Introduction to Through Tubing Rotary Drilling

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1 Introduction

This document is intended to provide an overview of current through tubing rotary drilling technology (TTRD). It is targeted at engineers and managers are currently considering through tubing drilling operations but experiencing some degree of apprehension as to whether this would be the right technology for their specific application.

World-wide experience of Through Tubing Rotary Drilling is still very limited. Some slim hole drilling technology addresses some of the pertinent issues but through tubing drilling still comes under the heading of, or considered 'New Technology'.

This introduction will hopefully promote the awareness and understanding of through tubing drilling technology.

This is by no means intended to be an exhaustive guide for TTD operations. It should be considered a guide and initial introduction to the advantages and limitations of the TTD technology.
2 Why Consider TTRD?

As fields mature, the development strategy for accessing the remaining reserves is driven predominantly by well engineering risks and costs. As drilling expenditure reduces, the relative cost of the completion becomes a more significant fixed sum, particularly in fields with complex completions. TTRD is one method to be considered for access to near well bore targets.

Each well will need to be reviewed on an individual basis to define costs and risks. The current extension from the main bore for the though tubing drilling envelope is approximately <2500ft for coiled tubing drilling and <3500ft for rotary drill pipe. Whilst this is considered a general rule, it should be carefully reviewed for each well. As the life cycle of the existing completion approaches end of field life and as targetable reserves diminish TTRD may be the only viable commercial opportunity available. Through tubing drilling, both rotary and coiled tubing rigged up through the derrick, can potentially provide additional production at a limited cost per barrel.

2.1 Coil or Pipe

The selection for coil or jointed pipe is not so much a technical as an economic consideration. If a fully functioning rig is available on the platform, jointed pipe operations can be considerably cheaper then using a coiled tubing drilling spread.

If, however, the platform is not normally manned or the rig and derrick have been decommissioned, coiled tubing drilling may be the best alternative. As stated above, each case has to be reviewed on an individual basis as both pipe and coil have advantages and limitations.
3 Well Planning

3.1 HSE ISSUES

3.1.1 Drill Pipe Racking & Handling

As the majority of TTRD is performed with 2-3/8" or 2-7/8" drillpipe, the major HSE issue is the manual handling and racking capability of this particularly flexible pipe. Whilst not being inherently dangerous, the main problems arises from using a much larger amount of slim DP than would have previously been used before for operations such as clean-outs. Total lengths of 12,000 to 15,000ft of 2-3/8" or 2-7/8" pipe may have to be accommodated in a standard derrick.

Previously a corral of larger pipe has been used to protect the slim pipe from the elements and provide more rigidity. This may be the best solution for some applications but the provision of an intermediate racking board is recommended, particularly if there are a number of TTRD wells planned. This reduces the exposure of personnel and equipment and makes the tripping times more reliable.

The trip time is often critical to the economic viability of the well and should not be underestimated. The number of trips required in through tubing activities is usually higher than in conventional side-tracks. This is one of the main benefits of utilising coiled tubing and could be a consideration for use in conjunction with rotary pipe. For example, if the reservoir risks or step out were considered too great for CTD itself, a hybrid solution could be utilised. For example, the coil could be used to prepare the well, then exit the completion and drill the new hole with slim jointed pipe and clean up/perforate again with coil. This keeps the surface rig up down to a minimum, utilises one coil size for all operations, yet still obtaining the benefits of both pipe and coil.
3.1.2 Well Control

Slim hole kick detection can be an issue as openhole annular clearances can be less than 0.0056 bbls/ft in some instances. Typical openhole annular volumes at TD can be less than 10bbls. Detecting a kick in openhole, with conventional sensitivities of +/-6bbls, often results in complete openhole evacuation before a kick has been detected. In the majority of TTRD applications this is not an issue as the formation strength is often sufficient to sustain a full evacuation to gas and the thru-tubing drilled wellbores are generally lateral extensions that do not have a large vertical displacement. Additional safety factors are also present if the tree is still in place.

