Drilling Hazards Management – Excellence in Drilling Performance Begins with Planning (Part 1 of DHM Series)

David M. Pritchard[i]
Owner, Successful Energy Practices International, LLC

Abstract

A drilling hazard is defined as any event off of the critical path of drilling operations. Drilling hazard management (DHM) focuses on wellbore stability and consequential hazards such as stuck pipe, fluids loss, and equivalent circulating density (ECD) management. These events lead to non-productive drilling time in the least case, or catastrophic wellbore failure and well control in the worst cases. DHM requires understanding the uncertainty of the drilling margin: the safe applied ECD between the in-situ pore pressure and/or stress equivalence and the fracture gradient as a result of the overburden at true vertical depth (TVD). All drilling operations have risk, therefore mitigating these is fundamental to DHM.

Complex wells require multi-disciplinary alignment to ensure and sustain performance. Aligning objectives is necessary to manage drilling hazards and associated mechanical risk critical to successful well execution. For example, geological uncertainties may require the ability to sidetrack a hole, yet a slim monobore solution is required for lower drilling costs. These objectives usually conflict. It is important to understand disciplinary trade-offs necessary to ensure drilling performance.

[i]David Pritchard is a Registered Professional Petroleum Engineer associated with the Petroleum industry since 1970. He has extensive experience managing and supervising worldwide drilling and production operations. David has consulted for an array of national and international independents, major companies and service providers in over 20 countries. Drilling and completion specialties include HPHT and Deepwater environments. David has analyzed, planned or audited over 40 Deepwater and HPHT global operations. David holds a Bachelor of Science in Petroleum Engineering from the University of Tulsa.

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1 Introduction

Down cycles outside of the energy industry's control often create resource deficits in both personnel numbers and experience, resulting in lost knowledge and a lack of mentoring. Because this situation is common to both operators and service providers, understanding the problem and its consequences is imperative in order to develop viable and practical solutions. The oil and gas industry has suffered numerous booms and busts over the years, the most notable downturn being in the 1980s. Attrition of experience and learning suffered heavily; the ramifications of which can still be felt.

From a well execution perspective, a generation of drillers has grown up without the mentorship of personnel who developed the intuitive art of "listening to the well". This human factor is fundamental to executing good drilling practices as evidenced by some in the industry that have become so dependent on real-time data that they misinterpret commonplace issues such as background gas. Good drilling practices revolve around interpretation of the totality of the data for correct pro-active decisions while drilling. For example, the tendency to weight up drilling systems arbitrarily when reacting to background gas alone is counterproductive to performance and can also induce dangerous drilling conditions.

In the 1990s service providers moved towards partner involvement with operators that included total integrated projects. In some cases, this working relationship shifted engineering responsibility from the customary operators to the service providers. Positive effects from this shift were realized, but it also created an environment where the emphasis for well design was placed on product and services rather than classic total well engineering historically practiced. Effective total well engineering requires true integration and compatibility of all technologies necessary to execute a well.

Service providers have made tremendous strides in technology development, especially given the dramatic historical cycles of the industry. Operators have shifted their emphasis from classic engineering to a more project management core responsibility. This approach entails justifiably improving health, safety, and environmental responsibilities as well as soft-skill engineering, which encompasses the human factor. Given the tremendous diversity requirements in the global industry, improving soft skills is long overdue. Although necessary, this focus has eroded away at the time needed to technically analyze each operation from an engineering perspective, often leading to copy and paste technologies or "widget" engineering.

2 Considering the Possibilities

The best-laid plans regard drilling and completion as a multi-disciplinary responsibility. Yet even with this approach, attaining significant performance improvement is a challenge because wells have grown more complex and are being drilled to greater depths. Complex wells require multi-disciplinary alignment to ensure and sustain performance. Aligning objectives is necessary to manage drilling hazards and associated mechanical risk critical to successful well execution. For example, geological uncertainties may necessitate sidetracking, yet a slim monobore is needed for lower drilling costs. Aligning these objectives so as to eliminate any conflict requires understanding disciplinary trade-offs necessary to ensure drilling performance.

A prudent place to begin coordinating a plan and aligning objectives lies with considering multiple issues and pre-emptive solutions that include the following:

- Managing drilling hazards
- Planning and aligning multi-disciplinary objectives
- "Listening" to the well
- Implementing a drilling hazards management (DHM) approach and a mechanical risk assessment process

3 Practicing Drilling Hazards Management (DHM)

A drilling hazard is defined as any event off of the critical path of drilling operations. Using a DHM approach early in the well planning process is essential to its effectiveness and success. DHM focuses on wellbore stability and consequential hazards such as stuck pipe, fluids loss, and equivalent circulating density (ECD) management. These events lead to non-productive drilling time in the least case or catastrophic wellbore failure and jeopardize well control in the worst cases. DHM requires understanding the uncertainty of the drilling margin—the safe applied ECD between the in-situ pore pressure and/or stress equivalence and the fracture gradient as a result of the overburden at true vertical depth (TVD). Because all drilling operations have risk, mitigating these risks is fundamental to DHM.

