CHAPTER 7

Pregnant Ladies and Fish Bones

Designer, horizontal and multi-lateral are common well types which are drilled to enable access to hydrocarbon reserves, lower field development costs and improve production. 'Pregnant Ladies and Fish-bones' describe complex twisting well-paths that have become necessary to access and drain numerous* reservoirs into a single wellbore[1].

Before the process of well engineering can begin, however, oil companies must complete a series of other activities. In sequential order, these range from geophysical surveys to well planning to drilling and completions. Later, we will present case studies of geo-steering, expandables and digitalisation.

X-rays enable doctors to 'see' inside the body and locate injuries without using a scalpel. Similarly, seismic enables scientists to 'see' inside the earth and locate potential hydrocarbon-bearing structures without using a drill bit[2].

An acoustic means of investigating the earth, seismic is used by oil companies to locate hydrocarbon accumulations within their acreage. Shooting seismic is the first step in reducing the risk accompanying oil and gas exploration. It enables the Geophysical and Geological team (G&G) to 'look' deep into the oil company's acreage and interpret the type and geometry of rocks contained therein.

* These can be less than two million barrels (MMbbl).

In this way, hundreds of square kilometers with vertical depths reaching 2 miles (six km) or more can be imaged without incurring the time, financial and environmental costs of drilling several dry holes. With diligence, geoscientists will find 'bright spots'—the industry term for a potential hydrocarbon reservoir. Bright spots will often form the basis of top drilling prospects. In this way, seismic allows the rapid and effective imaging of vast surface areas and the pinpointing of reservoir locations and properties. Drilling on bright spots is not a 'slam-dunk' as several International Oil Companies (IOCs) discovered in the early 1970s in offshore Florida. The bright spots were clearly there, but only a drop of oil was found.

Sound Waves

Shooting seismic essentially relies on a 'source' that emits sound waves ranging from 1 to 100 hz, and a 'geophone' that records the reflected waves as they 'bounce' back from different rock formations. This data is mapped by powerful computers using thousands of processors to yield 'processed' seismic information. This information forms 'seismic' sections which usually represent 10 km depths of the earth at a time[3].

The G&G team pores over these sections gaining knowledge of formation thicknesses, locations, beds, dipping planes and the all-important potential oil and gas reservoir. Coupled with advanced visualisation software, it is possible to 'walk through the earth'—a reference to viewing the distribution of rock layers or stratigraphy according to its depth and properties.

Pay-Per-View

As we have seen (Chapter 6 Properties, Players and Processes) oil and gas leases may be state or privately owned tracts either onshore or offshore. In either case, seismic cannot be shot without a permit. There is a rising scale of regulatory demands associated with seismic activity which follows the general rule that offshore seismic (shooting water bottoms) permits are more stringent than those onshore. Locations within nature reserves will have even more demanding permitting criteria.

In all cases, an Environmental Impact Assessment (EIA) will be undertaken by the oil company and submitted to the appropriate environmental regulatory authority for approval. To conduct seismic, a fee is usually paid to the landowner. Prices are determined by adjacent finds, the degree of exclusivity, regulatory burden, general market forces and whether the acreage is private or state-owned.

Needle in a Haystack

Licensed acreage refers to areas where an oil company or group of oil companies has obtained exclusive rights to explore, develop and produce hydrocarbons. Clearly finding oil and gas is a complex process with greater complexity added by offshore or remote locations and large unexplored blocks.

Waves, whales and winds are just some of the challenges facing a seismic program. Others include sea-currents, sea-traffic, minimising environmental impact and the technical challenges associated with the seismic process itself. These technical challenges are related to receiving clear signals and reducing background noise which can distort seismic data. Accurate seismic saves oil companies millions of dollars that would otherwise be spent in drilling dry holes and reduces the environmental impact of drilling[4].

Environmental Regulations

Regulations governing seismic are comparable in most oil and gas provinces and are based on wider environmental protection laws. The application for consent to

conduct or permit seismic is only issued after the EIA considers various factors including disturbance to animal life. In the case of shooting water bottoms, the animals most sensitive to disturbance are cetaceans (marine mammals) such as whales and dolphins.

Marine Mammal Observers (MMOs) are employed solely to minimise disturbance to cetaceans during seismic activity. For sensitive marine areas, the MMO must also be an experienced cetacean biologist or similar. Often, surveys are required to be conducted during summer months and during daylight; if there is poor visibility such as fog or storm weather, the survey may be stopped.

Regulations state that at least 30 minutes before a seismic source is activated, operators should carefully observe from a high observation platform whether there are any cetaceans within a 1600 ft zone of the vessel.

Hydrophones and other specialised equipment may provide further indications of submerged animals, and such equipment is to be used in particularly sensitive areas. If cetaceans are present, seismic sources cannot be activated until the animals have moved away, normally after at least a 20 minute waiting period[5].

Except for sensitive areas, all seismic surveys using a source size of more than 180 cubic inches must follow a slow ramp-up procedure. In other words, irrespective of whether marine mammals have been sighted, acoustic activity should be increased slowly. This can include starting with the smallest air gun and slowly building up. Space does not permit examination of other restrictions and procedures, but seismic activity is controlled and an extensive written report must be sent to the authorities after the survey is completed.

Surface Tow

The most common source of 'shooting water bottoms' is an air gun which releases compressed air into the water generating an acoustic shock wave that travels to the seabed and beyond. Seismic sources are towed behind the seismic vessel slightly beneath the surface of the water.

A streamer is towed behind the vessel on the surface of the sea picking up reflected sound waves. Usually, a streamer contains hundreds of pressure-sensitive hydrophones in a near-buoyant cable that can be 2 miles (five km) or more in length.

A geophone is a type of seismic receiver placed on land or on the seabed that records seismic waves by registering the minute movements of particles. In offshore operations, geophones are configured to record both compression waves (P-waves) and shear waves (S-waves). This is because sound travels through liquids (the sea) as compression waves, while it travels as both compression and shear waves through solids (the earth below the seabed).

