Practical Well Planning and Drilling Manual

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Preface

There are many excellent books dealing with drilling engineering, well planning, and drilling practices. Readers will note that the approach I adopt here differs from the "standard" books in three significant respects:

1. I have separated the office aspects from the rig aspects. Thus, the drilling engineer who needs to design the well and write the drilling program will find the relevant information together in the first two major sections. The wellsite drilling engineer/supervisor/toolpusher will refer more to the third major section, which deals with the practical rig site aspects of drilling the well. I hope this makes it easier for the reader to focus on his or her current area of interest. For instance, casing design information is in Section 1, notes on writing the casing part of the drilling program are in Section 2, and notes on running casing are in Section 3. For the wellsite drilling engineer, toolpusher, or drilling supervisor, much of the information given in Section 2 (Well Programming) is also relevant to the practical aspects of the work. I have tried to include extensive indexing and cross-referencing to help find all the relevant pages.
2. I have not included reference information that should be readily available in the office or on the rig. You will not find reproductions of casing design data, drillstring strength tables, cement formulations, etc. Space is limited in any paper-based media, and I would rather use that limited space for information that may not be so readily available to you.

3. I have not gone far into the deep theoretical aspects behind the work. While it is valuable to intimately understand the theoretical background, it is not strictly necessary for practical application during your everyday work. I have included references where applicable. Also, a few of the topics are covered to give some background and to show how they impact the well design and drilling program, but are not in themselves meant to be an authoritative text on the subject. For instance, completions are not usually designed by drilling engineers, but the completion requirements impact the whole well design because the completion dictates the hole sizes. Therefore, the design needs to be understood, questions need to be asked, and parts of it should be checked. Cementing is a huge topic and a nonspecialist book like this cannot cover it comprehensively; reference can be made to one of the excellent specialist books on cementing (recommended in the relevant section).

Circulate the Design for Comment
Distribute for comment, including:
- Requesting department
- Drilling department
- Other qualified reviewers

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Write the Drilling Program
- Methods by which the well design will be safely and efficiently implemented
- Show the assumptions and decisions made while writing the program (technical justification)

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Circulate the Program for Comment
Distribute for comment, including:
- Requesting department
- Drilling department
- Other qualified reviewers
- Approval once finalized

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Pre-spud Meeting
- Onshore briefing
  - Distribute the program
- Offshore briefing
  - Distribute the program to each person in supervisory position (drillers, geologists, T/P, mud loggers, etc.)

1.1.2. Data Acquisition and Analysis

The success or failure of a well, from a drilling viewpoint, is heavily dependent on the quality of well planning prior to spud. The quality of the well planning in turn is heavily dependent on the quality and completeness of the data used in planning. The successful drilling engineer is a natural detective, snooping around for every snippet of useful data to analyze.

The starting point in your data analysis trail is the well proposal. Usually the need for drilling a well starts as a request from the exploration or production department. They will put together a package of information for drilling that will define what the well should achieve and where it should be.

Well proposal checklist. The proposal should contain the following elements as relevant to the particular well:

1. Well objectives (exploration, appraisal, development, or workover)
2. Envisaged timescale (earliest/latest spud date desired)

ties. Logging will show large washouts (off-scale in places), but the benefits in saved time with avoided losses more than compensates.

If losses occur in spite of good mud control, try reducing the circulation rate. You may find that a small reduction is all that is needed to cure the losses. After an hour or two of drilling ahead, it may be possible to slowly bring the circulation back to full rate. If total losses occur, first measure how much water is needed to fill the annulus. If the hole is static and full with water on top, slowly kick in the pumps and try to attain a circulation rate that will at least lift cuttings up the hole to the loss zone and cool the bit with very low weight on bit/revolutions per minute (WOB/RPM). Circulation of 250 gallons per minute (GPM) will give 50 feet per minute annular velocity (FPM AV) around 5 in drillpipe in 12¼ in hole; this should be used as the minimum. Drill ahead at reduced parameters and monitor drags and torques carefully for signs of drilled solids causing problems (potential stuck pipe). The losses are likely to cure themselves as generated cuttings act as lost circulation material (LCM) to plug the loss zone. Note that in past wells, LCM and cement have both been pumped, lost lots of time, and did not work.

