Aspects of Effective Well Management

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Abstract

Data taken from the US Energy Information Administration from 1973 to 2006 shows that drilling efficiency peaked in 1986 at 517 ft per day but was down to 470 ft per day by 2006. The strongest and most prolonged improvement in Rate of Penetration (ROP) happened from 1981 (287 ft/day) to its peak in 1986. This corresponded with a decline in rig numbers from 3970 to 970 in the same period. Although these are figures based on US data, the same profile is anecdotally mirrored across the world's wells activities. There's no doubt that over the past few decades there have been several mile-stone developments in drilling and completion technology (and techniques) which have offered significant potential improvements in well construction efficiency. This begs the question as to why we're not as efficient at managing wells as the passage of time would have us expect. This paper addresses some of the issues, ranging from our misunderstanding as to what to expect of technology, or how to embrace it safely and profitably, to the evolution of political and social trends that are (and will continue) shaping and moulding the way we go about our business and how that impacts performance.

Introduction

In March of this year this interesting question came up on the SPE's Drilling Discussion Forum (one of the SPE's Technical Interest Groups):

"Data from the US Energy Information Administration from 1973 to 2006 shows that drilling efficiency peaked in 1986 at 517 ft per rig per day and was at 470 ft per rig per day at the end of 2006. The strongest & most prolonged improvement in ROP happened from 1981 (287 ft p.r.p.d) to the peak in 1986. This corresponded with a decline in rig numbers from 3970 to 970 in the same period. I had expected to see evidence of improvement over the 33 year period, even given increased complexity. On balance it seems reasonable to suppose that we can drill faster today than ever….?"

The statement / question raises an array of complex issues which will be explored in this paper, ranging from technological evolution to the ebb and flow of cultural and political persuasions which guide our commercial activities today (and will certainly do so tomorrow as well), it covers many critical aspects of effective well management.

In terms of drilling efficiency there have been numerous individual items of technology and innovative practices that have helped in the pursuit of 'better value' wells. In considering landmark innovations however, there have been relatively few, and expectations have taken time to be realised. For example, the 1960's brought us drilling jars and the positive displacement motor. The '70's was a highly technically innovative decade bringing us PDC bits, drilling turbines, oil-based-mud (OBM), the surface recording gyro (SRG) and measurement-while-drilling (MWD). Steerable motors and top-drives were ushered in during the eighties, and rotary steerable systems (RSS) were the talk-of-the-town in the nineties. The time taken however, for full commercial adoption of these technologies was varied for (again) a complex series of reasons. A couple of interesting technologies are potentially going to be the "next revolution" in this, the first decade of the twenty-first century, but more of that later.

The commercial drivers have not been easy to predict or steer during the past few decades; the "baby-boomers" (those born just after World War II) were culturally very different from their parents who had known the ravages and deprivations of conflict on an almighty scale. Expectations, especially in terms of material and social comforts meant that there was a very different environment in which to develop business. That in turn led to complex political environments. Oil and gas are global commodities, competed for by a world of vast complexity, so is it any wonder that we don't always get it right? Let's address a few of these issues.

The Technological "Enigma"

The word "Enigma" is deliberately chosen here, the dictionary defines it as: *"a puzzling or inexplicable occurrence or situation"*. It is easy to jump on to the technology band-wagon in the expectation that it will immediately resolve all our difficulties and instantly aid efficiency. Reality is somewhat different as its use often raises a whole range of hitherto unforeseen issues. Let's go through a few examples:

PDC Drill Bits: When PDC bits were introduced to the industry in the late 1970's, along with, turbines, MWD, and OBM systems, drilling efficiency improved beyond recognition, sections which had previously taken 10 – 15 roller-cone bits were suddenly drillable in one run at unheard of penetration rates. The race was on for the fastest cutting structure known to man. That though, created problems in other aspects of the drilling operation, that of establishing then holding an appropriate "tool-face" when directional drilling with a Positive Displacement Motor (PDM). Hitherto, roller-cone bits, by their very mode of construction were relatively easy to control in terms of tool-face (the rolling bearings enabling the directional driller to establish and hold a tool-face with a degree of sensitivity). The earliest PDC bits had ~10mm diameter cutters and were not overly demanding of drive torque, hence directional drillers learned to be able to handle them. Drill bit designers and manufacturers (encouraged, indeed by Operating companies) however, were on a mission; to drill further and faster than everyone else. This led to a plethora of cutter designs, sizes and geometry, each ever more "aggressive" than before. Cutter sizes of up to 30mm were installed at extremely low back-rake angles; this meant a significantly higher rotating torque was required whilst drilling. When this torque was supplied by a PDM in oriented mode the reactive torque it generated made it almost impossible for the directional driller to control his tool-face. This naturally slowed down the very process that these adventurous bits had been deployed to speed up!