Brown and Green Fields

Seismic has evolved greatly over the years and has applications in mature fields as well as the exploratory phases of oilfield development. The industry uses the terms brown and green fields respectively to describe the age of the field. In fact, seismic provides tremendous value during the production of an oilfield and as mature fields start to decline (see Chapter 9 Mature Fields for detail).

Deeper reservoirs, or those located below salt, would have been overlooked previously as seismic was not capable of being imaged beneath shallow reservoirs or below formations containing thick layers of salt. Accompanying advances in seismic enable imaging of deep targets, a drilling technology first that has overcome the directional control and drilling torque problems related to drilling 10,000 m or more. The current world record depth well is 40,320-ft (12,293 m).

For deeper or sub-salt seismic, two seismic vessels are run together with both shooting and using long streamers. Global Positioning Systems (GPS) are used to keep the two vessels at a known distance and this maintains the required distance between the source and streamer to accurately measure seismic reflections from deep and sub-salt formations. A new technique called 'coil shooting', whereby a single source/acquisition vessel sails in overlapping circles while acquiring data, provides rich-azimuth seismic imaging of deep and sub-salt formations at less than half the cost.

'Shooting seismic' is crucial to reducing oil and gas exploration risk because it enables the G & G team to visualise deep inside the earth and locate promising structures without the cost and impact of drilling[7].

4D Seismic

Time lapse or 4D seismic accompanies the lifecycle of an oil and gas asset providing valuable seismic information on the asset as it matures (see Chapter Nine Mature Fields for more detail). 4D seismic (the 4th dimension is time) is a technique involving comparison of successive 3D seismic surveys taken over the same area. Geoscientists can detect the effect of fluid migration over time and thus deduce the reservoir's preferential drainage patterns. This information is invaluable in situating additional in-fill wells or altering the pattern of injector wells versus producer wells. In a recent example, comprising the largest 4D survey ever acquired, the operator (Petrobras) was able to relocate 11 already-planned deepwater well trajectories and plan an additional nine wells for a total of 20 wells affected. The changes saved the company about $900 million US, which would have been the cost of drilling the 11 wells in the wrong place and it expects to gain considerable profits from the 20 wells drilled in the right place.

Well Planning

Well planning is the process of creating a blueprint for constructing oil and gas wells. Here is a behind the scenes look at the key components of well planning and their interaction[8].

The well plan, a book-like bundle of engineering and legal documents, covers all aspects of designing, drilling and completing a given oil and gas well. Large operators may refer to this as the 'pre-drill package' (purists may argue about the exact usage of terms but they both refer to the same thing). Smaller oil companies will simply refer to the documents as the well plan. This should be distinguished from the well profile, which only describes the proposed architecture and sizes of the well.

We have already seen how raw seismic information is processed into geological data. After poring over this data, bright spots and prospects are identified; however, a prospect must be converted into a well plan. Prospects are potential oil and gas reserves, destinations so to speak, and well plans are a means of reaching them[9].

Faster, Better, Cheaper

Picture this: six months before spudding a deepwater wildcat, the drilling team members are scratching their heads. Which rig will they contract? Will they keep the fragile balance between pore pressure fracture gradient and mud weight? Which drilling fluid will they use in high-pressure zones? Will they deliver a well that flows on time and within budget?

One way of managing budgets (as well as risk and uncertainty) is the Drilling Well Optimization Process (DWOP), also known as 'Drill the Well on Paper'. This refers to the process of analysing each step of the well construction process to generate ideas for improving performance and reducing cost. We will look at this concept in greater detail in due course. For now, it is important to define the technical limit for each activity or the minimum time required to complete each task in a perfect world. This will serve as a theoretical value only and can never be achieved as an actual target. Next, a realistic target based on the best past performance is established, which becomes the performance benchmark for the well[10].

Blueprint

Getting to the blueprint stage requires various scenarios to be enacted (DWOP) and huge volumes of information to be analysed and formatted. Well planning is a very broad concept that encompasses:

- The management of phased well construction service and supply processes to meet a desired timeline and objective
- Commercial aspects of contracts and pricing for well services and equipment
- Financial cover in terms of insurance and liabilities
- Legal conditions such as compliance with regulatory framework and outlining limits of responsibilities
- Design and operational aspects that cover detailed engineering drawings of well construction
- Health and safety considerations
- Environmental protection, and
- Political/cultural/linguistic aspects of operations.

There can be as many as a 100 different regulatory conditions and as many service and supply companies on a single well project. Subsequent issues will look in depth at regulatory issues such as permit to drill, supply and services procurement such as rig type, services contracts and well types. For now, we shall look at the main features of well planning and accompanying risk as well as the engineering aspect of a vertical exploratory well[11].

Essential Information

A well plan has essential information such as well number, location, block, partners, and level of confidentiality (confidential wells are called 'tight-holes'). It will include items such as the:

- Well objectives
- Surface location
- Longitude and latitude
- Eastings and Northings
- Water depths (in the case of offshore wells)
- Measured Depth (MD)
- True Vertical Depth (TVD)
- Azimuth
- Spud dates
- Critical dates such as first oil (which would really only be entered by a true optimist), and
- Seasonal or environmental factors that may affect operations.

The Well Plan also includes such things as:

- Rig details, rig preparations, transportation of the rig and setting it up
- Well control and contingencies
- Pressures (PPFG) and Temperature (Gradient)
- Directional targets and sidetracks
- Bottom Hole Assembly (BHAs) and hydraulics
- Casing depths and cementing details

• Contact list of key personnel, and

• Completion—how the final section of the well will be finished or completed.

Targets

Targets usually refer to geological targets, which are the depths of formations that likely contain oil and gas. They can also refer to pre-determined casing points. Depths are expressed as vertical and measured depths. TVD, for our purposes, refers to a depth taken from a ninety degree straight line from the surface down to the depth of interest. The measured depth is the actual distance drilled. Other formations or markers along with their age and lithology, i.e. sand/shale, will be noted. The TVD is measured from the top of the target to the bottom height of the reservoir. When you read that a reservoir had 78 feet (25 metres) of 'pay' or oil- bearing sands that refers to the vertical thickness of the oil and gas reservoir. 'First oil' refers to the first time at which production of a certain reservoir occurs[12].

