CHAPTER II
LITERATURE REVIEW

Excessive torque and drag in the design of a wellbore trajectory and drillstring configuration might cause severe damage to a device that turns the drillstring (topdrive) capacity, drillpipe strength, and available lifting capacity. It can increase pipe fatigue, casing wear, and mechanical borehole problems, such as hole enlargement and can lead to an inability to slide. Moreover, a conventional steerable assembly might increase frictional forces, which can lead to failures in the tubular from excessive wear, buckling, and collapse (Prurapark, 2009). Therefore, it is essential for engineers to accurately calculate torque and drag forces and attempt to reduce them in order to prevent these scenarios from occurring (McCormick *et al.*, 2011).

2.1 Torque and Drag Concept

2.1.1 Buoyancy Factor

Frafjord (2013) showed the drill string tension in a wellbore when filled with a drilling fluid is the unit pipe weight (w) multiplied by the buoyancy factor. The buoyancy factor as expressing in Equation (2.1) is applicable for local buoyancy factor calculations because the inside and outside of the pipe are submerged into the different fluid, such as during cementing and running drill string into the hole operations, used for. If there is the same fluid density between the inside of the drill string and in the annulus, like during pulling the drill string out of the hole, Equation (2.2) should be used.

$$\beta = 1 - \frac{\rho_0 A_0 - \rho_i A_i}{\rho_{pipe}(A_0 - A_i)} \tag{2.1}$$

$$\beta = 1 - \frac{\rho_0}{\rho_{pipe}} \tag{2.2}$$

2.1.2 Friction Factors

Conventional friction factors (FF) account for simultaneous interaction of a variety of factors including mud lubricity, pipe stiffness and cutting beds. FF also model stabilizer/centralizer interaction with the borehole, differential sticking and dogleg severity (DLS).

Xie *et al.* (2012) explained that drag force can be divided into two main components. The first force component is from the actual frictional between the drilling tubulars and the wellbore wall. It is directly proportional to the actual friction factor between formations and the tubulars. As the pipe starts moving, static friction breaks down and kinetic friction takes over. The kinetic value is always lower than static friction factor. Normally, the roughness of the annulus has an influence on this value. The friction factor of steel to steel is typically smaller than that of steel to rock. The bottom hole assembly (BHA) drilling through the cutting bed creates a higher resistance against the movement. Mud acts to lubricate resulting in reduced friction. Different mud types have different rheology, thus different range of friction factors.

The second force component is the result of various restrictions including the cuttings bed thickness. Normally, velocity is not considered in torque and drag modeling.

In real time the friction factor can be analyzed by using the drilling parameter as shown in Equation 2.3:

$$\mu = 36 \times \frac{T}{WOB \times D_{bit}} \tag{2.3}$$

where:

μ	=	friction factor
T	=	torque (ft-lbf)
WOB	=	weight on bit (lbf)
D_{bit}	=	bit diameter (inches)

This equation accounts for the friction since the force apply to the bit that creates the torque, but in reality the friction factor should be affected by all of force acting along the dtillstring, even the drilling fluid density or cutting movement, well geometry, and formation properties.

2.1.3 Normal Contact Force

The normal contact force is the force normally acting perpendicular to the contact surface that is the key parameter for T&D calculation. The magnitude of the normal contact force affects to drag force directly even occurred in any movement. However, the different well geometries of along the well trajectory are presented the different the normal contact area. The normal contact force can be diminish in real time by adjusting the drilling parameter, like drilling fluid density, the hole cleaning, and WOB etc.

