A PROJECT

ON

EXTENDED-REACH COILED-TUBING DRILLING

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Extending the Reach of Coiled Tubing in Directional Wells With Downhole Motors

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Abstract

A rigorous study has dispelled a longtime myth about coiled-tubing technology. The inability to rotate the tubing limits its reach in the lateral section of the wellbore. Past and current extended-reach techniques for coiled-tubing drilling (CTD) have not been sufficient (individually) in significantly increasing the reach of the tubing in the wellbore; often four or five extended-reach methods are combined to have significant tubing displacement in the wellbore, which is quite expensive to do.

After much rigorous investigations and computer simulation tests, the study has demonstrated that a downhole motor (second motor) can be employed in extending significantly the reach of coiled tubing in the wellbore. This technique is expected to also improve hole cleaning process (during CTD), since the configuration allows for the rotation of the coiled tubing string.

With the proposed technology having two tubing segments (rotating and nonrotating segments), the investigations show that the two segments will not buckle under applied torsional loads in the course of using a hydraulic downhole motor. But the nonrotating segment of the tubing string will be subjected to severe twisting.

Downhole electric motors and a dynamic torque anchor (or full-gaged stabilizer) coupled to a hydraulic motor can be employed to achieve the primary aim of the technology and prevent twisting of the nonrotating segment (the twisting of the segment destabilizes the drilling process).

Although the use of a dynamic torque anchor or full-gaged stabilizer can be employed in arresting the twisting moment, it induces high frictional forces, which reduce the lateral displacement of the tubing (relative to an electrodrill). To solve this problem, a new “dynamic torque arrestor” has been proposed in this project. The simulation tests show that the lateral displacements of the tubing in the wellbore (when the newly proposed dynamic torque arrestor is coupled to a hydraulic motor) are greater than the displacements achieved with the use of dynamic torque anchor or full-gaged stabilizer.

Since the proposed technology does not require the intense modification of the current configuration of the coiled tubing unit, its application will be inexpensive.

Introduction

Sliding the coiled-tubing string along the walls of the wellbore (deviated and lateral sections) generates axial frictional force. As the length of the tubing in these wellbore sections increases, the axial compressive force in the tubing exceeds the critical sinusoidal buckling force. With the tubing having a sinusoidal configuration, the axial drag force acting on the tubing increases and the compressive force in the tubing increases further (coupled with increased tubing length in the lateral section). The third stable configuration of the tubing develops when the axial compressive force exceeds the helical buckling force.

The unit normal contact force between the helically-buckled tubing and the wellbore is high and it increases as the axial compressive force in the tubing increases. After having long helically-buckled tubing length, pushing the tubing farther into the wellbore will be impossible (lockup condition).

Many techniques have been developed to delay the occurrence of lockup of the tubing in the wellbore but they have their limitations. One of the techniques is buoyancy reduction. Additional reach is achieved by reducing the magnitude of the normal force between the tubing and the wall of the wellbore; but the additional reach of CT in the lateral section of the wellbore is less than 15% (Bhalla 1995).

Also, the application of chemical friction reducers has been attempted to extend the reach of CT in the wellbore. The chemicals decrease the friction factor in the wellbore and consequently reduce the frictional force on the tubing. Unfortunately, the chemicals are ineffective in reducing the friction factor in the openhole sections. Similarly, these chemicals cannot be used with air drilling operations. The chemicals are capable of increasing the reach of CT in the wellbore by 35%.

Another extended-reach technique that has been explored is straightening of CT. Deploying CT into the wellbore exposes it to large bending stresses. The tubing plastically deforms in the process and a permanent residual curvature is induced in it. The residual curvature limits the extent of the tubing in wellbores. Straighteners are then used to remove the residual bend by subjecting the curved tubing through a reverse bending process. The removal of the residual curvature in the tubing has been seen to extend the reach of CT in deviated and horizontal wellbores by 23% approximately. Although the straightening of the tubing reduces the magnitude of the normal force on the tubing, the technique is not sufficient to highly increase the tubing displacement in the wellbore. Therefore, another extended-reach technique would need to be added to further reduce the drag force.

Furthermore, the use of tapered CT was considered to prevent early buckling of the tubular in the wellbore. Delaying the buckling of the tubing in the wellbore postpones lockup. Welding continuous sections of tubing with different wall thicknesses derates the yield strength of the tubing string; the welding joints are the points of weakness. Therefore, the use of tapered string has not been fully accepted in the industry.

In addition, tractors have been designed to pull or push the tubular into the wellbore. The tractors are powered by the hydraulic energy of the circulated drilling fluid. The tractors are ineffective in poor hole conditions and increase pipe sticking problems (Leising et al. 1997).

Also, the application of axial vibration on the CT marginally increases the reach of the tubing in the deviated and lateral sections of the wellbore (Newman 2007). Torsional vibration is ineffective in extending the reach of the tubing string in wellbores and that the tubing will be subjected to severe fatigue loads during the process.

Seeing the failures and limitations of some of the extended-reach techniques, efforts were then directed at revisiting the abandoned idea of Reilly's coiled-tubing rotary table. In 2003, Reilly designed a rotary table powered by two guide motors. The proposal was not accepted because of its impracticality.

Therefore, a canister concept was developed to rotate the coiled-tubing unit in 2006, but the idea is impracticable; the concept could not be commercialized because it was too complicated and ineffective.

Reel Revolution Limited in 2007 designed a rotary CT unit having operational characteristics similar to Reilly's rotary table. The proposed design is known as the Revolver. The CT reel is placed vertically on a turntable, unlike Reilly's design, which places the reel horizontally. The turntable is operated with a guide motor placed on the work platform. The reel's weight and other forces are statically and dynamically balanced on the table by a counterbalanced weight (the other forces on the reel are the axial forces generated by pressurized mud in the coiled tubing and the tug from the injector). Unfortunately, this novel idea is not receiving much enthusiasm from the oil and gas companies. One of the reasons is that the rotation of a massive coiled tubing reel, mounted on a skid that is about 4 to 10 ft high, can present itself as a hazard. Furthermore, the design is limited to a maximum rotary speed of 20 rpm, which will not be effective in overcoming the drag in the wellbore at high rates of penetration and increased CT diameter size.

Configuration of the Proposed Extended-Reach Method

The proposed method is based on the rotation of a predetermined length of the CT string while the section of the string upstream of the downhole motor does not rotate **(Fig. 1).** As a result of no rotation of the upstream segment of the tubing string, the segment will be subjected to twisting (if a downhole hydraulic motor is used) caused by the effect of the reactive torque from the operation of the hydraulic motor. To prevent the twisting of the nonrotating segment, a dynamic torque anchor or full-gaged adjustable stabilizer can be attached to the top sub of the mud motor **(Fig. 2).**

The rotating segment of the CT string will be powered by a hydraulic motor installed on the tubing string. CT connectors, preferably the dimple type, can link the hydraulic motor to the string at both ends of the motor. The dimple type is preferred because of its ability to withstand high torque and drilling shocks. In case the pin of the connector does not fit into the mud motor's top or bottom connecting box, an adapter that can withstand high torque will connect the motor to the tubing string.

The mud motor would have high torque and low speed characteristics. This simply means that the number of turbine stages for a turbo-drill mud motor would be high while a high lobe ratio would be required for a positive displacement motor (PDM). Also, increasing the eccentricity of the rotor to the stator axis for a PDM can be useful in achieving low rotary speed. Consequently, the high torque demand by the mud motor would lead to an increase in the pressure drop across it. Thus, the predetermined pressure drop must be added to the circulating pressure requirement for CTD operation to maintain the bottomhole pressure.

The location of the hydraulic motor on the coiled-tubing string is primarily determined by calculating the length of the rotating section of the coiled tubing. The rotating length of the coiled tubing string is primarily dependent on the hydraulic horse power of the mud motor and the torsional limit of the coiled tubing.

Alternatively, a downhole electric motor **(Fig. 3)** can be used in lieu of a hydraulic motor to prevent twisting. A downhole electric motor is a three-phase asynchronous motor with a spindle (screwed to the motor through a conic thread with journal bearings) that transmits the rotary torque to the driven load.

Use of a Downhole Electric Motor. Downhole electric motors have been used for drilling with jointed drillpipes since the early 1960s. But the running of the electrical cable inside jointed drillpipes, to power the downhole motor, is a big problem. However, coiled tubing provides a good medium for the running of the electrical cable **(Fig. 4).**

The electric cable is insulated from the drilling fluid to prevent electrocution (especially with high conductive drilling fluids). With the insulation kits on the cable, there is a reduction in the area of flow for the drilling fluid. The reduced area of flow increases the flow velocity of the fluid; but the reduced area increases the pressure drops in the tubing.

Reducing the rotary speed transmitted to the rotating tubing segment from the electric motor shaft is essential. The output speed from the electric motor is too high for a safe drilling operation; the rotor speed can be as high as 3,000 RPM. To step the rotary speed to a reasonable range, variable speed drive systems can be used in regulating the frequency of the electric power supply; the systems can reduce the frequency of the power supply to reduce the rotary speed of the rotor (Newman et al. 1996).

The rotor speed is

$$\omega_r = \frac{2 * 60 * f * (1 - s_l)}{n_p}. \tag{1}$$

Despite the use of the variable speed drive systems, a gear system **(Fig. 5)** can be used to further reduce the rotary speed; the planetary gear train is a good option for this application. The gear train can provide high gear ratio within a short distance. Large diameter gears are needed to make the significant speed reduction demanded. But the space limitation downhole may preclude the use of large diameter gears. Unless the rotor speed is significantly reduced by the variable speed drive systems or an alternative method to further reduce the rotary speed output from the epicyclic gear train is developed in the future, the use of a downhole electric motor to rotate the coiled tubing string may be difficult.

At stage-1 of the gear train system, the sun gear should be the input to the planetary gear assembly **(Figs. 6a and 6b)** while the planet carrier speed is transmitted to the sun gear at stage-2; this gear selection approach is aimed at having high gear ratio.

The governing equations for planetary gear assembly is

$$(n_j + 2) * \omega_{a,j} + (n_j * \omega_{s,j}) - 2(n_j + 1) * \omega_{c,j} = 0\,. \tag{2}$$

$$n_j = \frac{N_{s,j}}{N_{p,j}} \tag{3}$$

Where, $j = 1, 2, \ldots\ldots k$

For this application, the annulus gear is held stationary. Therefore, the gear ratio for each stage is

$$G_{R,j} = 1 + \frac{N_{a,j}}{N_{s,j}}. \tag{4}$$

The rotary speed of the planet carrier at the last stage of the gear train system is derived as

$$\omega_{c,k} = \frac{\omega_{s,1}}{2^k}\prod_{j=1}^{k}\frac{n_j}{b_j}\,. \tag{5}$$

Where,

$$b_j = \left(1 + n_j\right) \tag{6}$$

and k is the number of gear stages.

Increasing the number of stator poles may be another way of reducing the synchronous speed of the motor but the length of the motor would have to increase by the order of number of poles to maintain the same power output.

Using a downhole electric motor will require that the electric supply **(Fig. 7)** from the feeder be carefully designed to avert short circuiting and other electrical hazards.

Use of a Downhole Hydraulic Motor. A high torque-low speed motor characteristic is preferred for the rotation of the tubing segment. Using a dynamic torque anchor or full-gaged adjustable stabilizer to prevent the twisting of the nonrotating tubing segment generates additional normal contact forces **(Figs. 8a and 8b).** The magnitude of the induced normal contact forces depends primarily on the magnitude of the applied torque and size of the hole.

If the twisting-restraining tools are not used, the nonrotating tubing segment will twist as long as advancement is made into the wellbore; the nonrotating tubing will not buckle under the applied torque, since the minimum buckling torque of the string is higher than the torsional yield strength. The rate of change of the twist angle of the nonrotating tubing segment was derived by Oyedokun (2013) as

$$\frac{d\psi}{dt} = \left\{\left[\mu\left(w_{c,bit} - w_{c,mtr}\right)\frac{\partial\psi}{\partial M_{t,r}} + \frac{\partial\psi}{\partial l_{n,r}}\right]\frac{dl_{n,r}}{dt}\right\}. \tag{7}$$

Eq. 7 does not consider the effect of the traction forces acting on the nonrotating tubing segment; the equation is valid as long as the nonrotating tubing is not buckled. Noting that

$$\frac{\partial\psi}{\partial M_{r,t}} = \frac{l_{n,r}(t)}{GJ} \tag{8}$$

and

$$\frac{\partial\psi}{\partial l_{n,r}} = \frac{M_{t,r}(t)}{GJ}\,. \tag{9}$$

The twisting of the nonrotating tubing segment will cause destablization to the smooth running of the coiled tubing string. When the rate of change of the reactive torque is zero, the rate of change of the twist angle will reduce but will never be zero as long as the rate of change of the nonrotating tubing length changes. The rate of change of the twist angle becomes

$$\frac{d\psi}{dt} = \left(\frac{\partial\psi}{\partial l_{n,r}}\frac{dl_{n,r}}{dt}\right). \tag{10}$$

When the nonrotating tubing segment buckles under high axial compressive force (greater than the critical helical buckling load), the helically buckled section of the tubing resists the twisting moment. But the unit normal contact force within the helical buckled section where the effect of the twisting moment is felt will be higher than the rest of the helical buckled section “passive” to the twisting torque.

Maximum Rotating-Tubing Length

In determining the maximum length of the rotating segment the torsional yield strength of the CT material plays a big role. Since the applied torque on the string increases as the length to be rotated increases (for constant rotary speed), at a critical length of the tubing segment the rotary torque will equal the permissible torque (the product of safety factor and the tubing torsional yield strength) in the tubing string.

Similarly, the geometry of the well also affect the length of the rotating segment. The more tortuous the well path the lesser would be the rotating length (because of the increase in drag in the wellbore).

The location in the wellbore where the maximum power would be expended by the downhole motor needs to be identified. The location could be at the kickoff point or at the end of build. The ratio of the unit normal contact forces at the curved and lateral sections of the wellbore is a key criterion.

As an illustration, considering a 2D well profile **(Figs. 9a and 9b);** the greatest torque will be applied to the rotating segment when the hydraulic motor reaches the kickoff point if $\frac{|\vec{\vec{w}}_{c,d}|}{|\vec{\vec{w}}_{c,l}|} > 1$. On the other hand, if $\frac{|\vec{\vec{w}}_{c,d}|}{|\vec{\vec{w}}_{c,l}|} < 1$, then the maximum power will be expended when the mud motor reaches the end of build.

The average unit normal force in the curved section of the 2D wellbore is

$$\left|\vec{\vec{w}}_{c,d}\right| = \frac{1}{|\varphi_2 - \varphi_1|}\int_{\varphi_1}^{\varphi_2}\left(F_t(\varphi)\kappa - \frac{w_p sin\varphi \frac{d\varphi}{ds}}{\kappa}\right)d\varphi \tag{11}$$

Mitchell et al. (2011) derived the curvature of a wellbore as

$$\kappa = \sqrt{\left(\frac{d\varphi}{ds}\right)^2 + \left(\frac{d\vartheta}{ds}\right)^2 sin^2\varphi} \tag{12}$$

For a well profile with no azimuth change,

$$\kappa = \pm\frac{d\varphi}{ds} \tag{13}$$

For the lateral section of the wellbore, the unit normal force is

$$\left|\vec{\vec{w}}_{c,l}\right| = w_p sin\varphi. \tag{14}$$

In the quest to determine the location where the maximum torque would be applied on the rotating segment, the first case must be examined (i.e. $\frac{|\vec{\vec{w}}_{c,d}|}{|\vec{\vec{w}}_{c,l}|} > 1$). But the first case is usually valid; the unit normal force in curved section is usually greater than the unit normal force in the lateral section, if the tubing in the lateral section is not buckled.

The axial force in the tubing, at the end of built, is

$$F_{t,2} = F_0 + w_p sin\varphi_2 l_{r,l}. \tag{15}$$

The torque required to rotate unbuckled tubing (under high tension) in the curved section of the wellbore is derived (for a 2D well profile) as

$$M_t = \mu r_p R\left[\frac{F_{t,2}}{R}(\varphi_2 - \varphi_1) + 2w_p \cos(\varphi_2 - \varphi_1) + (\varphi_2 - \varphi_1) sin\varphi_2\right]. \tag{16}$$

For unbuckled tubing under low tension, the required torque is derived as

$$M_t = \mu r_p R\left[-\frac{F_{t,2}}{R}(\varphi_2 - \varphi_1) + (\varphi_2 - \varphi_1) sin\varphi_2\right]. \tag{17}$$

But the length of the rotating segment in the lateral section of the wellbore, when the second mud motor reaches the kick off point, is unknown. Therefore, $l_{r,l}$ is derived by summing the required rotary torques for each of the two sections under consideration (lateral and curved) to equal the permissible torque in the rotating segment (i.e. the product of the torsional yield strength of the tubing and a reasonable safety factor).

Considering high tension in the curved section of the wellbore when the mud motor gets to the kick off point, the lateral length of the rotating segment is

$$l_{r,l} = \frac{\left\{SF * T_y - \mu \sum_{j=1}^{m} r_{bha,j} w_{bha,j} sin\varphi l_{bha,j} - V_1 - V_2 + \mu r_p F_0\right\}}{\mu r_p w_p (cos\varphi_2 + sin\varphi_2)}. \tag{18}$$

$$V_1 = 2\mu r_p R w_p \cos(\varphi_2 - \varphi_1) \tag{19}$$

$$V_2 = \mu r_p R(\varphi_2 - \varphi_1)\sin(\varphi_2 - \varphi_1)\, w_p \tag{20}$$

For low tension, the lateral length of the rotating segment is

$$l_{r,l} = \frac{\left\{SFT_y - \mu \sum_{j=1}^{m} r_{bha,j} w_{bha,j} sin\varphi l_{bha,j} - V_2 - \mu r_p F_0\right\}}{\mu r_p w_p (sin\varphi_2 - cos\varphi_2)}. \tag{21}$$

The rotating length is thus derived as

$$l_r = l_{r,l} + R(\varphi_2 - \varphi_1). \tag{22}$$

In practice, the maximum rotating length may not be achievable because of the prevailing situation in the field. With coiled-tubing drilling, the measured depth at lockup, when the conventional CT drilling method (slide-drilling) is used, provides the available rotating length. On the other hand, if the lateral displacement at lockup (for slide-drilling) is greater than the rotating length **(Eq. 22),** then, the second motor can be placed at the end of build before rotating the string. Thus, the maximum rotating length of the tubing is

$$l_r = \frac{\left(SF * T_y - \mu \sum_{j=1}^{m} r_{bha,j} w_{bha,j} sin\varphi l_{bha,j}\right)}{\mu r_p w_p sin\varphi_2}. \tag{23}$$

Since the tubing in the vertical section of the wellbore has low critical buckling loads, having a segment of the rotating length buckled is not desirable (although sometimes it cannot but be allowed). Therefore, to avert the buckling of the rotating length when high weight on bit is required, the following must be taken into consideration:

a. Ensure the maximum weight on bit is less than the critical buckling loads (especially the helical buckling load) of the tubing in the lateral section of the wellbore.

b. Determine if the tubing string (rotating) in the vertical section of the wellbore will buckle anytime during the drilling operation before reaching the target, by calculating the critical buckling loads and comparing them with the estimated compressive forces in the string.

c. If the tubing (rotating segment) in the vertical section of the wellbore will buckle during the course of drilling, the rotating length should be calculated by placing the second motor at the kick off point. Since the rotating tubing in the curved and the lateral sections of the wellbore will not buckle because of higher critical buckling loads (if the maximum weight on bit is not greater than the critical loads at inclined and curved sections), the whirling of the rotating segment and other phenomena resulting from the rotation of buckled tubing will be prevented during the drilling process.

d. The weight of the second motor most be considered when determining the weight of the bottomhole assembly. Downhole motors with high torque specification have high weights which can be very significant for coiled-tubing drilling operations. If the weight of the second motor is not considered, the rotating length of the tubing string can be under excessive compressive force than designed for.

Although the proposed system configuration can be applied in a drilling operation demanding a high weight on bit (greater than helical buckling load), the procedures above will not be applicable in determining the maximum rotating length of the tubing string.

Similarly, it should be noted that the proposed extended-reach technique cannot be effective in extending the reach of coiled tubing in the wellbore when very high weight on bit (greater than the helical buckling load of the tubing string) is applied on the string.

With high inclination angle, the contributions of the bottomhole assemblies to the weight on bit may not be sufficient. Therefore, the rotating tubing segment will be under high compression. Since the segment is to be prevented from buckling, the permissible length can be estimated. The length of the rotating tubing (excluding the bottomhole assembly at the bit) that can support the weight on bit without buckling is

$$l_r = \frac{\lambda * F_{cr,s}}{w_p BF * cos\varphi}. \tag{24}$$

$$\lambda = \frac{SF * F_{0,max} - BFcos\varphi \sum_j^n w_{bha,j} l_{bha,j}}{F_{cr,s}} \tag{25}$$

In practice, $\lambda \leq 0.9$. Thus, the bottomhole assemblies (plus the second motor assembly) must be adjusted to ensure that the inequality is satisfied.

By comparing the values of l_r from **Eq. 25** and **Eq. 22** (or **Eq. 23**), the lower of the two is selected as the maximum rotating length of the tubing. Generally, the rotating length must be selected such that the tubing does not buckle when being pushed into the wellbore.

Maximum Lateral Displacement

The maximum lateral displacement is the algebraic sum of the buckled and unbuckled lengths of the nonrotating segment and the rotating segment of the tubing string (including the bottomhole assembly) at lockup.

As an illustration on how this calculation can be done in a typical well configuration, let us consider **Fig. 10.** Knowing the values of the axial forces at points A to G will be useful in determining the lateral dislpacement at lockup.

The rotating segment of the tubing string is prevented from buckling since the maximum weight on bit applied is less than the sinusoidal buckling load. The value of the axial force at point A can be easily determined through

$$F_A = \mathrm{F}_0 + w_p cos\varphi l_r. \tag{26}$$

Using a downhole electric motor, the force at B is

$$F_B = F_A + \left[\sum_{i=1}^{n} w_{ma,i} l_{ma,i} (cos\varphi - \mu sin\varphi)\right]. \tag{27}$$

On the other hand when a full-gaged stabilizer or dynamic torque anchor is mounted directly to the mud motor, the force at point B is

$$F_B = F_A + \left[\sum_{i=1}^{n} w_{ma,i} l_{ma,i} (cos\varphi - \mu sin\varphi)\right] - \mu \frac{M_{t,r}}{r_b}. \tag{28}$$

The length of the straight section in the nonrotating tubing string segment is

$$l_{str} = \frac{F_{cr,s} - F_B}{\left|w_p(cos\varphi - \mu sin\varphi)\right|}. \tag{29}$$

At point C, the sinusoidal buckling of the nonrotating segment is initiated; the value of the axial force is equal to the sinusoidal buckling load of the tubing in the lateral section **(Eq. 37).** Similarly, at point D the axial force is equal to the helical buckling force of the tubing in the inclined section of the wellbore.