Many, many innovations have been conceived regarding drill bits (PDC's in particular) though, in the intervening decades. To mention just a few: *[Ack. 1]*

- Dozens of well documented improvements in cutter technology (e.g. SPE 81167, 74526, 90845), including very abrasive resistant cutters, reducing friction between the PDC face and the rock removed, cutters for very hard and abrasive rock, saving bit trips. Thermostable PDC cutters (TSP technology) would fall under this categorization.

- Numerous breakthroughs in impregnated bits or hybrid bits, enabling efficiency in shales and hard rock (New Impregnated Bit : SPE 87096)
- Development of Hammer Bits (SPE99522) that seem to have potential in very hard formation (but not used very much today – why…?).
- Many improvements in cutter structure design (see the number of SPE papers dealing with "dramatically improve ROP" thanks to a new cutting structure design etc….).
- Many improvements in directional PDC bits for given specific directional systems; RSS "push-the-bit" or "point-the-bit" (PDC bit steerability), improving borehole quality. Some innovations regarding tool-face orientation issues with steerable mud motors; depth-of-cut control technology.
- Innovative bits including, for example: the micro-coring bit concept (SPE 115187) that enables micro-coring while drilling.
- At last! - a bit that requires zero weight-on-bit (WOB); this is the self-penetrating bit (SPE 105522) that should have some interesting applications in drilling where WOB transfer is an issue.

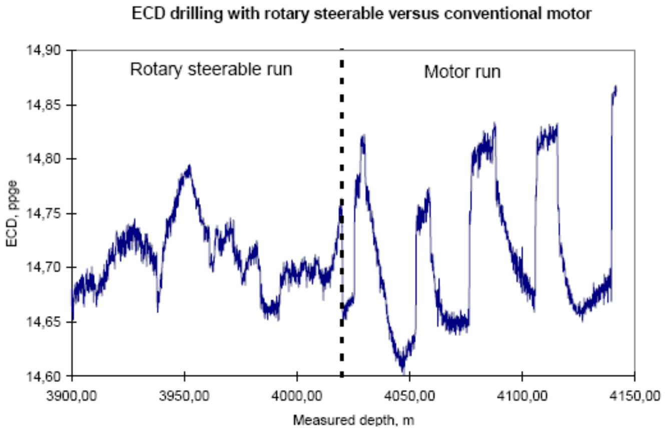
With all these breakthroughs, why has drilling efficiency not improved significantly over the past decades? As can be seen in the chart in appendix 1, average feet drilled per day has remained relatively constant at around 450 feet per day. Maybe the answer is that bit technology is not so pre-eminent a driver in managing drilling efficiency as we would all like to think, so maybe we have to look elsewhere for the answer.

Oil based Mud: As mentioned above, the advent of OBMs contributed significantly to drilling efficiency improvement. Those early OBMs however, were not pleasant to work with, they were usually diesel based and pervaded the workspace; the aromatics they contained were highly detrimental to elastomeric components of the drilling system (PDM stators, in particular were catastrophically damaged in a very short time). Synthetic OBM substitutes were introduced which certainly lessened the environmental impact, but as an increasingly environmentally aware public caused politicians to place ever stringent controls on Operating companies in respect of OBM management. This led to the notion of "skip-and-ship" where OBM saturated cuttings would be deposited in skips and sent ashore for "cleansing". Although an admirable philosophy, skip-and-ship often resulted in a reduction of drilling efficiency as bad weather and/or skip supply would severely compromise the driller's efforts to "make hole". Likewise the relatively new concept of cuttings re-injection (cuttings being disposed of in sacrificial / redundant wells) does not actively promote drilling efficiency advancement as injection systems have a finite volume capacity, which in many cases is less than the volumes created by fast drilling.

As ever though, the industry is reacting positively. The major technological advance over the past 25 years centres to a large extent on the drilling of highly-deviated and horizontal wells *[Ack. 2]*. Extended-reach and multi-lateral drilling, an offshoot of this technological advance, now enables horizontal displacements of up to 37,000 ft (11 km) and studies are currently being carried out to drill wells with projected horizontal displacements of 50,000 ft (15 km). The key component of the drilling technology that allows these wells to be successfully drilled and completed is the new non-aqueous drilling fluid systems with constant rheology that does not significantly vary with temperature. Standard oil-based systems' rheological properties are temperature dependent and often have uneven performance along the length of a well, especially in deepwater environments. The new fluids with constant rheology provide ideal "fragile gel strength", as well as improved visco-elastic characteristics which insures lower Equivalent Circulating Density (ECD) especially after circulation is initiated or flow rates changed, lower breaking circulation pressures, less surge and swab, and better cuttings transport and barite suspension.