In the Dark

Reservoir information on exploratory drilling or wildcats will be limited if not unavailable. Although there may be some basic information on formation markers, porosity and permeability, temperatures, and the expected hydrocarbon gas or oil, much more information needs to be predicted such as the reservoir pressure, formation markers, the TVD to the tops of formations, and a range of other pressures. Only upon drilling will the true values be confirmed.

Regulatory Compliance

All regulations including health and safety considerations and environmental protection will be cited and acted upon.

Potential Hazards

Hazards are identified as geological/formation related and environmental/operational. Exemplifying the former are shallow gas, shallow water flows, charged zones, depleted zones, overpressure, abnormal temperatures, the presence of H2S or CO2 and pressure faults. These will be covered in part by the Well Control Plan which will have considered all aspects of well control and associated equipment. This includes:

• All wellhead components

• BOP stack and valves

- Accumulator
- Choke and kill lines
- Choke manifold
- Gas buster (or poor boy de-gasser)
- Drill string safety valves
- Standpipe manifold
- High pressure mud lines and systems (including cementing system)
- Drill strings
- Drill stem testing surface and subsurface equipment, and
- Subsea well control equipment (if drilling from a floating vessel).

Operational hazards range from wellbore positioning (such as avoiding collision with existing wells or pipelines), avoiding shipping channels and avoiding cetaceans or other protected marine life. Operational risks include maintaining casing integrity, avoiding casing wear, maintaining wellbore stability and managing any pressure ramp near the Total Depth (TD).

Formation Evalution Plan

The Formation Evaluation Plan includes provisions for Logging-While-Drilling (LWD) or the electrical wireline logging program. This will outline the requirements for cutting samples, mud logging and formation evaluation logging. This allows the oil company to describe formations and understand actual drilling conditions which will vary from the seismic. Formation Pressure-While-Drilling (PWD) tools also exist. These can replace wireline or pipe-conveyed logging services and are made up as part of the BHA. This allows operators to measure formation pressure as it is encountered which improves well control, safety and drilling efficiency[13].

Potential hazards such as shallow gas flows or severe pressure changes can be noted earlier and preventative action taken which lowers risk and operational costs. Usually, these systems make use of binary coding using mud pulse telemetry where the surface operator and subsurface tools communicate by means of pressure pulses that are sent through the column of drilling mud. Mud pulse telemetry cannot be used while making a connection; this is one of its drawbacks.

Mud-Logging System

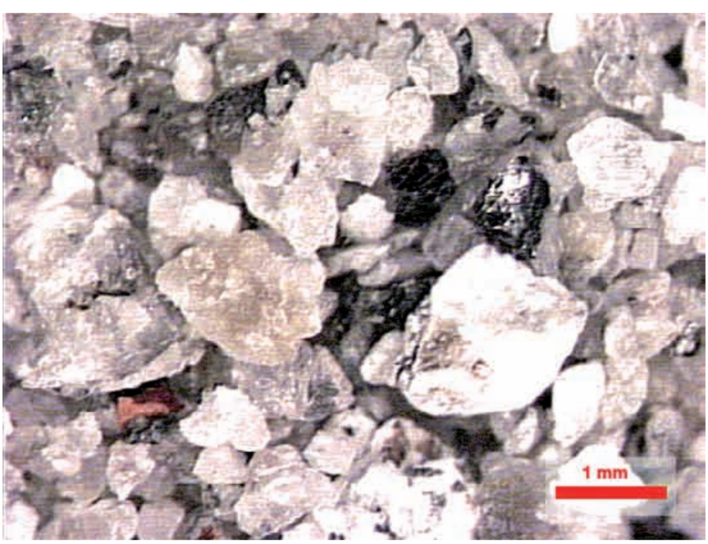
During drilling operations, a multitude of measurements are taken and monitored. Temperature, pressure, depth, torque and loading are just a few. Several systems exist on rigs to fulfill this function with mud-logging being a primary one.

The use of mud-logging systems was first introduced in the industry in the 1960s. Since then, advances in instrumentation and in the number of measured parameters have resulted in sophisticated mud-logging systems[14]. The advent of deepwater drilling also contributed to the progress of mud-logging techniques. Deep and ultra-deep water environments require very accurately controlled drilling operations. Any failure or negligence may cause human injury and economic losses. To control processes accurately, enhanced mud-logging is required.

Mud-logging systems encompass three different types of data. First, they collect and analyze drill cuttings (shale-shaker samples). Secondly, they measure and monitor the condition and content of the drilling fluid returns. Finally, they monitor and record mechanical parameters related to the drilling operation. All provide invaluable data as to whether the formations encountered bear oil and gas or how drilling is going[15].

Examining Cuttings

Drilling chips or returns, also known as 'cuttings', provide the operator with information as to whether hydrocarbons have been found by carefully examining cuttings brought up by the circulating mud. The mud logger or geologist samples cuttings from the flow equipment uses a microscope or ultraviolet light to determine the



presence of oil in the cuttings. Where gas reserves are concerned, they may use a gas-detection instrument. Often paleontologists examine drill cuttings under a microscope to detect and identify fossils that indicate the age of the formation and perhaps clues to its deposition[16].

During drilling, a mud logger will observe mud-logging parameters for any abnormalities. If an observed parameter presents unusual behavior, the mud logger immediately communicates this to the driller who will carry out certain procedures to solve the problem. Actually, the system allows the programming of alarms that will sound in the mud-logging cabin, alerting the mud-logger that the value of the observed parameter is outside the programmed range.

The number of observed parameters may vary according to a particular characteristic of the drilling operation, but the most commonly measured parameters are:

- Well depth (depth)
- TVD
- Bit depth
- Rate of Penetration (ROP)
- Hook height
- Weight on Hook (WOH)
- Weight on Bit (WOB)
- Vertical rig displacement (heave)
- Torque
- Drill string rotation per minute (rpm)
- Mud pit volume
- Pump pressure
- Choke line pressure
- Pump strokes per minute (spm)
- Mud flow
- Total gas
- Gas concentration distribution

- H_2S concentration
- Mud Weight in and out
- Drilling fluid resistivity
- Drilling fluid temperature
- Flow line
- Lag time, and
- Standard length[17].