The sinusoidal buckled length was derived by Oyedokun (2013) as

$$l_s = \frac{2EI\left\{arctan\left[\frac{1}{2}\frac{\mu ab^2\left(-F_{cr,h}r_c + 2\sqrt{Q}EIcw_p\right)}{\sqrt{D}}\right] - arctan\left[\frac{1}{2}\frac{\mu ab^2\left(-F_{cr,s}r_c + 2\sqrt{Q}EIcw_p\right)}{\sqrt{D}}\right]\right\}}{\sqrt{D}}. \tag{30}$$

Where,

$$D = w_p EIb^2 \mu r_c a[-cos\varphi + \mu(a + sin\varphi)] \quad (31)$$

$$Q = \frac{r_c}{EIw_p} \quad (32)$$

Gao and Miska (2009) derived the coefficients a, b, and c as

$$a = \frac{5(4p_{crs}^4 - 1)}{24p_{crs}^4 - 5} \quad (33)$$

$$(34)$$

$$b = \frac{24p_{crs}^4 - 5}{(12p_{crs}^4 - 1)\sqrt{5(4p_{crs}^4 - 1)}} \quad (35)$$

$$c = \frac{24p_{crs}^8 + 25p_{crs}^4 - 5}{2p_{crs}^2(24p_{crs}^4 - 5)} \quad (36)$$

the critical sinusoidal buckling force for a tubing in the inclined section of the wellbore as

$$F_{cr,s} = 2\zeta_s\sqrt{\frac{EIw_p sin\varphi}{r_c}}\,, \quad (37)$$

where,

$$\zeta_s = \frac{1}{2}p_{crs}^2\left(1 - \frac{3}{2}a_{crs}^2\right) + \frac{1}{2p_{crs}^2}\left(1 + \frac{1}{8}a_{crs}^2 + \frac{8\mu}{\pi a_{crs}}\right) \quad (38)$$

$$p_{crs} = 1 + 0.193\mu^{\frac{2}{3}}\,, \quad (39)$$

$$a_{crs} = 0.774\mu^{\frac{1}{3}} - 0.371\mu\,, \quad (40)$$

and the critical helical buckling force for a tubing in the inclined section of the wellbore as

$$F_{cr,h} = 2\sqrt{2}\zeta_h\sqrt{\frac{EIw_p sin\varphi}{r_c}}\,, \quad (41)$$

where,

$$\zeta_h = \frac{6}{3 - \pi\mu}\left[\frac{(\pi + 2\mu)(5 - \pi\mu)}{10\pi}\right]^{\frac{1}{4}}. \quad (42)$$

As more length of the nonrotating tubing string lies in the lateral section, points A to D will behave as "rigid points." Conversely, the displacement between points D and E continues to increase until pushing the tubing further into the wellbore becomes practically impossible (lockup phenomenon); lockup occurs when the compressive force at the kick off point approaches the maximum value

$$F_{kop,max} = \frac{F_{cr,s}^{eH}}{\zeta_s\sqrt{\mu}} tanh\left(\frac{s_{kop} w_p \zeta_s\sqrt{\mu}}{F_{cr,s}^{eH}}\right). \quad (43)$$

Since, the critical buckling load in the curved section of the wellbore is very high, this analysis assumes no buckling in that section of the wellbore. Therefore, the force at the end of build when lock up occurs in the vertical section of the wellbore can be derived by solving the differential equation,

$$\frac{dF_t}{ds} - EI\kappa\frac{d\kappa}{ds} + \mu|\overrightarrow{w_c}|(\kappa r_p cos\theta + 1) - w_p cos\varphi = 0, \tag{44}$$

for a 3D well profile,

$$|\overrightarrow{w_c}| = \sqrt{\left[F_t\kappa + EI\kappa\tau^2 - \frac{w_p sin\varphi\frac{d\varphi}{ds}}{\kappa}\right]^2 + \left[\frac{w_p sin^2\varphi\frac{d\vartheta}{ds}}{\kappa} - 2EI\tau\frac{d\kappa}{ds}\right]^2}. \tag{45}$$

For a 2D well profile, with constant curvature, the axial force distribution in the tubing (unbuckled) string lying in the curved section of the wellbore is

$$F_{kop} = \left[F_{eoc} - \frac{2\mu}{1+\mu^2}w_p R sin\varphi_0 - \frac{1-\mu^2}{1+\mu^2}w_p R cos\varphi_0\right]e^{\mu\varphi} + \frac{2\mu}{1+\mu^2}w_p R \tag{46}$$

Knowing the force at the end of build and comparing the value with the critical buckling loads (of the tubing in the lateral section of the wellbore), the configuration of the tubing in the lateral section of the wellbore can be known. If the value of the force at the end of build is greater than the helical buckling force **(Eq. 41),** it suggests that the nonrotating tubing segment will have straight, sinusoidally buckled, and helically buckled sections. **Eq. 29** can be used to estimate the length of the sinuoidally buckled section, while the length of the helically buckled section can be estimated by using the model derived by Oyedokun (2013),

$$l_h = \frac{2EI\left[arctan\left(\frac{1}{2}\frac{\mu r_c F_{eoc}}{\sqrt{A}}\right) - arctan\left(\frac{1}{2}\frac{F_{cr,h}\mu r_c}{\sqrt{A}}\right)\right]}{\sqrt{A}}. \tag{47}$$

Where, $A = EIw_p\mu^2 r_c sin\varphi - EIw_p\mu r_c cos\varphi$ (48)

Therefore, the lateral displacement at lockup (if lockup occurs in the lateral section) is

$$l_{max} = l_h + l_s + l_r + l_{str} + l_{ma} + l_{bha}. \tag{49}$$

Discussion

Considering the following specification for a horizontal coiled-tubing drilling operation: kick off point at 6,000 ft, build rate of 15^0/100 ft, openhole size of 6.5 in., openhole friction factor of 0.35, 6.5 in. internal diameter for the casing in the vertical section, 0.3 friction factor in the vertical section, mud density of 8.6ppg, and maximum weight on bit of 3,000 lbf.

Assuming a 2 in. tubing with the following specification is being used for the drilling operation: torsional yield strength (CT grade 90) is 3,844 lbf-ft (70% safety factor is assumed), unit weight 3.64 lbf/ft, internal diameter 1.624 in., Young's Modulus of steel is 30,000 psi. The weight of the downhole motor used (electric or hydraulic) in rotating the tubing is assumed to be 1,800 lbf. The weight of the two stabilizers is assumed to be 550 lbf (with four blades per stabilizer), coefficient of static friction (protective pad-casing) 0.4, and coefficient of static friction (protective pad-openhole) 0.42.

Solution: The friction correction factor for sinusoidal buckling load $\zeta_s = 1.7631$; and helical buckling load $\zeta_h = 2.6237$. Consequently, the buckling loads for the tubing in the horizontal section are: $F_{cr,s} = 4{,}404$ lbf and $F_{cr,h} = 9{,}268$ lbf.

a. Without the Rotation of the Tubing

The maximum compressive force at the kick off point, from Eq. 43

$$F_{kop,max} = 4{,}560.4 * tanh\left(\frac{6000 * 3.1621 * 1.6714 * \sqrt{0.3}}{4{,}174.88}\right) = 4{,}558 \text{ lbf}$$

But the axial force at the end of build, assuming constant curvature, is

$$F_{eoc} = \left[F_{kop,max} - w_p R\frac{2\mu}{1+\mu^2}\right] e^{-\mu\pi/2} + w_p R\frac{1-\mu^2}{1+\mu^2}$$

$$F_{eoc} = \left[4{,}558 - 3.1621 * 381.9719 * \frac{0.7}{1.09}\right] e^{-0.4712} + 3.1621 * 381.9719 * \frac{1-0.09}{1+0.09}$$

$$F_{eoc} = 3{,}140 \text{ lbf}$$

Since $F_{eoc} < F_{cr,s}$, the lateral section of the tubing will not buckle; the tubing displacement in the lateral section, derived is

$$l_{str} = \frac{F_{eoc} - WOB}{\left|w_p(cos\varphi - \mu sin\varphi)\right|}$$

$$l_{str} = \frac{3140 - 3000}{|3.1621(0-0.35)|} = 126 \text{ ft}$$

b. Using a hydraulic motor:

From the calculations above, the axial force at the end of build, $F_{eoc} = 3{,}140$ lbf and the axial friction force presumed to be induced in the lateral section when the hydraulic motor is assumed to be in the lateral section is

$$F_f = \mu\left(W_m + W_{stb} + \frac{24SFT_y}{d_h}\right)$$

$$F_f = 0.35\left[(1800+550) * \left(1 - \frac{8.6}{65.5}\right) + \frac{1.2 * 24 * 0.7 * 3844}{6.5}\right] = 4{,}887 \text{ lbf}$$

Since this frictional force is greater than F_{eoc}, it suggests that the hydraulic motor is either in the vertical or curved section of the wellbore.

At the end of build, the axial compressive force in the tubing must equal the weight on bit, because the tubing is subjected to rotation (which eliminates axial drag force). Therefore, determining the force at the kick off point, F_B .
From Eq. 46, the axial compressive force at the kick off point is

$$F_B = F_{eoc} - w_p R$$

$$F_B = 3000 - (3.1621 * 381.9719) = 1{,}792 \text{ lbf}$$

$$\text{But, } F_B = F_A + W_m + W_{stb} - \frac{\mu 24SFT_y}{d_h}$$

$$F_B = F_A + (1800+550) * \left(1 - \frac{8.6}{65.5}\right) - \left(\frac{0.4 * 24 * 0.7 * 3844}{6.5}\right)$$

$$F_A = 3{,}725 \text{ lbf}$$

The buckled length of the tubing in the vertical section , y, can be obtained from Eq. 5.51:

$$y = arctanh\left(\frac{\zeta_s\sqrt{\mu}F_A}{F_{cr,s}^{eH}}\right)\left(\frac{F_{cr,s}^{eH}}{w_p\zeta_s\sqrt{\mu}}\right) = arctanh\left(\frac{3724.654\sqrt{0.3}}{2498}\right)\left(\frac{2498}{3.1621\sqrt{0.3}}\right) = 1{,}654 \text{ ft}$$

This suggests that maintaining a constant weight on bit, the lateral displacement is

$$l_d = l_r - R\varphi$$

Since the mud motor is at the kick off point **(Fig. 11),** only the rotating length is in the lateral section of the wellbore, for this case.

$$l_d = \frac{\{0.7 * 3844 - 0.05625 * 1200 * 0.87 - 0.0291667 * 381.9719 * \pi/2 * 3.1621 + 87.5\}}{0.09222}$$

$$l_d = 28{,}891 \text{ ft}$$

To maintain the maximum weight on bit of 3,000 lbf, the compressive force at the kick off point is lower than the maximum compressive force 4,588 lbf. The tubing can still be pushed a little bit into the curved section of the wellbore, but the compressive force at “A” may approach the maximum compressive force.

c. Using a Downhole Electric Motor:

Assuming that the electric motor is in the lateral section of the wellbore, the axial friction induced on the tubing string by the installation of the electric motor is 547 lbf.
Estimating the length of the nonrotating tubing length in the lateral section,

$$l_{str} = \frac{F_{eoc} - F_f - WOB}{\left|w_p(cos\varphi - \mu sin\varphi)\right|}$$

$$l_{str} = \frac{3140 - 547.2824 - 3000}{|3.1621(0 - 0.35)|} = -368 \text{ ft}$$

The negative value validates that the electric motor is not in the lateral section of the wellbore, but in the curved or vertical section if the weight on bit is to remain 3,000 lbf. This suggests that the force at the end of built will be 3,000 lbf, since only the rotating tubing segment is in the lateral section of the wellbore.

In determining the lateral displacement the electric motor is assumed to be at the end of build. And the length of the electric motor is assumed to be 50 ft and weighing 1800 lbf.

From **Fig. 12a**

$$cos\varphi_1 = 1 - \frac{50^2}{2R^2}$$

$$\varphi_1 = 7.51^0.$$

It thus implies, the angle of inclination at point Y in Fig. 12is $\varphi = 82.49^0$.
Therefore, the axial compressive force at point Y

$$F_Y = 3000 + 1563.66(\mu sin82.49 - cos82.49) = 3{,}338 \text{ lbf.}$$

And the axial force at the kick off point is

$$F_Z = \left[F_Y - \frac{2\mu}{1+\mu^2}w_pRsin\varphi_0 - \frac{1-\mu^2}{1+\mu^2}w_pRcos\varphi_0\right]e^{\mu\varphi} + \frac{2\mu}{1+\mu^2}w_pRsin\varphi + \frac{1-\mu^2}{1+\mu^2}w_pRcos\varphi$$

But, $\varphi_0 = 0^0$.

$$F_Z = \left[3338 - -\frac{1-0.35^2}{1+0.35^2} * 3.1621 * 381.9719\right] e^{0.35*0.4583\pi} + \frac{0.7}{1+0.35^2} 3.1621 * 381.9719 sin 82.49 + \frac{1-0.35^2}{1+0.35^2} 3.1621 * 381.9719 cos 82.49$$

$$F_Z = 4{,}832 \text{ lbf}$$

The axial compressive force at the kick off point is greater than the maximum compressive force, 4,588 lbf. This result suggests that the motor assembly is located in the curved section of the wellbore **(Fig. 12b),** but the exact location is unknown. Through a wise guess, the approximate location of the electric motor can be determined.
Assuming $\varphi_1 = \varphi$, noting that $\varphi_2 = 7.51^0$
Therefore, $\varphi = 41.25^0$
The axial compressive force at point Y_1

$$F_{Y_1} = 3000 - w_p R cos 48.75 = 2{,}204 \text{ lbf}$$

$$F_{Y_2} = 2204 + 1563.66(\mu sin 41.25 - cos 41.25) = 1{,}389 \text{ lbf.}$$

And the axial force at the kick off point is

$$F_Z = \left[1389 - -\frac{1-0.35^2}{1+0.35^2} * 3.1621 * 381.9719\right] e^{0.35*0.2292\pi} + \frac{0.7}{1+0.35^2} 3.1621 * 381.9719 sin 41.25 + \frac{1-0.35^2}{1+0.35^2} 3.1621 * 381.9719 cos 41.25$$

$$F_Z = 1{,}779 \text{ lbf}$$

Therefore, the assumed position of the motor assembly is not exact, but it will be located between the assumed inclination angle and the end of build.

To estimate the buckled length of the tubing in the vertical section,

$$y = arctanh\left(\frac{\zeta_s\sqrt{\mu}F_Z}{F_{cr,s}^{eH}}\right)\left(\frac{F_{cr,s}^{eH}}{w_p\zeta_s\sqrt{\mu}}\right) = arctanh\left(\frac{1779\sqrt{0.3}}{2497.856}\right)\left(\frac{2497.856}{3.1621\sqrt{0.3}}\right) = 594 \text{ ft}$$

The displacement of the tubing in the lateral section is

$$l_d = 28{,}891 + 381.9719 * 0.851$$

$$l_d = 29{,}216\ ft$$

Conclusions

After much rigorous investigations, the application of downhole motors in rotating a determined length of coiled tubing, as an extended-reach technology for coiled tubing applications, has proven to be practicable. The other main conclusions are:

1. The twisting moment applied on the nonrotating segment will cause great destabilization when a hydraulic motor is used in rotating the tubing string. Although the rate of change of the twisting moment is zero when the second mud motor and the primary downhole tools are in the same wellbore section, the rate of change of the twist angle will not be zero; the destabilization will still persist.
2. A dynamic torque anchor or a full-gaged stabilizer assembly can be attached to a hydraulic motor to prevent twisting of the nonrotating segment of the tubing string. The use of these wall contact tools in “arresting” the twisting moment induces high normal and binormal contact forces in the wellbore. The induced normal and binormal forces increase the axial frictional forces acting on

the tubing string in the wellbore, thus reducing hookload. Nevertheless, the example calculation shows an increase in the lateral displacement of the tubing.

3. Alternatively, a downhole electric motor can be used in lieu of a downhole hydraulic motor (positive displacement motor and turbodrill) to prevent twisting of the nonrotating tubing string. The example calculation shows that the lateral displacement of the tubing in the wellbore increases significantly when a downhole electric motor is used to rotate the tubing segment (despite the additional weight contribution from the second motor).
4. Maximizing the length of the rotating segment of the tubing string increases significantly the lateral displacements of the tubing in the wellbore. The magnitude of the rotating length primarily depends on the torsional yield strength of the tubing and well geometry.
5. Rigorous investigations into the dynamics of the newly proposed coiled-tubing string configuration are needed to improve the robustness of the design.

Nomenclature

$\boldsymbol{BF}$	Buoyancy factor
E	Young's Modulus (psi)
$\vec{e}_b$	Unit vector in the binormal direction to the wellbore path
$\vec{e}_n$	Unit vector in the normal direction to the wellbore path
$\vec{e}_t$	Unit vector in the tangent direction to the wellbore path
f	Frequency of power supply to the electric motor (Hz)
$\vec{F}_b$	Internal shear force in the tubing binormal to its axis (lbf)
$F_{cr,h}$	Critical helical buckling load (lbf)
$F_{cr,s}$	Critical sinusoidal buckling load (lbf)
F_{crs}^{eH}	Critical sinusoidal buckling load in a horizontal section with same tubing-wellbore diameter ratio and friction factor (lbf)
F_{eoc}	Axial force at the end of build
$\vec{F}_n$	Internal shear force in the tubing normal to its axis (lbf)
$\vec{F}_{sh}$	Total shear force in the tubing (lbf)
$\vec{F}_t$	Internal force along the axis of the tubing (lbf)
G	Shear modulus of the tubing (psi)
$G_{R,j}$	Gear ration at a stage
I	Second moment of area of the tubing (in.^{4})
J	Polar moment of area of the tubing (in.^{4})
l_b	Length of the stabilizer/dynamic torque anchor assembly (ft)
$l_{bha,j}$	Length of a BHA component (ft)
l_d	Lateral displacement (ft)
l_{ma}	Total length of the second bottomhole assembly
$l_{ma,j}$	Length of a component of the second bottomhole assembly
l_h	Length of helical buckled section (ft)
$l_{n,r}$	Instantaneous length of the nonrotating tubing in the wellbore (ft)
l_r	Total rotating length of the tubing string, excluding the length of the BHA (ft)
$l_{r,l}$	Rotating length of the tubing when mud motor gets to the KOP (ft)
l_s	Length of sinusoidal buckled tubing section (ft)
l_{str}	Length of the straight section of the nonrotating tubing ft)

$\vec{M}_t$	Applied torque on the rotating tubing (lbf-ft)
$\vec{M}_{t,r}$	Reactive torque acting on the nonrotating tubing segment (lbf-ft)
n_j	Form factor at a gear train stage
$N_{a,j}$	Number of annulus gear teeth
n_p	Number of poles in the stator of the electric motor
$N_{p,j}$	Number of planet gear teeth
$N_{s,j}$	Number of sun gear teeth
R	Radius of curvature (ft)
r_b	Distance from the tip of the stabilizer's (or torque anchor) blade to the center of the wellbore. (in.)
$r_{bha,j}$	Radius of a BHA component (in.)
r_c	Radial clearance between tubing and the wellbore/casing (in.)
r_p	Outer radius of the tubing (in.)
s	Measured depth along the wellbore path (ft)
s_{kop}	Depth of the kick off point (ft.)
s_l	Slip velocity fraction
sf	Safety factor
T_y	Torsional yield strength of the tubing (lbf-ft)
w_b	Unit weight of the full-gaged stabilizer assembly or the dynamic torque anchor (lbf/ft)
$w_{bha,j}$	Unit weight of a component of the bottomhole assembly (lbf/ft)
W_{bit}, WOB	Weight on bit (lbf)
w_c	Unit normal contact force between unbuckled tubing and the wellbore (lbf/ft)
$w_{c,bit}$	Unit normal contact force between the rotating tubing end (lbf/ft) attached to the bottomhole assembly and the wellbore (lbf/ft)
$\overline{w}_{c,d}$	Average unit normal contact force between unbuckled tubing and the wellbore in the curved section (lbf/ft)
$\overline{w}_{c,l}$	Average unit normal contact force between unbuckled tubing and the wellbore in the lateral section (lbf/ft)
$w_{c,mtr}$	Unit normal contact force between the rotating tubing end attached to second motor and the wellbore (lbf/ft)
W_m	Weight of the second downhole motor (lbf)
w_p	Unit weight of the tubing (lbf/ft)
W_{stb}	Weight of the stabilizer or dynamic torque anchor(lbf)
y	Buckled length of the tubing in the vertical section of the wellbore (ft)
β	Dogleg angle (^{o})
γ	Velocity angle between rate of penetration and the rotary speed of the tubing (^{o})
ζ_h	Friction correction factor for critical sinusoidal buckling force
ζ_s	Friction correction factor for critical helical buckling force
ϑ	Azimuth angle of the well (^{o})
κ	Curvature of the wellbore (ft^{-1})
μ	Friction factor

τ	Torsion of the wellbore (ft^{-1})
ψ	Angle of twist of the nonrotating length of the tubing (^{o})
$\omega_{c,j}$	Rotary speed of the planet carrier at a stage (rev/min)
ω_{r}	Rotary speed of the rotor shaft (rev/min)
$\omega_{s,j}$	Rotary speed of the sun gear at a stage (rev/min)

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SI Metric Conversion Factors

ft	x	3.048*		E□01	= m
in.	x	2.54*		E+01	= mm
lbf	x	4.448	222	E+00	= N

*Conversion factor is exact.

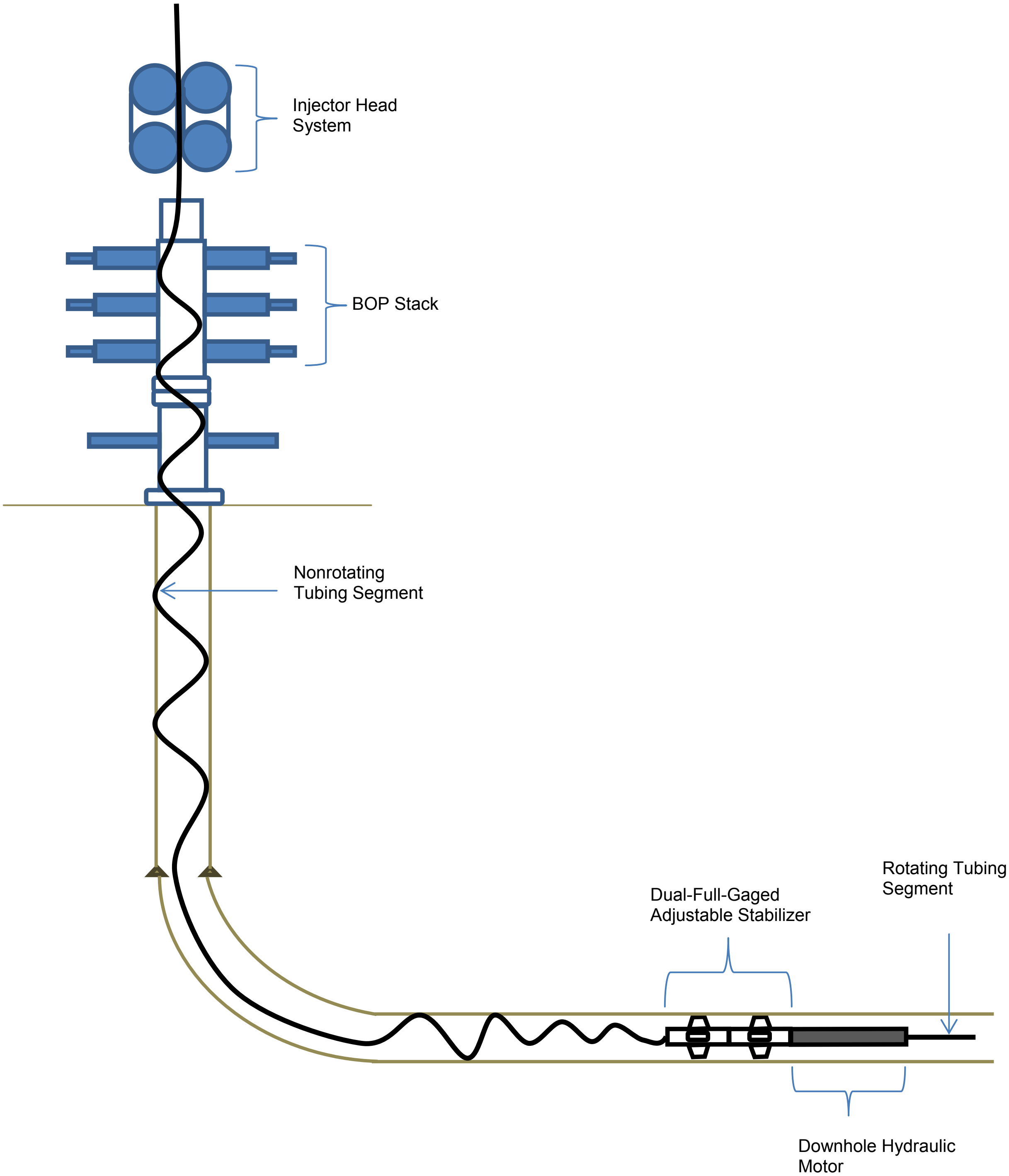

Fig. 1—Using a downhole hydraulic motor, coupled with a dual-full-gaged adjustable stabilizer, to rotate a determined tubing length can extend the reach of coiled tubing in the lateral section of the wellbore.