Based on the mineralogy and morphology of the target oil and gas reservoir rocks, the new non-aqueous fluid systems can be customized to avoid the formation damage problems. Special quality control tests are conducted at the wellsite, while drilling the reservoir section, to monitor the fluid characteristics and carry out the required corrective chemical treatments in timely manner. Whole mud invasion into the reservoir can be minimized by using properly sized degradable bridging material. Quick lift off and clean up of these particles allow the reservoir to flow at its maximum potential production rate. We are making progress!

Steerable Motors: The introduction of Steerable drilling motors in 1987 was hailed as a true revolution in terms of directional drilling. Suddenly there was no need to trip after kicking the well off (formerly with a bent-sub / motor combination) and replace the BHA (bottom hole assembly) with either a rotary build or hold assembly. We could just start rotating the drill string and continue drilling ahead, altering the trajectory as we went. Dozens of trips, purely for directional considerations, were saved and many high value bonuses earned! However, this “revolution” did not answer everyone’s prayers. Most obvious was the fact that in order to direct (orient) the well it was necessary to stop string rotation and “slide” the BHA / drillstring down the hole while trying to maintain a constant tool-face (orientation). This was often possible without losing too much penetration rate at lower inclinations, but as a well’s inclination became higher, it became increasingly difficult to slide and effect the necessary trajectory change. Often many hours would be wasted (lost) attempting the procedure.



The next, rather less obvious aspect was that of hole cleaning; while attempting to slide at high inclinations, solids would drop out of suspension and form a cuttings bed. This in fact contributed to two potentially problematic scenarios, firstly the well could become unstable because ECD (equivalent circulating density) management was not “managed”, this chart (left) clearly demonstrates the point – the right side of the chart shows the large variation in ECD experienced whilst sliding and rotating with a steerable motor, the left side of the chart shows the improvement to be had by using a BHA which is constantly rotating. Secondly, the consequential cuttings-bed build-up on the low side of the hole actually helped prevent the string from doing the very sliding that was being attempted!

The second phenomenon was that of a potentially “tortuous” borehole being drilled. What is meant by “tortuosity”? In regard to a well’s trajectory there is always a mathematically (geometrically) “ideal” well path – i.e. a “minimum curve” by which the target may be achieved. Tortuosity may be considered to be variance from that ideal curve for the “as-drilled” well-path, and should be minimised in order to:

- Reduce surface torque demand to drive the drill bit
- Better enable casing to be run

- Better enable subsequent wireline operations
- Better enable running of completions
- Make subsequent work-over operations easier and more efficient

In certain cases, if there is too much tortuosity in the upper reaches of a wellbore then it may indeed be impossible to drill the well to total depth (TD) as the amount of surface torque required of the rotary table or top-drive is more than they are capable of delivering! Drilling a hole quickly, but carelessly, can have extreme financial consequences, and can practically lead to a well being value-less as soon as it is drilled if it is not possible to run wireline logs, or run the completion (ESP's for example, typically need several hundred feet of smooth non-tortuous hole in which to be installed). If the well cannot be serviced because slick-line or coiled-tubing cannot be run-in, then the well certainly cannot be effectively managed. There always was (and still is, in many operations) insufficient inter-action between drilling, completion and workover personnel. Each have their own agendas, their own time (or monetary) goals, their own concept of "success" regardless of the overall imperative to "design, construct, operate, maintain, and abandon a well" for the design life of that well. Effective well management ensures that all contributors to the well's lifecycle have the same end-objective clearly in mind, and are rewarded accordingly.

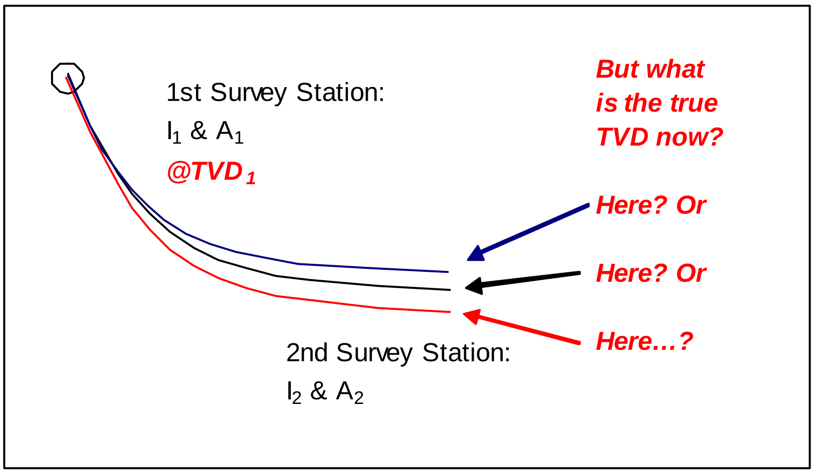
One last "enigma" of steerable motors is that depending on the operating habits or idiosyncrasies of an individual directional drilling engineer it is possible to completely miss the pre-designated target (or even the reservoir!). Before delving into this discussion however, we need to first discuss changes in well-bore surveying practices and procedures for reasons that will soon become obvious.