Only some of the listed parameters are measured using sensor devices; some of them are estimated from measured parameters. The WOB, for instance, is an estimated parameter that is calculated using hook weight (a measured parameter) and the weight of the drill string elements (which allows for buoyancy in drilling mud and wellbore inclination).

Well Logging

Using a portable laboratory truck-mounted for land rigs, well loggers lower devices called logging tools into the well on electrical wire-lines. The tools are lowered all the way to the bottom and then reeled slowly back up. As the tools come back up the hole, they are able to measure the properties of the formations they pass[18].

Electric logs measure and record natural (spontaneous potential) and induced (resistivity) electricity in formations. Some logs ping formations with acoustic energy and measure and record sound reactions. Radioactivity logs measure and record the effects of natural and induced radiation in the formations. These are only a few of the many types of logs available. Since all the logging tools make a record, which resembles a graph or an electrocardiogram (ECG), the records or logs can be studied and interpreted by an experienced geologist or engineer to indicate not only the existence of oil or gas, but also how much may be there. Computers have made the interpretation of logs much easier and logging tools using real-time transmission systems are now capable of imaging the wellbore as it is drilled[19].

Although, logging and measurement while drilling (LWD and MWD) tools have been available for many years, it is only recently that advances in data transmission and interpretation have progressed to generate accurate images of the wellbore. These images are based on real-time data and offer insight into what is really happening downhole.

Typically, a high-quality image is drawn from detailed, 3D resistivity data. This data is supplied by a resistivity tool similar to a logging formation micro-imager, which is run on wireline. This resistivity tool is capable of identifying wellbore features and characterising faults, cementation changes and threaded or spiraling caused by bit whirl. Software transforms the resistivity data into images of 3D wellbores that are viewable at all angles with simple mouse movements. The resistivity measurements are transformed into 360-degree azimuthal plots around the circumference of the wellbore to provide extremely detailed images[20].

The combination of resistivity and density services based on real-time logging images and geo-steering techniques enables operators to reduce risk and overcome geological uncertainties commonly associated with complex wells.

Ultra high telemetry rates (12 bits per second) have been successfully used to optimise horizontal well placement as well as warn of wellbore stability issues before they become serious enough to jeopardise operations or impact drilling costs.

Wellbore stability problems are detected with ultrasonic calipers from density or sonic LWD tools. Hole enlargement or washouts can be identified while drilling or during subsequent trips. This is beneficial as it helps monitor wellbore stability and allows adjustments to be made to mud weights or effective circulating density as required. Wellbore stability problems are confirmed using vision technology incorporating Azimuthal Density/Neutron viewer software, which provides density image and caliper data while drilling. The software also generates 3D images and caliper logs. Together, these offer easier methods of understanding wellbore conditions during drilling operations. Additionally, the 3D density images and ultrasonic caliper allow wellbore instability mechanisms to be better characterised, and when necessary, resolved. This is particularly important in completions where gravel packs or expandable screens are required. The ultrasonic and density caliper information gathered during drilling can indicate whether hole quality is good enough to permit specialised completions to proceed. Up-logs obtained on a subsequent wiper trip allows visualisation of the hole enlargement and stress failures after drilling[21].

Specialised software uses a recorded mode to gather real-time dip information, provided by the LWD resistivity imaging tools. This information is harnessed to view geological structures and reduce the uncertainties in pre-existent geological models. The software also allows structural dip picking from images, which can be used in combination with the real-time data for structural interpretation. Bed dips and layer thickness are also characterised, permitting the evaluation of structural cross-sections. The reduction in risk and geological uncertainty has made wellbore imaging hard to resist for production companies.

Pressure While Drilling

PWD tools are used to make accurate downhole measurements of:

- Equivalent Circulating Density (ECD)
- Kick detection, including shallow water flows
- Swab/surge pressure monitoring while tripping and reaming
- Hole cleaning
- Hydrostatic pressure and effective mud weight, and
- Accurate Leak-Off Test (LOT) and Formation Integrity Test (FIT) data.

Coring

Formation core samples may be taken and these are the most important way of examining formations and any oil- bearing strata. Cores are extracted by a 'core barrel' which usually takes 10 to 13 ft (three to four m) lengths of the formation. As the core barrel is rotated, it cuts a cylindrical core a few inches in diameter that is received in a tube above the core-cutting bit. A complete round trip is required for each core taken. Much smaller and less representative cores may be extracted using a sidewall sampler in which a small explosive charge is fired to ram a small hollow cylindrical bullet into the formation. The bullets are tethered to strong retaining wires. When the tool is pulled out of the hole, the bullets containing the small core samples come out with the tool. Up to 72 of the small samples can be taken per trip at any desired depth. This provides positive real evidence of cross-flow, permeability and porosity. Laboratory tests are complex and can include fluorescence gas chromatography (TSF)[22].

Sampling and Screening of Cores

On board the ship, cores are physically described, logged and sampled. Three sections from the bottom half of each core are sampled for geochemical analysis. Deeper core sections are used in order to avoid contamination from modern petroleum pollution sources near the surface. Analysis of three sections per core increases the likelihood of encountering petroleum seepage, which is typically not distributed homogeneously throughout the sediments. All core material is frozen and stored until it is returned to the lab[23].

The objective of these analyses is to characterise the composition and origin of solvent-soluble hydrocarbons. The cores are stored in specially created conditions to preserve their characteristics.

Drilling to Total Depth

The final section of the well is what the operating company hopes will be a production hole. The formation of interest (the pay zone, the oil sand, or the formation-bearing hydrocarbons) will determine the answer to the make or break question: 'Is the well commercial, i.e. does it contain enough oil or gas to make it worthwhile to run the final production string of casing and complete the well?'

After the operating company has studied all the data from the various formation tests, a decision is made on whether to set production casing and complete the well or to plug and abandon it. If the hole is considered to be dry, that is not capable of producing oil or gas in commercial quantities, it will be plugged and abandoned. Sometimes, a dry hole may be sidetracked in an attempt to make contact with productive formations. This is usually the case if formation faulting is detected because a well drilled just a few feet on the wrong side of a fault can miss the pay zone altogether. It's a relatively simple task to drill a sidetrack, and certainly less costly than starting over.

