Appendix 1 of this Chapter contains a set of curves demonstrating tool comparisons, and provides an approximation of the position uncertainty of a well. Ellipses of uncertainty are included in this section as a quick look guide.

6.5 GENERAL SURVEY PRACTICES AND GUIDELINES

This section describes running guidelines for wireline, multishot and MWD survey equipment and describes the quality control procedures associated with running the tools.

6.5.1 Wellsite Survey Quality Control Procedures

It is the responsibility of the DSV to ensure that the following procedure is performed, following completion of a well survey:

1. The Surveying Contractor shall report the data obtained for each survey run to the DSV.
2. The DSV shall check reported values conform to the acceptance criteria outlined below:

The Variance Between the:	Shall not Exceed
In-run and out-run inclination values for survey data from the same survey station	0.23 degrees
In-run and out-run azimuth values from the same survey Station	1.0 degree for all stations having an inclination of 10 degrees or over
In-run and out-run azimuth values from the same survey station	5.0 degrees for all stations having an inclination below 10 degrees

Table 29. Acceptance Criteria for Well Surveys

3. When the acceptance criteria are met, no further well site QA / QC shall be performed. The final survey report shall be subjected to a full quality control examination by the DM.
4. In the event that all the acceptance criteria are not met, the DSV shall inform the DM who shall advise further action.
   Repeat surveys shall only be undertaken with the full approval of the DM.
5. In the event of a survey miss-run, DM approval for a repeat survey shall not be required. In this instance the DSV shall ensure that all questionable equipment is replaced with fully checked-out units prior to the re-run of the survey.

6.5.2 MWD Running Guidelines

The MWD tool is a combined magnetic steering and surveying tool run close to the bit. It measures inclination, azimuth and toolface. The following guidelines shall be observed when running an MWD:

- Measure the fishing neck of the MWD tool.
- Run mud filter screens. It is preferable to have these installed in the surface equipment rather than in the top drill pipe single.

- Considerable care should be taken whenever handling MWD tools. They are built to withstand high axial loads but are easily damaged by transverse loading. MWD collars should always be snubbed when being handled out of transport cradles.

- Surveys should always be taken after making a connection in order to reduce the chances of stuck pipe. Although the pipe should remain stationary when the survey is being taken it should be reciprocated during transmission of the data to surface.

Benchmarking surveys should be taken in accordance with the MWD Survey QA/QC guidelines detailed below..

6.5.3 MWD Survey QA/QC Guidelines

The following guidelines should be routinely applied to assess the validity of MWD survey data. Adherence to the procedures below will assist identification of incorrect data.

6.5.3.1 Surface Function Test

The MWD tool shall be function tested at surface according to contractor procedures. Two tools should be prepared to ensure a back-up is ready in the event that the surface test fails. The tests shall be performed as follows:

1. Make up the MWD, aligning the scribe mark on the motor or bent sub to the MWD. The toolface offset shall be recorded by the Directional Drilling Contractor who shall supervise the operation.

2. Circulate directly above the MWD (with the bit and motor made up) at the planned flow rate.
   Record pressure versus flow rate and check performance of the tool.

3. Check the total gravitational field readings that should be close to unity.

6.5.3.2 Benchmark Survey

The following guidelines should be adhered to when performing a benchmark survey:

1. Take a survey in open hole at a suitable survey station at least 100' below the previous casing shoe to avoid magnetic interference and in order to provide a benchmark. Survey inclination should be within 0.5 degrees of the survey originally recorded at this station.
   Survey azimuth should agree within 2 degrees for survey stations above 10 degrees inclination.

2. Repeat the benchmark survey at the final survey station of the previous bit run before drilling ahead.

3. If the benchmark survey does not meet the above criteria, work the pipe and check the survey again at this or the following previously surveyed station.

Note: Repeatability of benchmark survey results is prone to variance below 10 degrees.of hole inclination. BHA centralisation, borehole anomalies, washouts and deformations could be the cause lack of repeatability. In the event of failure to meet the benchmarking acceptance criteria the DE shall advise further actions.

6.5.3.3 Survey Quality Checks

When the MWD tool transmits a sequence of quality control outputs with every survey, they can be used to validate the quality of the survey and check the correct functioning of the tool.

The level of quality control that is possible with the MWD depends on the number of "full survey" stations which have been obtained with the particular MWD tool within the hole section. At least the first, fourth, seventh, etc, stations shall be taken in full survey mode.

When long survey quality control outputs are obtained, the DSV shall check that all raw magnetic values are similar to computer predictions for the date and location provided by the MWD Service Contractor.

6.6 DIRECTIONAL DRILLING – ROTARY

During directional drilling the DSV shall supervise and monitor the activities of the Directional Drilling Contractor on behalf of GSLM.

6.6.1 General Guidelines

In general, only the bit, drill collars, and stabilisers are considered for trajectory control. The specific drilling operation shall determine the rest of the BHA components (e.g. shock subs, hammers, mud motors, MWD, jars, accelerators, heavy weight drill pipe, transitional drill collars, etc.).