If additional kick detection is required, the usual option is to improve the resolution of the existing equipment by reviewing a number of basic issues. Essentially, the requirement is for a more accurate measurement of the active mud system. This can be performed in a number of ways such as reducing the active system volume by isolating part of a larger tank or by the inclusion of flow meters in the discharge line from the mud pumps and the return line. There are also a number of advanced kick detection systems available, such as having a number of small individually monitored tanks to make up the active system. However the cost may not be justified for just the occasional well conversely its capabilities and sensitivity may not be applicable for remaining wells.

Generally, circulating and flowrates involved in TTRD are considerably less than in conventional drilling, and, the pressures involved generally higher. Hole cleaning, therefore, needs to be considered carefully. As the optimum operating range of the majority of conventional mud pumps is with higher flowrates, it may be advisable to utilise alternative pumps for the drilling phase. If the existing mud pumps are used, it is suggested, depending on pump output the smallest possible liners should be installed. Recommend slow circulation rates, SCR’s, are also taken with the cement unit for optimal control of a well kill.

If live well operations are required, it is unlikely that the well can be stripped to bottom with any significant wellhead pressure. If snubbing is required specialised contractors will have to be consulted to mobilise the correct equipment. For live well operations, coiled tubing may be the optimum drilling method.
3.2 Slim Hole Drilling Issues

3.2.1 Trip Times

Trip times are a critical part of the drilling of a project. It is easy to assume that trip times will be broadly similar to standard drill pipe sizes, however, depending upon the equipment and racking available, trip times may be greatly increased especially if the joints have to be pulled in singles and laid down.

3.2.2 Drill String Fatigue

An issue of concern with TTRD is drill pipe fatigue. With these types of wells, the dogleg severity is often much greater than with conventional operations. In general, the rate of drill pipe fatigue damage increases with the severity of the dogleg and the tension in the drill pipe at the dogleg. In any TTRD application, the issue of pipe fatigue must be considered. The smaller sizes of drill pipe should in theory be less susceptible to fatigue, however, another issue to consider in TTD applications is the past history of the drill pipe used. This should be addressed with the vendor.

3.2.3 Downhole Equipment

There is limited downhole equipment available because of the hole size. However a full MWD suite up to and including resistivity is available. If it is possible to go to a 3-3/8” drillcollar size, PWD is also available.

3.2.4 Cementing liner/ wiper darts

To minimise the OD of the drill pipe connections, the most applicable pipe for slim hole applications is the Hydril Wedge Thread (WT) series. One problem, however, with this connection is that it is also internally upset and therefore the bore is not constant. This does generally does not become a problem until the string is used for cementing the liner. The internal upsets have previously caused a number of plug failures, including the cementing up a complete string of pipe. Developments have been carried out on plug design and this problem has, partially been solved.
3.2.5 Critical Path

The main aim with TTRD is to reduce costs of the side-track operation. Therefore, it is important to optimise the operation in order to take as much work as possible away from the critical path. Any operations that can be performed concurrently without the rig must be considered. For example setting a whipstock can often be done with coil or wireline prior to the main rig being available.

3.2.6 BOP’s

The two options that are available for BOP’s are to either redress the existing models or to hire a dedicated 7-1/16” set of BOP’s. The best solution technically is to hire a dedicated set of BOP’s that are dressed as follows:

- Annular BOP
- Variable pipe rams 2-7/8” – 5”
- Blind / Shear rams
- Variable pipe rams 2-7/8” – 5”
- Riser and crossover

The riser section should be of sufficient length to space out the BOP’s appropriately. Depending on the application, it may be also be advisable to position a set of shear/seal rams directly on top of the tree to provide a primary seal in case of problems with the wellhead or riser. This will also allow coiled tubing to be cut at surface. If the coil is pulled into tension prior to cutting, the coil will then fall below the tree allowing well integrity to be maintained.

3.2.7 Pressure and Hydraulics

The area of concern with TTRD is the pressure, the hydraulic situation and in particular ECD’s. At lower flowrates, it is particularly likely that the rig pumps, even with 4” liners, will be stroking at fairly low levels. There also tends to be higher than normal surface pump pressures because of the small internal diameters, internally upset drill pipe, BHA restrictions and higher than normal ECD. Care should be taken in this area and software should be used to predict the entire hydraulic regime.
3.3 Well Path trajectory planning

Choice of wellpath and kick-off point is largely a matter of common sense. The trajectory and the location of the kick off point tend to go hand in hand and are solved normally using a number of trajectory iterations. The completion itself will often dictate where the kick-off can take place but it is good practice to avoid kicking off within a perforated section, mainly because of potential difficulties in setting a whipstock. There may also be issues with respect to reservoir depletion and losses within the produced section of a perforated zone.

