rate test while drilling. • Conduct critical speed test (plot of torque vs. RPM) prior to reaming/rotating off bottom. • Placement of vibration sensitive BHA component (e.g., MWD, LWD etc.) in region of low stress.
Mitigation (Mitigation barriers should be considered in the planning phase)	• Run vibration dampening subs/tools (e.g., NOV V-stab®, Frank's Harmonic Isolation Tool). • Adjust drilling parameters (WOB and RPM) per Table 3.1or use vibration as per vendors recommendation. • Perform dedicate reamer run to ream tight spots. • Include under-reamer in BHA to ream tight spot if not cost prohibitive.
Contingency	• Back-up tools (e.g., LWD, MWD, PWD) • Stabilizers on location if BHA needs to be stiffened.

Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Example Risks and Barriers – Differential Stuck Pipe



Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Example Risks and Barriers – Low ROP

- Prevention: Bit & BHA design, mud motor selection/RSS, mud design, drilling parameters, drilling practices such as hole cleaning
- Detection/Control: WOB, RPM, ROP, MSE, power graph & vibration measurement and trending
- Mitigation: Design BHA with anti-vibration tools, ROP enhancer
- Contingency: Plan to pull bit after wear, availability of different bit types on location (PDC vs. rock bit), spares on location

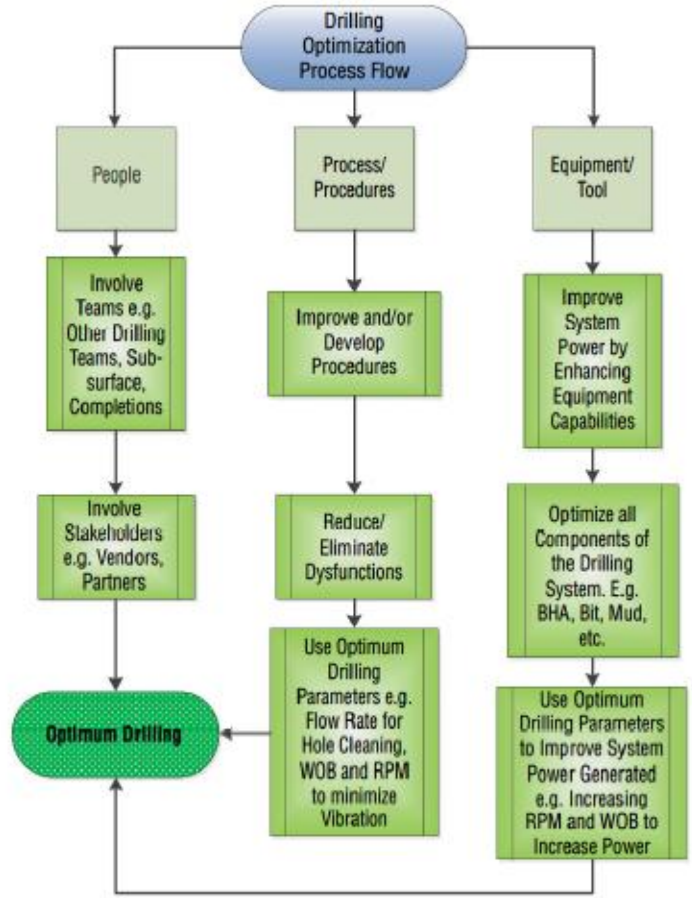
Example Risks and Barriers – Hole Cleaning