The following guidelines should be considered when checking the proposed BHAs.

- Only the lower 30 m of the BHA provides deviation control. More drill collars and additional stabilisers are used to provide additional weight and to provide standoff from the wellbore and to prevent drill collar "wobble" during drilling.
- In areas of strong formation dip, local knowledge, experience and computer modelling should be used when selecting BHAs to build or maintain hole inclination. These assemblies are more susceptible to the azimuth tendencies imposed by strongly dipping formations. Stabiliser sizes should be varied at the discretion of the Directional Drilling Contractor depending upon conditions encountered in individual wells.
- The following calculation shall be used to determine the neutral point of buckling:

$$\text{Weight of BHA in Air} = \frac{\text{Required WOB}}{\text{Bouyancy Factor x Safety Factor}}$$

The Safety Factor depends upon the type of BHA stabilisation. It is generally 85%, unless otherwise specified in the drilling program.

Further analysis is required to determine the neutral point of axial stress for BHA components, e.g. running drilling jars in compression or tension..

6.6.2 BHA Stabilisation

The following considerations shall be used to determine the BHA stabilisation configuration to be used:

- When it is desirable to prevent bending moment being carried through to the bit from the BHA above, a packed hole (or stiff) BHA should be selected. This arrangement can be used either in vertical or deviated wells where it is desirable to hold azimuth and inclination.
- In packed hole assemblies, the near bit stabiliser must be full gauge. The first string stabiliser should normally be full gauge. However, under-gauge, first string stabilisers are sometimes used to hold angle in deviated holes where there is a tendency to drop.
- In addition to improving the steerability of the drilling assembly as described above, stabilisers are also important in providing stand-off of the BHA from the wellbore, decreasing the possibility of differential sticking.
- In general, full 360° wall contact stabilisers should be used to prevent gouging the wellbore. In soft formations, integral blade stabilisers are preferred. As formation strength increases, roller reamers may be used to reduce torque.

6.6.3 Bottomhole Assemblies

Each generalised configuration of bottomhole assembly shown below represents a typical directional tendency while drilling. The effect of the tendency is dependent on a number of variables, including:

- Formation hardness and bed dip.
- Bit type.
- Stabiliser type and diameter.
- Hole size and drilling parameters, such as weight on bit and rotary speed.

Stabiliser wear in abrasive formations has a significant effect on directional tendency.

The diagram below describes the general stabiliser placements for drilling vertical or directional 8½" hole and 6 1/8" hole.

BHA's for directional wells will be detailed in the Drilling Program for that well.
Chapter 3 of this Manual provides more detailed summaries of each BHA configuration.