The whipstock itself should be considered when choosing a kick-off point in that the most effective setting depth should be chosen. Another consideration is the formation that is being side-tracked into. Essentially, the lithology and pressures of the zones to be drilled into are the deciding factors when determining the kick-off location. However in depleted reservoirs, low head or underbalanced solutions may be considered to combat potential losses.

Generally speaking, the exit point should be chosen as deep as possible with due consideration given to the maximum dogleg severity. The deeper the KOP, the greater number of subsequent side-tracks that can be performed from the same completion. This also allows for a contingency above the original casing exit if problems arise with the first window. There is no set limit to the along hole depth that a TTRD well is able to achieve since many factors are involved. However, from a practical viewpoint, open hole sections in excess of 3,000 ft are likely to increase the engineering challenges.
3.4 Side-track Techniques

There are currently three main techniques which currently exist for side-tracking from an existing wellbore. These are:

- Whipstock
- Section Milling
- Cement Whipstock

3.4.1 Whipstocks

To date, a number of slim-hole side-track exits have been performed using whipstocks and this has proved to be the most common and reliable technique available.

There are two main types available for different situations:

**Standard packer based systems**

This, in general, uses a type of bottom packer that acts as a positive fixing point in the well, which in return can also act as a pressure seal if required. There are a couple of different methods for milling a window through a mono-bore completion. If there is a packer or bridge plug in the required place in the wellbore, the window can be cut in a single trip. This would involve running a whipstock and milling assembly together with an anchoring assembly below the whipstock to ensure that once set, the whipstock does not move or rotate. Once at depth, and prior to landing out the assembly, a gyro is run through the drillstring, this enables the face of the whipstock to be oriented correctly. Once the toolstring has been set, the orientation is confirmed with the gyro prior to pulling this back to surface. The window milling assembly is then sheared off the whipstock and the window milling operation commenced.

Previous systems were run in two sections with the packer being set on pipe, wireline or coil. Following this, a gyro run was made to determine the position of the orientation key and ultimately the orienting assembly and whipstock run on pipe or CT. The window is then opened and dressed in three separate milling runs; starter mill assembly, window mill assembly and final window dressing mill.

As with any exit system, it is advisable to avoid the casing couplings and centralisers whenever possible. As there will always be a slight reduction in the window size in comparison with the liner size.
Thru-tubing Whipstock

Should restrictions exist in the completion, a through tubing whipstock can be run. This is a one-trip system to set the whipstock in place and can be run on pipe or coiled tubing using an MWD system. This allows accurate setting of the whipstock to the desired toolface and provides no pressure seal allowing a significant flow past area if the existing well is to be kept. It can also be set up to be recoverable after the side-track has been drilled, again through the tubing. The milling for this particular system is in two runs. Prior to setting the whipstock, it is advisable to run a multi-finger calliper to confirm the exact ID of the liner at the point of setting.

3.4.2 Section Milling

Section milling can be an effective technique for exiting the casing and provides some advantages over whipstocks. The main advantage occurs when the wellpath requires the window to be cut on the low-side of the casing or liner due to target or formation limitations or to prevent excessive tortuosity of the wellbore. Section milling has been utilised successfully in sizes down to 7” casing with 6-1/8” openhole sections.

3.4.3 Cement Whipstocks

A technique commonly used to exit casing, particularly prior to the current availability of reliable thru-tubing whipstocks is that of cement whipstocks. Cement is mixed and set over the desired interval and a window milled using time drilling techniques. Whilst this technique has improved it is still considered to pose a slightly higher risk than using a mechanical method for window milling, although this operation is routine on the North Slope in Alaska. Whilst some cement sometimes includes the use of small fibres, these do not prevent the cement from becoming fractured during the milling and drilling process but can help to maintain the integrity of the cement ramp. One possible drawback with the use of fibres is that can sometimes plug the cementing assembly.
3.5 Well preparation

Some wells may require a considerable amount of preparation for a TTRD sidetrack. However, prior to any work taking place, a drift run should be made to at least the KOP to confirm a whipstock can be successfully set. With all types of whipstock, (especially when using a through tubing whipstock), a multi-fingered calliper or Magnalog should also be run to confirm the ID and casing condition at the setting point prior to running the whipstock. Further workover operations may be required depending on the amount of scale?, or fill within the well. A further check is also made by pressure testing the completion and production annulus to the maximum expected surface pressures. Due consideration should be given to the expected downhole pressure.