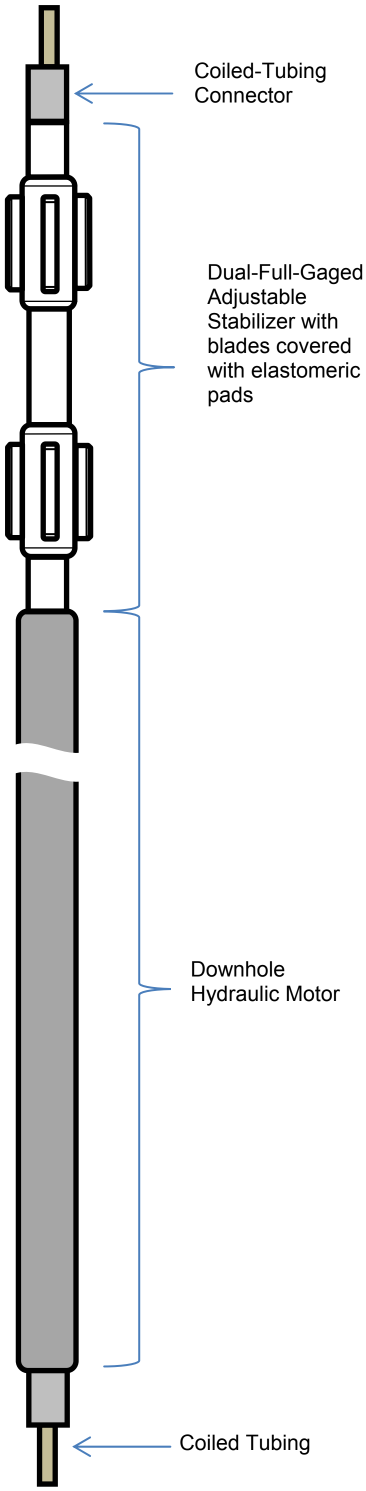

Fig. 2—Schematic drawing of the hydraulic motor and a dual-full-gaged stabilizer assembly. The elastomeric pads on the stabilizer blades are to prevent damage to casings.

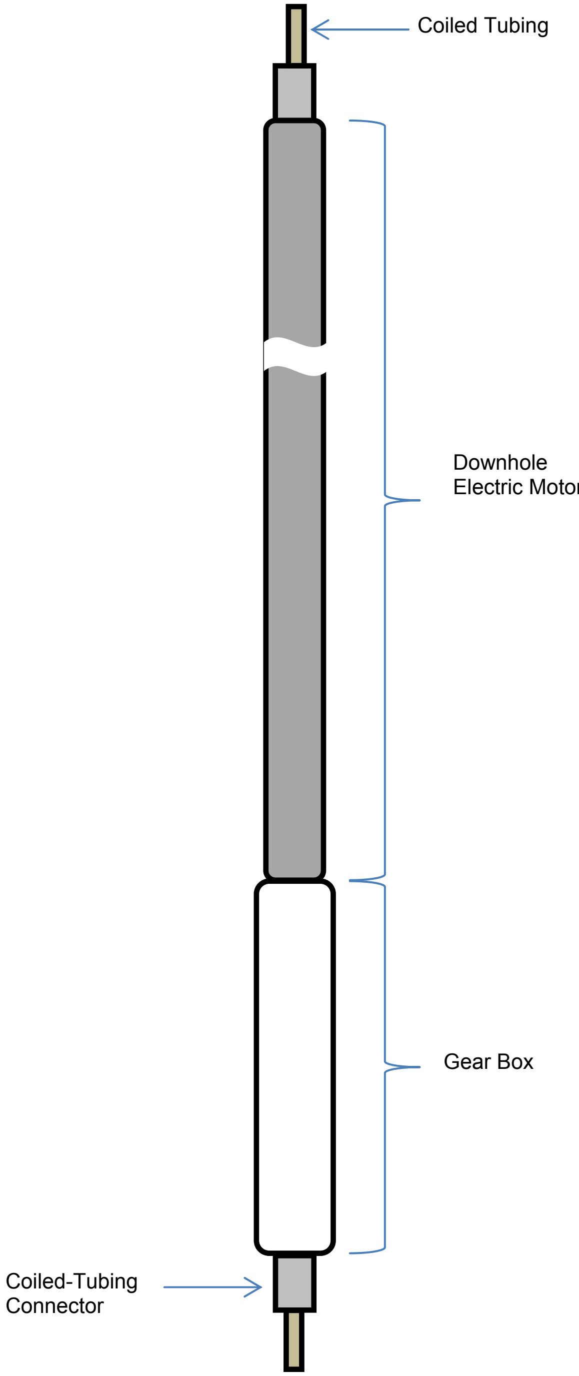

Fig. 3—Schematic drawing of the downhole electric motor assembly. Moderately big diameter gears will be needed to significantly reduce the rotor speed to a safe tubing rotary speed.

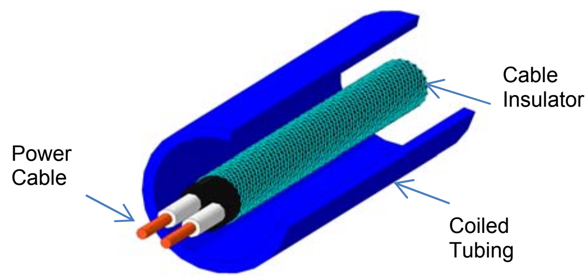

Fig. 4—The cable (two wires) transmits high voltage from the surface to the variable drive system, which regulate the frequency of the power supply to the electric motor (after Maurer 2013).

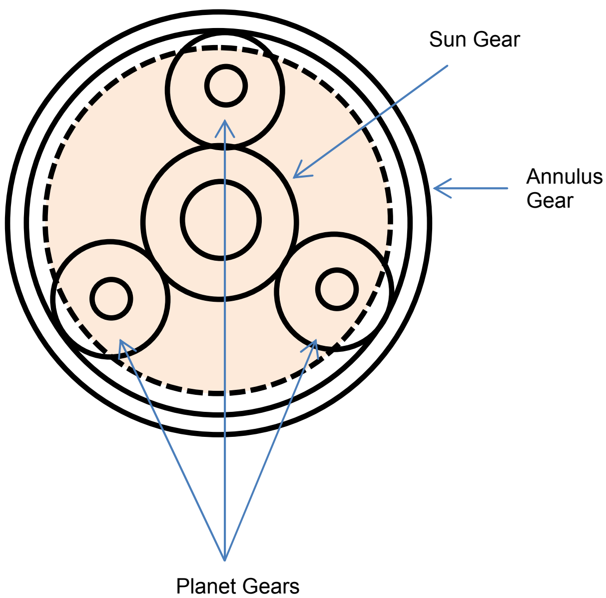

Fig. 6a—Epicyclic gear system provides high gear ratio within a short distance. The gears are oil field and hydraulic protected. In this drawing the planet carrier assembly is hidden.

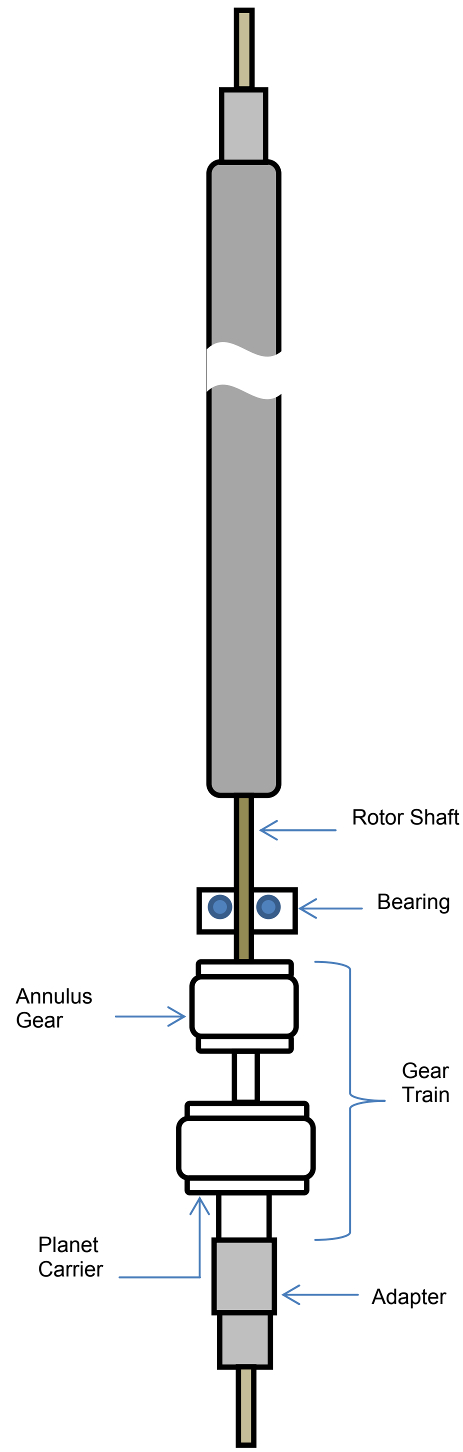

Fig. 5—With the use of a variable speed device system, the number of planetary gear train stages reduces; consequently reducing the diameter of the gear in the last stage.

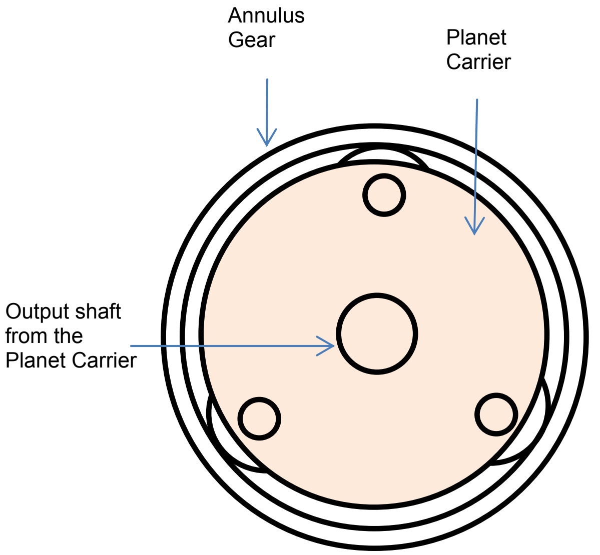

Fig. 6b—The rotary speed of the planet carrier is transmitted to the next planetary gear stage (or the tubing) through the output shaft. The shaft is not connected to the sun gear but coaxial to it.

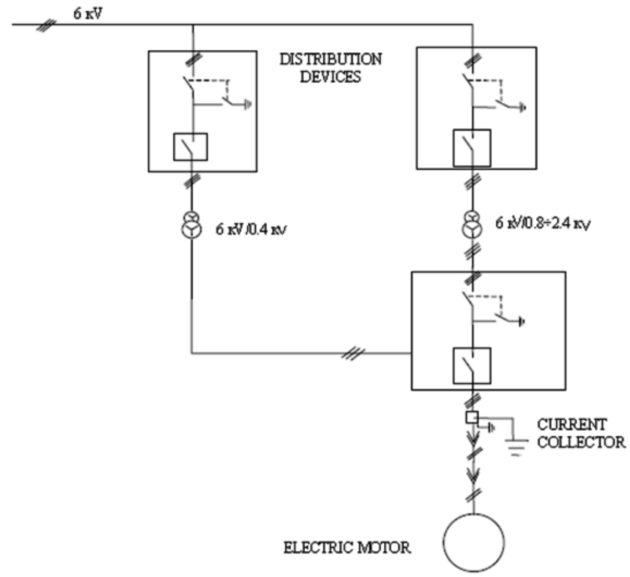

Fig. 7—Electric feed system for the running of the downhole electric motor (Maurer 2013)

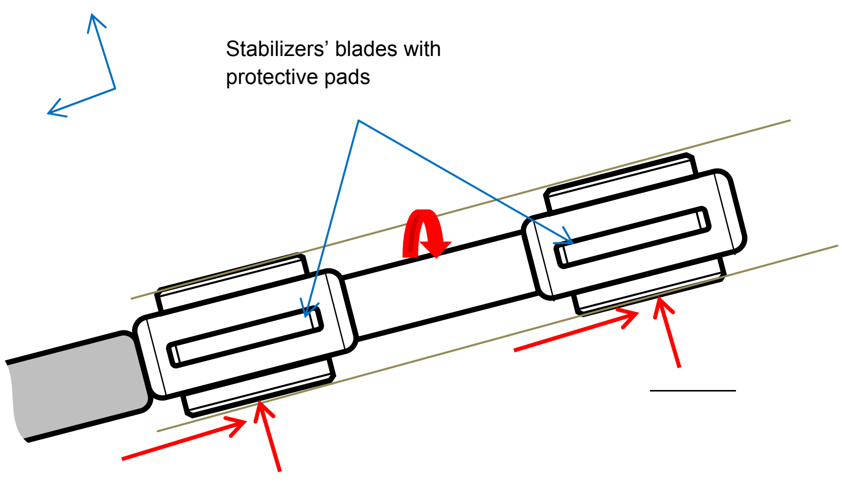

Fig. 8a—The twisting moments induce normal and binormal contact forces between the stabilizer blades (having eight blades) and the wellbore (top view).

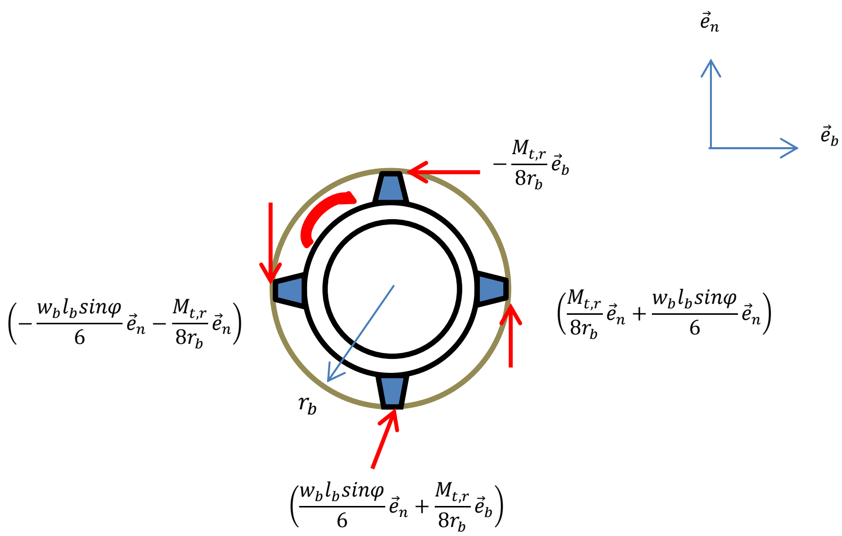

Fig. 8b—The twisting moments induce normal and binormal contact forces between the stabilizer blades (with 8 blades) and the wellbore (end view).

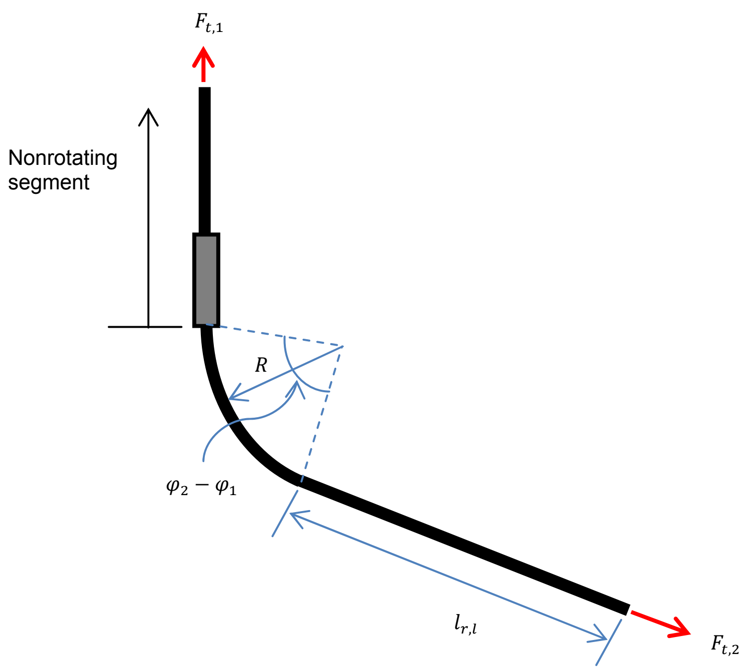

Fig.9a–When the second mud motor approaches the KOP, the maximum torque is applied to the rotating segment.

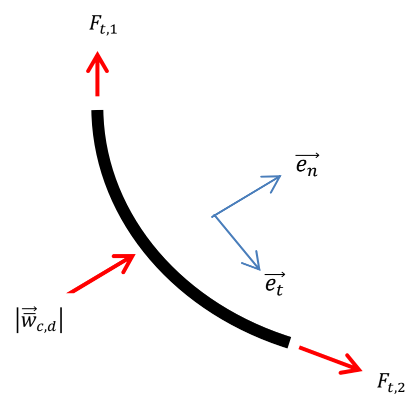

Fig. 9b–The unit weight of the tubing in the curved section of the wellbore varies with the axial load in the string.

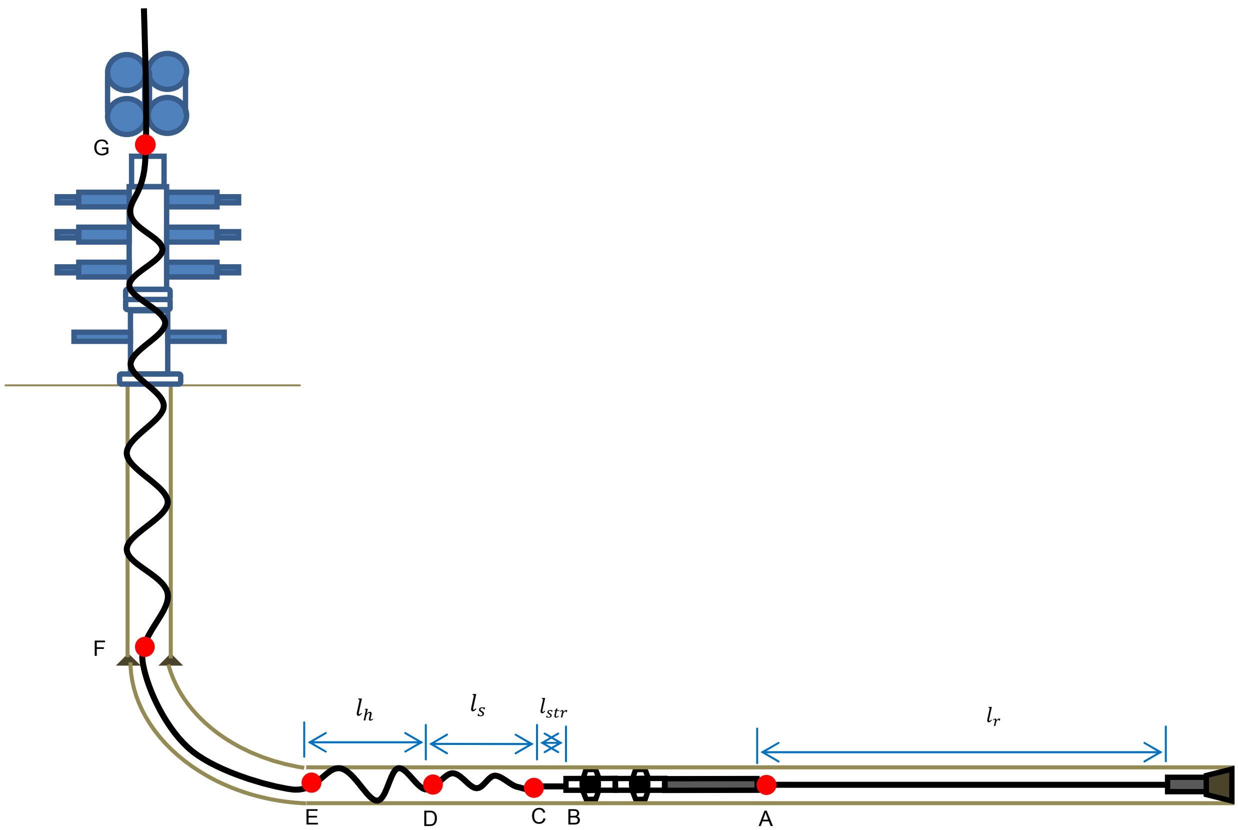

Fig. 10—Schematic representation of possible configuration of the tubing string at lockup condition

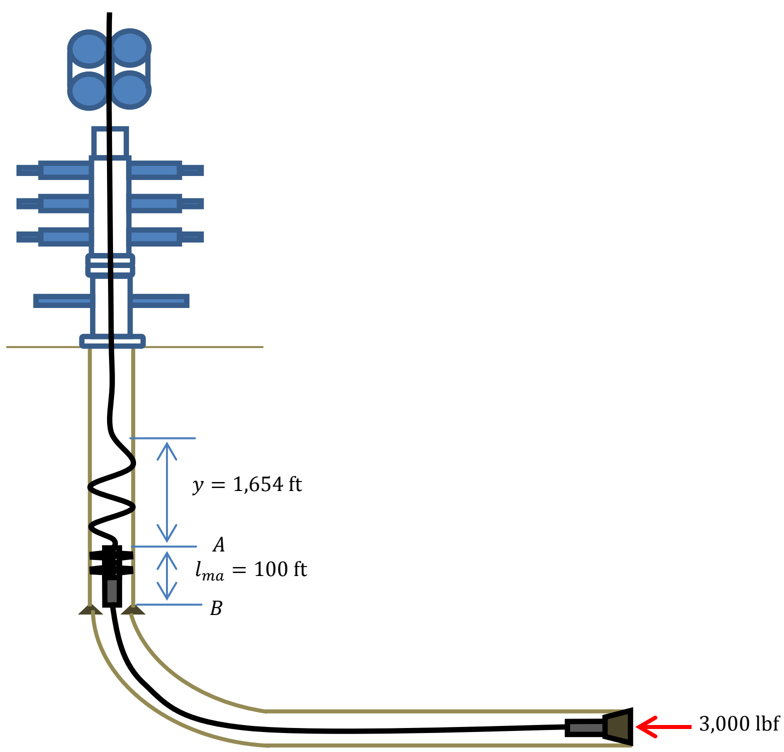

Fig. 11—The induced axial friction caused by the action of the twisting moment on the stabilizer limits the position of the mud motor to the vertical or curved section of the wellbore.

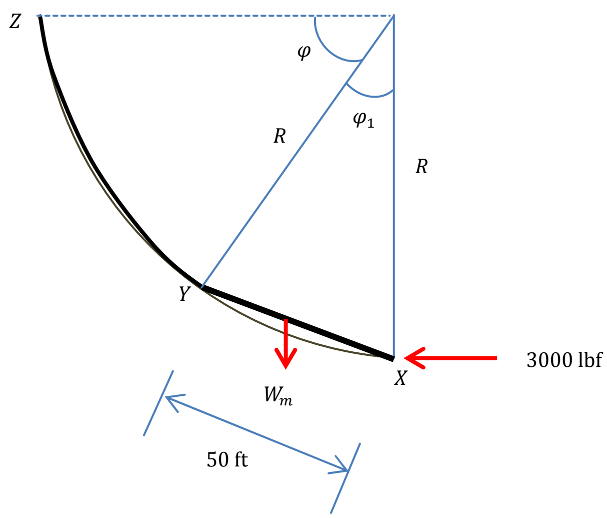

Fig. 12a—The electric motor at the end of build.

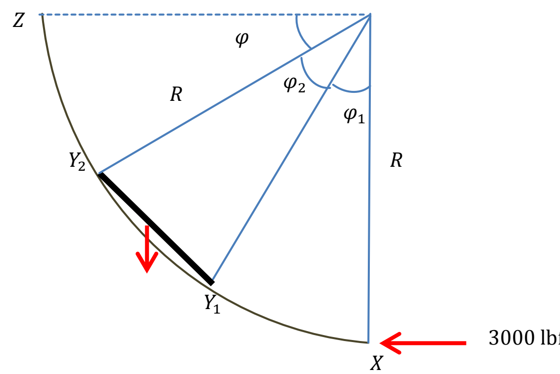

Fig. 12b—The electric motor in the curved section of the wellbore.