At times, not enough oil or gas may be present to justify the expense of completing the well; therefore, several cement plugs will be set in the well to seal it off. As oil prices are cyclical, it is often the case that wells that were plugged and abandoned in the past may be reopened to production if the price of oil or gas has become higher. The cost of plugging and abandoning a well is far lower than the cost of a production string of casing; therefore, the operator's decision is invariably oil or gas price driven[24].

Setting Production Casing

If the operating company decides to set casing, it will be brought to the well and for one final time, the casing and cementing crew will run and cement a string of casing. This casing is 'floated' into the hole to take advantage of its buoyancy and relieve the rig from holding the immense weight of several thousand feet of large diameter steel pipe. A 'float shoe' seals off the bottom of the casing and keeps drilling mud from flooding the casing as it is runs into the hole. Usually, the production casing is set and cemented through the pay zone; that is, the hole is drilled to a depth beyond the producing formation and the casing is set to a point near the bottom of the hole. As a result, the casing and cementing actually seal off the producing zone but only temporarily. After the production string is cemented, the drilling contractor's job is almost finished except for a few final touches.

Cementing

After the casing string is run, the next task is cementing the casing in place. An oil-well specialist cementing service company is usually called in for this job. Cementing is fundamental to the integrity of the well and considers factors such as annular volumes, formation-cement-wellbore interaction, slurry and set properties as well as cement sheath strength. Cement behaviour differs according to depth, pressure, temperature and loading conditions; however, this behaviour needs to be considered to ensure a good cement job.

Cementing applications include sealing the annulus after a casing string has been run, sealing a lost circulation zone, setting a plug in order to 'kick-off' a wellbore deviation or to plug and abandon a well.

Cementing involves pumping a cement slurry down the inside of the casing. When the slurry reaches the bottom, pump pressure is raised and this pops open a valve in the float shoe to allow the cement to be pumped out of the bottom of the casing, out the bottom end and back up the annulus. When the proper amount of cement volume has been pumped to seal off the casing and support it in the borehole, a plug is pumped to the bottom that wipes the wet cement off the inside of the casing and forces it all to the bottom, leaving the casing clean and ready for the next step in the completion process.

Perforating

Since the pay zone is sealed off by the production string and cementing process, perforations must be made in order for the oil or gas to flow into the wellbore. Perforations are simply holes that are made through the casing and cement and extend some distance into the formation. The most common method of perforating incorporates shaped-charge explosives, a principle that was developed during the war to penetrate tanks and other armored vehicles. The shaped–charge, when fired, creates a high-velocity, ultra-high pressure plasma jet that penetrates the steel casing, the cement sheath and several feet out into the formation rock. Several perforating charges are arrayed in a radial pattern along the carrier gun. They are usually fired simultaneously, but may be fired sequentially for special applications using select-fire equipment.

Acidising

Carbonate reservoirs (See Chapter 1 Origin of Oil) often hold oil, but the oil may be unable to flow readily into the well because the carbonate formation has very low permeability. Rocks that dissolve upon contact with an acid, such as limestone or dolomite, are often 'acidised' to optimize production. Acidising is mostly performed by an acidising service company and can be done with or without a rig. It consists of pumping appropriately sized volumes of acid down the well where it travels down the tubing, enters the perforations, and contacts the formation. When the acid enters the formation, it etches channels that provide flow paths for the formation's oil or gas to enter the well through the perforations[25].

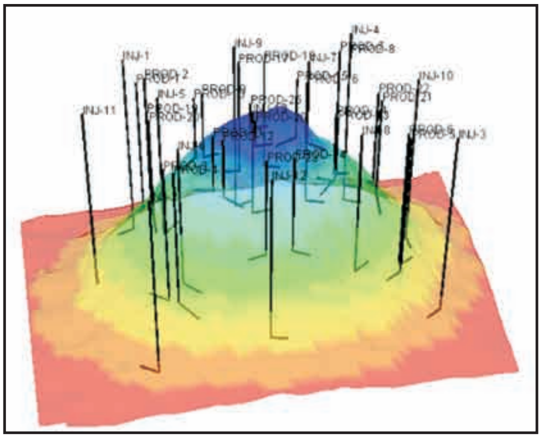
Fracturing

When rocks contain oil or gas in commercial quantities but the permeability is too low to permit good recovery, a process called fracturing may be used to increase permeability to a practical level. Basically, to fracture a formation, a fracturing service company pumps a specially blended fluid down the well and into the formation under great pressure. Pumping continues until formation integrity is overcome and literally cracks open. The fracturing fluid contains solid particles called 'proppant' (which can be plain sand or more-sophisticated material such as high-strength ceramic beads) suspended in a slurry, usually consisting of a polymer gel. When the formation fractures, the gel and proppant penetrate the fissure and travel out to the extreme end of the formation. When pressure is relieved, the formation fracture tries to close, but is propped open by the proppant material. After the pressure is released, a de-viscosifier chemical called a 'breaker' is released into the gel to lower its viscosity and allow it to flow freely back into the well without disturbing the proppant or washing it back out of the fracture[26].