2.1.4 Torque

Torque is rotational force generated from number of sources within the wellbore such as mechanical torque, frictional torque, dynamic torque, and bit torque. Along with this, drillstring dynamics or vibrations may also contribute additional torque contact loads between the drill string and the open hole or the casing generates frictional torque. The friction torque assumes perfect hole cleaning condition and rotating off bottom operation. Current torque is the function of the following aspects:

- Tension or compression in the drillstring
- Dogleg severities
- Hole and pipe sizes
- String weight
- Inclination
- Lubricity or friction factor

All these aspects must be well understood and controlled to meet operational requirements. The higher the tension or compression, the higher the contact forces between drillstring and wellbore. High dog leg severity will increase the contact forces. The dog leg severity has high effect in the drillstring length with a greater tension, i.e. in the shallow well depth. Along with this, contact forces are a function of the clearance between the drillstring and wellbore. The drillstring stiffness will be high in a small annulus and will contribute into the extra friction contact forces. In addition, having high string weight the contact force will be high due to the greater weight pushing against the side of the hole. The wellbore inclination is also a key parameter in the analysis. Higher inclinations results in a larger component of the string weight perpendicular to the borehole. Torque which is generated as the result of the interaction between drillstring or BHA and unstable formation or cutting accumulation is defined as a mechanical torque. Usually this torque is difficult to predict and simulate during the planning phase. Most of the industry torque and drag simulators do not take into account the mechanical torque. This gap could be compensated by using a slight high friction factor.

2.1.5 Drag

Drag is an axial force which is generated only when the pipe is moved in an axial direction without rotation. It always has an opposite direction to that in which the pipe is movedP12P. During tripping in and out operations, when the drillstring is not rotated, the drag forces are higher. While, when the drillstring is rotated the drag forces are reduced.

During the field operation we are particular interested in the measurements of the following parameters:

- Rotating of bottom weight –this is the weight of the drillstring without drag added with the pipe in rotation and the plus travelling block weight.
- Pick up weight - this is weight of the drillstring during the tripping out operation.
- Slack off weight - this is weight of the drilling during the tripping in operations.
- Torque off bottom is a measure of the torque when rotating off bottom of the hole.

A real time torque and drag monitoring, gives an opportunity to obtain current down hole drilling condition and predicts upcoming situations. During the planning phase of the torque and drag analysis the worst case scenario must be considered to be sure that the drillstring can be drilled, tripped in and out and rotated. Drag forces during tripping in and out operations are not liberalized reversals of one another. This happens due to the number of reasons such as wellbore geometry, drillstring geometry, the contact points which are different and which cause different friction factors. Particular attention must be paid to casing running and pulling operation if necessary. To evaluate bucking and tension capabilities it is required to determine effective tension/compression in the drillstring.

2.2 Torque and Drag Modeling

Drag is the excess load compared to rotating drillstring weight, which may be either positive when pulling the drillstring or negative while sliding into the well. It is noted that there is no axial friction drag in a rotating drillstring, so rotating drillstring weight is the zero-drag reference point. This drag force is attributed to friction generated by drillstring contact with the wellbore. When rotating, this same friction will reduce the surface torque transmitted to the bit. It is useful to be able to estimate the friction forces when planning a well or doing post-mortem analysis.

Analysis of these drillstring loads is done with drillstring computer models, and there have been many drillstring models developed over the last 30 years. By far the most common method, drillstring analysis is the "torque-drag" model originally developed by Dawson and Morehead (Johancsik *et al.*, 1984) and put into differential equation form by Sheppard *et al.* (1987). Because of the simplicity and general availability of this model, it has been used extensively for planning and in the field. If any drillstring model could be called "standard," this would be the one (Mitchell *et al.*, 2013).

There are 2 T&D models that are commonly used nowadays which are

2.2.1 Soft-string Model

Most common T&D software programs available are variations of the soft string model developed by Johancsik *et al.* (1984). A soft string model assumes that the entire drillstring lies against the wellbore and the stiffness of the drill string is not accounted for. The drillstring is modeled as a cable that is divided up into small elements (Figure 2.1) that only carry axial loads and torque contact forces are supported by the wellbore. The forces on the elements consist of tension, compression, and torsion that cumulatively build from the bottom of the string to the surface. In other words, torque and drag are calculated by summing the segments of the torque and drag generated from bottom of the string to the surface. Soft string models disregard the bending moments caused by the stiffness of the pipe and radial clearance of the drill string (McCormik *et al.*, 2011).