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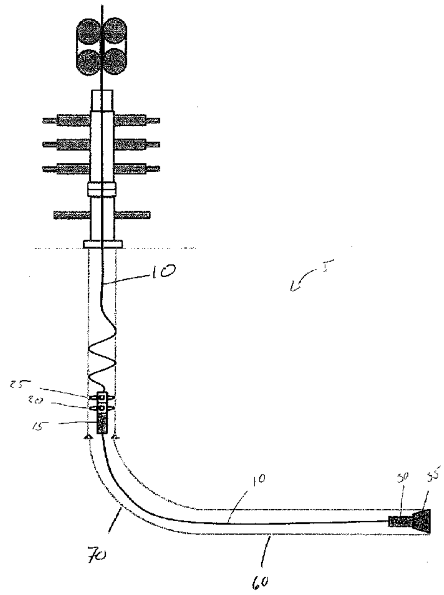
[Continued on next page]

(54) **Title**: Coiled Tubing Extended Reach with Downhole Motors

Figure 1



(57) Abstract: Disclosed is a method to enhance the reach of coiled tubing in the lateral section of a wellbore. The application of this method may enhance the use of coiled tubing in drilling very deep flowing wells. Similarly, the method may be applied in increasing the reach of the tubing for other coiled tubing well intervention applications. The method involves the use of downhole motor assemblies, stabilizers, and dynamic torque arrestors to rotate coiled-tubing string.

WO 2015/139015 A1

— *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments (Rule 48.2(h))*

Coiled Tubing Extended Reach with Downhole Motors

BACKGROUND OF THE INVENTION

Field of the Invention

The field of the disclosure is directed to coiled tubing drilling applications, and more specifically extending the reach of coiled tube piping in lateral sections of the wellbore.

Background of the Invention

Currently, the coiled tubing industry needs a technology that may enhance the reach of the tubing in the lateral section of the wellbore. The inability to rotate the tubing limits its reach in the lateral section of the wellbore. Past and current extended-reach techniques for coiled tubing have not been sufficient, individually, in increasing significantly the reach of the tubing in the wellbore. Often, four or five extended-reach methods are combined to have significant reach in the wellbore, which is quite expensive to do.

Consequently, there is a need for a single inexpensive method to extend the reach of coiled tubing in lateral wellbores. With the drive of exploiting oil and gas resources from deep wells increasing today, the reach of coiled tubing in the wellbore needs to be increased to meet this growing demand. The application of this technique may enhance the use of coiled tubing in drilling very deep flowing wells. Similarly, the method may be applied for increasing the reach of the tubing for other coiled-tubing well intervention applications.

BRIEF SUMMARY OF SOME OF THE PREFERRED EMBODIMENTS

These and other needs in the art are addressed in one embodiment by a method of drilling laterally with coiled tubing, wherein the method involves attaching a drill assembly to a coiled tubing, and attaching a second motor assembly to the drill assembly. The method also includes inserting the second motor assembly, the drill assembly, and the coiled tubing downhole, and attaching a first motor assembly to the coiled tubing. The method further includes inserting the first motor assembly downhole, rotating the coiled tubing with the first motor assembly, and rotating the drill assembly with the second motor assembly.

Further embodiments are addressed by a dynamic torque arrestor comprising a casing, an adaptor, and connector, wherein the casing houses an inner casing, a spindle, a machined spring, an upper plate, and a lower plate.

The foregoing has outlined rather broadly the features and technical advantages of the present disclosure so that the detailed description that follows may be better understood. Additional features and advantages of the disclosure will be described hereinafter that form the subject of the claims. It should be appreciated by those skilled in the art that the conception and the specific embodiments disclosed may be readily utilized as a basis for modifying or designing other embodiments for carrying out the same purposes of the present disclosure. It should also be realized by those skilled in the art that such equivalent embodiments do not depart from the spirit and scope of the disclosure as set forth in the appended claims.

BRIEF DESCRIPTION OF THE DRAWINGS

For a detailed description of the preferred embodiments of the disclosure, reference will now be made to the accompanying drawings in which:

Figure 1 illustrates a cut away view of the coiled tubing downhole assembly;

Figure 2 illustrates an embodiment of a stabilizer;

Figure 3 illustrates an embodiment of a dynamic torque arrestor;

Figure 4 illustrates an embodiment of a drill assembly;

Figure 5 illustrates an embodiment of a second motor assembly with stabilizers; and

Figure 6 illustrates an embodiment of a downhole electric motor.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

Disclosed embodiments of a downhole assembly may extend the lateral reach of coiled tubing. Embodiments may include systems and methods of operation to extend the reach of coiled tubing laterally. These systems and methods may be used in drilling extended reach wells and/or used for workovers in extended reach wells.

In embodiments, as illustrated in Figure 1, a downhole assembly 5 may comprise coiled tubing 10, a first motor assembly 15, a dynamic torque arrestor 20, a stabilizer 25, a second motor assembly 30, and a drill assembly 35. Downhole assembly 5 may be employed to extend the reach of coiled tubing 10 in downhole operations, more specifically lateral drilling operations. Coiled tubing 10 may comprise of a single tube that may be spun around a reel, not illustrated, and straightened before entering a well. During operations, a single coiled tube 10 may be used or a plurality of coiled tubing 10 may be used in conjunction with each other. Coiled tubing 10 may be any diameter suitable for drilling operations. A suitable diameter may be between about half an inch to about five inches, about an inch to about three inches, about two inches to about four inches, or about three inches to about five inches. To withstand a downhole environment, coiled tubing 10 may be any suitable material. Suitable material may be stainless steel, steel, carbon fiber, iron, black iron, or any combination thereof. As illustrated in Figure 1, coiled tubing 10 may be disposed downhole and connect to stabilizer 25 and first motor assembly 15. In embodiments, additional coiled tubing 10 may be used to connect first motor assembly 15 to second motor assembly 30 and drill assembly 35. During operations, first motor assembly 15 and second motor assembly 30 may create rotational forces. Rotational forces created by fist motor assembly 15 may prevent coiled tubing 10 from rubbing against a rock formation. Additionally, preventing coiled tubing 10 from twisting and rotating into a rock formation, stabilizers 25 may be disposed along coiled tubing 10, first motor assembly 15, and/or second motor assembly 30.

Stabilizer 25 may prevent coiled tubing 10 from touching the subterranean formation downhole. Additionally, stabilizers 25 may also prevent twisting and rotation of downhole assembly 5. In embodiments, as illustrated in Figure 2, stabilizer 25 may comprise a base 28 and/or a blade 26. Blade 26 may further comprise an elastomeric pads 27. Stabilizer 25 may have any number of blades 26 with any number of elastomeric pads 27. Elastomeric pads 27 may be disposed on the outside of blades 26. Blades 26 and elastomeric pads 27 may press against a subterranean rock formation, preventing torque. Blades 26 may also push coiled tubing 10 away from the subterranean formation rocky surface downhole. In embodiments, there may be a plurality of stabilizers 25 used during downhole operations. Stabilizers 25 may be connected in series and/or be separated by additional downhole devices. In embodiments, the number of stabilizers 25, and their spacing, may be based on the diameter of coiled tubing 10. A smaller diameter may require larger amounts of stabilizers 25 that are spaced closer together. This may prevent coiled tubing 10 from contacting the rocky surface of a subterranean formation. A large diameter may require less stabilizers 25 that are spaced farther apart. Referring to Figure 5, a stabilizer 25 may be positioned below a first motor assembly 15, and a plurality of stabilizer 25 may be positioned above first motor assembly 15. In an embodiment, not illustrated, there may be a plurality of stabilizers 25 below fist motor assembly 15 and a plurality of stabilizers 25 above first motor assembly 15. Stabilizer 25 may connect directly or indirectly with first motor assembly 15. First motor assembly 15 and stabilizer 25 may be connected by any suitable means. Suitable means may be, but are not limited to, a press fitting, nuts and bolts, threaded connector, or any combination thereof.

As illustrated in Figure 2, a plurality of stabilizers 25 may be connected by coiled pipe 10. Coiled pipe 10 may rotate freely between stabilizers 25. To prevent slipping and/or keep coiled pipe 10 centered downhole, stabilizer 25 may be made of any suitable material. Suitable material may be steel, stainless steel, black iron, plastic, or any combination thereof. In embodiments, base 28 may be any suitable length to prevent stabilizer 25 from slipping. A suitable length may be about one foot to about six feet, about two feet to about four feet, about three feet to about six feet, or about one foot to about three feet. Blades 26 may traverse base 28 any suitable length to prevent stabilizer 25 from slipping. In embodiments, stabilizers 25 may be disposed about second motor assembly 30 and drill assembly 35. Additionally, stabilizers 25 may be disposed about other downhole devices.

As illustrated in Figure 1, stabilizers 25 may be disposed about and/or connect to a dynamic torque arrester 20. In embodiments, there may be a plurality of dynamic torque arrestors 20 used in downhole operations. Dynamic torque arrestor 20 may connect directly or indirectly with first motor assembly 15 and/or second motor assembly 30 by any suitable means. Suitable means may be, but are not limited to, a press fitting, nuts and bolts, threaded connector, or any combination thereof. Dynamic torque arrestor 20 may prevent torque produced by first motor assembly 15 and/or second motor assembly 30 from twisting, moving, and/or breaking downhole assembly 5 within the wellbore. As illustrated in Figure 3, dynamic torque arrestor 20 may comprise a casing 40, an adapter 41, a lower plate 42, an elastomeric pad 43, a machined spring 44, an inner casing 45, an axial roller bearing 46, a thrust ball bearing 47, a spindle 48, a high viscous fluid 49, an upper plate 50, perforations 51, and connector 60. Casing 40 may act as an outer shell that protects internal parts from the downhole environment which may include, but is not limited to, mud, rock, water, and other subterranean elements. Casing 40 may comprise any suitable material. Suitable material may include, but is not limited to, carbon steel, stainless steel, plastic, or any combination thereof. Located at one end of dynamic torque arrestor 20, adapter 41, may attach coiled tubing 10, first motor assembly 15, second motor assembly 30, and/or stabilizer 25 to dynamic torque arrestor 20. Adapter 41 may attach to any downhole device by any suitable means. Suitable means may be, but are not limited to, a press fitting, nuts and bolts, threaded connector, and/or any combination thereof. In embodiments, adapter 41 may rotate about its axis which may help dissipate lateral movement that may be produced by first motor assembly 15 and/or second motor assembly 30.

Disposed inside casing 40, above adapter 41, is lower plate 42. Lower plate 42 may act to hold machined spring 44 in place. There may be any number of lower plates 42 that may hold and guide machined spring 44. Lower plate 42 may be secured to casing 40 by any suitable means which may include, but is not limited to, any form of welding, nuts and bolts, press fitting, and/or any combination thereof.

Elastomeric pad 43 may be attached to lower plate 42 along the inner most edge adjacent to machined spring 44. Elastomeric pad 43 may be attached by any suitable means which may include, but is not limited to, adhesive, press fitting, screws, and/or any combination thereof. Elastomeric pad 43 may comprise any suitable material that may act as a buffer to prevent wear and tear between machined spring 44 and lower plate 42. Suitable material may be, but is not limited to, any form of plastic, leather, neoprene, rubber, and/or any combination thereof.

Machined spring 44 may be disposed upon adapter 41 and may be held in place by lower plate 42 and elastomeric pad 43. Machined Spring 44 may comprise any suitable material. Suitable material may include, but is not limited to, carbon steel, stainless steel, plastic, or any combination thereof. Machined spring 44 may be of any resistance and length necessary to withstand torsional and axial loads that may be produced and transmitted through adapter 41 by first motor assembly 15 and/or second motor assembly 30. Machined spring 44 may move vertically within casing 40 to help dissipate torsional and axial loads. Spindle 48 may be placed upon machine spring 44 to prevent machined spring 44 from moving the entire vertical length of casing 40.

Spindle 48 may be of any suitable length to prevent machine spring 44 from moving the entire vertical length of casing 40. A suitable length may be about two inches to about twelve inches, about four inches to about ten inches, about six inches to about eight inches, or about six inches to about twelve inches. Spindle 48 may be of any suitable material which may be, but is not limited to, stainless steel, plastic, carbon steel, and/or any combination thereof. Spindle 48 may be of any suitable diameter to withstand forces placed upon it by machined spring 44. A suitable diameter may be about half a centimeter to about ten centimeters, about two centimeter to about eight centimeters, about four centimeters to about six centimeters, or about five centimeters to about ten centimeters. Spindle 48 may rest upon machined spring 44 at one end and at the opposite end be disposed in inner casing 45.

Inner casing 45 may be of any suitable material which may be, but is not limited to, stainless steel, plastic, carbon steel, and/or any combination thereof. Inner casing 45 may comprise highly viscous fluid 49, thrust ball bearing 47, and axial roller bearing 46. Inner casing 45 may have a flanged end in which to attach to upper plate 50. Inner casing 45 may be attached to upper plate 50 by any suitable means which may use, but is not limited to, nuts and bolts, adhesives, any form of weld, press fitting, and/or any combination thereof. Opposite the flanged end of inner casing 45 may be a capped end with a point of entry 52 for spindle 48 to pass through. Within inner casing 45, high viscous fluid 49 may comprise, but is not limited to, glycerine, heavy motor oils, axial grease, marine grease, magneto-rheological fluids, electro-rheological fluids, and/or any combination thereof. High viscous fluid 49 may provide resistance to prevent the rapid and/or upward movement of spindle 48. Spindle 48 may move as machined spring 44 reacts to torsional and axial loads produced by adapter 41. High viscous fluid 49 may further help dissipate torsional and axial loads experienced by spindle 48, preventing torsional and axial loads from transferring to dynamic torque arrestor 20.

Point of entry 52 may be of any suitable diameter that may accommodate spindle 48. A suitable diameter may be about half a centimeter to about ten centimeters, about two centimeter to about eight centimeters, about four centimeters to about six centimeters, or about five centimeters to about ten centimeters. Point of entry 52 may comprise any form of buffer material to prevent wear and tear on spindle 48. Buffer material may be, but is not limited to, any form of plastic, leather, neoprene, rubber, and/or any combination thereof. Point of entry 52 may also guide spindle 48 and prevent any lateral movement.

Axial roller bearing 46 may also guide spindle 48 and prevent any lateral movement. Axial roller bearing 46 may comprise any number of roller bearings within a housing. Roller bearings may be of any radius suitable to prevent lateral movement of spindle 48. Roller bearings may be any suitable material which includes, but is not limited to, carbon steel, stainless steel, plastic, or any combination thereof. Any form of lubricant may be used to allow for roller bearings to move freely in axial roller bearing housing 60. Lubricant may be, but is not limited to, axial grease or marine grease. Axial roller bearing 46 may attach within inner casing 45 above point of entry 52. Axial roller bearing 46 may be attached by any suitable means which may include, but is not limited to, any form of welding, nuts and bolts, or press fitting.

Thrust ball bearing 47 may also guide spindle 48 and prevent any lateral movement. Thrust ball bearing 47 may comprise any number of roller bearings within a housing. Thrust ball bearing 47 may be of any radius suitable to prevent lateral movement of spindle 48. Thrust ball bearing 47 may be any suitable material which includes, but is not limited to, carbon steel, stainless steel, plastic, and/or any combination thereof. Any form of lubricant may be used to allow for thrust ball bearing 47 to move freely in axial roller bearing housing 60. Lubricant may be, but is not limited to, axial grease, marine grease, and/or any combination thereof. Thrust ball bearing 47 may attach within inner casing 45 above point of entry 52 and axial roller bearing 46. Thrust ball bearing 46 may be attached by any suitable means which may include, but is not limited to, any form of welding, nuts and bolts, press fitting, and/or any combination thereof.

Inner casing 45 may be separated into two distinct areas by separator 53. Separator 53 may comprise any suitable material. Suitable material may include, but is not limited to, carbon steel, stainless steel, plastic, and/or any combination thereof. The lower separated area 65 may house thrust ball bearing 47 and axial roller bearing 46. The upper separated area 70 may house highly viscous fluid 49. Highly viscous fluid 49 may act to prevent the rapid lateral movement of spindle 48. Spindle 48 enters the upper separated area 70 through a second point of entry 54.

Second point of entry 54 may be of any suitable diameter that may accommodate spindle 48. A suitable diameter may be about half a centimeter to about ten centimeters, about two centimeter to about eight centimeters, about four centimeters to about six centimeters, or about five centimeters to about ten centimeters. Second point of entry 54 may comprise any form of buffer material to prevent wear and tear on spindle 48. Buffer material may be, but is not limited to, any form of plastic, leather, neoprene, rubber, and/or any combination thereof. Buffer material may create an air tight seal to prevent highly viscous fluid 49 from moving into the lower separated area 65 which may house thrust ball bearing 47 and axial roller bearing 46. Second point of entry 54 may also guide spindle 48 and prevent any lateral movement.

As discussed above, upper plate 50 may be used for attaching inner casing 45 to dynamic torque arrestor 20. Upper plate 50 may be located inside casing 40 at the opposite end of adapter 41. Upper plate 42 may act to hold inner casing 45 in place. Upper plate 50 may comprise any suitable material. Suitable material may include, but is not limited to, carbon steel, stainless steel, plastic, and/or any combination thereof. Upper plate 50 may have perforations 51 which may allow for drilling mud to pass through. There may be a plurality of perforations 51, which may be of any diameter suitable to allow for mud to flow freely through. A suitable diameter may be about half a centimeter to about ten centimeters, about two centimeter to about eight centimeters, about four centimeters to about six centimeters, or about five centimeters to about ten centimeters.

Opposite adapter 41 is connector 60 which may be used to attach to dynamic torque arrestor 20, coiled tubing 10, first motor assembly 15, second motor assembly 30, and/or stabilizer 25. Connector 60 may attach to any device by any suitable means. Suitable means may be, but are not limited to, press fitting, nuts and bolts, and/or threaded connector. Stabilizer 25 and/or dynamic torque arrestor 20 may be used prevent the rotational movement, produced by first motor assembly 15, from moving up coiled tubing 10. A first motor assembly 15 may comprise mud motor 200, electric motor 100, and/or turbine motors. As illustrated in Figure 6, first motor assembly 15 may comprise electric motor 100 and/or a mud motor 200. Electric motor 100 may be used in conjunction with mud motor 200 or as a standalone first motor assembly 15. Electric motor 100 may comprise a rotor shaft 101, bearings 102, annulus gear 103, and planet carrier 104. Electric motor 100 may connect to coiled tubing 10, stabilizers 25, dynamic torque arrestors 20, and/or mud motor 200 by any suitable means. First motor assembly 15 may be used to turn coiled tubing 10, which may further be attached to a second motor assembly 30 and/or a drill assembly 35.

In embodiments, as illustrated in Figure 4, drill assembly 35 may comprise a drill bit 36, connector 37, and/or directional drilling assembly 38. In embodiments, drill assembly 35 may attach to a second motor assembly 30. Drill assembly 35 may connect to second motor assembly 30 by any suitable means. Suitable means may be, but are not limited to, press fitting, nuts and bolts, threaded connector, and/or any combination thereof. Second motor assembly 30 may be used to help turn drill assembly 35. In embodiments second motor assembly 30 may be an electric motor 100, mud motor 200, and/or a turbine motor.

Drilling bit 36 may be of any type suitable to drill through a subterranean formation. Drill bit 36 may attached to connector 37 by any suitable means. Connector 37 is attached to directional drilling assembly 38, opposite drill bit 36, by any suitable means. Second motor assembly 30 may attach to directional drilling assembly 38, opposite connector 37, by any suitable means. Second motor assembly 30 may connect drilling assembly 35 to coiled tubing 10. Second motor assembly 30 may connect to coiled tubing 10 by any suitable means. First motor assembly 15 may attach to coiled tubing 10 at any suitable length from second motor assembly 30. As illustrated in Figure 5, first motor assembly 15 may attach to coiled tubing 10 by any suitable means. Suitable means may be, but are not limited to, clamps, bolts, nuts and bolts, threads, and/or any combination thereof. In embodiments, first motor assembly 15 and second motor assembly 30 may be disposed between different sections of coiled tubing 10. Second motor assembly 15 may be attached to a stabilizer 25 and/or dynamic torque arrestor 20 by any suitable means. There may be any number of stabilizers 25 and/or dynamic torque arrestors 20 attached to second motor assembly 15. Depending on the specific application, there may only be a single or multiple stabilizer 25 with a single or multiple dynamic torque arrestors 20. Stabilizers 25 and dynamic torque arrestors 20 may be attached below or above second first motor assembly 15. Furthermore, both stabilizer 25 and dynamic torque arrestor 20 may be used together or in any order.

During downhole operations, a method may be used to properly employ downhole assembly 5. The method may comprise drilling vertically with coiled tubing 10 and drill assembly 35 to a designated depth. At the designated depth, drill assembly 35 may then be controlled to move laterally across a formation. After drilling laterally to the extent allowed by coiled tubing 10, drill assembly 35 and coiled tubing 10 may be brought back to the surface. At the surface, coiled tubing 10 is altered to extend the lateral drilling reach of downhole assembly 5. Coiled tubing 10 may be fitted with drill assembly 35, a second motor assembly 30, a first motor assembly 15, dynamic torque arrestor 20, and stabilizer 25. Once fitted, downhole assembly 5 is placed downhole to where drilling operations stopped.

During operations, first motor assembly 15 may rotate coiled tubing 10, preventing coiled tubing 10 from dragging along the lower most horizontal surface of the lateral drilled hole 60 and downhole bend 70, as illustrated in Figure 1. Generally, most lateral drilling is limited in depth due to the amount of pipe that may be in contact with the surface wall of lateral drilled hole 60. Currently, as drill assembly 35 moves laterally, coiled tubing 10 drags along lateral drilled hole 60. This creates large amounts of friction along coiled pipe 10, the friction generated may eventually prevent the lateral movement of drill assembly 35. As disclosed, to overcome the friction, a first motor assembly 15 rotates the coiled tubing 10 section between first motor assembly 15 and second motor assembly 30. Rotation of the coiled pipe 10 by first motor assembly 15 may prevent coiled tubing 10 from dragging along lateral drilled hole 60. Rotation of the pipe prevents friction from being generated along coiled tubing 10. The reduction in friction may allow for drilling to move further lateral. Second motor assembly 30 may be used to drive drill assembly 35 through the formation laterally. Using the second motor assembly 30 to drill and the first motor assembly 15 to rotate the coiled tubing 10 may allow downhole drilling operations to move laterally across the formation. Coiled tubing 10 may also be prevent from dragging along the surface of drilled hole 60 and downhole bend 70. Moreover, the reachable drilling length of coiled tubing 10 in downhole operations may be increased.

Although the present disclosure and its advantages have been described in detail, it should be understood that various changes, substitutions and alterations may be made herein without departing from the spirit and scope of the disclosure.

CLAIMS

What is claimed is:

1. A method of drilling with coiled tubing, the method comprising:

attaching a drill assembly to a coiled tubing;

attaching a second motor assembly to the drill assembly;

inserting the second motor assembly, the drill assembly, and the coiled tubing downhole;

attaching a first motor assembly to the coiled tubing;

inserting the first motor assembly downhole;

rotating the coiled tubing with the first motor assembly; and

rotating the drill assembly with the second motor assembly.

2. The method of claim 1, wherein the first motor assembly rotates the coiled tubing between the first motor assembly and the second motor assembly.

3. The method of claim 1, wherein the drill assembly further comprises a drill bit.

4. The method of claim 1, wherein the first motor assembly is connected to a stabilizer.

5. The method of claim 4, further wherein there are at least two stabilizers.

6. The method of claim 1, wherein the first motor assembly is connected to a dynamic torque arrestor.

7. The method of claim 6, further wherein there are at least two dynamic torque arrestors.

8. The method of claim 1, wherein the motor assembly is connected to both a stabilizer and a dynamic torque arrestor.

9. The method of claim 8, wherein the first motor assembly is connected to a plurality of stabilizers and a plurality of dynamic torque arrestors.

10. A dynamic torque arrestor, comprising:

a casing;

an adapter at one end of the casing; and

a connector opposite the adapter.

11. The dynamic torque arrestor of claim 10, wherein the casing further comprises:

an inner casing;

a spindle;

a machined spring;

an upper plate; and

a lower plate.

12. The dynamic torque arrestor of claim 11, wherein the inner casing is attached to the upper plate.

13. The dynamic torque arrestor of claim 11, wherein the inner casing is divided into a lower and an upper area.

14. The dynamic torque arrestor of claim 13, wherein the lower area further comprises;

a thrust ball bearing; and

an axial roller bearing.

15. The dynamic torque arrestor of claim 13, wherein the upper area further comprises a highly viscous fluid.

16. The dynamic torque arrestor of claim 11, wherein the machined spring is disposed upon the adapter.

17. They dynamic torque arrestor of claim 11, wherein the lower plate guides and prevents lateral movement of the machined spring.