The shale interbeds need a fair amount of inhibition and by experience it has been determined that if KCl is maintained at 40-42 ppb and shaledrill polymer at 1.0-1.5 ppb, there are no shale hydration problems. Keep a close eye on the mud properties and have the mud man run several tests throughout the day. The drilling engineer can be delegated the specific task of keeping an eye on this and personally supervising the tests to ensure that the tests are done properly and accurate results are given. There have been cases of mud men giving false results after a test to make it look as if the mud is in good shape when in fact it needs treatment.

In order to get the best drilling performance, the driller has to have the freedom to adjust the parameters for best ROP. The formation is quite streaky and changes constantly. The limestone is more sensitive to high RPM/lower WOB and the shales are better drilled with maximum WOB/lower RPM. If the driller is given a range of parameters to work within and is constantly experimenting for best ROP, the overall bit run will be far better.

Most instances of overpressures occur in areas of fast deposition of sediments. Water held in the formation pore spaces does not have time to move out of the rock matrix as the rock becomes increasingly compressed with growing overburden. This will cause the formation fluids to bear a larger proportion of the overburden pressure as the grains of rock are prevented from increasing their contact and taking their share of the load. As porosity normally decreases with depth, any change in this trend that slows the rate of porosity decrease with depth is an indicator of possible abnormal pressure. If the formation contains salt water, then the normally decreasing trend of resistivity with depth will also slow down or stop. Abnormal pressures may start from the top of this trend change. Where overpressures are caused by this mechanism the increase is gradual with depth; ROP trends such as D exponent can be used to identify this type of overpressure as drilling continues.

Gas generated under an impermeable boundary by decaying organic matter (biogenic gas) will cause an increase in pore pressure.

Salt domes distort and compress the formations around them and high abnormal pore pressures can result.

Bad cement jobs on offset wells or faults below a sealing formation can allow gas migration into higher zones, charging those zones to abnormal pressures. A similar mechanism is where a long gas column is normally pressured at the bottom by an aquifer. Due to the low density of gas, as you move up the gas column the difference between the gas pressure and the normal pressure will increase and be highest at the top of the gas column. Since the transition is very sudden if the cap rock is not leaky, these types of abnormal pressure would not be detected by D exponent or ROP trends while drilling (see Fig. 1-6).

Some rock transformations can cause significant increases in rock volume. Montmorillonite changes to illite under pressure, releasing water. Gypsum ($CaSO_4 \cdot 2H_2O$) also releases water as it changes to anhydrite ($CaSO_4$). If this liberated water is unable to move, pore pressures could increase significantly.

Normal pressure trapped within a boundary may be moved up by tectonic activity. If the pressure cannot reduce within the boundary then it will become abnormally pressured at shallower depths. Severe kicks can be taken by drilling into a raft of fractured dolomite within a massive salt sequence. This is a good example of trapped pressure, originally normal, which migrates up inside a pressure containing system. Examples are seen in the Zechstein sequence of the North Sea; saltwater kicks may be taken at much greater pressure gradients than would otherwise be indicates that using thicker wall sections is preferable to using higher grades of steel.

Temperature correction factors for steel. Correction factors have an engineering basis, unlike safety factors that are arbitrary. Correction factors are applied as well as the relevant safety factors.

The yield strength of steel usually decreases with increasing temperature. A temperature correction factor can be applied to the minimum yield strength before applying the safety factor as mentioned. This correction factor should be obtained from the casing manufacturer. Apply the temperature correction factor as noted here.

Tension. Tensile load will decrease with depth so that as the casing gets hotter, it is also subjected to less tension. If the top joint of an unmixed casing string is strong enough in tension, it should be fine lower down. If a mixed string is used (different sections of the overall string that have different weights and/or grades) apply the factor when evaluating the tension applied to the top component of each section.

Compression. Compression is unlikely to be relevant. Helical buckling is more likely to occur than failure in compression in the hot part of the string.

Burst. Burst could be very relevant at depth, especially in a high-pressure, high-temperature well. This is not likely to be a problem while drilling but may be a problem later in the life of the well. If a frac treatment or other procedure can be used where significant surface pressure may be applied, this burst pressure will be imposed down the exposed casing string (i.e., above any packers set).