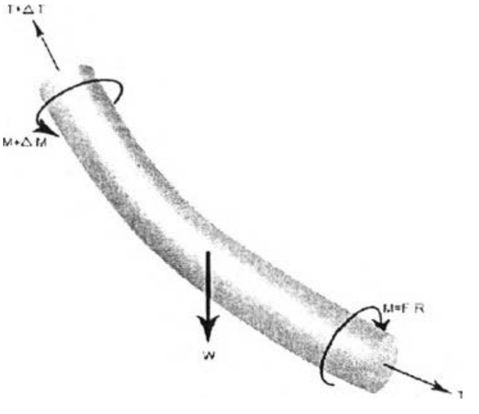

Figure 2.1 Short Elements in a string (McCormik *et al.*, 2011).

2.2.2 Stiff String Model

In addition to the soft string models, stiff string T&D models have also been developed. One major distinction between the soft string model and the stiff string model is that instead of treating the pipe as small elements of a cable, it accounts for the actual stiffness of the string. The stiff string model takes into consideration the bending moment in the tubular and radial clearance in the wellbore. Stiff string models are most beneficial when wells that have high tortuous trajectories, high DLS, or stiff tubulars (McCormik *et al.*, 2011).

Stiff-string mathematical models are considerably more complex to solve than soft-string counterparts (Mason *et al.*, 2007) that's why soft-string 3D mathematical model is used in this thesis because it is a lot easier and faster analysis which time consuming for calculation is one of the most important factors in real-time software.

2.3 T&D Modeling and Problems Prevention

T&D modeling becomes very important for drilling issue because it can predict and prevent problems while drilling which it can cause a lot of problems if it happens. Problems are Buckling and Tortuosity.

2.3.1 Buckling

Buckling is an important issue in the T&D modeling for several reasons. Firstly, buckling causes an increase in normal contact force between the string and wellbore. This means that as weight is released from the derrick, the string is progressively supported by wellbore friction rather than the bit. Ultimately, "lock-up" can occur where the string weight is consumed by the buckled portion of the string—i.e. a situation where further load cannot be applied to the bit. For example, lock-up is a common occurrence during coiled tubing operations (Mason *et al.*, 2007).

Buckling occurs when the compressive load in a tubular exceeds a critical value, beyond which the tubular is no longer stable and deforms into a sinusoidal or helical shape (constrained buckling). It is worth noting that these two special shapes are a particular case for a given situation. Depending on the hole geometry, the shape of the buckled drill strings may take differently. The sinusoidal buckling (first mode of buckling) corresponds to a tube that snaps into a sinusoidal shape and is sometimes called lateral buckling, snaking, or two-dimensional buckling. The helical buckling (second mode of buckling) corresponds to a tube that snaps into a helical shape (spiral shape). Since then, many theoretical works and/or experimental studies (see all references) have been developed to better understand and model the buckling phenomenon and to take into account the effects due to wellbore geometry, DLS, torque/torsion, tool-joint, friction, and rotation (Menand and Chen, 2013).

Recent studies have shown that the conventional sinusoidal and helical buckling criteria are accurate only in a perfect wellbore geometry as wellbore tortuous and c play a great role in the buckling phenomenon. An example is illustrated in Figure 2.2, which shows that sinusoidal and helical buckling take place simultaneously despite the same compression; DLS and tortuosity can play an important role on the onset of buckling (Menand and Chen, 2013).