18. The dynamic torque arrestor of claim 17, further comprising multiple lower plates.

19. They dynamic torque arrestor of claim 11, wherein the spindle is disposed upon the machined spring.

20. The dynamic torque arrestor of claim 11, wherein the upper plate further comprises perforations.

Figure 1

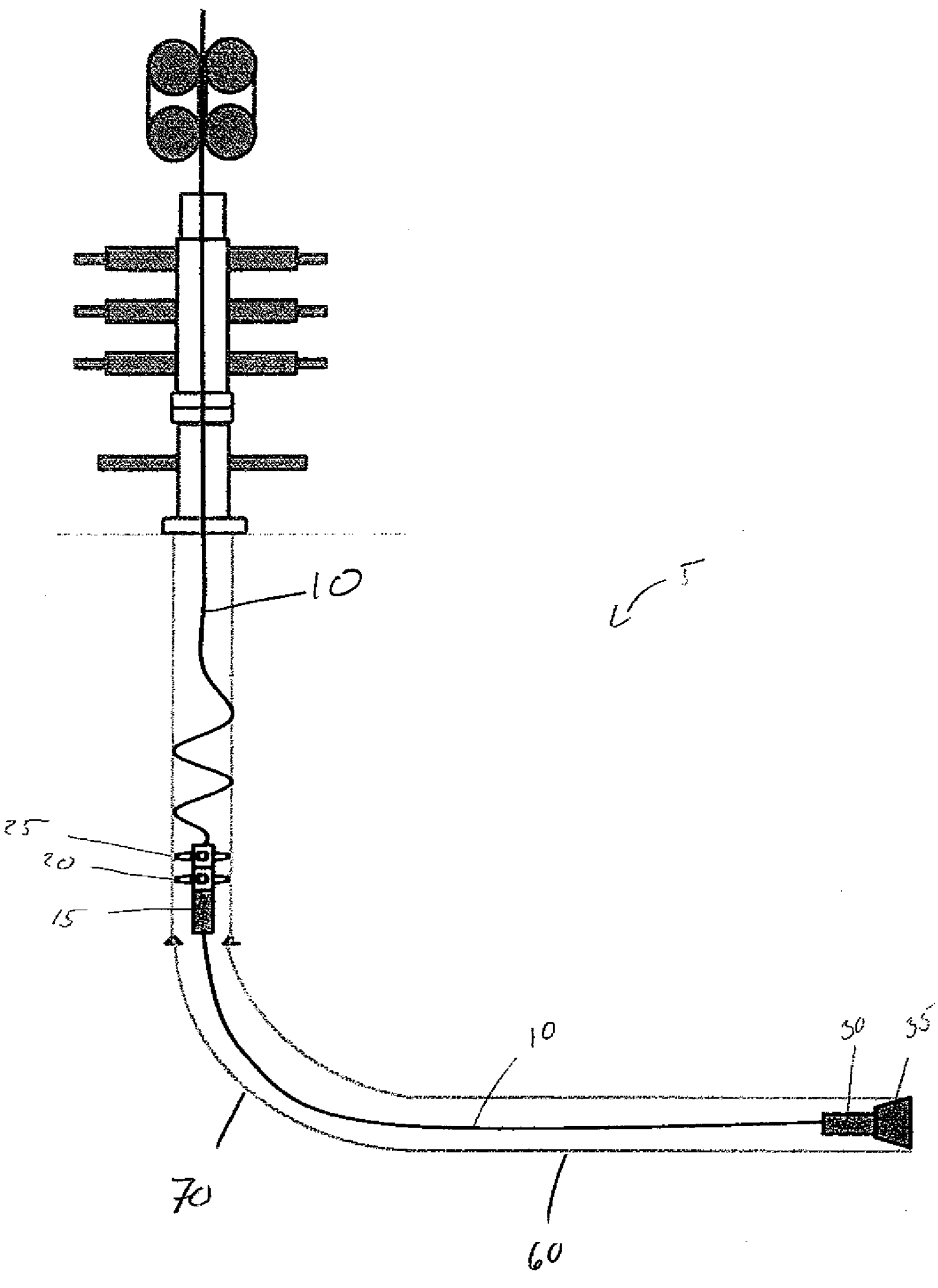


Figure 2

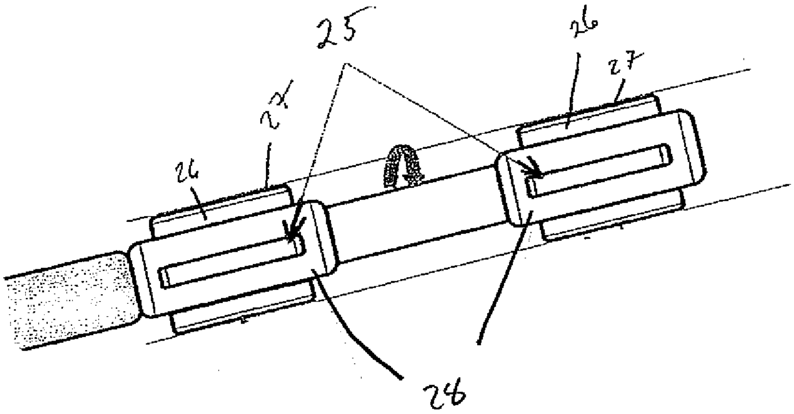
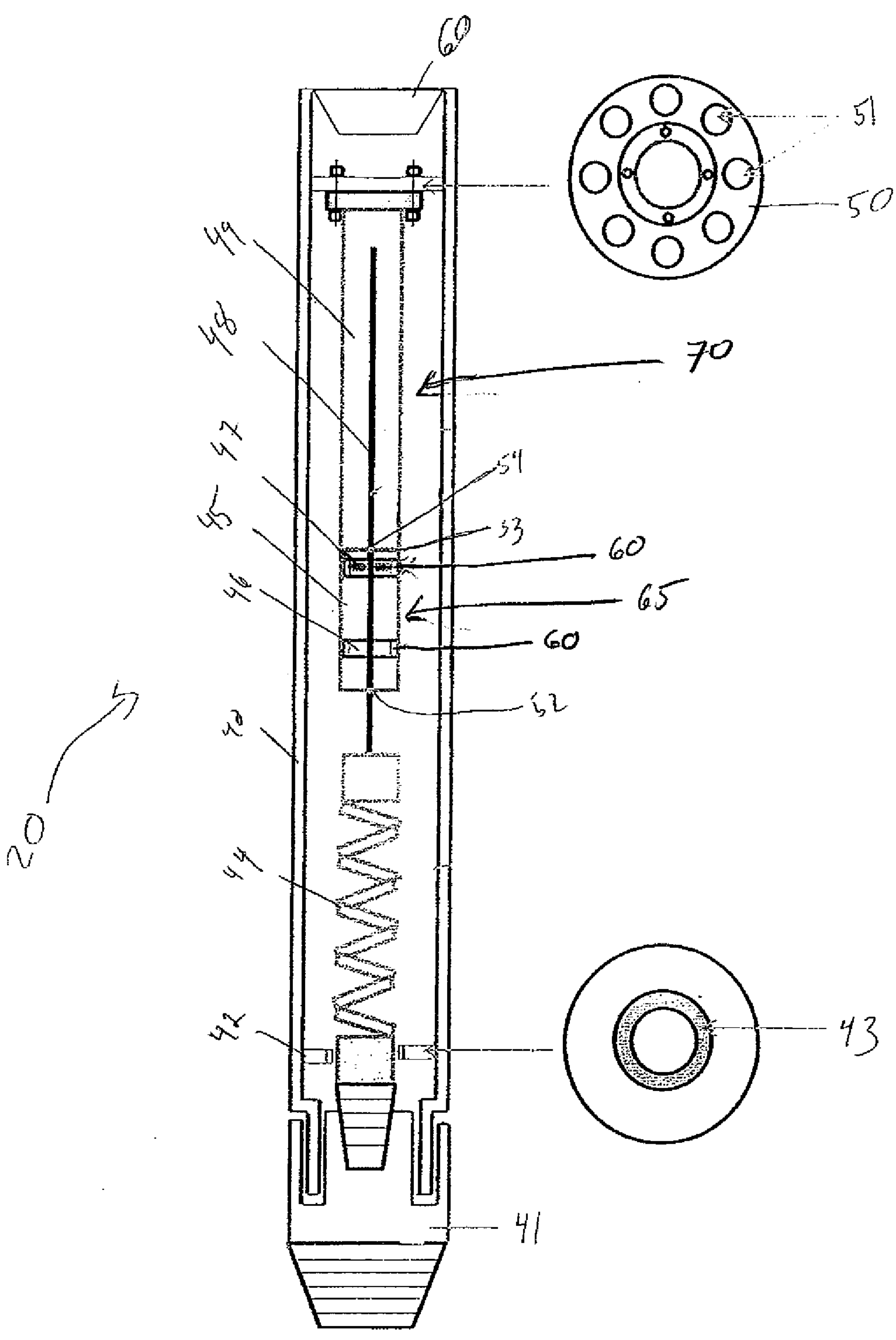


Figure 3



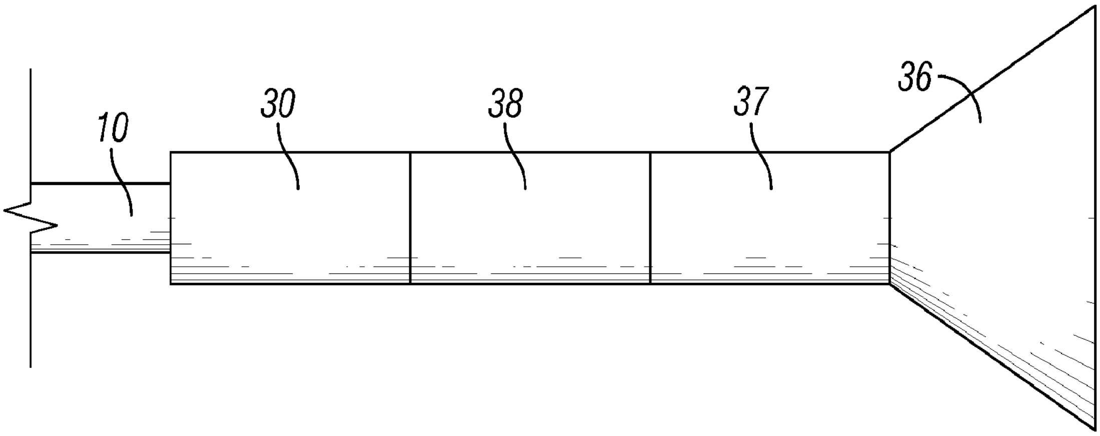


FIG. 4

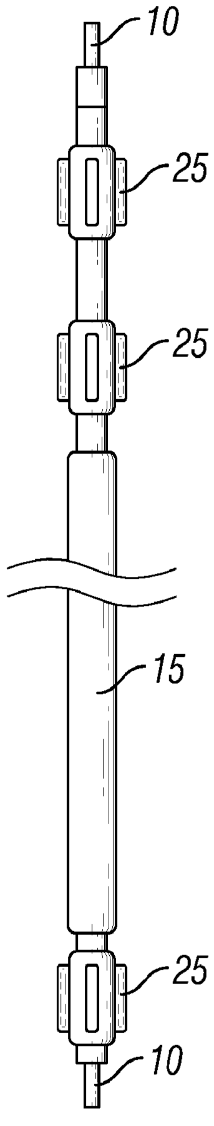


FIG. 5

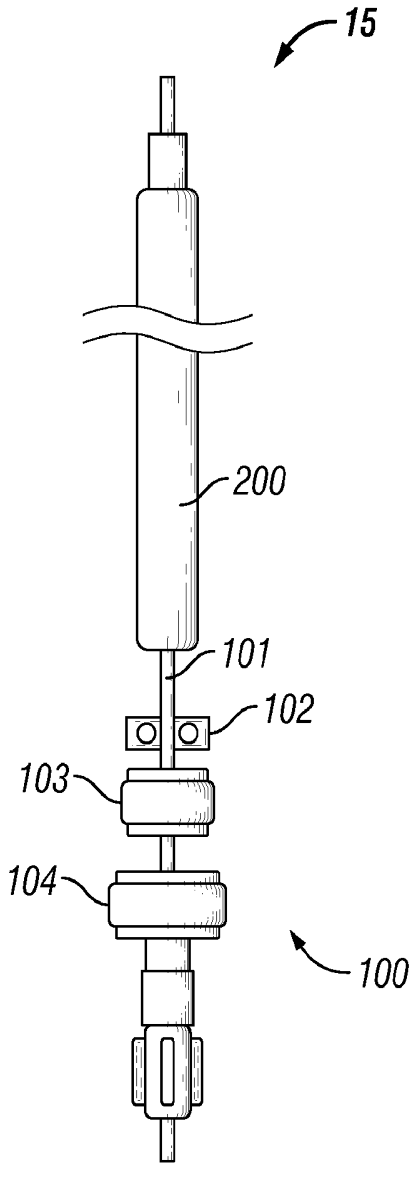


FIG. 6

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US 15/20653

A. CLASSIFICATION OF SUBJECT MATTER
IPC(8) - E21B 4/00, 4/16, 17/20 (2015.01)
CPC - E21B 4/16, 17/20
According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC(8) - E21B 4/00, 4/16, 17/20 (2015.01)
CPC - E21B 4/16, 17/20

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
CPC - E21B 3/00, 4/00, 7/00, 17/00

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
Patbase; Google Patents; Google Scholar; Google Web; Espacenet; Search Terms: additional*, arrest*, bit, bits, centrali*, coil*, downhole*, drill*, dual*, dynamic*, flex*, limit*, lower*, motor*, multi*, pair*, pipe*, piping*, plural*, prevent*, rota*, second*, stabili*, string*, torq*, tub*, upper*

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X --- Y	US 2012/0024539 A1 (Lehr) 02 February 2012 (02.02.2012), Figs. 1-2, para [0022]-[0025]	1-5 --- 6-9
Y	US 4,997,042 A (Jordan et al.) 05 March 1991 (05.03.1991), col. 4, ln. 32-38	6-9
A	EP 1291486 A1 (Shell) 12 March 2003 (12.03.2003), Figs. 1-2, para [0020]-[0022]	1-9
A	US 6,446,737 B1 (Fontana et al.) 10 September 2002 (10.09.2002), Figs. 2A-2B, col. 4, ln. 20-62	1-9
A	WO 1997/016622 A1 (Rigden et al.) 09 May 1997 (09.05.1997), pg. 6, ln. 27 - pg. 7, ln. 32	1-9

☐ Further documents are listed in the continuation of Box C. ☐

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
28 July 2015 (28.07.2015)	19 AUG 2015

Name and mailing address of the ISA/US	Authorized officer:
Mail Stop PCT, Attn: ISA/US, Commissioner for Patents P.O. Box 1450, Alexandria, Virginia 22313-1450 Facsimile No. 571-273-8300	Lee W. Young PCT Helpdesk: 571-272-4300 PCT OSP: 571-272-7774

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US 15/20653

Box No. II Observations where certain claims were found unsearchable (Continuation of item 2 of first sheet)

This international search report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:
because they relate to subject matter not required to be searched by this Authority, namely:

2. ☐ Claims Nos.:
because they relate to parts of the international application that do not comply with the prescribed requirements to such an extent that no meaningful international search can be carried out, specifically:

3. ☐ Claims Nos.:
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

Box No. III Observations where unity of invention is lacking (Continuation of item 3 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:
--- See supplemental box ---

1. ☐ As all required additional search fees were timely paid by the applicant, this international search report covers all searchable claims.

2. ☐ As all searchable claims could be searched without effort justifying additional fees, this Authority did not invite payment of additional fees.

3. ☐ As only some of the required additional search fees were timely paid by the applicant, this international search report covers only those claims for which fees were paid, specifically claims Nos.:

4. ☒ No required additional search fees were timely paid by the applicant. Consequently, this international search report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:
1-9

Remark on Protest

☐ The additional search fees were accompanied by the applicant's protest and, where applicable, the payment of a protest fee.

☐ The additional search fees were accompanied by the applicant's protest but the applicable protest fee was not paid within the time limit specified in the invitation.

☐ No protest accompanied the payment of additional search fees.

Box No. III - Observations where unity of invention is lacking

This application contains the following inventions or groups of inventions which are not so linked as to form a single general inventive concept under PCT Rule 13.1. In order for all inventions to be examined, the appropriate additional examination fees must be paid.

Group I: Claims 1-9, directed to a method of drilling with coiled tubing.

Group II: Claims 10-20 directed to a dynamic torque arrestor.

The inventions listed as Groups I-II do not relate to a single inventive concept under PCT Rule 13.1 because under PCT Rule 13.2 they lack the same or corresponding technical features for the following reasons:

Group I includes the special technical feature of attaching a drill assembly to a coiled tubing; attaching a second motor assembly to the drill assembly; inserting the second motor assembly, the drill assembly, and the coiled tubing downhole; attaching a first motor assembly to the coiled tubing; inserting the first motor assembly downhole; rotating the coiled tubing with the first motor assembly; and rotating the drill assembly with the second motor assembly that are not required in Group II.

Group II includes the special technical feature of a casing; an adapter at one end of the casing; and a connector opposite the adapter that are not required in Group I.

There are no shared/common technical features between Groups I and II that would otherwise unify the groups.

Therefore, Groups I and II lack unity under PCT Rule 13.

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(54) **OPTIMIZED COILED TUBING STRING DESIGN AND ANALYSIS FOR EXTENDED REACH DRILLING**

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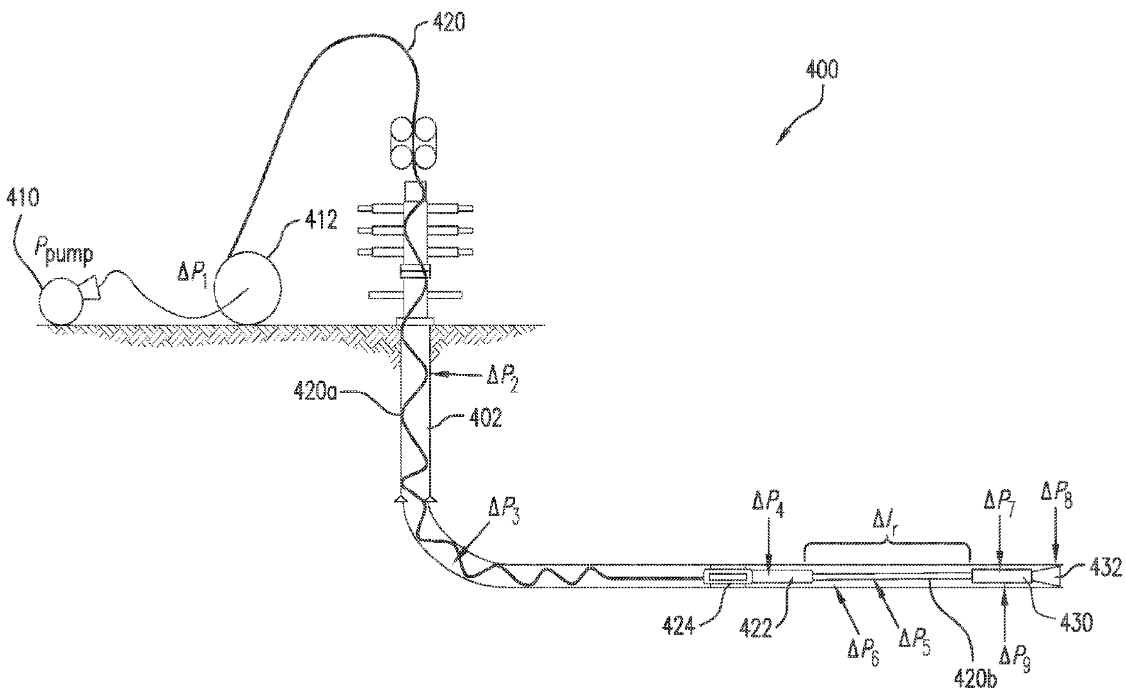
CPC ***E21B 17/20*** (2013.01); *E21B 44/00* (2013.01); ***E21B 7/061*** (2013.01)

(57) **ABSTRACT**

System and methods for optimizing coiled tubing string configurations for drilling a wellbore are provided. A length of a rotatable segment of a coiled tubing string having rotatable and non-rotatable segments is estimated based on the physical properties of the rotatable segment. A friction factor for the rotatable segment is calculated based on the estimated length. An effective axial force for one or more points of interest along the non-rotatable and rotatable string segments is calculated, based in part on the friction factor. Upon determining that the effective axial force for at least one point of interest exceeds a predetermined maximum force threshold, an effective distributive friction factor is estimated for at least a portion of the non-rotatable segment of the string. The rotatable and non-rotatable string segments are redefined for one or more sections of the wellbore along a planned trajectory, based on the effective distributive friction factor.