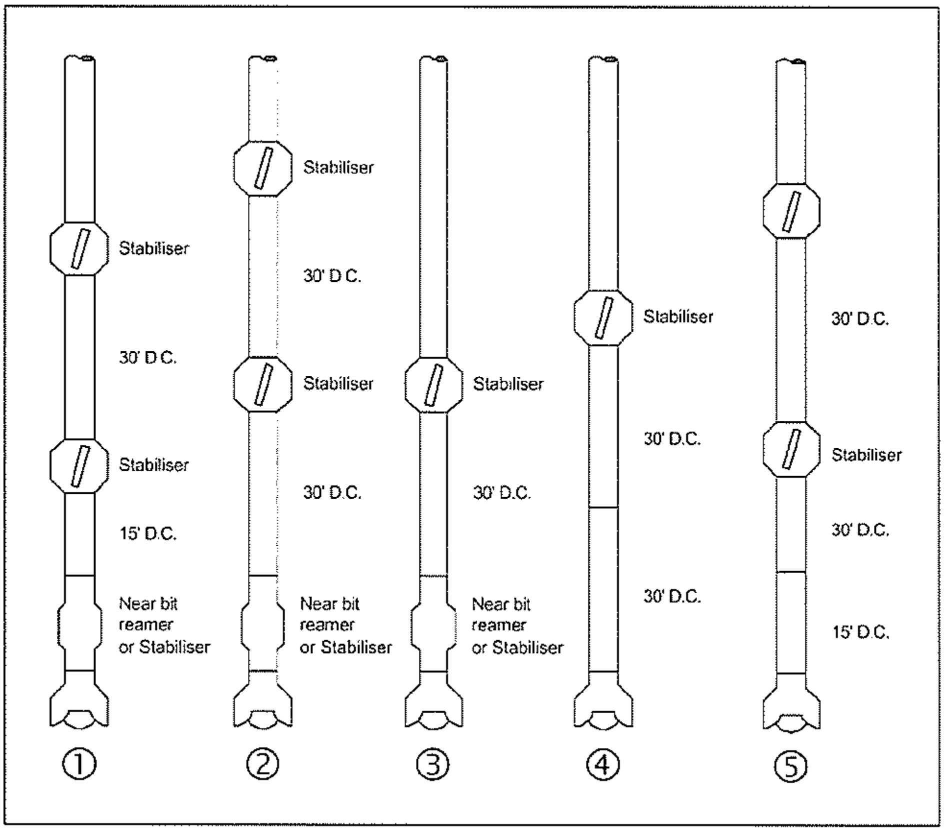

Table 30. Standard BHA Configurations in Nominally Vertical Wells

BHA	17 ½" Pendulum	12 ¼" Pendulum	8 ½ Pendulum	8 ½" Packed	6 1/8" Pendulum	6 1/8" Packed
1	17 ½" bit	12 ¼" bit	8 ½" bit	8 ½" bit	6 1/8" bit	6 1/8" bit
2	2 x 8" DC	8" Motor	6 ½" Motor	NBRR	4 ¾" Motot	NBRR
3	Stabiliser	2 x 8" DC	6 ¼" DC	6 ½" motor	4 ¾" DC	4 ¾" Motor
4	1x 8" DC	Stabiliser	Stabiliser	Stabiliser	Stabiliser	Stabiliser
5	11-15 x 6 ¼" DC	1 x 8" DC	20-26 x 6 ¼" DC	6 ¼" DC	20 x 4 ¾" DC	4 ¾" DC
6	6 ½" Jars	11-20 x 6 ¼" DC	Jars	Stabiliser	Stabiliser	Stabiliser
7	2 x 6 ¼" DC	6 ½" Jars	2-3 6 ¼" DC	20-26 6 ¼" DC	20 x 4 ¾" DC	20 x 4 3/4" DC
8	6 x 4 ½" HWDP	2 x 6 ¼" DC	6 x 4 ½" HWDP	6 ¼" Jars	4 ¾" Jars	4 ¾" Jars
9		6 x 4 ½" HWDP		3 x 6 ¼" DC	3 x 4 ¾" DC	3 x 4 3/4" DC
10				6 x 4 ½" HWDP	6 x 3 ½" HWDP	6 x 3 1/2" HWDP
Comments	Available WOB 25 - 40 klb	Available WOB 25 - 45 klb A mud motor may be run immediately above the bit.	Available bit weight approx 40klb	Available bit weight approx 40 klb.	Available bit weight approx 33 klb.	Available bit weight approx. 34 klb.

NOTE: Consideration should be given to using a slick BHA when drilling the Diorite commonly found in Tasmania.

6.6.4 Directional Drilling with Rotary BHAs

The natural tendency for a bit to drill perpendicular to bedding at low to moderate dip angles may be used to reach targets by optimum rig positioning. In areas where formation dip influence and directional surveys are well documented, consideration should be given to moving a drilling pad in order to achieve a tight target tolerance using conventional rotary drilling.

In general, the following shall apply (although specific wells may differ):

- In general rotary BHA's tend to build angle and directional control is maintained by selecting a BHA which gives the desired Build-up Rate (BUR).
- Due to generally strong build tendencies, the Directional Drilling Contractor should err on the low side of the deviated section, as it is generally easier to make a build correction than a drop correction.
- Maximum desired Build Up Rate is normally 2½ to 3 degrees/ 30 m. Dog-Leg Severity is generally 5 degrees/ 30 m.
- The abrasive nature of formations must be considered as stabiliser gauge wear can alter during the course of a bit run. This may change the directional characteristics of the BHA.
- Heavy Weight Drill Pipe (HWDP) and drill pipe must have smooth and flush hardfacing in accordance with API RP7G.

🕮 API RP7G (Specifications for Drill Pipe).

6.7 SIDETRACKING

Wells may require side-tracking for various reasons. These include, but are not limited to the following:

- Re-drill the well to a new target.
- Sidetrack past a fish.
- Sidetrack due to hole problems.

The main requirement in sidetracking a well is the development of a lateral force to allow the bit to cut on the side of the hole. This lateral force should be provided by the geometry of the BHA, forcing a cut on the side of the hole. Historically, the most effective BHA configuration to achieve a successful sidetrack kick-off is a mud motor with bent sub or steerable motor. This section provides guidelines and considerations for achieving a successful kick-off.

6.7.1 Kick-Off Point Selection

If possible, the kick-off location should be selected so that the formation is softer than the kick-off plug to increase the chances of obtaining a successful kick-off.

If, however, only medium to hard formations exist at the required side-track depth, operational difficulties and time are increased. A controlled ROP should be maintained until confirmation of a successful kick-off is achieved.

6.7.2 Kick-Off Plugs

The general requirements for setting sidetrack cement plugs are as follows:

- Cement plugs shall have a minimum length of 90 m in open hole.
- Cement slurry shall be a minimum 16.5ppg, to be confirmed by laboratory testing.
- Cement plugs should be batch mixed, if possible.
- Run a tubing stinger at least equal to the length of the cement plug.
- Consider running a pre-flush prior to balanced cement plugs, at least equal to the weight of the mud.
- A Hi-Vis pill may be spotted below the plug.