To protect any downhole safety equipment, wireline retrievable valves should be pulled and a dummy sleeve installed to protect the nipple. If the safety valve is tubing retrievable, the flapper is typically inset into the body of the valve in the open position and protected by a sleeve to prevent damage.

3.6 Tubing wear

Completion tubing wear is not typically a significant problem in the majority of the wells that have been reviewed.

It is good practice however to attempt to monitor wear as the operation progresses by collecting swarf with a ditch magnet. But, with the small annular velocities involved it is likely that metal cuttings may not be recovered.

3.7 Surface equipment issues

The main surface equipment concerns when considering TTRD occur with the handling of the drill pipe. In general, 2-7/8” or 2-3/8” drill pipe takes longer to handle and is more difficult to rack.
3.7.1 Intermediate Finger Board or Belly Board

The drill pipe used for this process is far more flexible and can fall from the fingers if racked in stands. To avoid this, an intermediate set of fingers, sometimes called a belly board, can be installed. This has the dual effect of increasing efficiency and improving safety. Each rig has to be reviewed on an individual basis as access onto the platform may require significantly differing designs.

3.8 Personnel Training and Experience

Little additional training is required for rig crews to handle this particular operation and an appreciation of the issues can be gained in a pre-spud session. The crews do however require an appreciation of the drilling parameters, as they are often very different to normal operations from WOB to annular volumes. The rig has to be consulted, visited early on in the planning stage to assess such issues as the racking back of slim pipe with regard to whether a belly board will be required or not. Confirm whether kick detection, due to the small annuli and consequent small volumes involved, is an issue with regard to monitoring and clarify any safety concerns raised.
3.9 BHA equipment

The BHA chosen for TTRD applications requires special attention mainly because of its size. However in general, it is likely that the BHA used will utilise 3-1/8” collars. The vast majority of the North Sea wells reviewed to date would allow a 3-3/4” hole size to be drilled through the completion.

3.9.1 Directional Drilling and MWD

There are, at present, a number of companies capable of providing a directional service in the slim hole sizes common in TTRD, the main systems utilising either mud-pulse or electric telemetry. There are, however, some limitations to both transmitting systems. When using compressible fluids, mud-pulse systems become incapable of transmitting data to surface as the signal is excessively dampened prior to reaching the transceiver. In relation to electric line conveyed systems, the tripping time to run the assembly is increased due to the time taken to rig up the wet-connects and deploy the toolstring.

3.9.2 Other BHA Components

When drilling through tubing, consideration should be given to a number of other BHA components. These are as follows:

- Circulating Sub
- Mechanical Release Tool
- Jars and Accelerators
- Orienting tool (if applicable)

3.9.3 Drilling Jars

It is generally advisable to use a jar and accelerator within the TTRD BHA as considered necessary. There are a number of systems available from vendors, and the three that specialise in slim hole jars within this area are Dailey, Bowen and Griffith Oil Tools. These systems are used within CTD but have also been designed for rotary drilling.
3.10 Bit and Hole Size Selection

The hole size is dictated by the clearance available within the completion. In general, the hole size should be maximised with consideration given to the available clearance. By maximising the hole size, clearance between the BHA and hole increases thus improving mechanical issues, differential sticking risks and reducing ECD problems by reducing the frictional losses in the openhole. In addition, fewer problems are anticipated with the liner and cement job. The increased volume of cuttings, however, must be considered when carrying out the hole cleaning simulations.

3.11 ECD Management

With TTRD, in relation to the small BHA/hole clearance, ECD management is extremely important. The affects of any increases in flowrate and swab and surge are amplified and therefore an increased awareness is required during the planning stages to ensure that any difficulties and limitations can be identified and rectified if necessary.