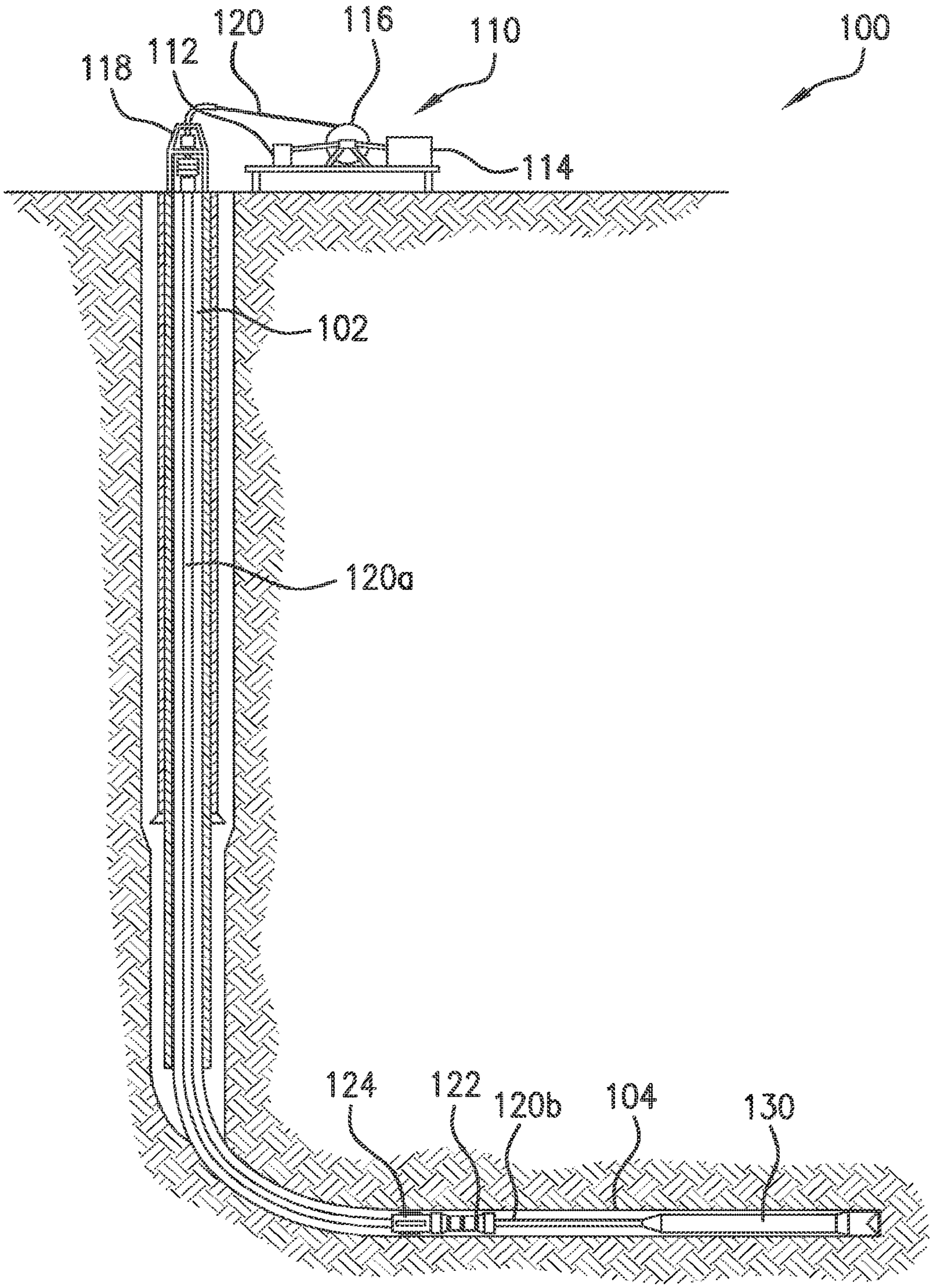


FIG. 1A

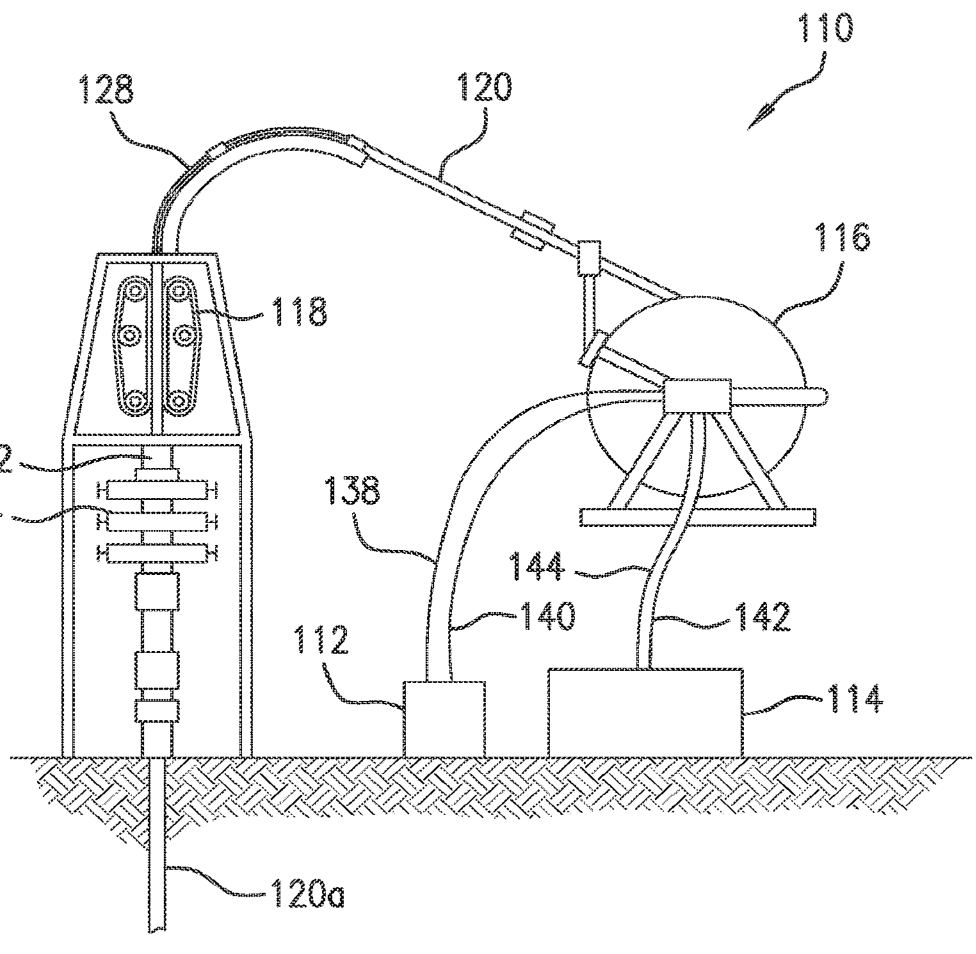


FIG.1B

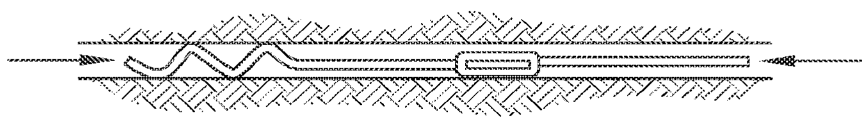


FIG. 2A

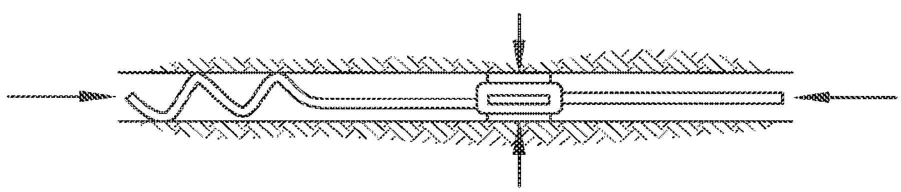


FIG. 2B

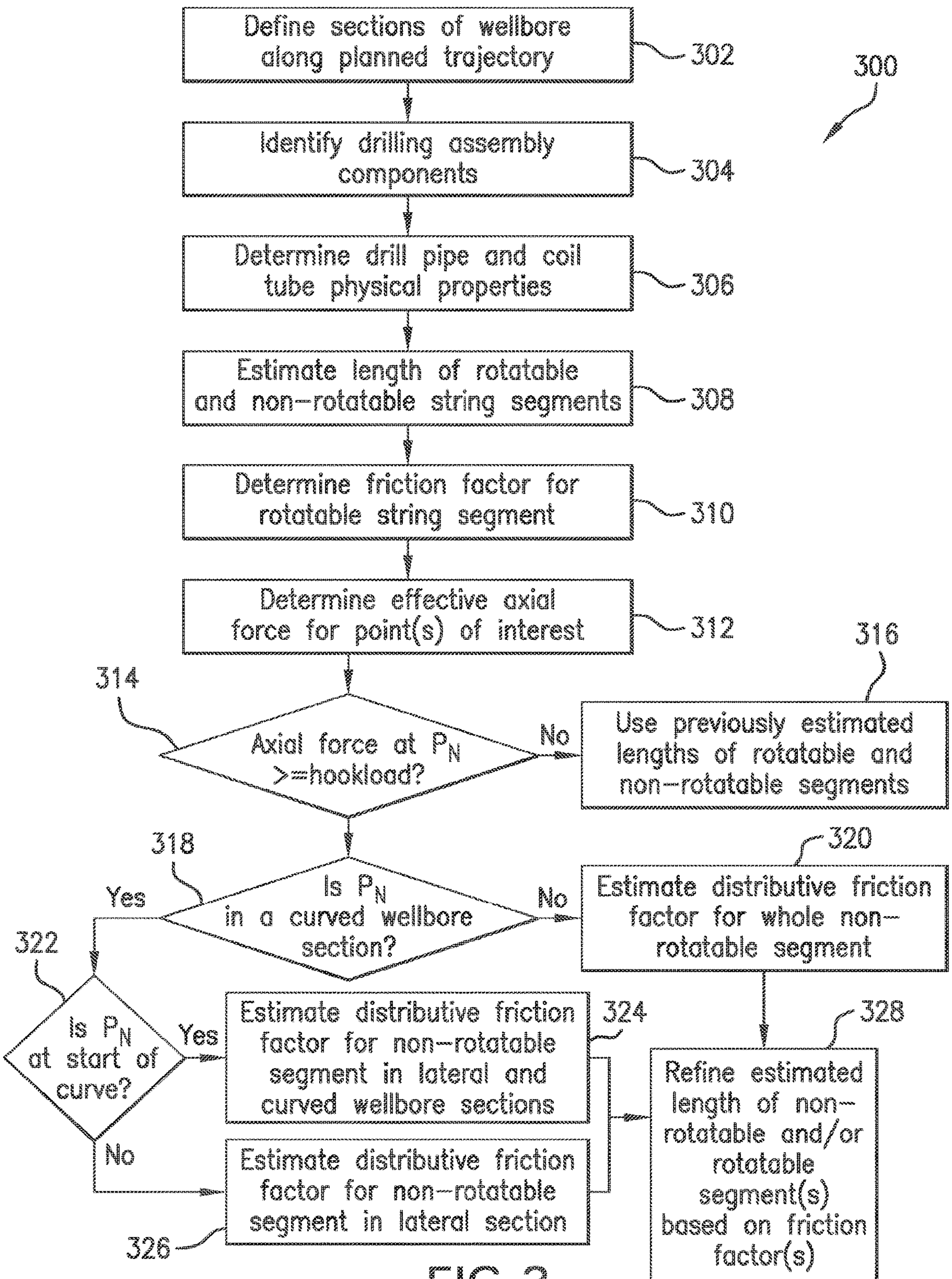
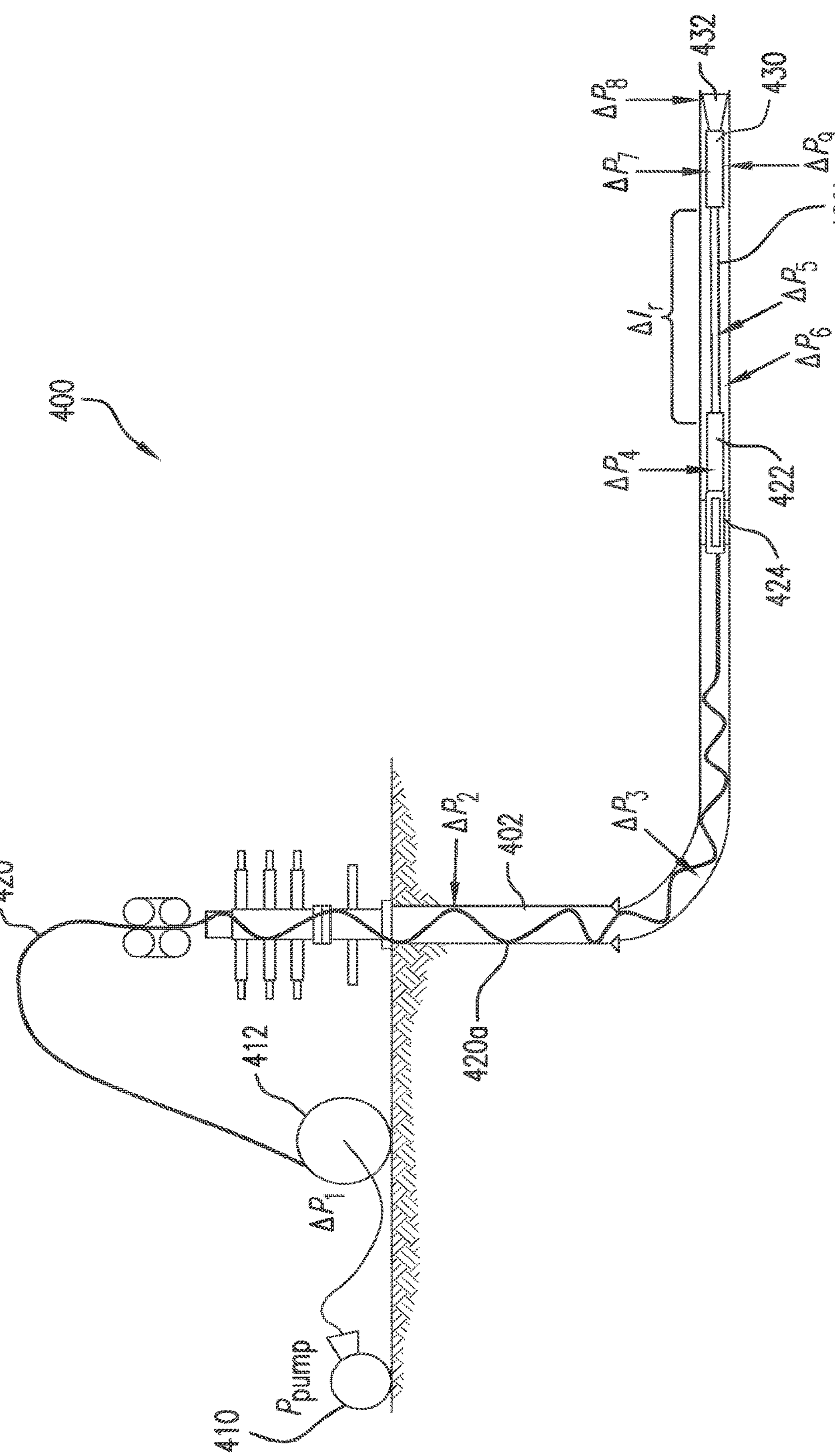

Define sections of wellbore along planned trajectory
302
300
Identify drilling assembly components
304
Determine drill pipe and coil tube physical properties
306
Estimate length of rotatable and non-rotatable string segments
308
Determine friction factor for rotatable string segment
310
Determine effective axial force for point(s) of interest
312
314
Axial force at P_N >=hookload?
No
316
Use previously estimated lengths of rotatable and non-rotatable segments
318
Is P_N in a curved wellbore section?
Yes
No
320
Estimate distributive friction factor for whole non-rotatable segment
322
Is P_N at start of curve?
Yes
Estimate distributive friction factor for non-rotatable segment in lateral and curved wellbore sections
324
No
Estimate distributive friction factor for non-rotatable segment in lateral section
326
328
Refine estimated length of non-rotatable and/or rotatable segment(s) based on friction factor(s)

FIG.3



400
410
P_{pump}
412
ΔP_1
420
420a
402
ΔP_2
ΔP_3
424
422
ΔP_4
Δl_r
ΔP_5
ΔP_6
420b
ΔP_7
ΔP_9
430
ΔP_8
432

FIG. 4

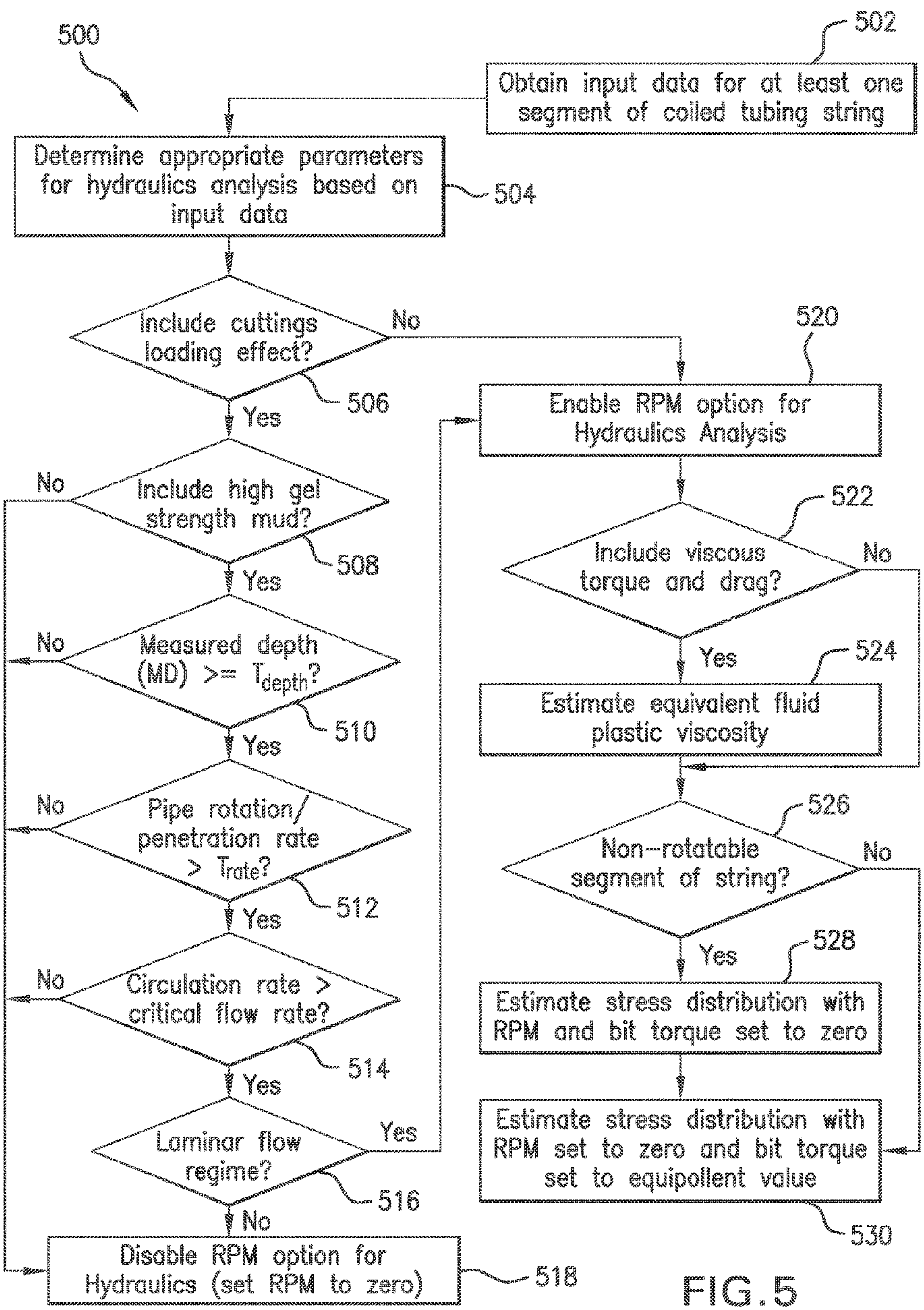

500
502
Obtain input data for at least one segment of coiled tubing string
Determine appropriate parameters for hydraulics analysis based on input data
504
Include cuttings loading effect?
506
No
Yes
520
Enable RPM option for Hydraulics Analysis
Include high gel strength mud?
508
Measured depth (MD) >= T_depth?
510
Pipe rotation/ penetration rate > Trate?
512
Circulation rate > critical flow rate?
514
Laminar flow regime?
516
Disable RPM option for Hydraulics (set RPM to zero)
518
522
Include viscous torque and drag?
524
Estimate equivalent fluid plastic viscosity
526
Non-rotatable segment of string?
528
Estimate stress distribution with RPM and bit torque set to zero
Estimate stress distribution with RPM set to zero and bit torque set to equipollent value
530

FIG. 5

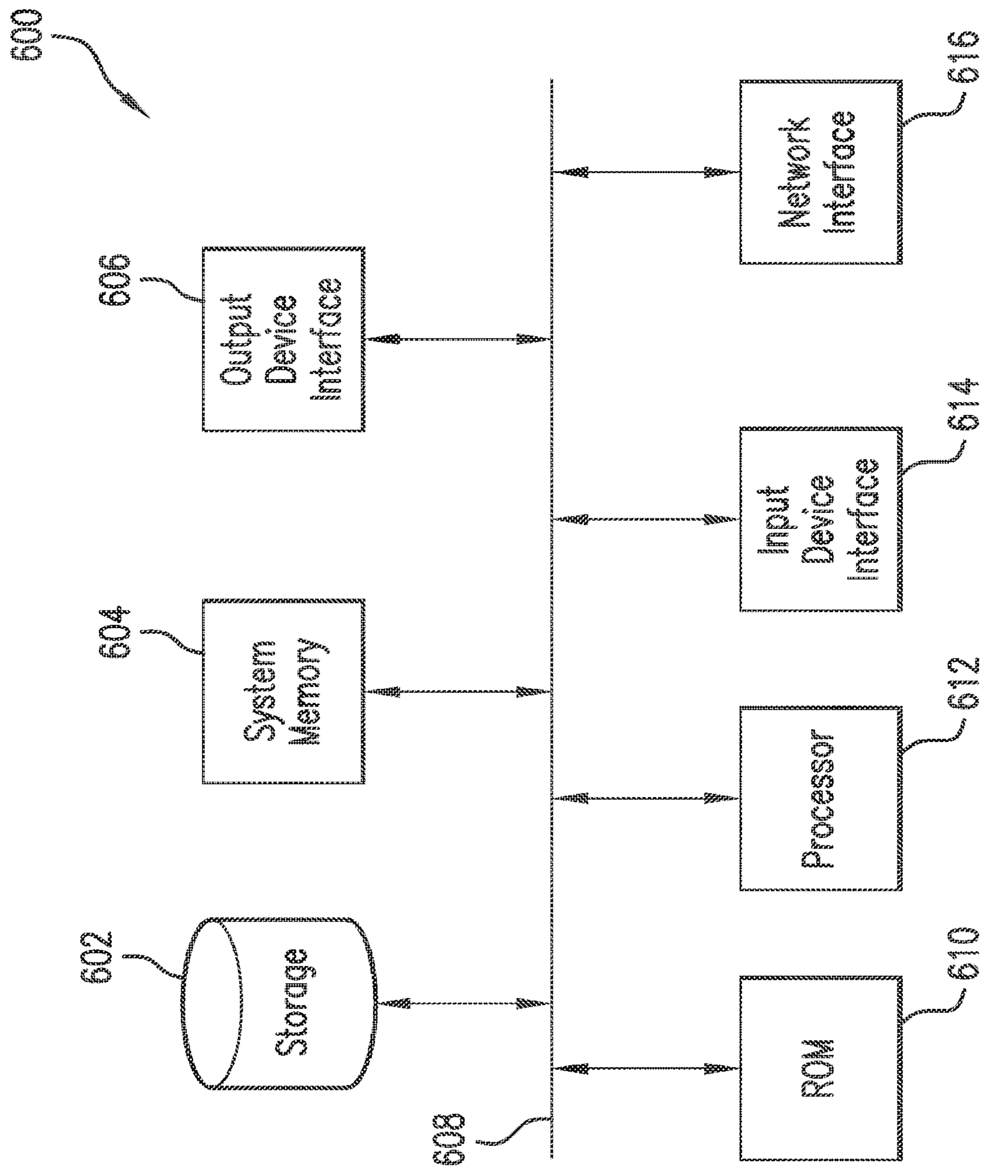

600
602
Storage
604
System Memory
606
Output Device Interface
608
610
ROM
612
Processor
614
Input Device Interface
616
Network Interface

FIG.6

OPTIMIZED COILED TUBING STRING DESIGN AND ANALYSIS FOR EXTENDED REACH DRILLING

FIELD OF THE DISCLOSURE

[0001] The present disclosure relates generally to directional drilling operations using coiled tubing and, more particularly, to extending the reach of coiled tubing within subterranean formations during directional drilling operations.

BACKGROUND

[0002] To obtain hydrocarbons, such as oil and gas, boreholes are drilled by rotating a drill bit attached to the end of a drill string. Advances in drilling technology have led to the advent of directional drilling, which involves a drilling deviated or horizontal wellbore to increase the hydrocarbon production from subterranean formations. Modern directional drilling systems generally employ a drill string having a bottom-hole assembly (BHA) and a drill bit situated at an end thereof. The BHA and drill bit may be rotated by rotating the drill string from the surface, using a mud motor (i.e., downhole motor) arranged downhole near the drill bit, or a combination of the mud motor and rotation of the drill string from the surface. Pressurized drilling fluid, commonly referred to as "mud" or "drilling mud," is pumped into the drill pipe to cool the drill bit and flush cuttings and particulates back to the surface for processing. The mud may also be used to rotate the mud motor and thereby rotate the drill bit.

[0003] In some drilling systems, the drill string may be implemented using coiled tubing, typically composed of metal or some type of composite material. Advantages of using such coiled tubing strings include eliminating the need for conventional rigs and drilling equipment. However, the inability to rotate the tubing is one of the primary disadvantages of conventional coiled tubing strings, as this limits the reach of the string and deviated portion of the wellbore within the formation. Also, conventional coiled tubing strings are likely to buckle as the BHA penetrates the borehole deeper into the formation. Buckling is particularly acute in deviated wells where gravity does not assist in forcing the tubing downhole. Depending on the amount of deviation and the compression of the drill string, the drill string may take on a lateral or sinusoidal buckling mode. When the drill string is in the lateral bucking mode, further compression of the drill string may cause the drill string enters a helical buckling mode. The helical bucking mode may also be referred to as "corkscrewing."

[0004] Buckling may result in loss of efficiency in the drilling operation and premature failure of one or more drill string components. For example, as the tubing buckles, the torque and drag created by the contact with the borehole becomes more difficult to overcome and often makes it impractical or impossible to use coiled tubing to reach distant bypassed hydrocarbon zones. Further, steel coiled tubing often fatigues from cyclic bending early in the drilling process and must be replaced. In such cases, coiled tubing may be as expensive to use for extended reach drilling as a conventional drilling system with jointed steel pipe and a rig.

BRIEF DESCRIPTION OF THE DRAWINGS

[0005] FIG. **1**A is a diagram of an illustrative drilling system for drilling a deviated wellbore through a subsurface formation using a segmented coiled tubing string configuration with a downhole motor located upstream from the string's bottom hole assembly.

[0006] FIG. **1**B is an enlarged view of a portion of the drilling system of FIG. **1**A located at the surface of the wellbore.