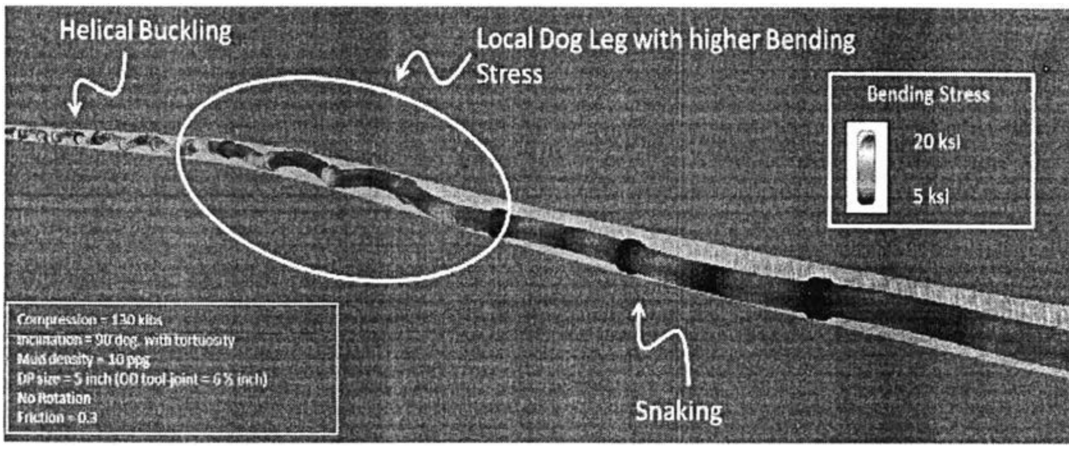

Figure 2.2 An example of numerical buckling simulation from a toque and drag software (Menand and Chen, 2013).

For illustration the critical forces that initiate sinusoidal and helical buckling are represented below in Equations 2.3-2.4.

$$F_S = 2\sqrt{\frac{EIW}{r}\sin\theta} \tag{2.3}$$

$$F_H = \sqrt{2}\,F_S \tag{2.4}$$

where

F_S is the sinusoidal buckling initiate force
F_H is the helical buckling initiate force
E is Young's modulus
I is the second moment of area
W is the buoyed weight of pipe
θ is inclination angle
r is radial clearance

Buckling may then be assessed by calculating the friction force, F and then comparing it with the various inequalities as defined below:

F	$< F_S$	no buckling
F_S	$< F < \sqrt{2}F_S$	sinusoidal buckling initiated
$\sqrt{2}F_S$	$< F < (2\sqrt{2}-1)\ F_S$	helical buckling initiated
$(2\sqrt{2}-1)\ F_S$	$< F$	helical buckling

In the case of sinusoidal buckling, there is no significant increase in wall force; however, in the case of helical buckling, wall force increases, and the drilling engineer will pick up the best well design and attempt to avoid the buckling problem. In general the sinusoidal buckling case may be acceptable, but the helical buckling case has to be avoided. If the helical buckling is unavoidable, the T&D models need to be improved more; thus, it has to be solved by equations in this research. However in the vertical section, the buckling calculations will be used differently (Prurapark, 2009).

2.3.2 Tortuosity Effects

Gaynor *et al.* (2001) explained that tortuosity has been recognized recently as one of the critical factors in extended-reach well operations. The effects include high torque and drag, poor hole cleaning, drillstring buckling and loss of available drilled depth, etc. Conventional wisdom has always held that tortuosity is most often generated by steerable motors while attempting to correct the actual well trajectory back to the planned trajectory.

Kogsboll *et al.* (1993) stated that the causes of tortuosity can be grouped into two sources. First is curvature of the pathway leading from the wellbore to the main fracture. If the well trajectory is not in line with the fracture direction (perpendicular to the far field least principal stress) the induced fracture will re-orientate so that it propagates perpendicular to the far field least principal stress.

Second is multiple fractures competing for opening space in the same region. The effect is that the individual fracture width will be reduced approximately linearly with the number of multiples relative to the width of the main fracture. In order to minimize the number of initiated multiple fractures, a short perforated interval is used. This also minimizes the potential length for fracture turning.