Elimination	• Plan wellbore trajectory to avoid drilling large hole size at high angle of inclination – small wellbore sizes are more stable. The disadvantages of drilling a smaller hole are increased surface pressure, ECD while drilling, and cementing because of smaller annular clearance. A reduced annular clearance increases the chance of mechanical sticking while running casing and also reduced kick tolerance. Also, annular clearance should be large enough to accommodate casing accessories like centralizers. As a rule of thumb, start with a clearance of not less than 2″ in casing size greater than 16″, a clearance of not less than 1.25″ in casing sizes from 14″ to 16″ and a clearance of not less than 1.1″ in casing sizes less than 14″. See Chapter 12 for calculation of maximum casing OD that can be run in a hole and also optimizing BHA OD to maintain adequate hole size for casing running. • Control drilling to ensure wellbore is sufficiently cleaned while drilling – this is a good technique if ROP is limited by hole cleaning. The time saved by avoiding potential hole cleaning problems, pack-off, and lost circulation problems outweighs the time benefits from drilling at a slightly higher ROP. • The best defense for a hole cleaning problem is to clean the hole while it is being drilled (i.e., rate of cuttings generation equals rate of cuttings removal).
Prevention	• Use a combination of flow rate, rotation, and adequate mud rheology to ensure good hole cleaning. Use hydraulic software to optimize flow rate, RPM, and mud rheology. • Design a mud system for flat rheology to reduce pressure surges during hole cleaning. • Optimize the use of rotary drilling – minimize sliding as much as possible or use rotary steerable systems to get hole cleaning benefits from rotation. • Use booster pumps in riser to increase annular velocity. Use of a riser pump instead of increasing circulation rate through the drill string will help minimize ECD at depth, hence reducing the potential for lost circulation. • To reduce likelihood of plugging drill bits in small hole size (less than 8-½″), run bits with nozzles with a diameter of at least 10″/32. • Use continuous circulation subs while making or breaking connections to enable continuous circulation of drilling fluids downhole during connections. These subs are pre-installed on each stand to be drilled down. • Minimize length of rat hole by setting casing as close to the bottom as possible. This will reduce the available space for large cuttings to be trapped thus minimizing the risk of a pack-off.
Control	• Monitor MSE, torque and drag, standpipe pressure, and ECD for signs of inefficient hole cleaning. • Use adequate RPM during dedicated hole cleaning operations. • Track cuttings carrying index. • Monitor cuttings volume return to the shakers and compare with calculated cutting generation rate from ROP. • Monitor and record cuttings shape – coffee grind/round cutting is a sign of inadequate hole cleaning. Round shape is as result of regrinding.
Mitigation	• Stage up pump to the maximum allowable flow rate and rotate at the maximum allowable RPM to clean the wellbore. • Pump sweeps at frequency determined by wellbore condition. This could be every stand for hole cleaning. • Pump 5–10% (v/v) or (0.1–0.5 ppb) fibrous LCM pills or add to sweeps to help remove fines and low gravity solids. • Plan to use a cutting bed agitation tool (mechanical hole cleaning device) in wellbores with inclinations greater than 30 degrees to stir cutting into fluid flow path. Cutting bed agitation tools may not be needed if stabilizers are run in the BHA and drill pipe protectors run in drill strings. Stabilizers and drill pipe protectors will provide the same benefit. • Reciprocate drill string in near vertical wellbores to disturb cuttings that have settled down the wellbore and rotate in high-angle wellbores to disturb the cutting bed on the low side of the wellbore.
Contingency	• Wiper trip before running casing/ logging the wellbore if hole condition dictates. • Plan for a dedicate reamer run to ream tight spots using the proper reaming procedure. Avoid back reaming in high-angle wellbores especially if wellbore instability is anticipated.

Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Impact of Barriers on Drilling Optimization

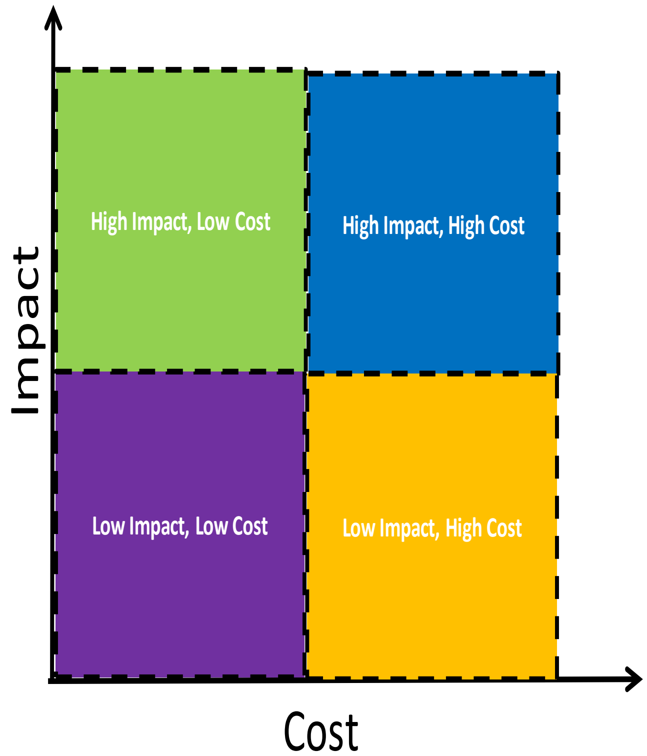
- Reduced well cost due to low probability of NPT events
- Reduce cost of recovery from NPT event due to available mitigation and contingency barriers
- Quick detection and control of NPT events (parameters monitoring & trending)
  - Real time provides quick detection and better control
- Effective barriers reduce the chance of NPT events
- People, process/procedures/equipment are barriers to risk events



Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Barriers Generation

- Barrier creation is a technical challenge that can be addressed by:
  - Using existing technology e.g. Use of expandable liners
  - Modifying of existing technology e.g. Development of RSS for onshore application, casing drilling
  - Inventing new technologies where appropriate and economical e.g. Ranging etc.
- Cost and impact of barriers should be evaluated
- Barrier options should be risk-weighted to determine the most economical option
- Incremental cost of developing a barrier should not outweigh its benefit and reliability



Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

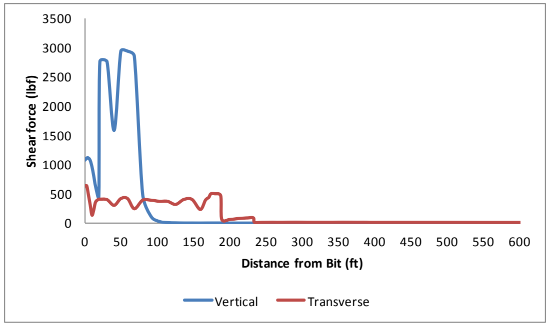
Barrier Design & Selection Concepts (ISD)

- Simplification: Avoid complex systems where possible, minimize number of weak links, select barriers/designs that does not introduce other risks.
  - Design cement jobs to limit the use of DV/stage cement tools
  - Avoid foam cement in hydrocarbon zone
- Substitution: Use materials that are less "hazardous" or design well components to reduce risk
  - Use of heavy weight drill pipe instead of drill collars in horizontal wells
  - Use spiral drill collars in high angle wells to minimize the probability of differential stuck pipe
  - Using rock bits to drill out cement plug
- Moderation: Avoid excess processes/procedures, people and equipment/tools
  - Clear and concise procedures, well defined roles and responsibilities
  - Limit downhole tools to what is absolutely necessary
  - Optimize number of stabilizers and centralizers
- Modification: Modify well design, mud design, BHA design etc. to address identified risks
  - Running PBL subs in BHA for lost circulation
  - Adding stabilizers to BHA to control vibration
  - Running intermediate casing/liner to isolate formation prone to wellbore instability
  - Improve mud salinity to address wellbore instability

Inherently Safer Design/Practices (ISD)

When possible, select designs that eliminates and/or reduce hazards rather than controlling them (designs with preventative barriers). If cost prohibitive , select designs robust enough to minimize impact of a risk event (designs with mitigation barriers)

- Well Design:
  - Drilling away from faults or intercepting faults at 90 degrees to minimize wellbore exposure within faults, drilling away from shallow gas prone area
  - Optimizing wellbore trajectory to minimize contacts force to reduce the chance of stuck pipe
- Mud Design:
  - Adequate mud weight, sufficient rheology for hole cleaning
  - Mud properties to address wellbore stability
- Drilling procedures/practices:
  - Minimize swab and surge
  - Proper connection make-up
- BHA Design:
  - Placing sensitive BHA components in section of BHA with low stress
  - Stabilized BHA to prevent vibration and differential stuck pipe
- Casing Design:
  - Setting high integrity casing prior to penetrating hydrocarbon zone
  - Using connections adequate for possible loads
  - Long string vs. Liner + tieback