DHM is the practice of managing the mechanical and efficiency risk[ii] of all drilling operations. The basic premise of DHM begins with understanding the uncertainties of drilling and the risks that are possible and/or probable. Managing these risks requires applying the best practices and mitigating technologies to successfully reduce the risk profile while improving the risk-adjusted cost of applying such mitigants successfully. Because hazards may not be geological but rather mechanical failure or human error, comprehending the totality of drilling data avoids inducing risks and enables implementing the most applicable best practices and technologies to mitigate those risks.

One such example of DHM is to simply apply casing seat optimization to the maximum uncertainties of the drilling margin predictions. Predictions are always uncertain in the earth model, but a well can be planned accordingly. Maximizing the seat at the maximum safe ECD point of the overburden fracture gradient ensures drilling the next hole section to the maximum depth and reduces the risk and opportunity for issues such as ballooning in the next interval.

Another example looks at the propensity to plan an increase in mud weight at the base of an intermediate casing string before drilling out the shoe, especially in high pressure/high-temperature operations. Arbitrarily weighting up the mud is usually made because higher pressures are anticipated at greater depths. This mud weighting scheme actually masks drilling conditions and negatively impacts drilling performance by increasing the confining stress of the mud weight column. This increase also creates unnecessary bit wear, resulting in premature trips that further impacts wellbore stability (swab/surge during trips). This practice is often defended as being the safest approach, but in reality, a safer and more effective action would be to drill out the casing shoe

[ii] DHM related to the risk of mechanical success. This paper does not deal with risk associated with health, environment, or safety (HES).

with the same mud weight as the casing was set with. Follow up with a full leak-off test to obtain the safest ECD that the next hole section can tolerate and then drill ahead, raising mud weight as conditions dictate. Figure 3.1 – The Evolution of mud weighting schemes illustrates this phenomenon. Note how the increase in mud weight affected drilling efficiency in virtually the same depositional environment, lithology with similar MD/TVD.

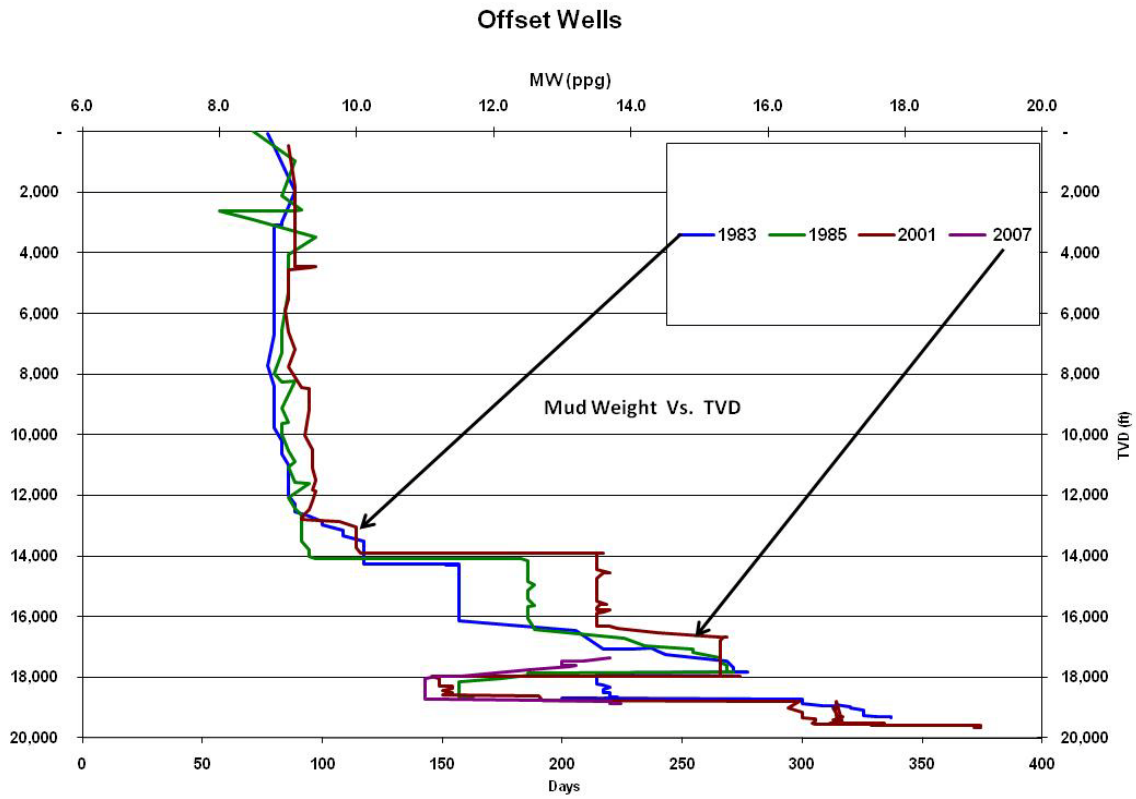

Figure 3.1 – The Evolution of mud weighting schemes.