The procedure for drilling kick off plugs should be as follows:

1. Pull out of plug slowly.
2. Circulate conventionally to clean string (do not reverse circulate, to avoid traces of cement remaining in the string that may fall onto mud motor when drilling recommences).
3. RIH with mill tooth bit. Wait on cement for a minimum of 12 hours.
4. Dress off 5 m, and weight test the plug.
5. If the cement appears to be hard, RIH mud motor and bent sub. Wait a minimum of 24 hours from pumping cement before attempting to kick-off. Wait longer if necessary to achieve hard cement.
6. If the plug does not show signs of compressive strength, drill and wash through sufficient cement to allow placement of a second 90 m plug at a suitable depth for sidetracking.

6.7.3 Casing Windows

When preparing to cut a casing window, the following guidelines should be applied:

- When making the initial cut, care should be taken to avoid casing collars and centralisers.
- The cut should be initiated a minimum of 3 m above a casing collar.
- The lengths of window to facilitate an effective sidetrack are tabulated below:

Casing Size	Minimum Window	Optimum Window
7" Casing	9m (30')	12 m (40')
9 5/8" Casing	10.51 m (35')	15 m (50')

Table 31. General Lengths of Window to Effect a Sidetrack.

6.7.4 Sidetracking on the Low Side of the Hole

At commencement of a sidetrack, the low side sidetrack can take off rapidly. As there is a risk of creating high doglegs in this instance, it may be preferable to come off at a low right or low left angle rather than a direct vertical drop off. Once the new hole has been cut, lateral separation should be maintained to prevent collapse of the old hole onto the new.

6.8 DIRECTIONAL DRILLING REQUIREMENTS

The following section provides a series of guidelines and considerations relating to the drilling of high angle or horizontal wells. The guideline and considerations are presented to augment the well design and directional contractor procedures and provide a broad overview of the required practices, procedures and considerations to assist in the maintenance of safe, efficient and cost effective operations whilst drilling high angle and horizontal hole sections.

6.8.1 Preparation

Effective equipment preparation and full dissemination of programme requirements and drilling procedures are essential for the successful completion of high angle and horizontal wells.

1. Daily Briefings
A routine daily meeting should be held between well site and office to identify potential problem areas, the forward program and logistical requirements for the forthcoming 24hr period.

This section describes the requirements to be considered during directional drilling activities.

6.8.2 Kick-Off and Initial Build Selection

1. An initial kick-off and build section with smooth build rates is required to minimise torque and drag in deeper critical hole sections. The DSV should ensure all personnel are aware of this requirement and that potentially troublesome doglegs are wiped immediately.

2. Excessive doglegs or a drop in build rate have a much greater effect on torque and drag in top hole than in deeper hole sections. Extensive use of torque and drag analysis while drilling shall be made to assess the impact of directional variations on the overall directional operations plan.

6.8.3 High Angle/Extended Reach Tangent Sections

6.8.3.1 Bit Selection

The choice of bit should take into account the degree of reactive torque produced and the limitations of the motor. For instance some PDC bits can make motor tool face control difficult resulting in erratic hole, increased torque and drag and low ROP's. The use of motor bearing three-cone bits is often preferred for these sections.

The design criteria when selecting three-cone bits are:
- Maximise penetration rate to limit open hole time.
- Extended bearing life to reduce the frequencies of bit trips.
- Bits should be resistant to cone erosion as greater than normal flow rates are required for hole cleaning.
- Enhanced gauge protection on cutters, shank and shirt tail in order to withstand the increased lateral loading when used with steerable systems.

The design criteria when considering PDC bits are:
- Maximise penetration rate to limit open hole time.

- Small cutter size to reduce reactive torque and enhance steering capability.
- High cutter density and gauge studs to limit gauge wear.

6.8.3.2 Hydraulic Requirements & Practice

Efficient hole cleaning is essential to the success of directional drilling. As such all hydraulic programs should be designed for maximum hole cleaning capability as follows:

- Circulate at the highest possible rate within the constraints of ECD on weak formations. Install a by-pass nozzle on mud motors to increase flow area if necessary.
- Circulate the hole clean (as much as practical) prior to commencing a trip, a minimum of 1.5 times the bottoms up volume is normally required.
- Consider using a hi vis / low vis / hi vis sweep regime to facilitate disturbance and removal of cuttings beds. Keep pipe rotating while pill circulating.
- Apply enhanced monitoring of drilling parameters for increases in torque and drag.
- Perform wiper trips as required.
- Ensure Fann viscometer 6 rpm reading is 1.0 – 1.5 times hole diameter.

6.8.3.3 Casing Wear Monitoring and Prevention.

- Install 2 ditch magnets in the flowline or possum belly to monitor casing wear. The amount (weight) of recovered shavings should be reported daily.
- HWDP and drill pipe should have smooth hardfacing only.

6.8.3.4 BHA Component Inspections

All BHA components should have received a full inspection prior to use on a directional well. The complete BHA should be returned for further inspection after completion of thewell.
Stress relief grooves are required on all components (including non-magnetic components and jars).

6.8.3.5 Drilling Jars

Enhanced hydraulic (up/down) short jars should be used. Use of a drilling accelerator or 2 jars should be considered.