[0007] FIG. **2**A is a schematic view of a segmented coiled tubing string for which frictional forces induced by an upstream downhole motor are shown for different segments of the string.

[0008] FIG. **2**B is a schematic view of another segmented coiled tubing string for which frictional forces induced by an upstream downhole motor with a twisting-restraining tool are shown for different segments of the string.

[0009] FIG. **3** is a flowchart of an illustrative process for estimating a distributive friction factor for different segments of a coiled tubing string configuration along different sections of a planned wellbore to be drilled within a subsurface formation.

[0010] FIG. **4** is a schematic view of an illustrative drilling system including a segmented coiled tubing string with a downhole motor located upstream from the string's bottom hole assembly for drilling a deviated wellbore through a subsurface formation.

[0011] FIG. **5** is a flowchart of an illustrative process for analyzing the effect of a segmented coiled tubing string configuration on fluid flow characteristics in one or more sections of the planned wellbore of FIG. **3**.

[0012] FIG. **6** is a block diagram of an illustrative computer system in which embodiments of the present disclosure may be implemented.

DESCRIPTION OF ILLUSTRATIVE EMBODIMENTS

[0013] Embodiments of the present disclosure relate to optimizing the design and analysis of coiled tubing strings for drilling deviated wellbores within a subsurface formation. While the present disclosure is described herein with reference to illustrative embodiments for particular applications, it should be understood that embodiments are not limited thereto. Other embodiments are possible, and modifications can be made to the embodiments within the spirit and scope of the teachings herein and additional fields in which the embodiments would be of significant utility.

[0014] In the detailed description herein, references to "one embodiment," "an embodiment," "an example embodiment," etc., indicate that the embodiment described may include a particular feature, structure, or characteristic, but every embodiment may not necessarily include the particular feature, structure, or characteristic. Such phrases are not necessarily referring to the same embodiment. Further, when a particular feature, structure, or characteristic is described in connection with an embodiment, it is submitted that it is within the knowledge of one skilled in the art to implement such feature, structure, or characteristic in connection with other embodiments whether or not explicitly described.

[0015] It would also be apparent to one of skill in the relevant art that the embodiments, as described herein, can be implemented in many different embodiments of software, hardware, firmware, and/or the entities illustrated in the figures. Any actual software code with the specialized control of hardware to implement embodiments is not limiting of the detailed description. Thus, the operational behavior of embodiments will be described with the understanding that modifications and variations of the embodiments are possible, given the level of detail presented herein.

[0016] The disclosure may repeat reference numerals and/or letters in the various examples or figures. This repetition is for the purpose of simplicity and clarity and does not in itself dictate a relationship between the various embodiments and/or configurations discussed. Further, spatially relative terms, such as beneath, below, lower, above, upper, uphole, downhole, upstream, downstream, and the like, may be used herein for ease of description to describe one element or feature's relationship to another element(s) or feature(s) as illustrated, the upward direction being toward the top of the corresponding figure, the downward direction being toward the bottom of the corresponding figure, the uphole and upstream directions being toward the surface of the wellbore, and the downhole and downstream directions being toward the toe of the wellbore. Likewise, the term "proximal" may be used herein to refer to the upstream or uphole direction with respect to a particular component of a drill string, and the term "distal" may be used herein to refer to the downstream or downhole direction with respect to a particular drill string component. Unless otherwise stated, the spatially relative terms are intended to encompass different orientations of the apparatus in use or operation in addition to the orientation depicted in the figures. For example, if an apparatus in the figures is turned over, elements described as being "below" or "beneath" other elements or features would then be oriented "above" the other elements or features. Thus, the exemplary term "below" can encompass both an orientation of above and below. The apparatus may be otherwise oriented (rotated 90 degrees or at other orientations) and the spatially relative descriptors used herein may likewise be interpreted accordingly.

[0017] Moreover even though a figure may depict a horizontal wellbore or a vertical wellbore, unless indicated otherwise, it should be understood by those skilled in the art that the apparatus according to the present disclosure is equally well suited for use in wellbores having other orientations including vertical wellbores, slanted wellbores, multilateral wellbores or the like. Likewise, unless otherwise noted, even though a figure may depict an onshore operation, it should be understood by those skilled in the art that the apparatus according to the present disclosure is equally well suited for use in offshore operations and vice-versa. Further, unless otherwise noted, even though a figure may depict a cased hole, it should be understood by those skilled in the art that the apparatus according to the present disclosure is equally well suited for use in open hole operations.

[0018] As will be described in further detail below, embodiments of the present disclosure may be used to optimize the design and analysis of a segmented coiled tubing string configured with a downhole motor located upstream from the string's bottom hole assembly for drilling a deviated wellbore within a subsurface formation. In one or more embodiments, the coiled tubing string may include a non-rotatable segment that extends from the surface of the wellbore to a proximal end of a downhole motor. The distal end of the downhole motor may be attached to a rotatable segment of the string that extends from the motor to a bottom hole assembly (BHA) attached to the end of the string. The BHA may include, for example, a rotary steerable tool and a drill bit for drilling the wellbore along a planned path through the subsurface formation in addition to various measurement-while-drilling (MWD) and/or logging-while-drilling (LWD) sensors for collecting different types of downhole data while the wellbore is drilled. In contrast with conventional drill string configurations in which the downhole motor is integrated within the BHA at the end of the string, the downhole motor of the coiled tubing string described herein is attached to the string as a separate component that is located upstream from the BHA and therefore, may be referred to herein as an "upstream downhole motor" or simply, "upstream motor." The use of such an upstream motor may also be more cost effective than using conventional articulated tractor technique for extended-reach drilling operations, as the rotation of a significant length of the string may significantly reduce the cuttings bed volume in the lateral section of the wellbore and thereby reduce operating costs allotted to the surface pump that is generally used in coiled tubing systems.

[0019] During the drilling operation, the upstream motor may be used to rotate the rotatable segment of the string including the drill bit at the very end of the string for purposes of drilling the wellbore through the subsurface formation. The rotational forces applied to the rotatable segment of the string by the motor may cause significant twisting of the non-rotatable segment of the string. Such twisting can destabilize the coiled tubing string and limit the reach of the string and wellbore within the subsurface formation. In some implementations, a stabilizer or twisting-restraining tool may be placed between the upstream motor and the non-rotatable segment to prevent or at least mitigate any twisting that may occur in this portion of the string. However, the non-rotatable segment of the string may still be subjected to high axial compressive forces, particularly in curved or tortuous sections of the wellbore path, which can lead to buckling that also limits the reach of the string during the drilling operation. Therefore, an effective design and implementation of such a coiled tubing string configuration should account for the drilling forces expected during a directional drilling operation so as to ensure that such forces remain within an optimal range over the course of the operation and thereby maximize the rate of penetration and reach of the string and wellbore within the formation.

[0020] Illustrative embodiments and related methodologies of the present disclosure are described below in reference to FIGS. **1A-6** as they might be employed, for example, in a computer system for well planning and analysis. For example, the disclosed techniques may be implemented as part of a comprehensive workflow provided by a well engineering application executable at the computer system for analyzing different sets of parameters related to the coiled tubing string configuration described above during the design and/or implementation phases of a directional drilling operation. Such a workflow may be used to optimize the configuration of the coiled tubing string as well as the different types of analysis that may be performed on the string configuration for a particular drilling operation. Other features and advantages of the disclosed embodiments will be or will become apparent to one of ordinary skill in the art upon examination of the following figures and detailed description. It is intended that all such additional features and advantages be included within the scope of the disclosed embodiments. Further, the illustrated figures are only exemplary and are not intended to assert or imply any limitation with regard to the environment, architecture, design, or process in which different embodiments may be implemented.

[0021] FIG. **1**A is a diagram of an illustrative drilling system **100** for drilling a deviated wellbore through a subsurface formation using a segmented coiled tubing string configuration with a downhole motor located upstream from the string's bottom hole assembly. As shown in FIG. **1**A, system **100** includes a coiled tubing control system **110** at the surface of a wellbore **102**. Control system **110** includes a power supply **112**, a surface processing unit **114**, and a coiled tubing spool **116**. An injector head unit **118** feeds and directs a drill string or coiled tubing string **120** from spool **116** into wellbore **102**. Coiled tubing string **120** includes a non-rotatable segment **120***a* that extends from the surface of wellbore **102** to a proximal end of a downhole motor **122** and a twisting-restraining tool **124**. The distal end of downhole motor **122** is attached to a rotatable segment **120***b* of string **120** within a horizontal or lateral section **104** of wellbore **102**.

[0022] Downhole motor **122** may be, for example, a hydraulic motor (e.g., a mud motor) used to rotate rotatable segment **120***b* along with the drill bit attached to a BHA **130** at the very end of string **120** for purposes of drilling wellbore **102** through the subsurface formation. However, it should be appreciated that the disclosed embodiments are not limited to hydraulic motors and that other types of motors (e.g., electric motors) may be used instead. Twisting-restraining tool **124** may be, for example, a stabilizer or other drill string component for restraining non-rotatable segment **120***a* of coiled tubing string **120** to prevent or at least mitigate any twisting of this portion of the string due to the rotational forces applied by motor **122** during the drilling operation. As downhole motor **122** in this example is a separate component of string **120** that is located upstream of BHA **130**, downhole motor **122** may be referred to as an "upstream motor," as described above.

[0023] In one or more embodiments, BHA **130** may include a drill bit and one or more downhole tools within a housing that may be moved axially within wellbore **102** as attached to coiled tubing string **120**. Examples of such downhole tools may include, but are not limited to, a rotary steerable tool and one or more MWD and/or LWD tools for collecting downhole data related to formation characteristics and drilling conditions over different stages of the drilling operation. In some implementations, one or more force sensors (not shown) may be distributed along coiled tubing string **120** and BHA **130** for measuring physical force, strain, or material stress at different points along coiled tubing string **120** and BHA **130**.

[0024] The data collected by such downhole tools and sensors may be transmitted to surface processing unit **114** via telemetry (e.g., mud pulse telemetry) or electrical signals transmitted via a wired or wireless connection between BHA **130** and surface processing unit **114**, as will be described in further detail below. Surface processing unit **114** may be implemented using, for example, any type of computing device including at least one processor and a memory for storing data and instructions executable by the processor. Such a computing device may also include a network interface for exchanging information with a remote computing device via a communication network, e.g., a local-area or wide-area network, such as the Internet. An example of such a computing device will be described in further detail below with respect to FIG. **6**.

[0025] FIG. **1**B is an enlarged view of coiled tubing control system **110** of drilling system **100** shown in FIG. **1**A, as described above. As shown in FIG. **1**B, control system **110** includes a spool **116** for feeding coiled tubing string **120** over a guide **128** and through an injector **118** in line with a stripper **132**. In operation, coiled tubing string **120** is forced by injector **118** through a blowout preventer **134** into the subsurface formation. A power supply **112** is electrically connected by electrical conduits **138** and **140** to corresponding electrical conduits in the wall of coiled tubing string **120**.

[0026] Also, as shown in FIG. **1**B, surface processing unit **114** includes communication conduits **142** and **144** that are connected to corresponding conduits housed in the wall of coiled tubing string **120**. It should be appreciated that while only power conduits **138**, **140** and communication conduits **142**, **144** are shown in FIG. **1**B, any number of power conduits and/or communication conduits may be used as desired for a particular implementation. It should also be appreciated that power conduits **138**, **140** and communication conduits **142**, **144** may extend along the entire length of coiled tubing string **120**.

[0027] Referring back to FIG. **1**A, power conduits **138**, **140** and communication conduits **142**, **144** in some implementations may also be connected to downhole motor **122** and BHA **130** or component thereof. In one or more embodiments, communication conduits **142** and **144** may be used to transfer data and communication signals between surface processing unit **114** and BHA **130** or component(s) thereof. For example, communication conduits **142** and **144** may be used to transfer downhole measurements collected by MWD and/or LWD components of BHA **130** to surface processing unit **114**. Additionally, surface processing unit **114** may use conduits **142** and **144** to send control signals to BHA **130** for controlling the operation of BHA **130** or individual components thereof. In this way, surface processing unit **114** may implement different kinds of functionality, e.g., adjusting the planned trajectory of the wellbore, during different stages of the drilling operation. Similarly, surface processing unit **114** may use conduits **142** and **144** to send control signals for controlling the operation of downhole motor **122** during the drilling operation.

[0028] In one or more embodiments, surface processing unit **114** may provide an interface enabling a drilling operator at the surface to adjust various drilling parameters to control the drilling operation as different sections of wellbore **102** are drilled through the subsurface formation. The interface may include a display for presenting relevant information, e.g., values of drilling parameters, to the operator during the drilling operation as well as a user input device (e.g., a mouse, keyboard, touch-screen, etc.) for receiving input from the operator. As downhole operating conditions may continually change over the course of the operation, the operator may use the interface provided by surface processing unit **114** to react to such changes in real time and adjust various drilling parameters from the surface in order to optimize the drilling operation. Examples of drilling parameters that may be adjusted include, but are not limited to, weight on bit, drilling fluid flow through the drill pipe, the drill string rotational speed, and the density and viscosity of the drilling fluid.

[0029] As described above, the rotational forces applied to the rotatable segment of a coiled tubing string, such as string **120**, by an upstream downhole motor may cause significant twisting of the non-rotatable segment of the string. Conventional wellbore analysis techniques are generally designed to implement and analyze directional drilling operations using conventional coiled-tubing or jointed-pipe strings. However, an effective design and implementation of a directional drilling operation using the segmented coiled tubing string configuration described herein should account for the types of forces that may be imposed on different segments of the string during the drilling operation, as shown in FIGS. **2**A and **2**B.

[0030] FIG. **2**A is a schematic view of a portion of a segmented coiled tubing string that illustrates the various axial forces that may be induced by such an upstream downhole motor. FIG. **2**B is a schematic view of the portion of the segmented coiled tubing string shown in FIG. **2**A, which shows the additional friction that may be induced by a twisting-restraining tool, such as twisting-restraining tool **124** of FIG. **1**A. To obtain the same force boundary conditions as in FIG. **2**A, i.e., where no twisting-restraining tool is used, the additional frictional drag forces may be distributed over a selected length of the non-rotatable segment of the string.

[0031] In one or more embodiments, inversion techniques may be used to estimate an effective-distributive friction factor representing the distribution of frictional forces for any cumulative length of the non-rotatable segment of the string. The primary aim of the techniques that are used may be to ensure that the force boundary conditions estimated for starting and ending points of the non-rotatable segment of a string design are representative of the real-world conditions that may be expected during the actual drilling operation.

[0032] The value of the effective-distributive friction factor may depend on, for example, the length of the non-rotatable segment of the string. In one or more embodiments, the length of the non-rotatable segment may be constrained to a predetermined length of the string over which the frictional forces are to be distributed. The length of the non-rotatable string segment may be based on, for example, physical properties of this segment of the string. Examples of such physical properties include, but are not limited to, the torsional yield strength of the tubing material associated with this section of the string and the weight of the string. Other factors that may constrain the length of the non-rotatable segment in the string design may include the planned trajectory of the wellbore (or tortuosity thereof) and the viscosity of the drilling fluid that may be used during the drilling operation.

[0033] The effective-distributive friction factor for different portions of a particular string configuration may be expressed using Equation (1) as follows:

$$\frac{dF_t}{dx_j} - \left[\sum_{k=1}^{r} \mu_k \xi_k w_{c,k}\right]_j + w_p \cos\varphi_j \tag{1}$$

[0034] where ξ_k is a Boolean parameter that defines the string configuration for the non-rotatable segment of the string along a particular section of the wellbore; k is an index defining the tubing configuration; j is an index defining the section of the wellbore for which an effective distributive friction factor may be applied to a corresponding portion of the non-rotatable string segment; $w_{c,k}$ is the wall contact force acting on the string; $w_p \cos \varphi_j$ is the string weight component in the axial direction; and F_t is the axial force in the string.

[0035] In one or more embodiments, the effective-distributive friction factor may be estimated for the non-rotatable segment of the coiled tubing string as part of a workflow for developing an overall well plan for a directional drilling operation. As will be described in further detail below with respect to FIGS. **3**-**5**, such a workflow may involve performing different types of analyses, including, but not limited to, a torque and drag analysis and a hydraulics analysis, for the non-rotatable and rotatable segments of the coiled tubing string configuration.

[0036] In one or more embodiments, the steps of the workflow may be implemented as part of the functionality provided by a well engineering application executable at a computing device of a user (e.g., drilling engineer). The computing device may be implemented using any type of computing device having at least one processor and a processor-readable storage medium for storing data and instructions executable by the processor. As will be described in further detail below with respect to FIG. **6**, such a computing device may also include an input/output (I/O) interface for receiving user input or commands via a user input device, e.g., a mouse, a QWERTY or T9 keyboard, a touch-screen, a graphics tablet, or a microphone. The I/O interface also may be used by each computing device to output or present information to a user via an output device. The output device may be, for example, a display coupled to or integrated with the computing device for displaying various types of information, including information related to the torque and drag and hydraulics analyses described herein.

[0037] FIG. **3** is a flowchart of an illustrative process **300** for estimating an effective-distributive friction factor for one or more segments of a coiled tubing string configuration along different sections of a deviated wellbore to be drilled along a planned trajectory within a subsurface formation. For discussion purposes, process **300** will be described using drilling system **100** of FIGS. **1**A and **1**B, as described above. However, process **300** is not intended to be limited thereto. For example, the coiled tubing string configuration for which the effective-distributive friction factor is estimated may be coiled tubing string **120** of FIGS. **1**A and **1**B, as described above. As described above, the deviated wellbore in this example may be drilled using an upstream downhole motor (e.g., downhole motor **122** of FIG. **1**A, as described above), which rotates a drill bit of a BHA attached to the end of a rotatable segment of the coiled tubing string. The rotatable segment of the string may be attached to a distal end of the downhole motor while a non-rotatable segment extending from the surface of the wellbore is attached to a proximal end of the motor.

[0038] As shown in FIG. **3**, process **300** begins in step **302**, which includes defining a plurality of sections for the planned wellbore trajectory to be drilled within the subsurface formation. The sections that may be defined in step **302** may include, for example, vertical, curved, and lateral sections of the planned wellbore trajectory. As will be described in further detail below, the effective-distributive friction factor estimated using process **300** may be used to refine a previously estimated length of the rotatable and/or non-rotatable segments of the string for one or more of these sections of the planned wellbore trajectory, e.g., as part of the overall well plan being developed for the directional drilling operation in this example.

[0039] In step **304**, components of the coiled tubing string associated with each of the non-rotatable and rotatable segments are identified. The components that may be identified for the non-rotatable segment may include, for example and without limitation, one or more stabilizers or twisting-restraining tool(s) (e.g., twisting-restraining tool **124** of FIG. **1**A, as described above). The physical or mechanical properties of the non-rotatable and rotatable string segments along the wellbore trajectory are then determined in step **306**. In step **308**, a length of the rotatable segment of the string along one or more sections of the wellbore may be estimated, based on the corresponding properties of the rotatable segment within one or more wellbore sections. Similarly, the length of the non-rotatable segment may be estimated based on the corresponding properties of the non-rotatable segment within one or more wellbore sections.

[0040] In one or more embodiments, the length of the rotatable segment of the string may be estimated using a three-dimensional (3D) torque and drag model, e.g., as expressed by Equation (2):

$$l_R = \frac{M_t - \mu_j r_p \int_{\beta^*}^{\beta^{**}} w_c R d\beta - M_{bit} - \mu_j \sin\varphi \sum_{i=1}^{k} w_{p,i} l_i r_{p,i}}{\mu_j r_p w_p \sin\varphi} + R(\beta^{**} - \beta^*) + \sum_{i=1}^{k} l_i \tag{2}$$

where β* and β** may represent curved sections of the wellbore trajectory, e.g., in the form of dog legs, within the subsurface formation. The estimated length may exclude the portions of the rotatable segment corresponding to the downhole motor and the BHA.

[0041] In the above torque and drag model according to Equation (3), it is assumed that no surface pump constraints are imposed on the downhole coiled tubing string, e.g., as in drilling system **100** of FIGS. **1**A and **1**B, as described above. However, a different model may be used to estimate the rotatable length of the coiled tubing string when constraints are imposed on the string by a surface pump, as shown in the example of FIG. **4**.

[0042] FIG. **4** is a schematic view of an illustrative drilling system **400** including a surface pump coupled to a segmented coiled tubing string configuration with a downhole motor **422** located upstream from the BHA for drilling a deviated wellbore through a subsurface formation. As shown in FIG. **4**, a surface pump **410** may be used to pump or inject pressurized drilling fluid, e.g., drilling mud, into a wellbore **402** via a coiled tubing string **420** fed from a spool **412** at the surface of the wellbore. While not shown in FIG. **4**, it should be appreciated that spool **412** may be part of a coiled tubing control system that includes a power supply and a surface processing unit, e.g., similar to control system **110** of FIGS. **1**A and **1**B, as described above. The drilling fluid may be used, for example, to cool a drill bit **432** attached to the end of a BHA **430** as well as to flush cuttings and particulates back to the surface during the drilling operation. In some implementations, downhole motor **422** may be a hydraulic motor (e.g., a mud motor) and the drilling fluid (e.g., mud) may also be used to rotate the motor and thereby rotate drill bit **432**.

[0043] Similar to coiled tubing string **120** of drilling system **100** of FIGS. **1**A and **1**B, described above, coiled tubing string **420** includes a non-rotatable segment **420***a* that extends from the surface of wellbore **402** and attaches to a proximal end of downhole motor **422** and a twisting-restraining tool **424**. The distal end of downhole motor **422** is attached to a rotatable segment **420***b* of string **420**, which is located within a horizontal or lateral section of wellbore **402** in this example. In contrast with drilling system **100** of FIGS. **1**A and **1**B, the use of surface pump **410** in system **400** may impose constraints on coiled tubing string **420** within wellbore **402**.

[0044] For example, the pressurized fluid injection capability or discharge capacity of surface pump **410** may constrain the length of rotatable segment **420***b* during the drilling operation. In one or more embodiments, the amount of pressure change (ΔP) may be estimated for different points of interest along the length of coiled tubing string **420**. In the example as shown in FIG. **4**, ΔP_4 may represent the pressure drop at downhole motor **422** while ΔP_5 and ΔP_6 may represent pressure drops in the drill pipe/tubing and annulus, respectively, corresponding to rotatable segment **420***b*. Accordingly, the pressure drop ΔP_L along coiled tubing string **420**, excluding downhole motor **422** and rotatable string segment **420***b*, may be expressed as the sum of the pressure drop values at the remaining points of interest along the length of coiled tubing string **420**, as expressed by Equation (3):

$$\Delta P_1+\Delta P_2+\Delta P_3+\Delta P_7+\Delta P_8+\Delta P_9=\Delta P_L \tag{3}$$

[0045] In one or more embodiments, the constrained length and/or other dimensions of the rotatable string segment may be estimated based on an optimization technique that accounts for such surface constraints on the string configuration at different points within wellbore **402**. Such an optimization technique may be based on, for example, a Pareto optimization or Lagrange multiplier. The objectives of the optimization may include maximizing the total measured depth (l_{md}), maximizing the total length (l_r) of rotatable segment **420***b*, and minimizing the pressure drop within rotatable segment **420***b* of coiled tubing string **420**, as expressed by Equations (4), (5), and (6), respectively:

$$\text{Maximize: } l_{md}=\Sigma_{j=1}{}^{t} l_j \tag{4}$$

$$\text{Maximize: } \Delta l_r=f(\Delta P_4, \vec{\chi}) \tag{5}$$

$$\text{Minimize: } \Delta P_5=f(\Delta l_r, \vec{\psi}) \tag{6}$$

where $\vec{\chi}$ and $\vec{\psi}$ are vectors of parameters affecting the rotating length estimation which can be optimized in the process of determining constrained optimum value of the length. As used herein, the term "measured depth" may refer to a depth of the string that is estimated or expected to be measured for one or more sections of the wellbore once it is actually drilled along its planned trajectory within the subsurface formation.

[0046] The constraints for the above-described optimization technique may be expressed by Equations (7), (8), and (9) as follows:

$$P_{pump}=\Sigma_{j=1}^{9}\Delta P_j \tag{7}$$

$$\sigma_{MSE}<\sigma_Y \tag{8}$$

$$F_0=\zeta \tag{9}$$

where P_{pump} is the pumping pressure, σ_{MSE} is the mechanical specific energy of the string, σ_y is the string's yield strength, F_0 is the force applied to a top portion or proximal end of the string's downhole assembly or BHA within the subsurface formation, ζ is the force applied at a bottom portion or distal end of the string's downhole assembly or BHA within the subsurface formation.