The final DHM example examines the uncertainty of pore pressure prediction. This risk uncertainty is manifested by exceeding the boundaries of the drilling margin, or the safe envelop, that can be drilled without danger of well control events or conversely suffering fluid losses, ballooning, or fracturing the well.

After risks are identified and assessed, the cost-benefits of mitigating and managing them can be weighed. DHM engages a risk-assessment process to determine the best methodology to mitigate and manage risk, and can be applied to any drilling and completion operation.

4 Planning and Aligning Multi-Disciplinary Objectives and Alternatives

Alignment of multi-disciplinary objectives begins with a stage, gated well-planning process as summarized in Table 4.1.

Table 4.1 – The well planning process.

Phase 1	Phase 2	Phase 3	Phase 4	Phase 5
Concept	**Analysis**	**Design**	**Execution**	**Operate**
Define and align well objectives.	Analyze design alternatives to best achieve the totality of agreed objectives.	Detail engineering of the selected well model for a Basis of Design (BoD).	Pre-spud, mobilize, spud, and execute well construction program.	Deliver a functioning well and resets for future well construction activities.
• Define objectives using the SMART profile for multi-disciplinary alignment. Make certain the disciplines understand the trade-offs of the nice-to-haves, wants, needs, and must haves. • Define the drilling uncertainties and narrow the range of uncertainties.	• Develop alternative well models that best narrow the range of uncertainties. The Uncertainty Management Plan • Review and analyze historical data, metrics, and lessons. • Apply engineering, rock mechanics, and other pertinent data. • Apply the Risk Assessment (RA) process to each alternative to determine the best risk profile. • Select the alternative models that best fit SMART objectives and narrowed uncertainties.	• Engage Front End Loading for detailed engineering: casing design, rig and hydraulics capabilities; logistics, fluids, cement, and directional programs; bits and BHAs. • Develop completion program and design. • Detail risk assessments of all FEL issues. • Write detailed drilling and completion procedures using metrics and benchmarks for time estimates. • Determine contingency practices, plans, and/or mitigating technologies, programs, and procedures using the RA process. • Integrate all information into a final BoD. • Finalize cost estimates based on BoD. • Drill the well on paper using the RA process as a precursor for discussion points linked to the drilling procedures. • Conduct a post DWOP revision of any changes. If any risk profiles are unacceptable, revise design issues. • Lock the BoD into the rig schedule. • Develop detailed communications and logistics procedures. • Develop any rig-site training necessary for hazards avoidance.	• Conduct pre-spud meeting to review risks, hazops, logistics, communications and all other pertinent information. • Conduct rig specific training for hazards avoidance and management such as stuck pipe, lost circulation, well control procedures, etc. • Mobilize and spud. • Execute well. • Capture and record all information: daily drilling reports, lessons, metrics, etc. • Conduct root cause analysis as the foundation for lesson sessions and closure on lessons learned.	• Close the well construction loop. • Roll all reports, data, etc., into knowledge modules for future planning and well construction activities. • Write the end-of-well report.

The initial phase of the process is where the well is formulated and objectives are determined. SMART well objectives consider and define the following:

- Specific
- Measurable
- Achievable
- Relevant
- Timely

Often the root cause of failure lies with objectives that are not initially aligned and understood by the disciplines or stakeholders. Well planners must guard against developing objectives that are not measurable, often conflict, and together are not achievable. The following objectives for a 12,000 ft TVD, 15,000 ft MD directional well do not follow the SMART criteria:

- Right size initial flow capabilities
- Adequate hole size for evaluation, coring, completion
- Completions free of formation damage
- High "rig-less" intervention capabilities
- Minimal complexity
- Directional well with a target on-bottom radius of 200'
- Multiple targets
- Well availability, design life
- Good reservoir surveillance
- Provide for a future sidetrack
- Case the well with a minimize number of casing strings
- Monobore small wellbore with minimum costs
- Optimize costs
- Ability to stimulate the well by fracturing
- ESP artificial lift system

For example, a small wellbore does not lend itself to fracture stimulation, has limited if any automated reservoir surveillance capabilities, and has limited sidetrack capabilities. Furthermore, the number of casings necessary to reach TD may prevent fracturing, high initial production rates, and optimum installation of artificial lift systems. The ability to maintain a stable wellbore becomes challenging especially in directional sections with a small hole size, disabling the ability to apply enough horsepower to clean the hole. A small hole also complicates the ability to slide and achieve a smooth hole. These design objectives induce wellbore stability issues and can impact the following issues:

- Poor drilling performance as a result of reduced hydraulic pumping rates.
- Bit wear.
- Bottomhole steering difficulties, excessive geo-steering creating a tortuous well path.
- Inability to apply mud weight and effectively manage ECD in a slim hole environment.

These objectives result in a myriad of conflicts too difficult to manage and successfully achieve. Misalignment of objectives can complicate mitigation efforts and often result in inducing drilling hazards by limiting:

- The ability to apply adequate hydraulic horsepower.
- The ability to manage the ECD of the well and therefore obscure managing the drilling margin.