3.12 Hole Cleaning

Due to the annular velocities that are sometimes experienced in TTRD operations, hole cleaning can become an issue. In the openhole section, the velocities tend to be acceptable for good hole cleaning due to the smaller annulus between the drilling assembly and drillstring and the openhole. It is a generally accepted industry standard that velocities in excess of 100 ft/min are required for adequate hole cleaning in any horizontal section. Many TTRD side-tracks are either high angle or horizontal and exhibit openhole annular velocities in excess of 150 ft/min.

In general terms hole cleaning becomes apparent if a larger diameter casing is exposed, such as at the liner top. At such positions in the wellbore, the increase in hole size can reduce the annular velocity considerably, resulting in cuttings fall out. If this occurs in the critical angle, cuttings beds can occur, resulting in the annulus packing off or the pipe becoming stuck. One method of prevention this is to include larger diameter pipe in the larger diameter hole section.
This will also have the effect of improving tensile and torsional drill string characteristics, and reducing frictional forces inside the tubing and increasing annular velocities.

3.13 Formation evaluation

Due to the annular clearances and high dogleg severity the exposure risk to open slim hole logging is larger than conventional hole sizes. The level of exposure is difficult to determine as the current experience is sporadic. The fact that the open hole is exposed for longer and the normal operating pressure regime of through tubing applications has high differentials only serves to add to the risk.

The majority of through tubing well profiles may not be suitable for wireline deployment but the risks are still applicable to coiled tubing or DP conveyed logging.

The number of available tools is limited in geographical areas and hence longer lead times should be expected than normal.

3.14 Liner equipment

The types of 2-3/8" and 2-7/8" tubing that have, up until now, been used for slim-hole completion include Hydril 511, New Vam, CS Hydril, Atlas-Bradford FL-4S and Hydril PH-6.

A few systems currently exist which depend upon the liner size run and the size of casing that the liner is to be hung off in. One system consists of the liner setting sleeve being directly made up on the liner string. Two more runs are then required in order to clean the liner PBR and the DB packer setting area and then set a DB packer (Tie-back packer). If the DB packer is set within a 6-5/8" or 7" liner, the recommendation is to clean the liner PBR and the DB packer setting area in two separate runs. It is advantageous, if a choice is available, to run a single trip system, (such as an SC-1 hanger) which includes pressure isolation.
3.15 Cementing & Clean Up

Cementing in slim hole does not present any specific or new challenges. The CT liner setting sleeve running tool uses a single wiper plug/wiper dart system which is launched behind the slurry. The type 'S' system uses a conventional dual top & bottom dart and plugs.

3.16 Perforating

There are limitations on the type, size and performance of perforating guns capable of being run within 2-7/8" and 3-½" liner. The two main types available are strip guns (with encapsulated charges) and scalloped guns.
4 Technical limitations and specifications

The pipe being utilised considerably limits the use of TTRD. This is generally 2-3/8", 2-7/8" or 3-1/2". The most widely chosen pipe would normally be 2-7/8" since this has sufficient strength, torque capabilities and through bore and also has a small enough connection OD. One factor that must be taken into account is the ability to fish anything that is run. In the smaller hole sizes there are many restrictions that would need to be introduced, especially when the hole is reduced to less than 4-¾".

5 Technology Developments & Industry Position

There is very little through tubing drilling on going in the UK sector. BP is completing the majority of this work on the Forties and Magnus assets. Whilst this has been with reasonable success, there have, understandably, been some problems in the early wells.

With exception of BP few operators have taken advantage of the technique, although more, Kerr McGee, for example, are showing an increasing interest in its application. In the longer term, operators view CTD as having the greatest potential with its small footprint, portability and minimal crewing. However, in the short to medium term, operators are looking at TTRD as a real alternative to a full conventional sidetrack. This will enable them to maintain operations for their platform based drilling units for a considerable period of time.

Technically speaking, there has been considerable development in slim hole drilling techniques, mainly within the BHA’s. This has been driven by the desire for CTD with these BHA’s being adapted for use in rotary applications. A number of very smart systems exist for CTD, however, some of these have not made the transition over to TTRD which exists as a very small market.
6 References


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