6.8.4 Final Build and Horizontal Hold Section

6.8.4.1 Bit Selection

The criteria for bit selection are identical to those detailed in section 6.8.3 above. The Following figure illustrates the common problems encountered when drilling horizontal hole sections and potential preventative measures relating to bit selection.

PROBLEMS ENCOUNTERED	PREVENTATIVE MEASURES
Side-Loading Using Steerable Systems	Shorten shank or gauge length Increase gauge protection Opt for rotary drilling if possible
High Torque - Reduced Directional Control	Use less aggressive PDC Shorten gauge length of PDC bit Increase Number of gauge cutters Opt for Roller Cone Bit
Difficulty Maintaining Hole Angle	Longer Gauge Length on PDC Bits Lug Pads On Roller Cone Bits Use Steerable system
Excessive Cuttings Bed Generation	Use Lug Pads on Roller Cone Bits Increase gauge cutters on PDC bits (Both measures to facilitate efficient back-reaming operations)
Reduced Bit Life Due To Motor Use	Use PDC Use Motor Bearing Roller Cone Bits Use Low speed PDMs Opt for rotary drilling if directional control allows

Table 32. Bit Selection Guidelines

6.8.4.2 Drilling Fluids & Hydraulics

As per 6.8.3., item 2.

6.8.4.3 Drilling Jars

Two sets of jars can be run. Place one set above the DC's. Place a second set in the cased hole section.

6.8.4.4 Drill Pipe Requirements

Drilling horizontal sections places high buckling and torque stresses on the DP. Use of torque and drag analysis is essential to predict actual loads and determine the grade of drill pipe required. Actual requirements and design loads shall be indicated in the Drilling Programme.

Drill pipe should be fully inspected prior to use on high angle or horizontal wells.

6.8.4.5 BHA Design

The directional contractor shall use offset well and contractor experience to design the BHA.. The DSV and Directional Drilling Engineer shall base their BHA configurations on those proposed, however modification based on the previous BHA runs will be required. The use of steerable systems which have a neutral tendency in rotary mode are optimum for these hole sections.

6.8.4.6 Casing Wear Monitoring & Prevention

- Install 2 ditch magnets in the flowline or possum belly to monitor casing wear. The amount (weight) of recovered shavings should be reported twice daily.
- HWDP (and DP rotating within the casing) should have smooth hardfacing only.
- Consideration should be given to using drill pipe casing protectors.

6.8.4.7 Data Recording

Successful performance in horizontal drilling of wells requires the development of a comprehensive database of experience as optimum practice is often very area specific. As such all personnel should be reminded of the requirement to accurately record all possible data, specifically:

- Drilling parameters used, WOB, RPM, Torque, pressures, circulation rates etc.
- Motor condition, stabiliser wear patterns.
- Mud properties.
- Comparison of predicted vs. actual BHA performance.
- Survey data, toolface control data.
- Hole conditions on trips.
- Formation data, hydrocarbon data (gas compositions ratios etc.).

6.8.5 Common Problems and Remedies

Problems commonly encountered in drilling extended reach and horizontal wells are illustrated in the table below.

Problem	Recommended Precautionary Measures
Inefficient Hole Cleaning and Reduced Borehole Stability	• Maintain high annular velocity, use turbulent flow pattern wherever possible. • Use low rheology fluid (horizontal sections) 6 rpm = 1.5 to 1.0 x hole size. • Use extended rheology drilling fluids for high angle 12 ¼" and larger hole sections. • Pump in/out of the hole - rotate as much as possible. • Perform frequent wiper trips. • Monitor drilled cuttings for signs of caving.
Poor Tool Face Control - Weight Stacking	• Monitor torque closely. • Use single bend steerable systems. • Drill in rotary mode as much as possible. • Orient after connections. • Use water-melon profile stabilisers. • Minimise heavy BHA components. • Monitor helical buckling of drill pipe in orienting mode.
Casing Wear - Excessive Torque and Drag	• Use minimum HWDP - smooth hardfacing only (also on DP rotating within casing). • Install flowline magnets - record metal filings recovered twice daily. • Record torque values at the shoe on every trip. • Wiper trip at first signs of increasing torque/drag. • Keep BHA as light as possible. • Use non-rotating DP protectors in casing.
Drill String Failures	• Ensure full inspection prior to well. • Perform visual inspection on every trip. • Monitor rotary torque closely. • Ensure adequate back-up equipment availability. • Perform full inspection of drill string after completion of the well.

Table 33. Recommended Precautionary Measure for Problems in Drilling Directional Well Sections.