5 Developing SMART Objectives

Developing SMART objectives requires alignment from all stakeholder disciplines to determine well design alternatives that can best be accomplished. This multi-disciplinary process requires understanding the trade-offs, conflicts, and compromises that are necessary between the "nice-to-haves", "wants", "needs," and "must haves". Prioritizing objectives is the first step of a process to ensure initial disciplinary alignment.

Mapping a process to define ranges of measures for the objectives is the initial step in the process. This process is facilitated by capturing the ideas and committing to an auditable trail to ensure decision quality. Table shows an objective alignment process where all the objectives meet the SMART criteria. Further qualification and quantification of the objectives are required with the desired outcome being a prioritized list of objectives, after which the design process begins. DHM cannot occur until at a minimum, objectives are prioritized, which leads to alternative well design considerations.

Table 5.1 depicts typical project objectives where conflicts are obvious.

Failure to align objectives at the onset in well planning usually results in execution issues that are counterproductive to good performance and sustained learning. As an example, consider excessive geo-steering. Even though the tools and technologies are available, excessive geo-steering can complicate the well path and actually create drilling hazards. Target boxes must be agreed on in the initial well planning stages and ensured during execution. A target box is a window around the entire directional section that limits or prescribes the limits of geo-steering. Although an exceptional amount of geo-steering may be agreed to by the stakeholders, there is a tradeoff in the risk of successful execution, and at the minimum, a negative impact on performance and well cost. Many things can change, such as the design of the bit and BHA. Multiple BHA and bit combinations are necessary to achieve this objective, requiring trips and inducing wellbore instability. All of these tradeoffs must be understood, quantified, and risk assessed to ensure multi-disciplinary alignment and ultimate decision quality.

Examples such as this is also where total well engineering comes into play, versus "widget" engineering, defined as engineering a single product or service that does not consider total well engineering and the well objectives. A bit designed for a build-and-hold angle does not work well when geo-steering is required, nor does a tight or locked assembly to ensure holding angle even with adjustable stabilization. These individual "widget" engineering designs are in conflict.

Table 5.1 – SMART well objectives.

SMART Well Objectives	Measure	Key Uncertainty	Comments	Conflicts	Actions
Overall Well Plan: Appraisal well 1: 12,000' TVD, 20,000 MD ERD Horizontal Well: Surface, Intermediate at 10,000 TVD for stability, Productivity to TVD: Section1: Surface, 2 Intermediate, 3 Production					
HES Incident Free	HES Metrics: Contractor and company	Rig Availability	Three rigs meet availability criteria, 2 have poor IFO	Timing for best metrics rig	Investigate needed improvements on other rigs, training?
Drill First Quartile 2010	Lose Concession	Rig Availability	Must have at least 2000 HHP and backup pump for target section	Only rig 2 has HHP requirements, no zero discharge capabilities	Investigate needed improvements on other rigs, training?
	AFE Approval	Funding AFE	Asset manager says over 100MM$ is outside of budget	Low cost well	Need to prioritize objectives
Low Cost Well	Top quartile in regional cost/well: Metrics	Well Design	Assets want simple, small diameter monobore to reduced cost	Completions wants gas lift and smart completions	Need to prioritize objectives
Ability to sidetrack well	Dry hole at location	Well Design	Small Monobore will not accommodate sidetrack	Low Cost Well	Need to prioritize objectives
Achieve Production Rates of 10,000 BOPD	Production Rate	Well Design	Completion Production Rate Targets	Small Monobore Hole Size will not accommodate minimum production rate	Will need to fracture well for max rate, small wellbore will not accommodate HHP
Geological Primary Target: 12,000 TVD	Intersect target at optimum depth	Well Path: Faults	Tight well path requires significant geo-steering: Cuttings beds and key seats, high torque/drag	Low Cost Well	Priorities drives well cost
Geological Secondary Target: 11,750 TVD	Intersect target at optimum depth	Well Path: Faults	Tight well path requires significant geo-steering	Low Cost Well	Priorities drives well cost
Core Secondary Target	Successful core for future evaluation	Depth of Target 2	Require trips, impact well bore stability, increase success risk case	Low cost well	Priority drives well cost: What is the overall cost/benefits for the well?
Run conventional logs on drill pipe in ERD/Horizontal	Successful log evaluation	DP conveyed logs	Require trips, impact well bore stability, increase success risk case	Low cost well	Tradeoff is LWD: What are the risk adjusted cost/benefits?
		Time	Requires trips, impact well bore stability, increases success risk case	Low cost well	Tradeoff is LWD: What are the risk adjusted cost/benefits?
		Wellbore stability	Requires trips, impact well bore stability, increases success risk case	Low cost well	Tradeoff is LWD: What are the risk adjusted cost/benefits?
Drill 5 additional wells if successful on same footprint	Successful logs and production test	Production Test	Well path and footprint must consider future wells	Low cost well and future development	Tradeoff: Future development cost
Ensure wellbore stability	Achieving hole section	Drilling Margin/Faults	Could Requires Drilling Liner	Last well lost hole sections	Could require two intermediate casing strings: well cost
	Minimum Unscheduled Events and NPT: Hazards: Ballooning, susceptible shales	Drilling Margin/Faults	Could Require Drilling Liner	Low cost well, sidetrack capability	Requires real time monitoring, contingency plans
Ensure top quartile rotating performance	Metrics, Improved critical path time	Rock Geomechancis	Requires compiling geomechanis log	Geologists tight holing logs on prior well	Develop a plan to for rock log that ensures confidentiality
No formation damage	Productivity Index	Formation sensitivity	Reservoir engineer require OBM	Impedes logging eval, no rigs have zero discharge capabilities: Well cost	Align fluids with geoscientitists. Understand cost benefits of requirements