Case Studies

Geo-Steering

In order to maximise drilling in the 'filet mignon' of the reservoir, geologists often require tight TVD corridors to be maintained or for several reservoirs to be drilled at a optimal inclination and azimuth. To achieve this, TVD and directional corrections can be made in either rotary or oriented mode. The limiting factors associated with oriented drilling led drilling engineers to seek rotary options[27]. Since the first use of



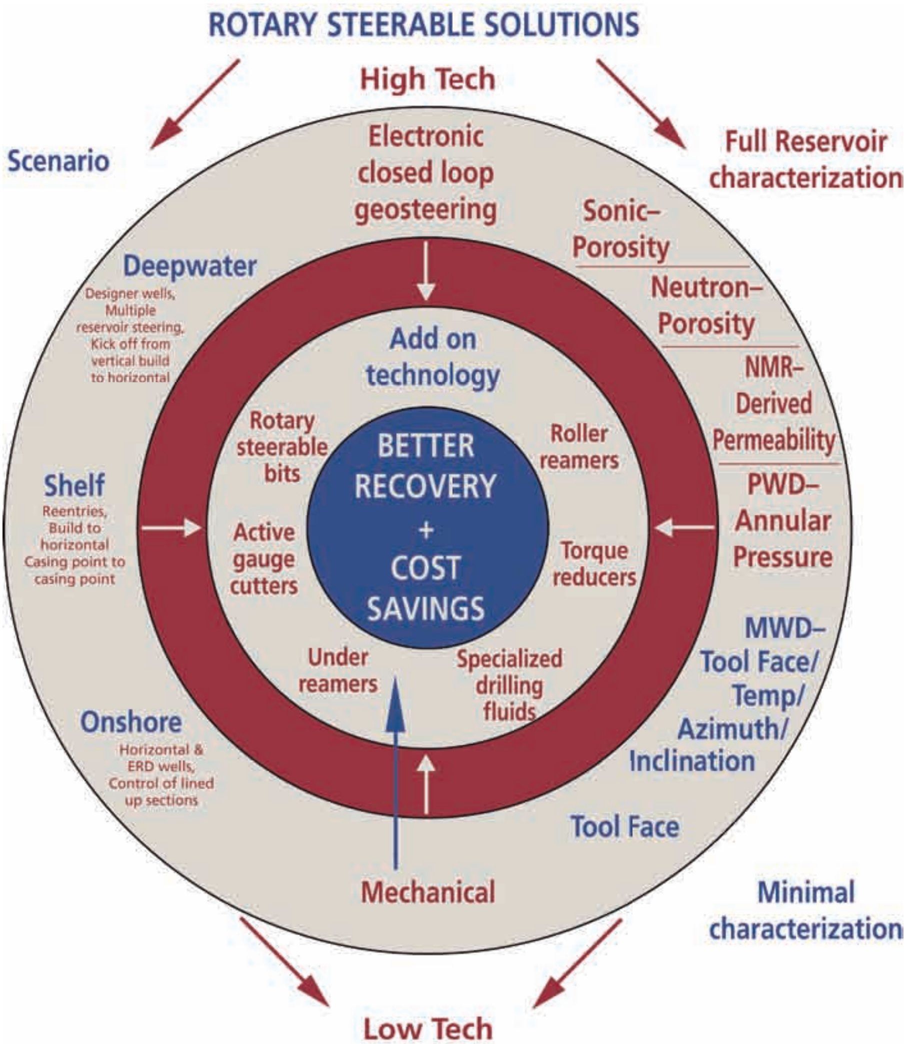
the technology in the early nineties, Rotary Steerable Systems have been proven as 'fit for purpose' and particularly well- suited to horizontal and multi-lateral drilling. Today, they are essential to geosteering as they almost universally deliver higher penetration rates, better hole quality and improved steerability[28].

Refining BHAs Through Offset Data

Thorough analysis of offset data enables BHAs to be refined and optimised. An extensive database allows previous BHA performance to be pinpointed and considered, thereby increasing the success of future BHAs. Once the major factors are characterised—bit walk tendencies, lithology, bedding and dip angles, BHA type, components, spacing and configuration—they can be collated to calculate the likely changes in wellbore curvature that the system can create. By extending the use of Rotary Steerable Systems to field development programs or horizontal drilling campaigns, these benefits make very substantial cost savings[29].

Rotary Steerable Technology

Advances in rotary steering technology are bringing intelligent systems even closer. Although geosteering systems capable of finding and accessing reservoirs are still some years away, several rotary steerables exist today. While high-tech electronic solutions are sophisticated by nature, these systems are especially suited to costly complex designer wells. A different approach is being adopted by a number of smaller service providers who are developing more cost-effective systems for the intermediate market. While most still rely on electronics, there are also simple systems reliant on mechanical devices. Simple or sophisticated, all systems can generate cost savings and improve recovery[30].



Less clear is whether criteria exist to make one system better than another. Perhaps a more objective approach is to determine the best fit by broadly matching rotary steerables with the varying dictates and expectations of deepwater, shelf or onshore drilling and completions.

Drawing these variables together, Figure 1 depicts deepwater, shelf and onshore sectors and its appropriately matched technology. Certainly, a rotary steerable system must help reach the reservoir and optimise the footage drilled within it, but beyond this there are many reservoir and well-dependent variables. The dogleg severity (the change in direction, measured in degrees per hundred feet, required to reach optimal reservoirs) performance of a rotary steerable system, for example, should be matched with the complexity and number of targets involved. In complex designer wells, sophisticated systems shine; in less complex horizontal wells, simple systems suffice. Similarly, costs also drive system choice. It is well known that the tight economics of onshore or shelf assets cannot withstand high rig rates, let alone expensive downhole equipment. Here, a match depends as much on reservoir placement needs* as it does cost. Consider deepwater versus onshore trip costs. In the former, an average round trip may cost US $500,000; the same trip onshore is hardly a tenth of this figure. In the first instance, it makes commercial sense to minimise trips; however, onshore it might make better commercial sense (depths and profile permitting) to induce trips by using conventional steering technology to line up sections and run in with rotary steerables where they have best effect[31].

Deepwater exploration frontiers are characterised by the highest rig rates in the industry and extreme exploration risk. This means contingency planning is a key component of deepwater operations. Relatively straightforward activities, such as logistics, can be rendered complex due to the remote and specialised nature of operations. Consequently, sophisticated rotary steerable systems that maximise efficiency and minimise risk are not only desirable, but are necessary.

In these deepwater instances, a full range of reservoir characterisation tools is also required. Sophisticated systems, coupled with full logging capability, reflect and meet deepwater frontier needs as offset data is often scarce and further asset development is dependent on data acquisition and interpretation. The general rule is the more data acquisition and characterisation the better. Data gathered while drilling supplements the pre-drill seismic package by increasing the footage drilled in optimal reservoir zones. A good rule-of-thumb is to consider the time-relevance of information; if the information is required to make critical decisions while drilling, real-time systems should be used[32].