6.8.6 Mudmotor Operating Practices

The following practices should be applied to ensure efficiency of motor operations:

a. Surface Checks

- Check the bent sub offset to ensure it is as planned.
- Make up the motor, (MWD if used) and bit. Test the motor and MWD at two or 3 differing flow rates, record circulating pressures and rates.
- Lock the hook and ensure bent sub orientation is tracked while RIH (align the I I scribe mark on the motor with that of the MWD, if used).
- Ensure dump valve installed to avoid tripping out wet.

b. Running In The Hole

- Check the string is full every 10 stands, or if a float is used, fill the drill pipe every 10 stands.
- Care should be taken when running in open hole. Damage to the motor bearings or bit may occur from hitting hard ledges of formation, particularly with a high angle bent sub.
- Wash down the last stand, gently tag bottom, establish the required tool face before commence drilling.

c. Tripping Out Of The Hole

- No rotation of the drillstring should occur when using a high angle bent sub (greater than 2 degrees).
- Circulate bottoms up at the shoe where the shoe is at a high angle.

d. Motor At Surface

- Inspect the body for signs of wear and damage.
- Check the play in the bearing section by manipulation of the bit box on the motor to evaluate bearing wear based on the play and determine if the motor is to be re-run.
- Test the motor at the same flow rates as in the surface test in 1 above and compare resulting circulating pressures. It is normal to see some reduction in pressure as the motor/stator tolerance increases.

6.8.7 General Recommendations When Using Motors

a. Bit Selection

Select suitable bit and motor combinations. Where PDC bits are used, they should generally have a diamond reinforced gauge of short length (for steerability).

b. Spiral vs. Straight-blade stabilisers

All stabilisers should have short blade, barrel profiles to reduce wall contact. The difference between spiral and straight blades is formation dependent.

c. High Speed Vs. Low Speed Motors

In general there is little ROP improvement with faster motors. The shorter, high torque, low speed motors enhance steerability and provide longer bearing life for rock bits.

Appendix I: Lateral Position Uncertainty

The set of curves shown below demonstrate tool comparisons and provide an approximation of the position uncertainty of a well.
The positional estimate is made by dividing the well into sections and using the curves to estimate the uncertainty for each section.
The results are then summed to obtain the total position uncertainty.
A worked example is given after the figure below to demonstrate the application of the curves.

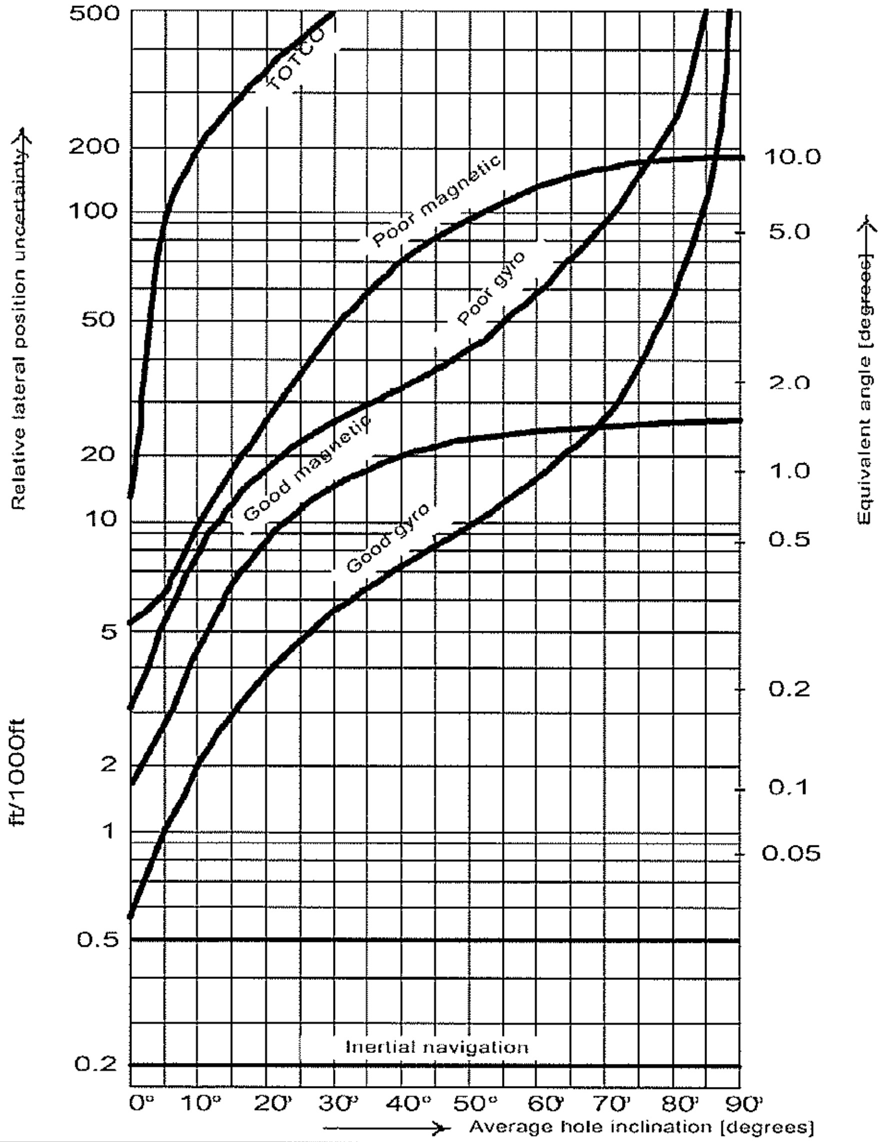

Figure 5. Lateral position Uncertainty – Tool Comparison

Appendix II: Worked Example

The following worked example uses the Lateral Position Uncertainty curves above to demonstrate the approximate positional uncertainty for the well, based on a "good magnetic survey".