6 Understanding the Impact of Uncertainties

Uncertainties drive risk in everything. For example, the weather is an uncertainty. If the objective is to play golf, the more known about the forecast, the more narrow the range of uncertainty. This same philosophy applies to managing hazards and risk for any drilling and completion operation.

It is first necessary to understand how uncertainties impact risk. Uncertainties represent the unknowns in any drilling operation. An important aspect of uncertainties is to know whether they can be eliminated by way of decisions, or at least narrow the range of uncertainty. Eliminating or narrowing uncertainties is a multi-disciplinary process. Decisions to eliminate uncertainties can be represented by the rig selection process, posting a locked basis of design (BoD), or deciding bottomhole targets and locking them into the well path.

The uncertainties that create the most problems and ancillary risks are the drilling margin. At the onset, establishing the safe drilling margin is an unknown prediction of pore pressure and fracture gradient. While predictions may come from many sources, they are never absolute. If the plan is to "nail" predictions to ensure good drilling performance, then success will not be sustained. Risk occurs at the boundaries of the margin. For example, if the ECD is too high, fluid losses with varying consequences can occur from slight losses to catastrophic losses. If the mud weight is too low, well control can result with varying consequences. In the planning phases, the key to narrowing the range of uncertainty of the drilling margin is to make certain that predictions are as reliable as possible and are adjusted with actual historical data, such as the mud weight that was applied in a well where fluids losses actually occurred. There are many other techniques that can be used including improving predictions while drilling, such as "D" Exponents.

For the planning phase, once the predictions are as accurate as possible, alternative models can be developed that deal the well objectives, uncertainties, and mitigate then manage the risk or hazard.

The first step then towards managing hazards and risk is to narrow the range of drilling uncertainties by developing a multi-disciplinary uncertainty management plan. This plan should be developed in concert with SMART objectives in the initial concept phase of planning.

Consider the following SMART objectives for a hypothetical well:

- Low cost monobore, less than $5,000,000(US). For training purpose, use a spread rate of $100,000(US)/day for all goods and services.
- TVD: +/-12,000 ft.
- Horizontal section, approximate MD: 17,000 ft.
- Production rate range, target 2: 0 to 5,000 BOPD.
- Available 2,000 horsepower rig date in schedule: June 2010.
- Artificial lift, gas lift: Minimum 8,000 ft TVD; Maximum for maximum drawdown: 9,000 ft TVD.
- Geological primary Target 1: Primary target in the horizontal section between 11,750 to +/-12,000 ft TVD. This is an exploratory target and the existence is uncertain.

- Secondary Target 2: 11,000 to +/-11,250 ft, possibly depleted to an estimated 7 to 12 PPG MWE.
- Target 2 is a backup target if Target 1 is deemed non-commercial.
- Target box in the horizontal section: 200 ft rectangle for the horizontal window. (Note: A target radius or window is the tolerance allowed for the bottomhole location.)

7 Key Uncertainties

- The cost of well to best accomplish the objectives.
- Production rate range: 0 to 5,000 BOPD and the productivity index of the reservoir.
- Drilling hazards: Fluids losses, stuck pipe. Pore pressure in the Target 2 interval could range from 7 to 12 PPG, but is estimated at 7 PPG MWE:
- Height and thickness of Target 1 reservoir. The objective is to stay in the target box window.
- Ability to geo-steer in tight box and the uncertainty of Target 1 height and thickness dictates alternative well models to deal with the objectives and uncertainties.

Table 7.1 – Developing an uncertainty management plan illustrates how these uncertainties can impact the models and the resolutions required to determine the best-fit model for the final well design.