Drilling practices and survey calculation methods can almost unknowingly induce significant "gross errors", by this we mean errors which are undetected mistakes (often "human errors") that cause a measurement to be very much farther from the mean measurement than other measurements. For more than 15 years the directional well surveying industry has settled on a standard method of calculating the position of a wellbore from inclination and azimuth measurements. This method, called minimum curvature, determines the smallest radius curvature between two survey stations. The position co-ordinates for the second survey, in terms of easting (X), northing (Y) and true vertical depth (Z), can then be calculated. A basic assumption is that there is no appreciable change in the curvature between the surveys. *[Ack. 3]*

Two things happened in the early 1990's that have shown this assumption to be fundamentally flawed. First, positive displacement motors (PDMs) with bent housings made it possible to drill directionally with a high curve rate (5-10°/100ft) when slide drilling and then switch to drilling in rotary mode with curve rates usually less than 1°/ 100ft. Secondly, top drives on offshore and some land rigs made it possible to drill three 30-ft joints of pipe (or a 'stand') without stopping to make connections. MWD tools usually take a directional survey when the mud pumps are cycled off, and then on when a connection is made. This means that surveys gradually came to be taken every 90ft instead of every 30ft.

These two developments meant that the probability of differing curve rates between survey points increased dramatically; the interpolation between the surveys did not reflect the actual trajectory of the wellbore. It became difficult to model and predict curve rates for various PDM's, and there was speculation that the location of the wellbore at any point may be incorrect. This positional difference would be in addition to the positional uncertainty that results from sensor accuracy and alignment specifications. Directional drillers took extra surveys or 'check-shots' to help with trajectory tendency work, but little was done to determine the effect on wellbore position. Let's explore this further:

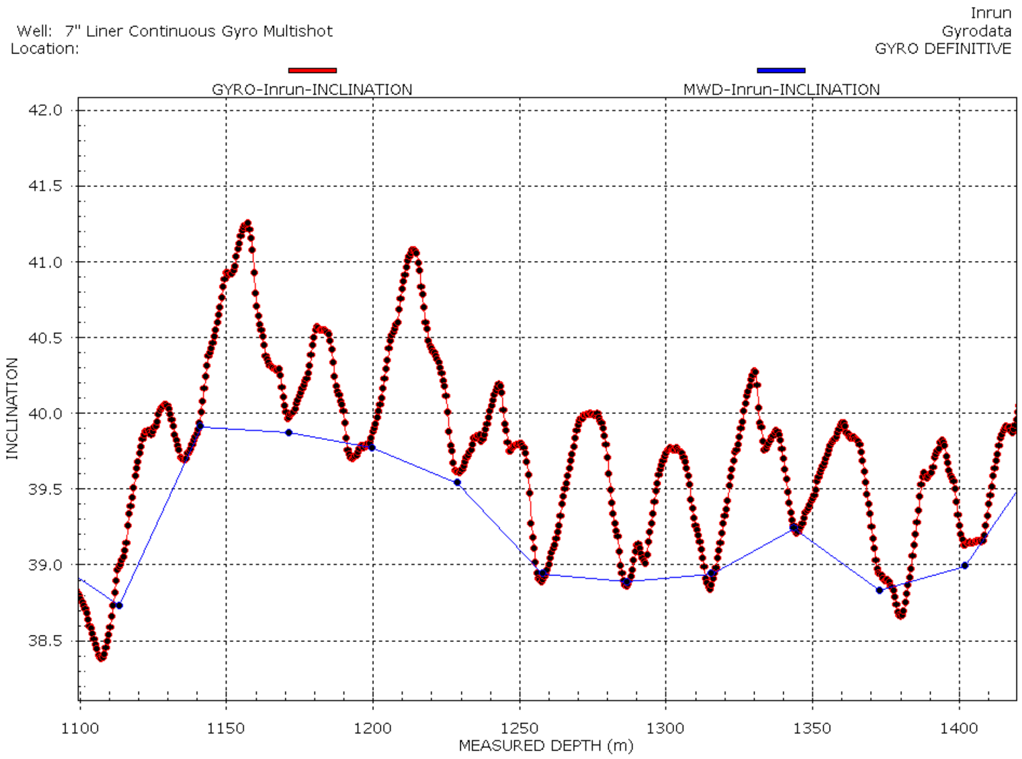
Assume the first survey station here defines the origin (i.e. there is no error at this point). A stand is directionally drilled and a second survey is now taken. An industry used and accepted "minimum curvature" algorithm produces a ΔNorthing, ΔEasting, and ΔTVD (True Vertical Depth), which are added to the positional data for the previous survey station to determine the well's definitive (?) position. However, this algorithm assumes a perfect great arc between the two survey stations, which may, or (more likely) may not be the reality. If the directional driller has altered the BHA's tool-face orientation at any point (or points) during the drilling of the stand, the whole basis of the model is compromised. The second survey station (see diagram) has a discrete Inclination (I2) & Azimuth (A2) – and we know, exactly, the difference in measured depth so we can calculate the relevant ΔN, ΔE, ΔTVD but – depending on the actual path between survey stations, these carefully and confidently calculated departures may indeed be wrong. This potentially erroneous set of positional data is then, of course used as the basis for the next calculation and so the potential error perpetuates.