The well is divided into 3 sections (see Simplified Sections of Example Well, overleaf)

Section 1	A vertical section from 0 to 550m (1800') AHD.
Section 2	A tangent section with an inclination of 18.5° from 550m (1800') to the target at 975m (3200').
Section 3	A tangent section with an inclination of 18.5° from 975 m (3200') to TD at 1143m (3750').

The position uncertainty from each section can then be estimated.

Section 1 (The vertical section from 0 to 550m {1800'})

From the 'good magnetic' curve at 0° inclination, 1.8' per 1000' is obtained.
The Along Hole depth of this section is 550m {1800'}
the uncertainty radius is (1800/1000) x 1.8 = 3.2' or 0.975m

Section 2 (The tangent section from 550m to 975 m {1800 to 3200'} AHD)

From the 'good magnetic' curve at 18.5° inclination, 8.25' per 1000' is obtained.
The Along Hole depth of this section is 975-550m = 425m {3200-1800' = 1400'}
The uncertainty radius is (1400/1000)x 8.25 = 11.5' or 3.505m

Section 3 (The tangent section from 975m to 1143 m {3200 to 3750'} AHD)

The same uncertainty of 8.25' per 1000' is obtained from the curve.
The Along Hole depth of this section is 1143-975m = 168m {3750-3200' = 550'}
The uncertainty radius is (550/1000) x 8.25 = 4.5' or 1.372m

Summation of errors from individual sections

From the above Sections, the position uncertainty at the target will be the uncertainty of Section 1 added to Section 2 = 3.2 + 11.5 = 14.7', rounded up to 15' (4.48 m).

Thus the estimated position uncertainty at the target is a circle with radius 15'. (4.48 m)

At TD the uncertainty will be the uncertainty at the target added to the uncertainty of Section 3 which is 15 + 4.5 = 19.5' rounded up = 20'. (5.94 m)

Thus the estimated position uncertainty at TD, is a circle with radius 20'. (5.94 m)

Note:
This method of estimating position uncertainty produces a circle of uncertainty, and should only be used as a guide to possible error. In reality the uncertainty will be an ellipsoid which, when calculated with a computer will give a smaller and better defined position uncertainty of a well. For any work involving well position uncertainty, the ellipsoids should be used.