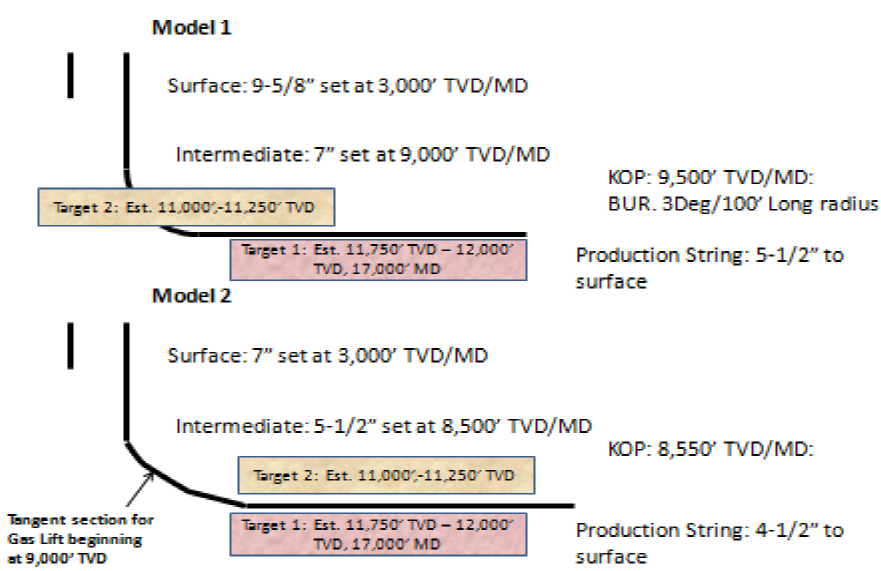

Figure 7.1a - Example well models for the objectives.

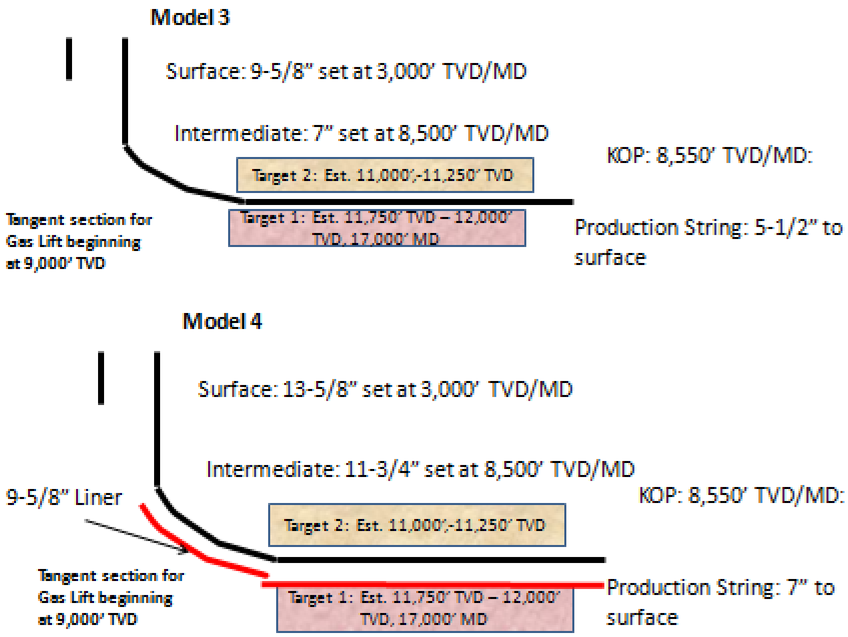

Figure 7.1b – Example well models for the objectives.

Table 7.1 – Developing an uncertainty management plan.

Narrowing the Range of Uncertainties						
Objectives	**Uncertainty**	**Model 1**	**Model 2**	**Model 3**	**Model 4**	**Conflicts, Comments, Requirements**
Low cost: Less than $5,000,000 (US).	Requires budgetary estimates for all models.	Needs budgetary cost estimates, this model being the most cost effective, but limits depth of artificial lift capabilities: gas lift mandrels.	Least expensive, smaller casings.	Moderately expensive, but size of casing may prohibit lift capabilities.	Most expensive.	Further engineering to determine casing sizes necessary to meet cost goals, hazards management, and lift requirements.
Target 2 pore pressure.	Pore pressure in open hole in Target 2.	This model does not allow for any casing contingency of the margin, which will be very difficult to manage while drilling deeper	This model does not allow for any casing contingency of the margin and cannot be managed while drilling deeper.	Allows for isolation of T1 while drilling T2.	Allows for isolation of T1 while drilling T2.	This known hazard requires further engineering. Consider designing for maximum casing sizes, but if the T2 reservoir pressure is not as depleted as suspected, it could be possible to drill without the liner. The design needs to accommodate this hazard.
Rig Schedule.					Will the rig have the horsepower to execute this hole section: hole cleaning and hookload?	Evaluate all models for maximum hookload and optimum hole cleaning rates for the given BHAs and fluid systems.

Narrowing the Range of Uncertainties

Objectives	Uncertainty	Model 1	Model 2	Model 3	Model 4	Conflicts, Comments, Requirements
Production rate range, Target 1. 0 to 5,000 BOPD		Might not be large enough casing to provide production rate criteria.	Might not have large enough casing to provide production rate criteria.	Might not have large enough casing to provide production rate criteria.	This model should provide for rate criteria and hazards management.	All models should be evaluated for rate capabilities.
Height and thickness of Target 1 reservoir, the objective is to stay in the target box window.	Geo steering, hole cleaning.		Slim hole will complicate hole cleaning hydraulics and the ability to geo-steer.			Hole cleaning capabilities should be evaluated for all models to avoid inducing hazards.
Artificial gas lift: Minimum 8,000 ft TVD, maximum for maximum drawdown: 9,000 ft TVD.	Casing sizes need to be evaluated.			Improves lift capabilities, deeper and large casing.	Improves lift capabilities, deeper and large casing.	Lift capacity should be evaluated for each casing size and the deeper capabilities of Models 3 and 4.