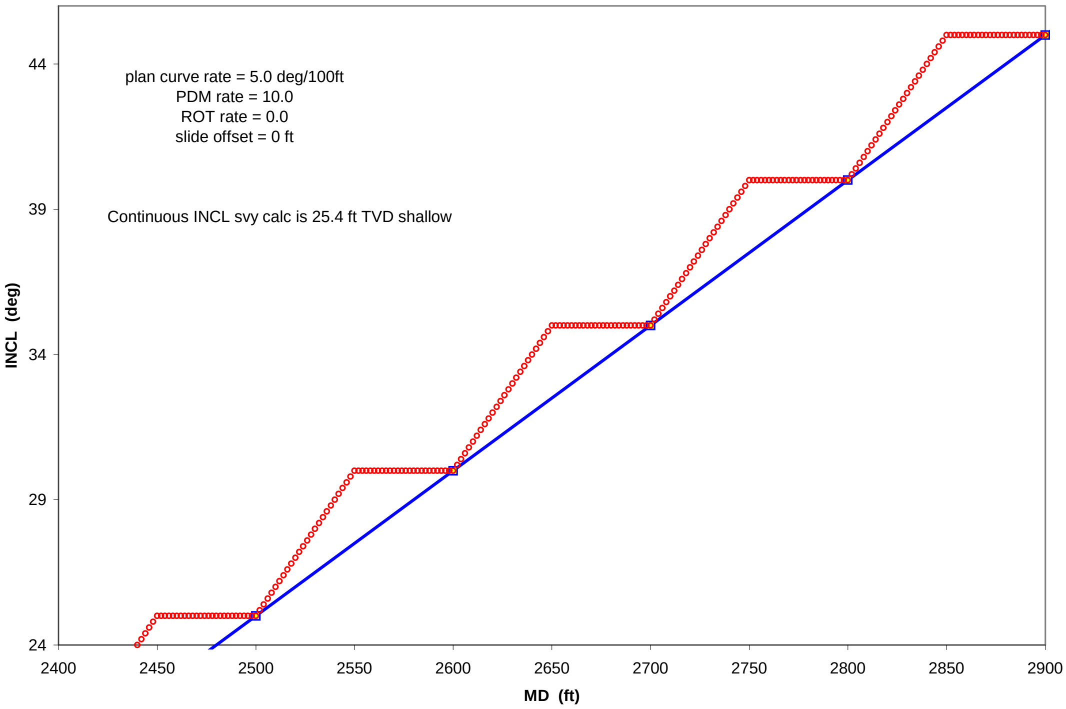
If the survey interval were to be sufficiently short, say 1 ft, then the actual well path would be adequately and accurately mapped, but the practicality of 1 ft survey intervals, whilst drilling is of course, nonsense. Modern "continuous" surveys typically performed post-drilling, however does give the industry a means to produce such accurate mapping of wellbore trajectories by effectively negating gross errors emanating from inappropriately spread survey intervals.

The plot below demonstrates the point *[Ack. 4]* - here we see the blue line on the plot joining up the inclination element of the respective survey stations (blue dots) as the well is drilled, stand by stand. Look now though, at the red line plot – each dot is the inclination data produced from a post-drilling continuous-gyro survey, logged every ½ metre. Note that both survey sets are "correct" as each MWD inclination survey point is verified by an adjacent continuous-gyro derived inclination. The continuous-gyro, however is defining the true path drilled by the directional driller. If each data set is run through the minimum curvature algorithm the effect of this (hitherto unknown) gross error becomes very apparent – over this relatively short interval there is about an 8 metre TVD (True Vertical Depth) error!