2.3.2.1 Micro and Macro-Tortuosity Effects

The macro-tortuosity corresponds to a DLS observed over a length greater than 10 m, and the micro-tortuosity is defined as the tortuosity that occurs on a much smaller scale as compared to macro-tortuosity, typically 0.5 m to 9 m. As the macro-tortuosity can be measured with conventional survey taken every 10 m or 30 m, the micro-tortuosity can only be detected by advanced wireline survey techniques, measurement-while-drilling (MWD) caliper tools or with an instrumented sub measuring the bending moments. The micro-tortuosity is often associated with wellbore oscillations, such as hole spiraling, rippling and hour-glassing, and is often the consequence of directional operating systems (Menand *et al.*, 2006).

2.3.2.2 Properties of the Scaled Tortuosity Index

Brands and Lowdon (2012) stated there are several properties of the proposed scaled tortuosity index that show it strengths and limitations as follows.

➢ The cumulative elastic energy penalizes undulated wellbores significantly more than wellbores with the same cumulative tortuosity consisting of continuous curves, as more energy is lost along the way. In an undulated well (see example), the bending in multiple directions requires significantly more energy (many repeating cycles) than bending each piece of pipe in a single direction.

➢ The location of the curvature in the wellbore (i.e., at the start or end of a section) matters. Undulations that occur at the start of the section will lead to higher scaled tortuosity index results, as more pipes will have to pass them.

➢ There is a natural interpretation and cutoff for very high DLS values in very short intervals. Borehole undulations with very high frequency at low amplitude could be (at a certain level) effectively considered “rugosity”, which might have contact friction implications, but not stiffness and clearance consequences.

➢ As a planning metric, which is characterized by long low-DLS curves, it favors wellbores that have the least amount of curvature. Hence the potential trade-off for S-shape wells that consider tangent angle and total length is not made. This is due to the square of the bending moment in the formula for elastic energy. Torque-and-drag modeling is a more suitable tool to decide on the trade-off between well path options. However, it would be useful to consider potentially imperfect wellbores, given planned steering strategies, and review their contingencies.

2.3.2.3 Tortuosity Level Analysis

Striving to an optimal and smooth wellbore, while aiming to minimize the index, is a logical consequence of using an objective metric. Another practical aspect is to define an acceptable level of wellbore undulations such as boreholes 1 and 3 could still be considered fit-for-purpose because it doesn't have much roughness, while for 2 and 4 the stiffness of the pipe and limited clearance with the borehole will result in high sideforces (and hence friction losses), leading to the inability to run pipe in the hole (Figure 2.3). This would help formulate a suitably smooth wellbore while balancing that with other cost- and risk- related objectives (Brands and Lowdon, 2012).

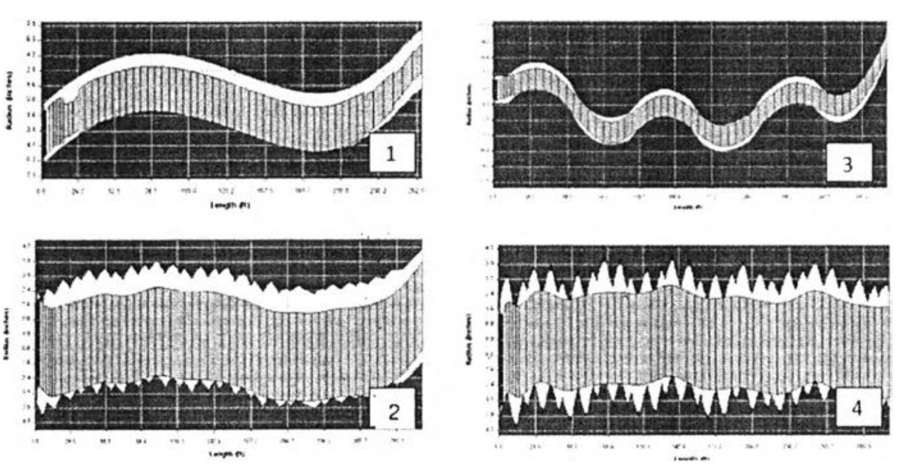

Figure 2.3 Various forms of Tortuosity (Brands and Lowdon, 2012).