Multiply the burst strength by the temperature correction factor and apply the safety factor before comparing the amended burst strength to the calculated burst pressure.

Collapse. Collapse could be a problem while drilling if severe losses are taken, high drawdowns are used during production, and the reservoir becomes depleted. Also if massive salts are covered, we generally assume that the salt transmits the full overburden pressure against the casing in collapse (1 psi/ft).

Multiply the collapse strength by the temperature correction factor and apply the safety factor before comparing the amended collapse strength to the calculated collapse pressure.

The following table is supplied by Nippon Steel. Figures for other

If the casing has been designed for the 1 psi/ft collapse gradient *and* if the casing has a good cement sheath throughout the salt interval then failure probability is minimal. It is important to note that for preventing distortion and shear, a complete and competent cement job is as important as the casing strength. Refer to "Cementing against massive salts" in Section 2.7.4.

1.4.18. Casing Properties and Other Considerations

Having calculated the minimum strength requirements and preferred weights and grades of the casing, you now have to check against other considerations. These include:

1. *Inside diameter for running completion tools.* In production casing the ID is important to ensure that all required completion components can be run. For instance if a dual 3½ in completion was to be run, 9⅝ in 57# casing may not give the required clearance to run the completion accessories.
2. *Seamless pipe vs. seamed, electric resistance welded (ERW) pipe.* The seamless method is most common for pipe production. Historically seamed pipe was not used for casings below surface casing due to considerations of quality of the pipe. Modern ERW pipe can now be produced in quality equal to seamless pipe and because it is cheaper, ERW pipe can save a lot on the cost of a well. Major operators such as Shell have decided that seamed pipe can be used as casing for deeper strings where quality control is assured.

   Whether or not you can use seamed pipe will probably be dictated by company or government policy. It is certainly worth the effort to consider seamed pipe.
3. *Availability.*
4. *Cost.* Of the casings that are both suitable and available in time, the lowest cost string can be chosen.

1.4.19. Material Grades

API defines the characteristics of various steels and assigns letters to identify those grades; refer to *API Specification* 5CT for complete defbetween surveys, "minimum curvature," assumes a perfect arc between survey points. In practice the actual dogleg severity will be greater in some places than others, imposing a point loading at those places. If the limit for dogleg severity were 2.05°/100 ft, you could plan on an average 1.5° dogleg severity to allow for this variation.

There is also a practical solution to allow higher dogleg severities than the limit calculated above. If drillpipe protectors were to be positioned at the midpoint of each joint of drillpipe, and if the OD of those protectors were similar to the tool joint OD, you would effectively halve the length of the drillpipe joint. The load would be taken by the protectors that would reduce the load on the tool joints. As the factor related to the length of the drillpipe joints *L* is on the bottom half of the formula, halving the length would double the allowable dogleg severity. Therefore, by using drillpipe protectors, one per joint on drillpipe being rotated through the build section, the allowable DLS will double to just over 4°. Two protectors per joint, equally spaced at one-third and two-thirds inches along the pipe, will further reduce the load and allow a larger DLS.

Drillstring fatigue. The area of the drillpipe subjected to the severest cyclic bending stresses when rotated in a dogleg is where the drillpipe body joins the tool joint. Here the stiffness of the drillpipe changes very quickly between the rigid tool joint itself and the flexible pipe body.

Calculation of fatigue is fairly complicated. Calculations for fatigue limitations of dogleg severity gives greater dogleg severities than the maximum found by calculating for preventing tool joint damage, except at very low drillstring tensions (below about 75,000 lbs or lower). Therefore, as long as doglegs are limited by the 2000 lbs lateral force for tool joint damage, pure drillpipe fatigue is not likely to be a problem.

Reference can be made to the graphs in Section B4 of the *IADC Drilling Manual* and also in API RP7G These graphs show the maximum dogleg severity for commonly used drillpipes. Preston Moore's *Drilling Practices Manual* also has some graphs illustrating fatigue limitations of dogleg severity. The most commonly referenced paper on the subject is "Maximum Permissible Dog-legs in Rotary Boreholes," by A. Lubinski.

Fatigue failures can occur at other areas on the drillpipe. If the pipe is not sufficiently torqued up so that the shoulders are compressed together, fatigue failure of the pin will occur very quickly. Also, if the