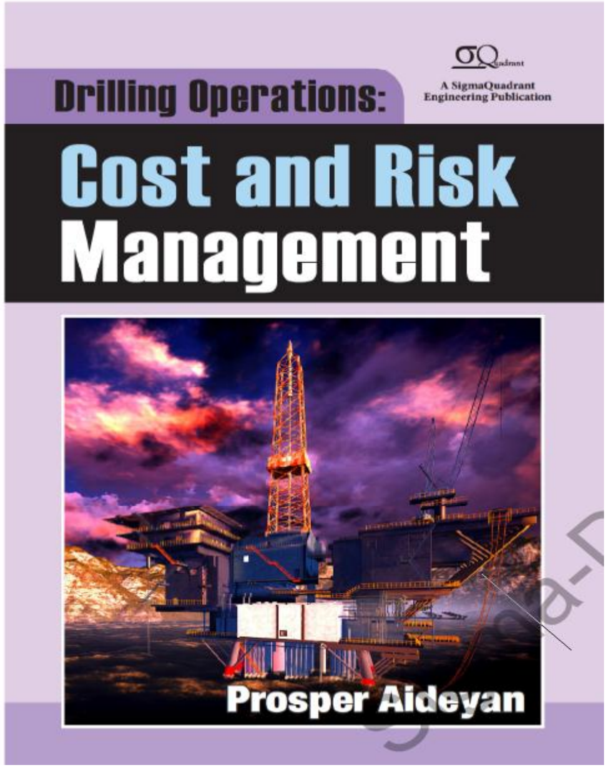
Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Risk Management/Barriers – Other Considerations

- Risks/barrier generation can be transferred to third party contractors through contracts and legal agreement. (barriers are generated by people with more expertise)
  - for example the transfer of BOP NPT to rig contractors or BOP manufacturers which forces them to perform rigorous testing, inspection and maintenance
- Barriers to identified common risk can be jointly developed by companies that share same risk by forming a consortium
  - for example the development of capping stack by Marine Well Containment Company (MWCC) or by participating in joint industry project

Reference

- Drilling Operations – Cost and Risk Management
  - www.sigmaquadrant.com
  - www.amazon.com



THANK YOU

QUESTIONS & COMMENTS

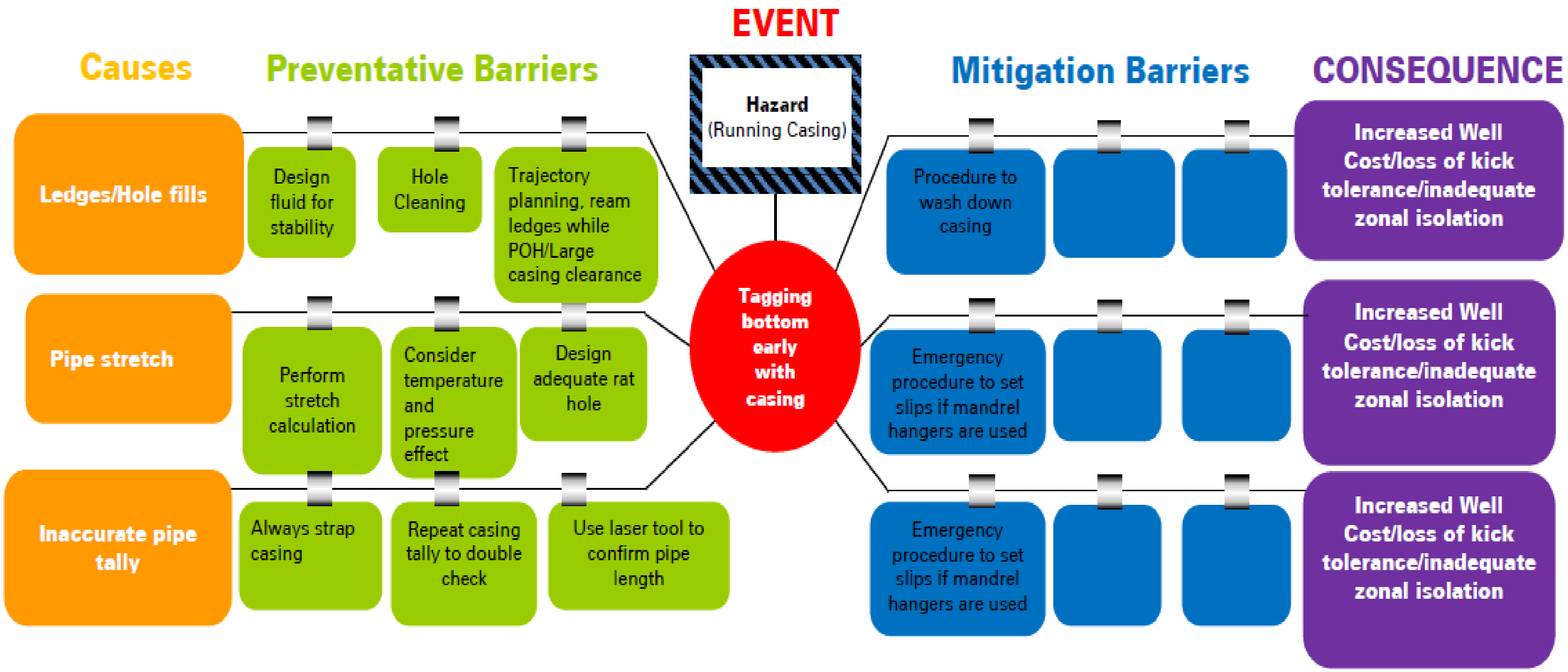
Evaluating Barriers to Manage Drilling Costs and Risks