2.4 Real-time Modeling-while-drilling

Borjas *et al.* (2012) indicated that to ensure the highest level of operational efficiency, engineers must monitor and intervene in wells for the following.

- Stuck pipe prevention
- Drilling performance
- Shock and vibration mitigation
- Well path trajectory control
- Real-time data quality

For most of these items, proper planning is the best solution for preventing wellbore incidents; for example, using the proper bit and BHA will help maximize drilling performance as well as reduce shock and vibrations. However, for stuck pipe prevention, the monitoring engineer can now effectively predict incidents by using the right tools and data analysis.

2.5 Directional Survey for 3D Reservoir Modeling

With the growth in drilling deviated, extended-reach, and horizontal wells, the location of the wellbore is increasingly a 3D problem. It is encountered in one of two situations:

- To direct and define the trajectory of the well during the drilling process
- To characterize the well path after drilling

The former has contributed to huge increases in well productivity. The latter is a vital element of integrated reservoir studies in which the aim is to generate a 3D model of the reservoir based on correct well locations. This discussion is set within the context of the latter.

There are several known methods of computing directional survey. The five most commonly used are: tangential, balanced tangential, average angle, curvature radius, and minimum curvature (most accurate) (Dept, 1985).

2.5.1 Tangential

This method uses the inclination and hole direction at the lower end of the course length to calculate a straight line representing the wellbore that passes through the lower end of the course length (Figure 2.6). Because the wellbore is assumed to be a straight line throughout the course length, it is the most inaccurate of the methods discussed. The Equations 2.5-2.7 are used for calculating well trajectory by tangential method as following:

$$\Delta North = \Delta MD \times [sin(I_2) \times cos(A_{Z2})] \quad (2.5)$$

$$\Delta East = \Delta MD \times [sin(I_2) \times sin(A_{Z2})] \quad (2.6)$$

$$\Delta TVD = \Delta MD \times [cos(I_2)] \quad (2.7)$$

where:

$\Delta North$ = distance between two survey point in north direction

$\Delta East$ = distance between two survey point in east direction

ΔTVD = true vertical depth between surveys

ΔMD = measured depth between surveys

I_2 = inclination (angle) of lower

A_{Z2} = azimuth direction of lower survey

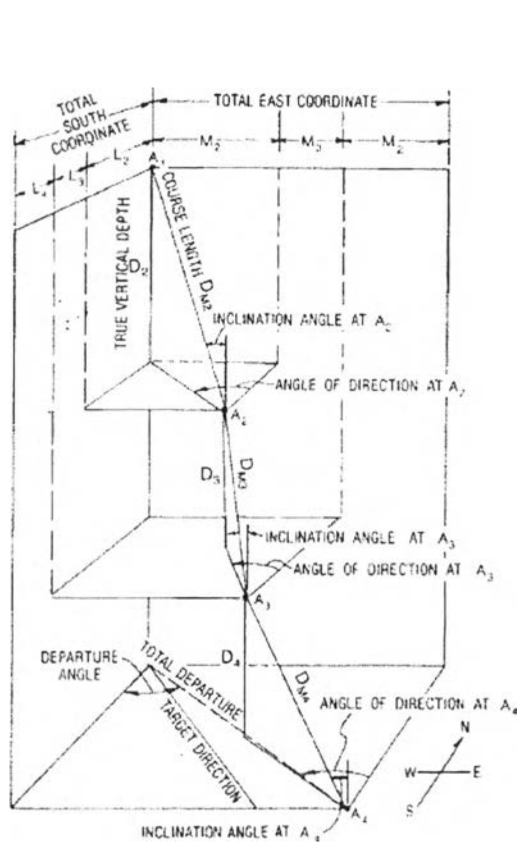

Figure 2.4 Three-dimensional view of a wellbore showing the well trajectory that comprise the X, Y, and Z parts in tangential method (Bourgoyne *et al.*, 1986).