The design of any well alternative begins with the recognition that the uncertainties of the drilling margin must be honored. Each casing seat must address the maximum force it can exert against the fracture gradient with safe tolerance at TVD. The summation of the forces must balance, that is:

$$\sum \mathbf{F1} = \sum \mathbf{F2}$$

Where, F1 represents the force of the applied ECD and F2 represents the force exerted by the overburden fracture gradient of the earth in the wellbore.

Setting casing and ignoring the principle of force balance results in a casing seat that is not at optimum depth and will not facilitate an optimum depth for drilling the next hole section. This deficit continues to compound with each successive casing seat. This is especially critical in narrow margin drilling operations in any environment especially in HPHT or deepwater where loss of overburden due to water depth plays a critical role in top hole sections of the well.

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Figure 7.2 – Optimum casing seats maximizing the uncertainty of the drilling margin depicts an example of a deepwater environment and the optimum casing seats normally inserted to the top of salt in a subsalt environment. Applying this methodology enables the optimum depth of each casing string, minimizing the number of casing strings required to complete the well. Managing the uncertainty of the drilling margin minimizes the occurrence of boundary risks and should be an initial principle of well planning and DHM.

Figure 7.3 – Conventional vs. optimum casing seats: stacking vs. optimum represents the "stacking" effect created by the failure to optimize casing seats in the deepwater environment. It also indicates where the casing seats should be to optimize the uncertainties of the drilling margin.

In narrow drilling margin operations, the question is how can casing seats be optimized given that the boundaries of the drilling margin and that predictions are inaccurate. First, the casing seat design must follow the principle of Figure 7.2 – Optimum casing seats maximizing the uncertainty of the drilling margin. Any particular casing string must be designed for the depth as if predictions are absolute and with casing specifications having a design tolerance to drill and set deeper if conditions dictate. This is why actual drilling conditions must be monitored and why it is important to understand "well listening" as a necessary condition of casing seat optimization. That is, knowing what all drilling dynamics are representing. The well must be designed for success in that the planned depth becomes the maximum predicted depth plus more if hole conditions dictate. The contingency becomes a shallower setting depth if drilling conditions dictate. It is critical to ensure that the applied ECD plus safe tolerance is optimized for the given TVD. Actual drilling conditions will dictate this depth. In addition, other tools become useful such as pressure while drilling (PWD), coupled with ahead of the bit trend predictions as "D" Exponents[iii] (drilling exponents normally compiled in "mud logs") and seismic data.

However, even tools such as PWD and seismic data will not predict stress, and there is a distinct difference between stress and pore pressure. Stress is a vector and imposed on the borehole by issues such as tectonics, faults, or creeping salt diapers. These vectors can be quite different both in magnitude and direction than pore pressure. Pore pressure can be normal, yet stress can be much

[iii] There are several industry references for "D" Exponents not investigated in depth herein, but used as reference only.

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higher, but both require the same solution to stabilize the borehole—casing or mud weight. The uncertainty of this dynamic is critical in HPHT and deepwater environments. One reliable predictor of stress is "D" Exponent trends, which represents the specific energy supplied to the drilling string and bit as well as the total of dynamics drilling conditions.

Casing optimization begins with the design and ends with understanding and properly interpreting actual drilling conditions to result in the correct setting depth. In terms of DHM, a mistake often made is to set the casing at a predetermined depth regardless of drilling conditions. Casing seat tolerance not high enough for the next hole section results in the premature setting of another string of casing or drilling liner. This makes all risks more difficult to manage and routinely results in expending unnecessary casings. The typical mitigant is then to set the liner or full string of casing and hope for better results, shifting the uncertainties and risk yet deeper. The shallower the hazard can be managed, the better the risk profile, drilling performance and cost, and the safer the well.