Conversely, because mature assets usually are well-characterised and offset data is plentiful, the same degree of data acquisition may be unnecessary. This makes mature or onshore fields ideal candidates for simpler rotary steerable tools. As one moves down the characterisation list, there is a diminished need for complete characterisation. Intermediate or mature shelf assets may not require nuclear magnetic resonance or sonic logging, and in a marginal onshore context it is highly likely that a full LWD suite becomes redundant. Little more than toolface, azimuth, inclination, temperature and formation identification is required in this context. In exceptional onshore cases, the uncertainty associated with complex targets may require further

* Dog Leg Severity which is the change in direction measured in degrees per hundred feet (required to reach optimal reservoirs).

logging, but often MWD plus a gamma system provides ample data. In this way, technology can be pared down to bare essentials and costs can be lowered. What may have once been considered a marginal or mature field can be revisited with new economic parameters and perhaps be revitalised.

Often, however, a serendipitous use of real-time data pays dividends. Recently, an operator drilling in the shallow shelf waters of offshore Texas, encountered two extremely abrasive formations. On an offset well, each consumed ten drill bits to get through the zones. The logging requirements were not particularly sophisticated, but the service company pointed out that if the sections were drilled using its Rotary Steerable System with ultra high-speed telemetry, it could measure and monitor drill bit vibration thought to be the cause of the rapid bit-wear. The operator accepted the recommendation and with real-time vibration monitoring, was able to detect and analyse the circumstances causing bit wear. By adjusting weight-on-bit, rpm and mud weight, the operator was able to minimise destructive vibration and drill both problem sections with a single bit each, saving more than US$2 million from US$12 million Approval For Expenditure (AFE). The sophisticated solution costs more, but rig time was saved by eliminating eight bit change trips, and the added cost was more than compensated by the rig-time savings.

Add-On Technology

Representing opportunities for reducing casing wear, torque reducers can help overcome the concerns of the effects of increased rotation on tubulars. Also, roller reamers aid BHA stabilisation and reduce downhole vibrations. Under-reamers enable the diameter of production holes to be increased (especially important in deepwater scenarios where narrow pore pressure fracture gradients can jeopardise reservoir hole size) by allowing casing to be telescoped without sacrificing production. Specialised drilling fluids exist to reduce torque and improve rotary drilling efficiency[33].

Expandable Tubulars

Although the reality of a down-hole monobore* (a single diameter casing string from well-head to reservoir-toe) is not in existence yet, half of the essential technology has been proven.

In the late 1990s, a relatively small group of engineers within Shell E&P, Halliburton and Baker Hughes laid out the plans for a technology that would have made Erle P Halliburton smile[34].

* Slimhole completions such as coiled tubing fall beyond this scope. Our interest lies in 8 ½-in or larger diameter conventionally rotary drilled wellbores.

By forming technology ventures with Enventure (Halliburton) and E²Tech (the precursor to today's independent expandable technologies from Baker Hughes) Shell gave the nascent expandable market the support it needed. Shell would later go on to sign deals with Weatherford allowing it to enter the expandable market.

In parallel to these deals, some service companies had already developed the expertise to expand slotted tubulars and were realising commercial downhole applications. Similar commercial applications for solid tubular, however, have only become available in the past two or three years. Now a broad range of operators have expanded solid tubulars to overcome well construction challenges such as preserving wellbore diameter, isolating lost circulation zones below the casing shoe and sealing off swelling or poorly consolidated formations.

Today, there are three main open-hole applications for expanding solid tubular: slimming down well designs, contingency casing and repairs, handling lost circulation and bypassing trouble zones.

Slimming Down
In the deepwater arena, technology offers a real alternative to the seven or eight string casing configurations where 'telescoped casing' or 'borehole tapering' can severely restrict the production hole diameter in the geological objective. Another feature of the technology is that through 'localised' applications, repairs can be made to damaged or worn casing while patches or old casing strings can be replaced without the need for costly cutting and pulling casing. From an engineering perspective, wellbore stability and burst/collapse ratings of casing can be maintained in this way[35].

Contingency
Contingency systems can provide operators with an extra string of casing, which can be the decisive factor in terms of successfully drilling deepwater prospects. Increasing the section length of the casing without compromising casing diameter is especially useful in operations where large diameter top hole casing sections are otherwise technically or cost prohibitive. Consequently, it can be said that the technology gives the operator two casing strings for the price of one. The system enables operators to extend a conventional casing program for an exploratory well to reach promising zones that are deeper than anticipated.

Lost Circulation and Trouble Zones
For unexpected lost circulation or shallow-water flow zones in deepwater and sub-

salt environments, the system provides affordable contingency solutions. In sub-salt environments, the system offers the most cost-effective solution for original casing that is stuck high or for reaching TD with larger production casing. Unexpected trouble zones are a common challenge in sub-salt or deepwater low-fracture-gradient environments. The open hole technology allows the operator to simply drill another hole section to bypass these zones. In older fields requiring redevelopment, the system can help reach deeper reserves and isolate water or gas zones that have penetrated horizontal re-entry wells. The well is drilled to the target reservoir, casing is run, cemented and expanded.

This technology holds much in store for deepwater fields where deep targets below the mudline may not be accessed economically with conventional technology.

Before the economies of scale regarding standardised casing design and supply materials, however, there are still further operational and design challenges that must be overcome. These challenges are the delivery of so called 'gun barrel' under-reamed gauge holes, increasing the expansion ratios of under-reamers to above 25% of pass through or body size, measurement thereof, cementing type and method, maintaining a consistent internal diameter of casing which has been expanded at connections, and reducing the risk of swab/surge dependent on the expansion method. Here rotary expansion may have some advantages as the application of torque and weight is used to expand the casing as opposed to weight/force applied axially. At any rate, top down expansion is always preferable because if the expansion mechanism fails then any subsequent fishing can be achieved more easily. In the opposite, it is harder to fish a larger diameter component into or within a smaller diameter as would be the case of bottom up expansion.