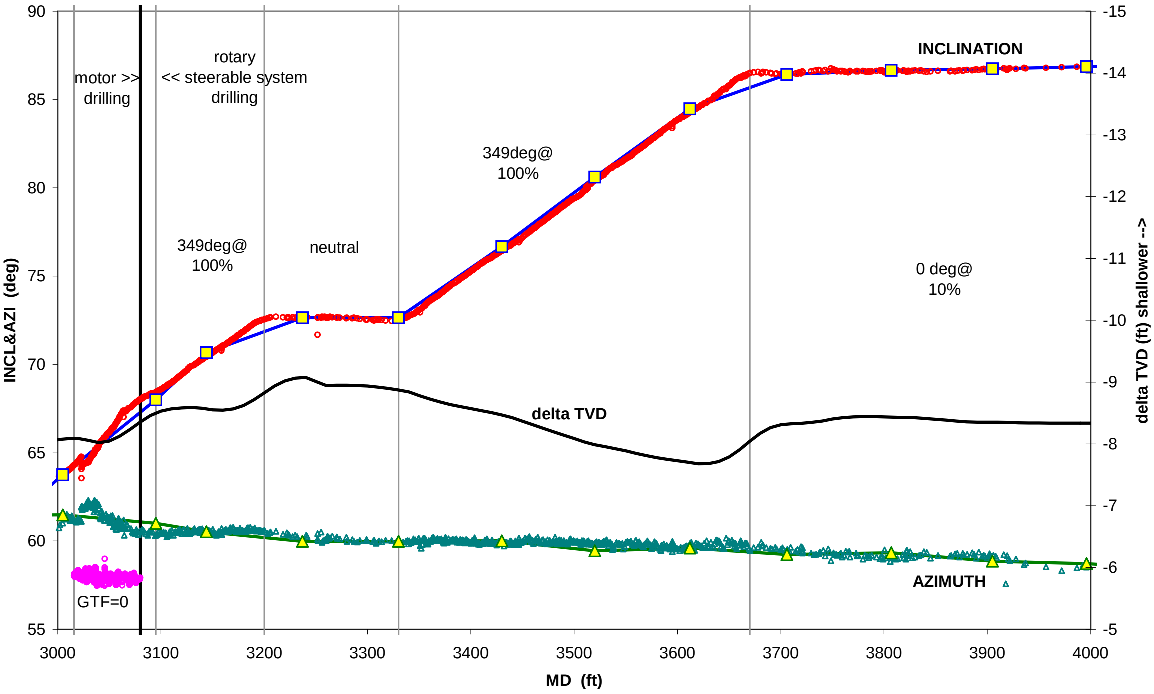
These error types are potentially most detrimental when a well is drilled with a steerable motor because quite large, virtually instantaneous dog-legs can be produced, but their presence is often masked when the directional driller switches to rotating mode.



The figure below shows the reality of a particular directional driller (they all have their own habits) building angle from 24˚ to 45˚. Here he's effecting his "build" by orienting high side for the first joint of a stand, then rotating the next two joints as he completes the drilling of a stand. MWD surveys have been taken every stand and were used for plotting the well trajectory in real time. Subsequent continuous-gyro derived inclination surveys reveal the reality of the trajectory – in this instance an error of some 25-1/2ft in TVD – potentially more than enough to miss a target – or even reservoir! It's that serious.



The advent of modern-day Rotary Steerable Systems (RSS) which have, in varying degrees, automated the well-guidance process has somewhat reduced the potential for such gross errors but by no means nullified it entirely as can be seen in the plot below. Depending on the sophistication of the steering mechanisms of the well's trajectory, the well-path may well change discretely between or through MWD survey stations. Again this plot shows the TVD errors as the RSS is actually developing "elbows" in the vertical section (see inclination data) – seen only after the event by running a continuous-gyro survey. In this instance the wellbore's final placement is 8-1/2 ft shallower than that derived from the MWD data.



In reservoir situations there is perhaps more concern over TVD errors (derived from inclination measurement) than lateral errors (derived from azimuthal measurement). The effect of TVD positional differences in horizontal wells can lead to poorly placed drain-hole sections or even missing the target reservoir completely. Since both the operator personnel and service company directional drillers are not aware of this problem caused by non-constant curvature in surveys, the problem is usually attributed to an unexpected change in geological structure. "Forty percent of gestured horizontal wells encounter a geological surprise" was a statement made in 1996. These surprises were usually in the range of a 10 – 20 feet TVD shift. How many of these shifts were the result of non-constant curvature in survey calculations as opposed to problems in structural mapping? Financial implications are therefore obvious. Let's now switch focus and have a look at a completion example:

Expandable Sand Screens: Sand production from formation rock along with hydrocarbons is a continuing problem within the industry because of its operational and economic implications, the mitigation of which is a challenging task. Apparently, it is mostly the unconsolidated and clastic formations that produce sand because of lower rock mechanical strength, which is often exceeded either during the drilling or production phase, leading to the breakdown of matrix due to higher stresses encountered. It is therefore often required to apply a sand control completion technique that will retain sands downhole for multiple benefits. Though producing sand to surface along with the hydrocarbons increases the productivity of a well, it is more appropriate to control sand production downhole in view of the implications: risk of failure of completion components, cumbersome remediation processes at surface, formation impairment due to perforation plugging in cased hole completions, losing the well integrity etc. There are a few available techniques to control sand downhole namely: Gravel pack (GP), Stand-Alone screens (SAS) and Expandable Sand screens (ESS). *[Ack. 5]*

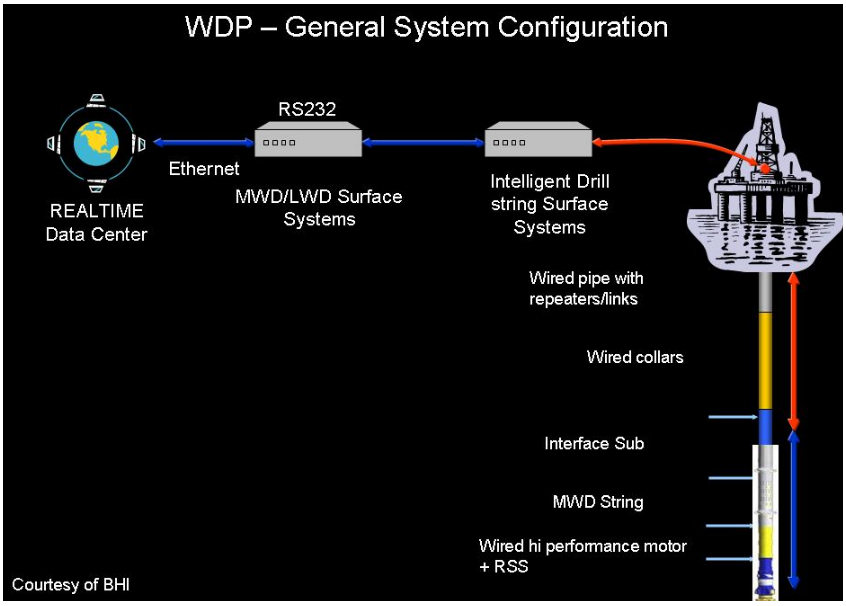
Of the available techniques, Expandable Sand Screen (ESS) completion has been a recent major technological breakthrough for completing wells with sand-prone formations, but so far with mixed success. Initially this type of completion was employed only in clean and consolidated formation sands but was later extended to unconsolidated reservoirs (non-conformity co-efficient D40/D90>5) with a lower Net/Gross (<80%). A recent report reviewed the Candidate Selection Criteria for applicability of the ESS technique and the sustainability and reliability of some selected ESS installations. Major Operators provided relevant data based on actual field performance, which became the basis of recommending ways to improve success rates for both open hole (OH) and cased hole (CH) ESS completions. The analysis concluded that of the 107 open hole ESS installed wells, 24 had lost sand retention ability (that's almost a quarter of the total) and majority of those were associated with low Net/Gross and/or water production. Of 67 cased hole ESS analysed, there were 22 wells that lost sand retention ability due to sand impingement (plugged perforations, not properly packed perforations). That represents a third of all such completed wells! Based on the analysis it was recommended that the ESS envelope should be limited to consolidated formations and higher net/gross ratio for OH completions and properly packed perforations and deburred casings for CH completions.

This is another expensive example of expectations failing to be met by the use of "technology" in an inappropriate application.

The New Horizon

In the introduction I promised a glimpse of the "next technological revolution", here is an overview of what I consider to be the first major technological mile-stone of this twenty-first century:

The "IntelliServ Network" is the industry's first high-speed, bi-directional drill string telemetry system, generically referred to as "Wired Drill-Pipe" (WDP). This breakthrough technology transforms the drill string into an advanced information tool that enables bi-directional communication between down-hole tools and the surface at speeds up to 57,000 bits per second, allowing instantaneous communication and control with all downhole tools. When run in parallel with a mud pulse device, full telemetry redundancy dramatically reduces the risk of data transmission loss, reducing unplanned

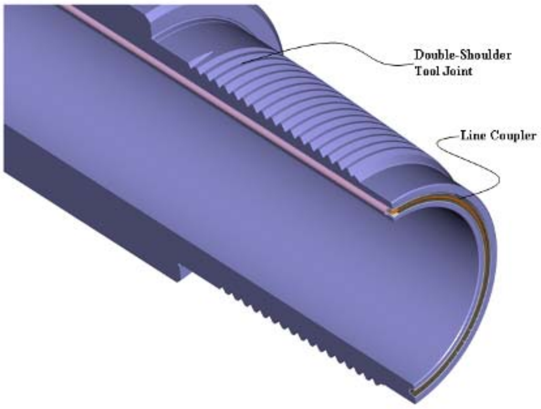


Courtesy of BHI

trips and eliminating associated non-productive time and well costs. This transmission speed compares to the current fastest MWD rate of 16 bits per second, that's over 3,500 times faster…..