2.5.2 Balanced Tangential

Modifying the tangential method by taking the direction of the top station for the first half of the course length, then that of the lower station for the second half can substantially reduce the errors in that method (Figure 2.7). This modification is known as the balanced-tangential method. This method is very simple to program on hand-held calculators and in spreadsheets and gives accuracy comparable to the minimum-curvature method. The Equations 2.8-2.10 are used for calculating well trajectory by balanced tangential method as following:

$$\Delta North = \frac{\Delta MD}{2} \times [sin(I_1) \times cos(A_{Z1}) + sin(I_2) \times cos(A_{Z2})] \quad (2.8)$$

$$\Delta East = \frac{\Delta MD}{2} \times [sin(I_1) \times sin(A_{Z1}) + sin(I_2) \times sin(A_{Z2})] \quad (2.9)$$

$$\Delta TVD = \frac{\Delta MD}{2} \times [cos(I_1) + cos(I_2)] \quad (2.10)$$

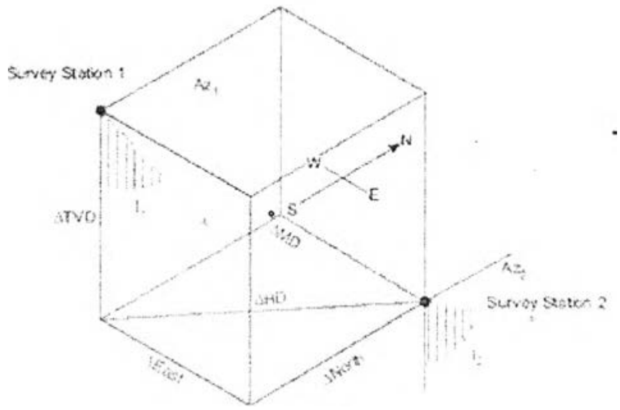

Figure 2.5 Balanced tangential method (Drillingformulas, 2010).

where:

I_1	=	inclination (angle) of upper survey
I_2	=	inclination (angle) of lower survey
A_{Z1}	=	azimuth direction of upper survey
A_{Z2}	=	azimuth direction of lower survey

2.5.3 <u>Average Angle</u>

The method uses the average of the inclination and hole-direction angles measured at the upper and lower ends of the course length. The average of the two sets of angles is assumed to be the inclination and the direction for the course length. The well path is then calculated with simple trigonometric functions. The Equations 2.11-2.13 are used for calculating well trajectory by average angle method as following:

$$\Delta North = \Delta MD \times sin\left(\frac{I_1+I_2}{2}\right) \times cos\left(\frac{A_{Z1}+A_{Z2}}{2}\right) \quad (2.11)$$

$$\Delta East = \Delta MD \times sin\left(\frac{I_1+I_2}{2}\right) \times sin\left(\frac{A_{Z1}+A_{Z2}}{2}\right) \quad (2.12)$$

$$\Delta TVD = \Delta MD \times cos\left(\frac{I_1+I_2}{2}\right) \quad (2.13)$$

2.5.4 Curvature Radius

With the inclination and hole direction measured at the upper and lower ends of the course length, this method generates a circular arc when viewed in both the vertical and horizontal planes. Curvature radius is one of the most accurate methods available. The Equations 2.14-2.16 are used for calculating well trajectory by curvature radius method as following:

$$\Delta North = \frac{\Delta MD \times [cos(I_1) - cos(I_2)] \times [sin(A_{Z1}) - sin(A_{Z2})]}{(I_2 - I_1)(A_{Z2} - A_{Z1})} \times \left(\frac{180}{\pi}\right)^2 \tag{2.14}$$

$$\Delta East = \frac{\Delta MD \times [cos(I_1) - cos(I_2)] \times [cos(A_{Z1}) - cos(A_{Z2})]}{(I_2 - I_1)(A_{Z2} - A_{Z1})} \times \left(\frac{180}{\pi}\right)^2 \tag{2.15}$$

$$\Delta TVD = \frac{\Delta MD \times [sin(I_1) - sin(I_2)]}{I_2 - I_1} \times \left(\frac{180}{\pi}\right)^2 \tag{2.16}$$