Digitalisation of the Asset Lifecycle

Imagine producing a commodity but not knowing how much you have to begin with or have left. This kind of blind production is likely to be a relic as digitalisation promises to offer oil companies with the ability to see production in the form of subterranean migration of hydrocarbons as they are produced over the lifecycle of the asset. As well as radically changing production, it promises to do the same with drilling completions through remote-controlled centres[36].

Combined with 3D seismic, e-drilling will provide the technology to realise real time modelling, supervision, optimisation, diagnostics, visualisation, and control of the drilling process from a remote drilling expert center. This system will enable decision makers to have better insight into the status of the well, and formation surrounding the well, and thus make better and quicker decisions. This is of particular importance when problems or unusual situations arise and experts are called in to make decisions. They will quickly be able to grasp the situation and make the correct decision.

As compared to classical integrated reservoir engineering studies, an Event Solution study typically includes seismic and geology characterization, reservoir simulation, history match, fi eld development, facilities and economics. Performed in 2-3 months duration, the Event Solution is characterized by a myriad of multiple parallel workfl ows and processes to assemble a rapid and integrated reservoir understanding towards the study objective is includes uncertainty analysis and risk assessment to focus on what really matters to the study objectives. A team of 20 to 30 experts collectively work during the 2-3 month project duration, providing synergy of mind and direction to reach study objective and maintain consistency in each study discipline.

By combining real-time drilling analysis with 3D visualisation, the system allows all involved personnel a common working tool. It also provides the user with access to historical data (playback scenarios) for experience exchange and training.

The overall result is a more cost-effective and safer drilling and well construction operation.

Seismic multi-component 3D and 4D technologies, along with better seismic imaging, help drill more productive wells because they provide greater precision of the location and migration of hydrocarbons. Multi-component involves larger volumes of data and enables the direct detection of hydrocarbons as well as reservoir geometries.

Vertical Seismic Profiling (VSP) aids exploratory and development drilling by reducing risk and uncertainty. In this way, seismic has evolved from being an exploratory risk mitigating tool to a reservoir management tool with applications in mature fields.

Recently, companies have successfully implemented seabed permanent seismic arrays which take a lifecycle approach and include taking repeat shots, overlaps and using permanent cables that use fibre optics.

By creating visualisation rooms in different operational sites and in other locations where engineers can 'see' reservoirs, oil companies can image 'harder to see' reservoirs such as thin layers which can be missed by conventional seismic. Visualisation serves as the 'common language' that enables geophysicists, geologists, engineers and asset managers to work effectivly toward a common goal. With 4D time-based seismic, it is also possible to view migration as two-time lagged surveys, say a year apart, which will show how hydrocarbons have moved. This has tremendous value in understanding reservoir fluid paths and behaviour which ultimately means more oil.

Using satellites and fibre optic cables to communicate with multiple pay zones, the industry has set its sights on truly intelligent completions and has commercialised the downhole tools required to harmonise production.

In the old days, the equation was pretty simple: one reservoir meant one completion which meant one well. This changed, however, with the advent of dual completions, which allowed a single wellbore to receive production from two reservoirs. Although dual completions could reduce well numbers by half, reserves were not exploited effectively and well numbers remained unnecessarily high. Combining completions to commingle production from multiple pay zones reduced well numbers and costs, but two drawbacks emerged. First, well intervention was required more often than not. Second, heterogeneous reservoirs were treated as if they were identical.

The ideal is to treat pay zones individually as this makes for a much deeper understanding of reservoir characteristics. Consequently, this leads to better reservoir management, which in turn means higher levels of production over a longer life span. This was the overwhelming logic behind single and dual completions. Large numbers of wells, however, do not make the best use of resources.

Although reservoirs are complicated, intelligent completions are simple. Essentially, they take a big-picture view and aim to cost-effectively manage heterogeneous pay zones. Production from interrelated or layered reservoirs must be continually regulated and commingled and real-time data must be provided to make the best management decisions regarding the use of a network of downhole chokes, gauges and fibre optics to regulate production.

It is widely recognized that depleting one reservoir affects another nearby. By regulating the flow and pressure of several reservoirs, a balance can be achieved to ensure reservoirs behave according to what is best in light of the big picture. Zonal isolation is a good example of how intelligent completions can help predict, isolate and balance water and gas influxes in different locations according to long-term needs. Another benefit is that gas and water can be injected into multilateral or multilayer reservoir zones with a better understanding of how this will affect production from interconnected reservoirs.

By manipulating a downhole network of chokes and gauges, a production engineer seated hundreds of miles away can manage the production of several reservoirs, wells and fields. In this way safety is improved, costs are cut, and more reserves are accessed.

Broadly speaking, high-cost developments such as subsea installations with high intervention costs are particularly well suited to intelligent completion. Their greater depths and complex well trajectories also make them ideal candidates. Two other areas suited to intelligent completion are selective production of multiple reservoirs and the optimisation of artificial lift operations.

With intelligent completion still in its infancy, financial costs are high and investment can be justified only on high-return projects. Technical restrictions also exist. Usage is limited to wellbore diameters of seven inches or larger, with high flow rates typically 6,000 bbl or greater. Downhole temperatures cannot exceed 247ºF (120ºC).

Despite these limitations and relatively few worldwide installations, major oil companies are devoting more resources to completing wells intelligently.

Truly intelligent completion systems are, however, not in the immediate future. Perhaps a more accurate description of today's technology would be remote control completions, as completions are not yet closed-loop. In other words, they are not autonomous, self-controlling systems and human input is still required. With technology moving at an inexorable pace, closed-loop completions will be operating downhole within this decade.

Representing unquestionably better production, automation is an irreversible process. Each downhole sensor that sends real-time data makes us more conscious of its value. As more subsea equipment is integrated within the intelligent completion, it becomes more difficult to view reservoirs separately. Automation offers an unprecedented flexibility in terms of asset and production management strategy. As commodity prices fluctuate, production from a given field can be halted or accelerated to mirror market conditions.

We have seen how complex the well construction process is and how imaginative well profiles are helping increase production. We have seen that the ultimate decision to complete or plug and abandon a well is dependent on the oil price. As oil reserves become scarcer, Chapter 8 Extreme E&P considers the most daring of wells that are drilled in the deepest waters, Arctic conditions and deepest reservoirs.