Back-up

Others Example Bow-ties and Risk Barriers

- Tagging Casing Early
- Well Collision
- Casing Wear
- Cementing

Tagging Casing Early while RIH



Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Well Collision Barriers

Prevention	• Ensure that directional planning company personnel are competent in the use of selected well planning software. • Ensure that the approved directional planning software is used for well planning. Approved software should apply approved survey calculation methods. • Train company personnel involved in well planning on the use of approved well planning software. • Develop procedures that address survey frequency, tools, error models, survey projections, and reporting requirements. • Wellhead position uncertainty should be accounted for in error modeling. • Use the latest magnetic models in well planning. • Survey with gyro if magnetic interference could be an issue especially when spacing is tight. • Ensure that the necessary survey corrections such as BHA sagging, magnetic interference and so on are performed. • Use rotary steerable systems (RSS) to ensure directional control in wells with a high risk of collision.
	• BHA design should factor BHA walking tendencies. BHA should be stabilized if dropping tendency is high. • Use tools with a lower error margin (e.g., gyro) in wells with a high risk of collision. • On wells drilled on a pad, drill wells with a higher inclination (higher tendency to drop) before wells with a lower inclination if azimuth direction is same or close.
Control	• MSE and Torque and Drag trending. • In wells with a high risk of collision, survey more frequently and/or take check shots in between surveys. • Track loss circulation to detect whether another well has been drilled into. • Mud logging to track presence of hydrocarbon and cement. The presence of cement is an indication that an offset well barrier has been drilled into and the presence of hydrocarbon especially when drilling a non-hydrocarbon zone is an indication that the offset well has been penetrated.
	• Set cement plug inside batch drilled surface hole sections to prevent hydrocarbon migration to surface in the event of underground blow out and broaching in a nearby well. • Directional drillers should send updated surveys at a predefined frequency. Surveys should include projections and ellipse of uncertainty. • Drilling engineers and well positioning specialists should review surveys and check for errors after receiving them. Engineers should work with specialist and directional drillers to make appropriate corrections when needed. Corrective actions should minimize dogleg severity and tortuosity. • Use tools such as traveling cylinder plots, ladder plots, and spider plots as visual aids for survey monitoring and projection. These plots should be printed and pasted in conspicuous locations by the driller, directional driller, company's man, and at the office.
Mitigation	• Develop procedures to address any deviations from the approved plan. The procedure should call for stoppage of all drilling activity if the tolerance line is crossed and should also include a notification chart if a deviation from plan should occur. • Adjust the drilling parameters accordingly if BHA build or drop is noticed. • Trip BHA out of hole and run in with a redesigned BHA (e.g., with motor and bent sub, or with RSS, or another MWD tool) if MWD tool fails, if directional control proves to be difficult and/or if error ellipse of tools is too large. • If offset well is drilled into, drilling should be suspended and a plan to move forward worked.
Contingency	• Design BHA with options to drop a gyro if the MWD tool fails for any reason or if the position uncertainty is high due to magnetic interference. • Cement squeeze and contingency casing may be needed to restore barriers between the reference and offset wells. • A contingency LCM pill should be available on location in the event of lost circulation. • Run gyro while drilling tool as a back up to MWD tool in the event of MWD failure of presence of magnetic interference.

Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Casing Wear

	• Use downhole motor/drill in slide mode to eliminate drill string rotation.
Control	• Torque and drag monitoring to detect casing wear. Monitor surface and downhole torque. • Running a ditch magnet – collect metal shavings periodically and maintain a log of metal recovered. Generate a plot of total metal recovered against the total rotating/reaming hours or depth. See Figure 9.4. • Consider caliper log or pressure testing of casing after drilling for an extended period and/or if metal shavings generated are more than predicted. Note – there may be regulatory requirements to verify casing integrity after drilling for a certain length of time. • Watch for shiny tool joints when tripping pipe. • Modify drilling parameters to address wear (e.g., avoid excessive compression of drill string (optimize weight on bit (WOB)) to prevent drill string buckling which can cause deflection of drill string.) Even with drill pipe protectors, casing wear could be severe if pipe deflects and exposes rough hard banding to casing. Also avoid a too low WOB that will result in more tension in the string and hence a larger side force. • Use a downhole motor without surface string rotation. • Minimize the number of wirelines run. • Preferably use previously used wirelines since new wirelines will cause more wear. • Optimize drilling parameters to minimize downhole failure in others to reduce number of drill string trips (i.e., control vibration, better hole cleaning etc.) • Minimize backreaming – it introduces higher side forces.
	• Use conventional and non-rotating drill pipe protectors in high side force areas. • Use a torque reducing sub which is free to rotate around a central mandrel. • Use a specialized drill pipe coated with wear resistant materials. • Use lubricants to reduce friction between casing and drill string. • Ensure adequate hole cleaning to reduce sand and silt content in mud. Generally, solid materials in mud help prevent casing wear but the particles have to be large enough to prevent contact and hard enough not to be crushed easily by contact force but not too hard to cause abrasive wear. Barite particles in weighted mud systems are effective in reducing wear; however smaller sand and silt particles generated from cutting regrinding may work against casing wear reduction.
Mitigation (these should be evaluated during the planning phase)	• Raise planned top of cement to cover predicted high wear area of casing if annular pressure build up is not a concern. • Select the lowest suitable grade of pipe with maximum wall thickness. Wear test indicates reduced wear in lower grade pipes (White J.P. et al.). Higher grade pipes have larger Rockwell hardness values and are hence more susceptible to wear. • Use thread sealant in place of thread compound for casing connections in wear prone areas. • Plot an actual wear to allowable wear graph to determine appropriate remedial actions.
Contingency	• Cement patch. • Scab liner. • Liner/casing patch. • Sidetrack plan. • Running a tie-back to cover worn casing.

Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN

Cementing

- Cement additives for gas migration and losses (if chances of lost circulation are high).
- Casing/liner rotation during cement job if possible to allow for proper displacement and to prevent channeling.
- Centralizer design to provide adequate stand-off.
- Hole cleaning and mud conditioning prior to pumping cement.
- Design to prevent mud contamination of cement. Contaminated cement will have a very low compressive strength.
- Do not use nitrogen foamed cement in oil based mud because nitrogen break-out may occur.
- Design to ensure compatibility between the mud and the spacer; consider temperature effect. If the mud and spacer are not compatible, the mixture interface may gel up leading to channeling as it takes more pressure to move the gel. See Figures 11.2 and 11.3.
- Pump excess cement volume to account for contamination, losses, and hole enlargement (use pump strokes when circulating bottoms up to estimate hole washout, run caliper logs or historical data from offset wells where available).
- Account for compressibility when calculating the cement displacement volume to ensure adequate zonal isolation and also to prevent tagging cement high inside casing.
- Caliper the casing and accurately measure the displacement volume of the landing string and casing.
- For cement plugs, design the stinger to prevent swabbing of cement when pulling out of hole with stinger; avoid over displacement when cement stinger is used. See the section on estimation of under-displacement volume if the stinger is used to set a balanced plug late in this chapter.

Mitigation (these should be evaluated during the planning phase)	• Have only essential personnel on the rig floor during cementing. • Account for compressibility when calculating cement displacement volume. See Chapter 14 for calculation of volumes due to compressibility. • If top plug does not bump, plan to pump additional volume to account for compressibility of displacement fluid but not to exceed half of the volume of shoe track. • Design adequate length of shoe track for shoe track volume to be at least twice the calculated compressibility volume of displacement fluid (See calculation of minimum shoe track length below). • If floats fail, pump back volume of mud ejected and hold pressure until cement attains required compressive strength.
Contingency	• Have contingency plans (displacing out cement). Design thickening time to allow for displacement of cement for any reason after pumping. • Have an adequate volume of cement on location for excess and for a second cement job. • Have a spare pump available in case of pump failure. • Have a contingency plan for a cement squeeze job and/or casing patch. • Have a contingency plan to evaluate cement coverage (e.g., CBLs/USIT logs). • Have adequate mud weighting materials on location for displacement and wellbore circulation.

Source: Drilling Operations: Cost and Risk Management by P. AIDEYAN