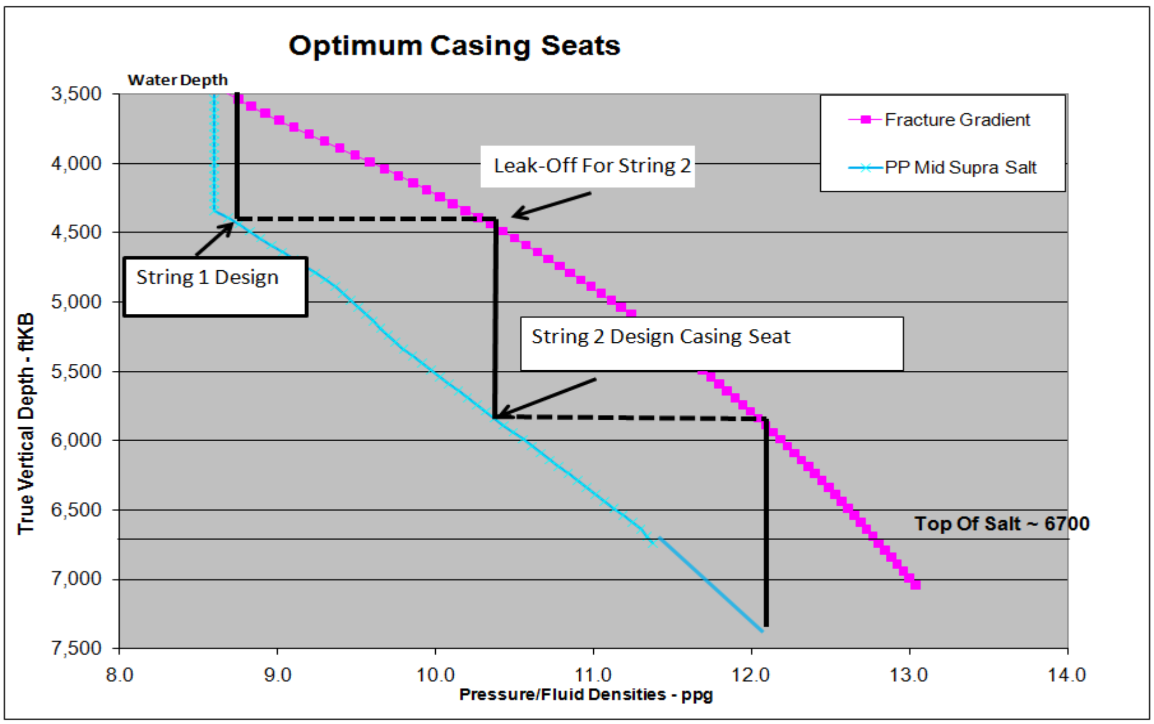

Figure 7.2 – Optimum casing seats maximizing the uncertainty of the drilling margin[iv]

[iv] David Prichard and Kenneth Kotow, Patent Pending USPTO, Applicant Serial Number 12635511.

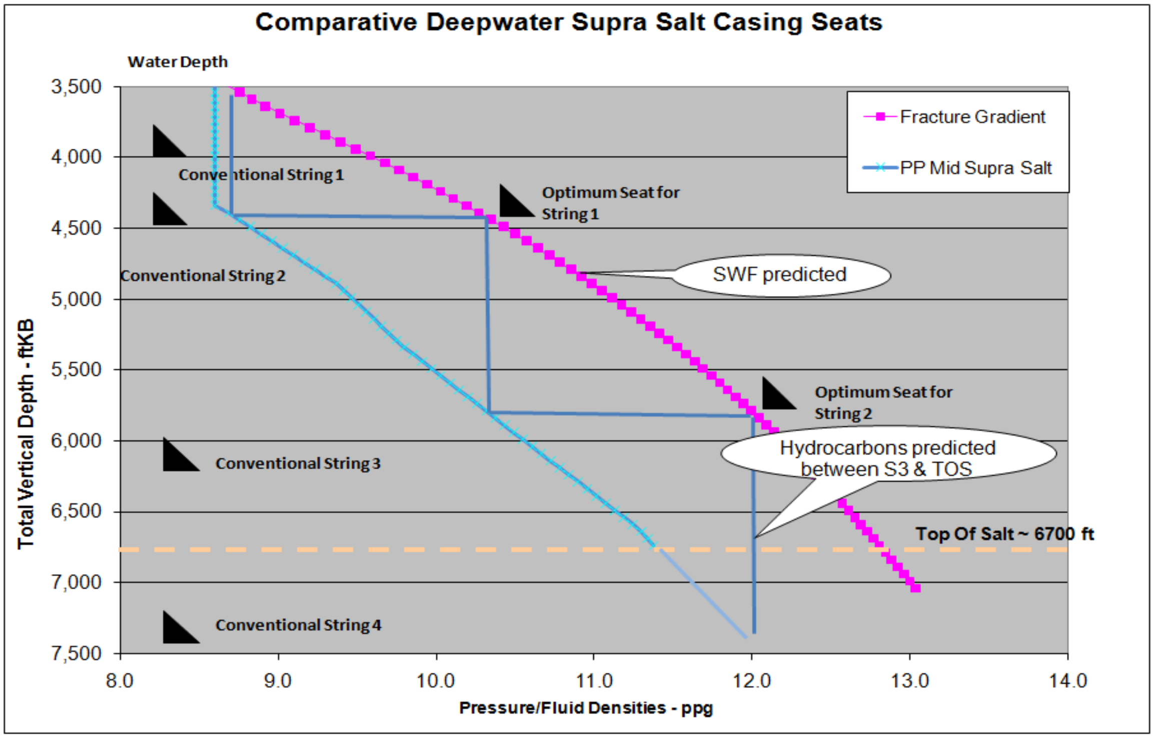

Figure 7.3 – Conventional vs. optimum casing seats: stacking vs. optimum.[v]

[v] Prichard, opt. cit.