2.5.5 Minimum Curvature

Like the curvature-radius method, this method, the most accurate of all listed, uses the inclination and hole direction measured at the upper and lower ends of the course length to generate a smooth arc representing the well path as shown in Figure 2.8. The difference between the curvature-radius and minimum-curvature methods is that curvature radius uses the inclination change for the course length to calculate displacement in the horizontal plane (TVD is unaffected), whereas the minimum-curvature method uses the DLS to calculate displacements in both planes. Minimum curvature is considered to be the most accurate method, but it does not lend itself easily to normal, hand-calculation procedures. The Equations 2.17-2.21 are used for calculating well trajectory by minimum curvature method as following:

$$\beta = cos^{-1}\left[cos(I_2 - I_1) - sin(I_1) \times sin(I_2) \times \left(1 - cos(A_{Z2} - A_{Z1})\right)\right] \tag{2.17}$$

$$RF = \frac{2}{\beta} \times tan\left(\frac{\beta}{2}\right) \tag{2.18}$$

$$\Delta North = \frac{\Delta MD}{2} \times [sin(I_1) \times cos(A_{Z1}) + sin(I_2) \times cos(A_{Z2})] \times RF \qquad (2.19)$$

$$\Delta East = \frac{\Delta MD}{2} \times [sin(I_1) \times sin(A_{Z1}) + sin(I_2) \times sin(A_{Z2})] \times RF \qquad (2.20)$$

$$\Delta TVD = \frac{\Delta MD}{2} \times [cos(I_1) + cos(I_2)] \times RF \qquad (2.21)$$

where:

β = the dog leg angle

RF = ratio factor

The survey results are compared against those from the minimum-curvature method as shown in Table 1. Large errors are seen in the tangential method for only approximately 1,900 ft of deviation. This demonstrates that the tangential method is inaccurate and should be abandoned completely. The balanced-tangential and average-angle methods are more practical for field calculations and should be used when sophisticated computational equipment or expertise may not be available. These should be noted as "Field Results Only."

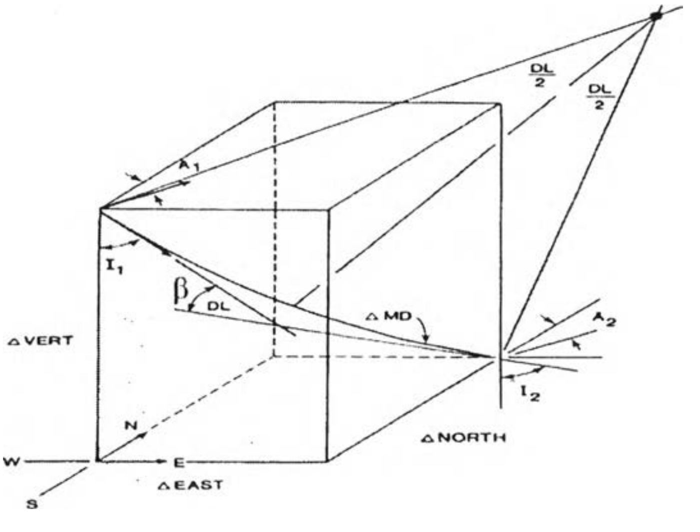

Figure 2.6 Minimum curvature method (Drillingformulas, 2010).

Table 2.1 Comparison of Results of the Five Commonly Used Server Methods (Dept, 1985)

Calculation Methods	TVD Error (ft)	Displacement Error (ft)
Tangential	-4.76	+14.99
Balanced tangential	-0.11	-0.03
Average angle	0.00	-0.25
Curvature radius	-0.04	-0.31
Minimum curvature	-	-

This thesis used soft-string model as T&D modeling to calculate torque and drag and balanced tangential method to define the trajectory of the well during the drilling process because it is less time consuming to calculate and it gives accurate results.