In brief, the system delivers fast, seamless connectivity to the bottom-hole environment for real time operational control and optimization. Operators can take full advantage of formation evaluation, navigation and drilling tools. The system facilitates precise control of downhole equipment regardless of total well depth, rate of penetration, drilling fluid or formation characteristics. A large number of new components are included in the system; from complex petrophysical tools, managed pressure systems, and BHA equipment like reamers, stabilizers, drill collars, and float valves.

The system is based on premium quality NOV GrantPrideco® tubulars with proprietary double shoulder connections (see diagram). The heart of the IntelliServ Network is the high speed telemetry drill pipe. Each joint of drill pipe is modified for high speed communications by use of inductive coils installed on pin and box secondary shoulders. The coils connect to a high-speed, high-strength data cable that is anchored at the pipe joint, The cable exits to the internal diameter of the tubular at the upset and runs under tension along the inside of the pipe without affecting drill pipe properties. Once made up, the coils come near each other and induce the signals down the pipe without direct contact. *[Ack. 6]*



Recently StatoilHydro tested WDP during the drilling of the horizontal section of a well on the Visund platform in the Norwegian North Sea (IADC/SPE 112702). Several value cases were identified during the test, most of which were used in the drilling decision process. These could be broadly categorized into HSE, improved drilling operations, well placement / geosteering and data transmission. The most obvious and immediate benefit of WDP technology was identified in the areas of fast downlinks and control of downhole tools. High-frequency, time-based data was also useful for real-time torque and drag analysis and borehole quality using real-time calliper data. Better monitoring of downhole formation and wellbore pressures provided a basis for improved well control and borehole stability. The ability to send significantly more curves with higher resolution enhanced the well placement / geosteering process, and may, in the end, represent an even more significant value potential for this technology. Future WDP wells may easily implement these technologies.

The Socio-Political Scene

In contemplating this "wrap-up" I reflected upon the last section from the prologue of an engrossing book written by Daniel Yergen: "The Prize", it is a compelling history of oil since the days of Edwin Laurentine Drake's ("Colonel" Drake) famous Titusville discovery of 1859 (I recommend anyone to get a copy and enjoy a very good read). So here I'll sum up with that final section:

"The cry that echoed in August of 1859 through the narrow valleys of western Pennsylvania-that the crazy Yankee, Colonel Drake, had struck oil set off a great oil rush that has never ceased in the years since. And thereafter, in war and peace, oil would achieve the capacity to make or break nations, and would be decisive in the great political and economic struggles of the twentieth century. But again and again, through the never-ending quest, the great ironies of oil have been made apparent. Its power comes with a price. Over almost a century and a half, oil has brought out both the best and worst of our civilization. It has been both boon and burden. Energy is the basis of industrial society. And of all energy sources, oil has loomed the largest and the most problematic because of its central role, its strategic character, its geographic distribution, the recurrent pattern of crisis in its supply and the inevitable and irresistible temptation to grasp for its rewards. It will be remarkable if we go through the next several years without the pre-eminence of oil being tested or challenged yet again by political, technical, economic, or environmental crises, perhaps foreseen, perhaps coming by surprise. Nothing less should be expected in a century and a half that has been so profoundly shaped and affected by oil.

Its history has been a panorama of triumphs and a litany of tragic and costly mistakes. It has been a theatre for the noble and the base in the human character. Creativity, dedication, entrepreneurship, ingenuity, and technical innovation have coexisted with avarice, corruption, blind political ambition, and brute force. Oil has helped to make possible mastery over the physical world. It has given us our daily life and, literally, through agricultural chemicals and transportation, our daily bread. It has also fuelled the global struggles for political and economic primacy. Much blood has been spilled in its name. The fierce and sometimes violent quest for oil and for the riches and power it conveys will surely continue so long as oil holds a central place. For ours is an era in which every facet of our civilization has been transformed by the modern and mesmerizing alchemy of petroleum. Ours truly remains the age of oil."

There are truly many, many "Aspects of Effective Well Management" …!

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Appendix 1: Activity / "Efficiency" vs. Oil Price - Historic Trends

Source: Energy Information Administration