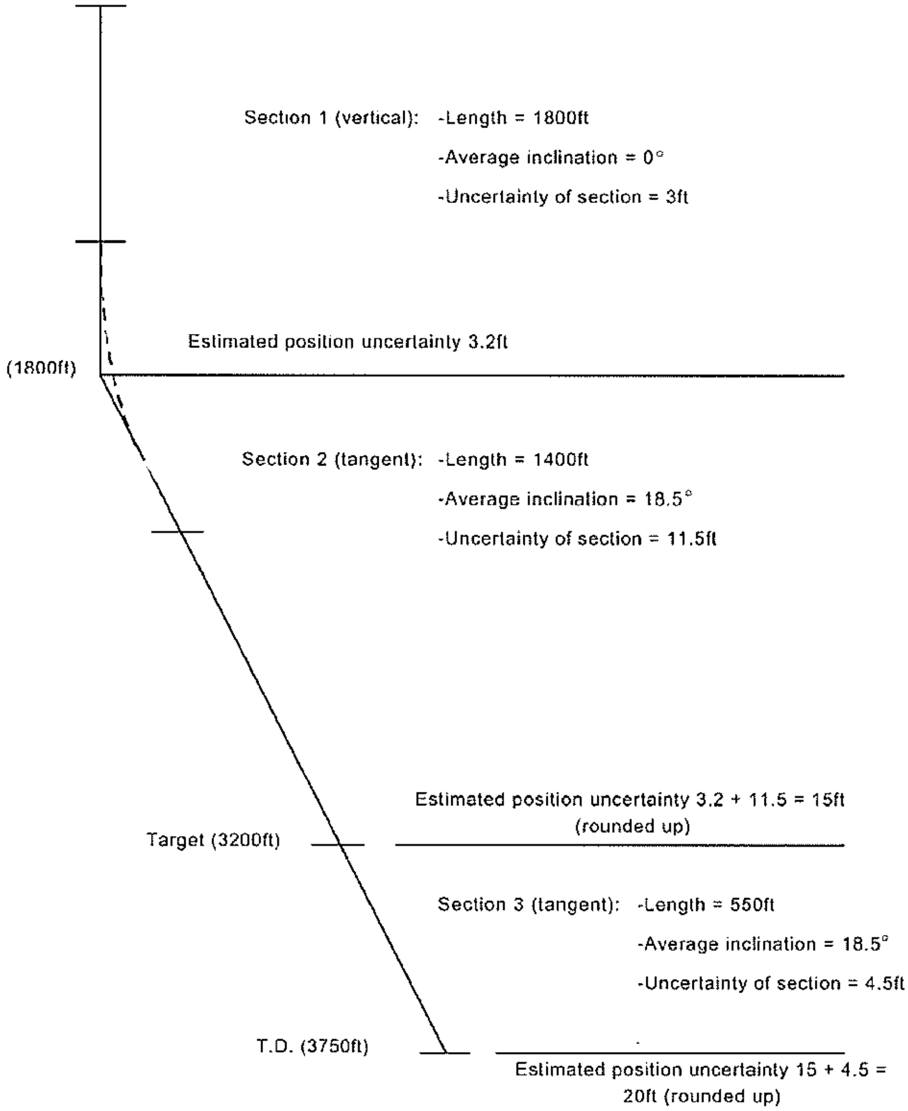

Figure 6. Simplified Sections of Example Well

Appendix III: Ellipse of Uncertainty

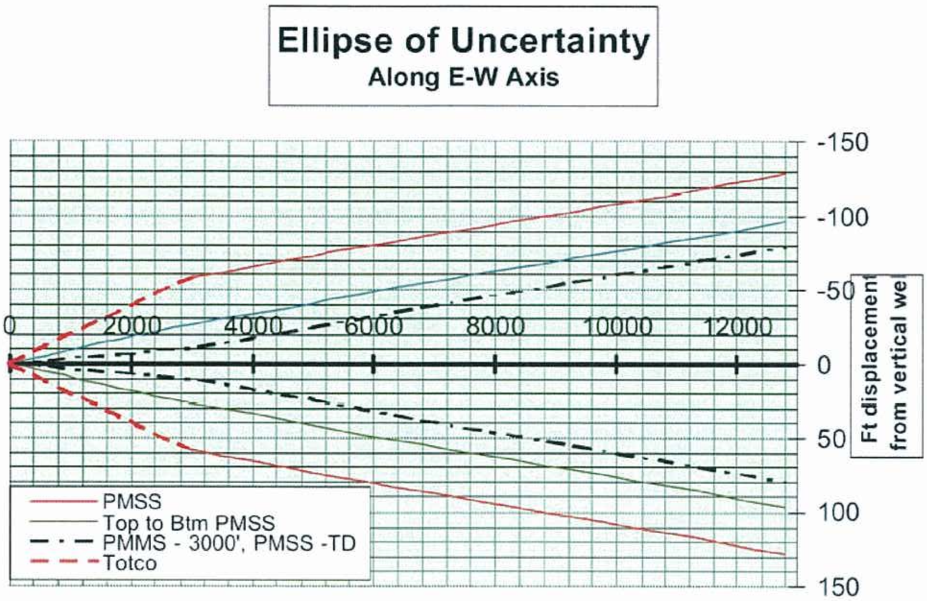

Figure 7. **Ellipse of Uncertainty – Along E-W Axis**

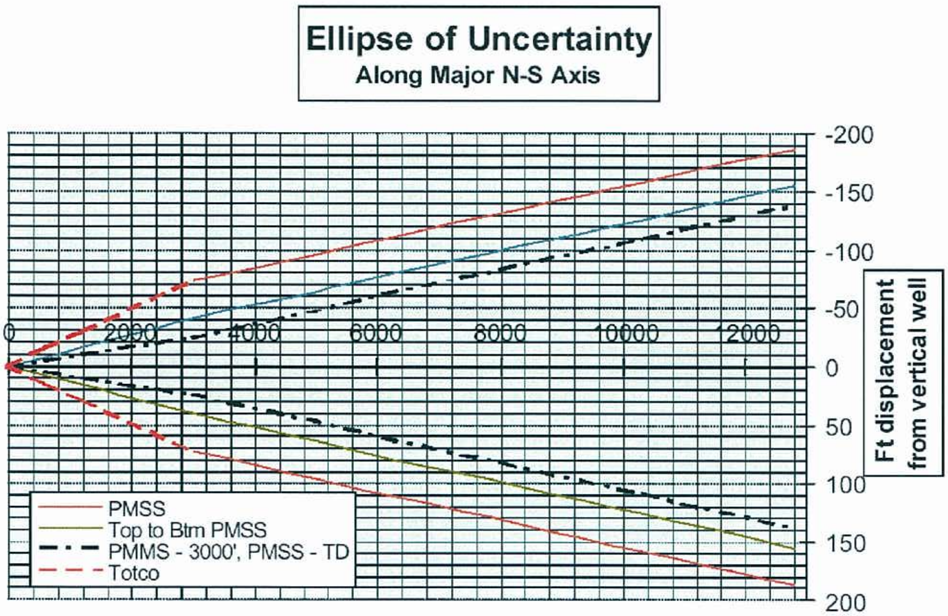

Figure 8. **Ellipse of Uncertainty – Along Major N-S Axis**