[0047] Referring back to FIG. **3**, once the length of the rotatable segment is estimated in step **308**, e.g., using either the torque and drag model or the optimization technique as described above, process **300** then proceeds to step **310**, which includes calculating a friction factor for the rotatable segment based on the estimated length. In step **312**, an effective axial force may be estimated for one or more points of interest along the non-rotatable and rotatable segments of the drill string, based in part on the friction factor calculated for the rotatable segment in step **310**.

[0048] Process **300** then proceeds to step **314**, which includes determining whether or not the effective axial force estimated in step **312** for at least one point of interest exceeds a predetermined maximum hook load threshold. If it is determined that there are no points of interest for which the effective axial force exceeds the predetermined maximum hook load threshold, process **300** proceeds to step **316**, in which the previously estimated length of the rotatable string segment (from step **308**) for one or more sections of the wellbore trajectory is used for the coiled tubing string design. However, if the effective axial force for at least one point of interest is determined to exceed the predetermined maximum hook load threshold, process **300** proceeds to step **318**, which includes determining whether or not the particular point of interest is within or corresponds to a curved section of the wellbore.

[0049] If it is determined in step **318** that the point of interest does not to correspond to a curved wellbore section, process **300** proceeds to step **320**, which includes estimating the effective-distributive friction factor for the entire non-rotatable segment of the drill string, including for portions of the non-rotatable segment within the vertical, curved, and/or lateral sections of the planned wellbore trajectory. However, if the point of interest is determined to correspond to a curved wellbore section, process **300** proceeds to step **322**, which includes determining whether or not the point of interest is located on a part of the non-rotatable string segment at or near the start of the curved section.

[0050] If the particular point of interest is determined in step **322** to be located at or near the start of the curved section, process **300** proceeds to step **324**, which includes estimating the effective-distributive friction factor for a portion of the non-rotatable segment corresponding to the curved and lateral sections of the planned wellbore trajectory. Otherwise, it may be assumed that the point is located on a part of the non-rotatable string segment at or near the end of the curved section and process **300** proceeds to step **326**, which includes estimating the effective-distributive friction factor for a portion of the non-rotatable segment corresponding to only the lateral section of the planned wellbore trajectory. The effective-distributive friction factor that is estimated for the portion(s) of the non-rotatable segment in either of steps **320** or **326** may then be used in step **328** to refine the length of the non-rotatable segment as previously estimated (in step **308**) for one or more sections of the planned wellbore trajectory. In one or more embodiments, the refined length of the non-rotatable segment may also be used to refine the previously estimated length of the rotatable segment of the string.

[0051] In one or more embodiments, the steps of process **300**, including the estimation of the effective-distributive friction factor for the non-rotatable string segment as described above, may be part of a torque and drag analysis of the string configuration. The distributive friction factors resulting from the torque and drag analysis may then be incorporated into a hydraulics analysis for the string configuration. The hydraulics analysis may include, for example, analyzing the effect of rotating a portion of the coiled tubing string (e.g., rotatable segment **420***b* of string **420** of FIG. **4**, as described above) on the fluid flow characteristics expected for one or more sections of the wellbore along its planned trajectory through the subsurface formation.

[0052] In one or more embodiments, such an analysis may involve adjusting a plastic viscosity parameter of a drilling fluid to be used with the particular coiled tubing string configuration. The plastic viscosity parameter may be adjusted according to, for example, Equation (10):

$$K_2 = K_1\left[\frac{(\dot{\gamma}_1+\Delta\dot{\gamma})^n}{(\dot{\gamma}_1)^n}\right] \tag{10}$$

where K2 is the resultant plastic viscosity due to the rotation of the rotatable segment of the string, K1 is the initial plastic viscosity, and $\Delta\dot{\gamma}$ is the shear rate of deformation of the fluid as a result of the rotation of the string segment. In addition to adjusting the plastic viscosity parameter using Equation (10), the hydraulic analysis may include adjusting or calibrating operating parameters of the string configuration that may impact the fluid flow along the planned wellbore trajectory, as will be described in further detail below with respect to FIG. **5**.

[0053] FIG. **5** is a flowchart of an illustrative process **500** for analyzing the effect of a segmented coiled tubing string configuration on fluid flow characteristics in one or more sections of the planned wellbore of FIG. **3**, as described above. For discussion purposes, process **500** will be described using drilling system **100** of FIGS. **1**A and **1**B, as described above. However, process **500** is not intended to be limited thereto. Also, for discussion purposes, process **500** will be described using drilling system **400** of FIG. **4**, as described above, but is not intended to be limited thereto. For example, the coiled tubing string configuration may be implemented using either string **120** of FIGS. **1**A and **1**B or string **420** of FIG. **4**, as described above.

[0054] Process **500** begins in step **502**, which includes obtaining input data for initiating the hydraulics analysis for at least one segment of the coiled tubing string. The input data may include, for example, data related to the properties of the subsurface formation in which one or more sections of the wellbore are to be drilled along with the properties of the drilling fluid associated with the well plan. Additionally, the input data may include operating parameters associated with the drilling operation including, but not limited to, the rotation rate or rotary speed of the rotatable segment of the tubing string, e.g., as measured in revolutions per minute (RPM), which may initially be set to a value of zero. The input data may further include the pump rate and other parameters that may be relevant to the particular type of fluid to be used for drilling.

[0055] Process **500** then proceeds to step **504**, which includes determining appropriate parameters for the hydraulics analysis based on the input data. In addition to the fluid plastic viscosity parameter described above, examples of other parameters that may be considered for the hydraulics analysis include, but are not limited to, cuttings loading effect, mud type, measured depth, pipe rotation or penetration rate, circulation rate, and type of flow regime. As illustrated in the example of FIG. **5**, step **504** may be performed as a series of decisions regarding whether or not such parameters are to be included in the hydraulics analysis, as will be described in further detail below with respect to steps **506**, **508**, **510**, **512**, **514** and **516** of process **500**.

[0056] In one or more embodiments, such decisions may be made based on input from a user of a well engineering application executable at the user's computing device, as described above. For example, the steps of process **500** may be implemented as part of the functionality provided to the user by the well engineering application. In one or more embodiments, the user may access such functionality via a graphical user interface (GUI) of the well engineering application. The user may interact with the GUI to specify various options corresponding to the parameters of interest for the torque and drag analysis described above with respect to process **300** of FIG. **3** as well as the hydraulics analysis based on process **500**. In some implementations, the parameters associated with each type of analysis may be displayed as user-selectable options within a corresponding settings panel or other dedicated window or area of the GUI for providing user control options for each type of analysis to be performed for the string configuration in this example.

[0057] In one or more embodiments, the inclusion or exclusion of certain parameters may be used to determine whether or not the rotation rate/rotary speed (or RPM) of the string should be included in the hydraulics analysis, e.g., whether or not to automatically, without user intervention, disable (step **518**) or enable (step **520**) an RPM option within a hydraulics analysis settings panel of the GUI provided by the well engineering application, as will be described in further detail below.

[0058] For example, step **506** may include determining whether or not to include the effect of a cuttings loading parameter in the hydraulics analysis. If the cuttings loading effect is determined not to be included (e.g., the user has disabled this option for the hydraulics analysis), process **500** proceeds directly to step **520**, in which the string's rotation rate/rotary speed (or RPM) is taken into account for the hydraulics analysis, e.g., by automatically enabling the RPM option in the hydraulics settings panel of the as described above. Otherwise, process **500** proceeds to step **508**, which includes determining whether or not the drilling fluid under analysis is a high gel strength mud. If the fluid is determined not to be a high gel strength mud, process **500** proceeds directly to step **518**, in which the string's rotation rate (or RPM) is excluded from the hydraulics analysis, e.g., by automatically disabling the RPM option in the hydraulics settings panel as described above or setting the string's rotation rate to a value of zero. Otherwise, process **500** proceeds to step **510**, which includes determining whether or not a "measured" depth (MD), which may be an estimated depth of the string or value of the depth expected to be measured within the subsurface formation, is greater than or equal to a predetermined threshold depth (T_{depth}). The estimated depth of the wellbore trajectory may be based on, for example, a length of the rotatable segment of the coiled tubing string, e.g., as estimated in step **308** of process **300** of FIG. **3**, as described above.

[0059] If it is determined in step **510** that such a measured depth is less than the predetermined threshold depth, process **500** proceeds directly to step **518** and the string's RPM is excluded from the hydraulics analysis as described above. However, if the measured depth is determined to be greater than or equal to the predetermined threshold, process **500** proceeds to step **512**, which includes determining whether or not a pipe rotation/penetration rate exceeds a predetermined threshold rate (T_{rate}).

[0060] If it is determined in step **512** that the pipe rotation/penetration rate does not exceed the predetermined threshold rate, process **500** proceeds directly to step **518** as before. Otherwise, process **500** proceeds to step **514**, which includes determining whether or not a circulation rate of the drilling fluid exceeds a predetermined critical flow rate. If it is determined in step **514** that the fluid's circulation rate does not exceed the predetermined critical flow rate, process **500** proceeds directly to step **518**. Otherwise, process **500** proceeds to step **516**, which includes determining whether or not the type of flow regime associated with the fluid is a laminar flow regime.

[0061] If it is determined in step **516** that the type of flow regime is not laminar flow, process **500** proceeds to step **518**, after which process **500** ends. Otherwise, process **500** proceeds to step **520**, in which the string's rotation rate (or RPM) is taken into account, e.g., RPM option is enabled and set to a specified value, for the hydraulics analysis, as described above. Process **500** then continues to step **522**, which includes determining whether or not to include viscous torque and drag as part of the hydraulics analysis.

[0062] If it is determined in step **522** that viscous torque and drag is to be included in the hydraulics analysis, process **500** proceeds to step **524**, which includes estimating an equivalent fluid plastic viscosity. Otherwise, process **500** proceeds to step **526**, which includes determining whether or not the particular segment of the coiled tubing string that is currently under analysis is a non-rotatable segment of the string.

[0063] If it is determined in step **526** that the current segment is a non-rotatable segment of the string, process **500** proceeds to step **528**, which includes estimating or calculating the stress distribution for the non-rotatable segment with the string's rotation rate or RPM and bit torque set to values of zero. However, if it is determined that the current segment is a rotatable segment of the string, process **500** proceeds to step **530**, which includes estimating the stress distribution for the rotatable segment with the string's RPM set to zero and the bit torque set to an equipollent value. In one or more embodiments, the torque and string rotary speed may be implemented as separate modules within the above-described well engineering application, where the modules may provide corresponding sets of input options for the hydraulics analysis in different areas of the application's GUI.

[0064] FIG. **6** is a block diagram of an illustrative computer system **600** in which embodiments of the present disclosure may be implemented. For example, the steps of processes **300** and **500** of FIGS. **3** and **5**, respectively, as described above, may be performed by system **600**. Further, system **600** may be used to implement, for example, surface processing unit **114** of FIGS. **1**A and **1**B, as described above. System **600** can be any type of electronic computing device or cluster of such devices, e.g., as in a server farm. Examples of such a computing device include, but are not limited to, a server, workstation or desktop computer, a laptop computer, a tablet computer, a mobile phone, a personal digital assistant (PDA), a set-top box, or similar type of computing device. Such an electronic device includes various types of computer readable media and interfaces for various other types of computer readable media. As shown in FIG. **6**, system **600** includes a permanent storage device **602**, a system memory **604**, an output device interface **606**, a system communications bus **608**, a read-only memory (ROM) **610**, processing unit(s) **612**, an input device interface **614**, and a network interface **616**.

[0065] Bus **608** collectively represents all system, peripheral, and chipset buses that communicatively connect the numerous internal devices of system **600**. For instance, bus **608** communicatively connects processing unit(s) **612** with ROM **610**, system memory **604**, and permanent storage device **602**.

[0066] From these various memory units, processing unit (s) **612** retrieves instructions to execute and data to process in order to execute the processes of the subject disclosure. The processing unit(s) can be a single processor or a multi-core processor in different implementations.

[0067] ROM **610** stores static data and instructions that are needed by processing unit(s) **612** and other modules of system **600**. Permanent storage device **602**, on the other hand, is a read-and-write memory device. This device is a non-volatile memory unit that stores instructions and data even when system **600** is off. Some implementations of the subject disclosure use a mass-storage device (such as a magnetic or optical disk and its corresponding disk drive) as permanent storage device **602**.

[0068] Other implementations use a removable storage device (such as a floppy disk, flash drive, and its corresponding disk drive) as permanent storage device **602**. Like permanent storage device **602**, system memory **604** is a read-and-write memory device. However, unlike storage device **602**, system memory **604** is a volatile read-and-write memory, such a random access memory. System memory **604** stores some of the instructions and data that the processor needs at runtime. In some implementations, the processes of the subject disclosure are stored in system memory **604**, permanent storage device **602**, and/or ROM **610**. For example, the various memory units include instructions for computer aided pipe string design based on existing string designs in accordance with some implementations. From these various memory units, processing unit(s) **612** retrieves instructions to execute and data to process in order to execute the processes of some implementations.

[0069] Bus **608** also connects to input and output device interfaces **614** and **606**. Input device interface **614** enables the user to communicate information and select commands to the system **600**. Input devices used with input device interface **614** include, for example, alphanumeric, QWERTY, or T9 keyboards, microphones, and pointing devices (also called "cursor control devices"). Output device interfaces **606** enables, for example, the display of images generated by the system **600**. Output devices used with output device interface **606** include, for example, printers and display devices, such as cathode ray tubes (CRT) or liquid crystal displays (LCD). Some implementations include devices such as a touchscreen that functions as both input and output devices. It should be appreciated that embodiments of the present disclosure may be implemented using a computer including any of various types of input and output devices for enabling interaction with a user. Such interaction may include feedback to or from the user in different forms of sensory feedback including, but not limited to, visual feedback, auditory feedback, or tactile feedback. Further, input from the user can be received in any form including, but not limited to, acoustic, speech, or tactile input. Additionally, interaction with the user may include transmitting and receiving different types of information, e.g., in the form of documents, to and from the user via the above-described interfaces.

[0070] Also, as shown in FIG. **6**, bus **608** also couples system **600** to a public or private network (not shown) or combination of networks through a network interface **616**. Such a network may include, for example, a local area network ("LAN"), such as an Intranet, or a wide area network ("WAN"), such as the Internet. Any or all components of system **600** can be used in conjunction with the subject disclosure.

[0071] These functions described above can be implemented in digital electronic circuitry, in computer software, firmware or hardware. The techniques can be implemented using one or more computer program products. Programmable processors and computers can be included in or packaged as mobile devices. The processes and logic flows can be performed by one or more programmable processors and by one or more programmable logic circuitry. General and special purpose computing devices and storage devices can be interconnected through communication networks.

[0072] Some implementations include electronic components, such as microprocessors, storage and memory that store computer program instructions in a machine-readable or computer-readable medium (alternatively referred to as computer-readable storage media, machine-readable media, or machine-readable storage media). Some examples of such computer-readable media include RAM, ROM, read-only compact discs (CD-ROM), recordable compact discs (CD-R), rewritable compact discs (CD-RW), read-only digital versatile discs (e.g., DVD-ROM, dual-layer DVD-ROM), a variety of recordable/rewritable DVDs (e.g., DVD-RAM, DVD-RW, DVD+RW, etc.), flash memory (e.g., SD cards, mini-SD cards, micro-SD cards, etc.), magnetic and/or solid state hard drives, read-only and recordable Blu-Ray® discs, ultra density optical discs, any other optical or magnetic media, and floppy disks. The computer-readable media can store a computer program that is executable by at least one processing unit and includes sets of instructions for performing various operations. Examples of computer programs or computer code include machine code, such as is produced by a compiler, and files including higher-level code that are executed by a computer, an electronic component, or a microprocessor using an interpreter.

[0073] While the above discussion primarily refers to microprocessor or multi-core processors that execute software, some implementations are performed by one or more integrated circuits, such as application specific integrated circuits (ASICs) or field programmable gate arrays (FPGAs). In some implementations, such integrated circuits execute instructions that are stored on the circuit itself. Accordingly, the steps of processes **400** and **500** of FIGS. **4** and **5**, respectively, as described above, may be implemented using system **600** or any computer system having processing circuitry or a computer program product including instructions stored therein, which, when executed by at least one processor, causes the processor to perform functions relating to these processes.

[0074] As used in this specification and any claims of this application, the terms "computer", "server", "processor", and "memory" all refer to electronic or other technological devices. These terms exclude people or groups of people. As used herein, the terms "computer readable medium" and "computer readable media" refer generally to tangible, physical, and non-transitory electronic storage mediums that store information in a form that is readable by a computer.

[0075] Embodiments of the subject matter described in this specification can be implemented in a computing system that includes a back end component, e.g., as a data server, or that includes a middleware component, e.g., an application server, or that includes a front end component, e.g., a client computer having a graphical user interface or a Web browser through which a user can interact with an implementation of the subject matter described in this specification, or any combination of one or more such back end, middleware, or front end components. The components of the system can be interconnected by any form or medium of digital data communication, e.g., a communication network. Examples of communication networks include a local area network ("LAN") and a wide area network ("WAN"), an inter-network (e.g., the Internet), and peer-to-peer networks (e.g., ad hoc peer-to-peer networks).

[0076] The computing system can include clients and servers. A client and server are generally remote from each other and typically interact through a communication network. The relationship of client and server arises by virtue of computer programs running on the respective computers and having a client-server relationship to each other. In some embodiments, a server transmits data (e.g., a web page) to a client device (e.g., for purposes of displaying data to and receiving user input from a user interacting with the client device). Data generated at the client device (e.g., a result of the user interaction) can be received from the client device at the server.

[0077] It is understood that any specific order or hierarchy of steps in the processes disclosed is an illustration of exemplary approaches. Based upon design preferences, it is understood that the specific order or hierarchy of steps in the processes may be rearranged, or that all illustrated steps be performed. Some of the steps may be performed simultaneously. For example, in certain circumstances, multitasking and parallel processing may be advantageous. Moreover, the separation of various system components in the embodiments described above should not be understood as requiring such separation in all embodiments, and it should be understood that the described program components and systems can generally be integrated together in a single software product or packaged into multiple software products.

[0078] Furthermore, the exemplary methodologies described herein may be implemented by a system including processing circuitry or a computer program product including instructions which, when executed by at least one processor, causes the processor to perform any of the methodology described herein.

[0079] As described above, embodiments of the present disclosure are particularly useful for optimizing coiled tubing string configurations for drilling operations. In one or more embodiments of the present disclosure, a method for optimizing coiled tubing string configurations for drilling operations includes: determining a plurality of sections for a wellbore to be drilled along a planned trajectory through a subsurface formation; determining physical properties of a coiled tubing string for drilling the wellbore along the planned trajectory, the coiled tubing string having a non-rotatable segment and a rotatable segment; estimating a length of the rotatable segment of the coiled tubing string, based on the physical properties corresponding to the rotatable segment; calculating a friction factor for the rotatable segment based on the estimated length of the rotatable segment; estimating an effective axial force for one or more points of interest along the non-rotatable and rotatable segments of the coiled tubing string, based in part on the friction factor calculated for the rotatable segment; upon determining that the effective axial force for at least one of the one or more points of interest exceeds a predetermined maximum force threshold, estimating an effective distributive friction factor for at least a portion of the non-rotatable segment of the coiled tubing string; and redefining the rotatable and non-rotatable segments of the coiled tubing string for one or more of the plurality of sections of the wellbore to be drilled along the planned trajectory, based on the estimated effective distributive friction factor for the portion of the non-rotatable segment.

[0080] For the foregoing embodiments, the method or steps thereof may include any of the following elements, either alone or in combination with each other: the effective-distributive friction factor represents a distribution of frictional drag forces over a selected length of the non-rotatable segment of the coiled tubing string along one or more of the plurality of sections of the wellbore; the predetermined maximum force threshold is a predetermined maximum hook load; the effective distributive friction factor is estimated for portions of the non-rotatable segment corresponding to lateral and curved sections of the wellbore along the planned trajectory; the effective distributive friction factor is estimated for a portion of the non-rotatable segment corresponding to a lateral section of the wellbore along the planned trajectory; the rotatable segment of the coiled tubing string includes a downhole motor and a bottom hole assembly, and the downhole motor is located upstream from the bottom hole assembly on the rotatable segment of the coiled tubing string; the non-rotatable segment of the coiled tubing string extends from a surface of the wellbore and attaches to a proximal end of the downhole motor; and the downhole motor is a hydraulic motor.

[0081] Also, a system for optimizing coiled tubing string configurations for drilling operations has been described. Embodiments of the system may include at least one processor and a memory coupled to the processor having instructions stored therein, which when executed by the processor, cause the processor to perform functions including functions to: determine a plurality of sections for a wellbore to be drilled along a planned trajectory through a subsurface formation, determine physical properties of a coiled tubing string for drilling the wellbore along the planned trajectory, where the coiled tubing string has a non-rotatable segment and a rotatable segment; estimate a length of the rotatable segment of the coiled tubing string, based on the physical properties corresponding to the rotatable segment; calculate a friction factor for the rotatable segment based on the estimated length of the rotatable segment; estimate an effective axial force for one or more points of interest along the non-rotatable and rotatable segments of the coiled tubing string, based in part on the friction factor calculated for the rotatable segment; determine whether or not the effective axial force for at least one of the one or more points of interest exceeds a predetermined maximum force threshold; estimate an effective distributive friction factor for at least a portion of the non-rotatable segment of the coiled tubing string, when the effective force for at least one of the one or more points of interest is determined to exceed the predetermined maximum force threshold; and redefine the rotatable and non-rotatable segments of the coiled tubing string for one or more of the plurality of sections of the wellbore to be drilled along the planned trajectory, based on the estimated effective distributive friction factor for the portion of the non-rotatable segment. Likewise, a computer-readable storage medium has been described and may generally have instructions stored therein, which when executed by a computer cause the computer to perform a plurality of functions, including functions to: determine a plurality of sections for a wellbore to be drilled along a planned trajectory through a subsurface formation; determine physical properties of a coiled tubing string for drilling the wellbore along the planned trajectory, where the coiled tubing string has a non-rotatable segment and a rotatable segment; estimate a length of the rotatable segment of the coiled tubing string, based on the physical properties corresponding to the rotatable segment; calculate a friction factor for the rotatable segment based on the estimated length of the rotatable segment; estimate an effective axial force for one or more points of interest along the non-rotatable and rotatable segments of the coiled tubing string, based in part on the friction factor calculated for the rotatable segment; determine whether or not the effective axial force for at least one of the one or more points of interest exceeds a predetermined maximum force threshold; estimate an effective distributive friction factor for at least a portion of the non-rotatable segment of the coiled tubing string, when the effective force for at least one of the one or more points of interest is determined to exceed the predetermined maximum force threshold; and redefine the rotatable and non-rotatable segments of the coiled tubing string for one or more of the plurality of sections of the wellbore to be drilled along the planned trajectory, based on the estimated effective distributive friction factor for the portion of the non-rotatable segment.

[0082] For any of the foregoing embodiments, the system or computer-readable storage medium may include any of the following elements, either alone or in combination with each other: the effective-distributive friction factor represents a distribution of frictional drag forces over a selected length of the non-rotatable segment of the coiled tubing string along one or more of the plurality of sections of the wellbore; the predetermined maximum force threshold is a predetermined maximum hook load; the effective distributive friction factor is estimated for portions of the non-rotatable segment corresponding to lateral and curved sections of the wellbore along the planned trajectory; the effective distributive friction factor is estimated for a portion of the non-rotatable segment corresponding to a lateral section of the wellbore along the planned trajectory; the rotatable segment of the coiled tubing string includes a downhole motor and a bottom hole assembly, and the downhole motor is located upstream from the bottom hole assembly on the rotatable segment of the coiled tubing string; the non-rotatable segment of the coiled tubing string extends from a surface of the wellbore and attaches to a proximal end of the downhole motor; and the downhole motor is a hydraulic motor.

[0083] While specific details about the above embodiments have been described, the above hardware and software descriptions are intended merely as example embodiments and are not intended to limit the structure or implementation of the disclosed embodiments. For instance, although many other internal components of the system **600** are not shown, those of ordinary skill in the art will appreciate that such components and their interconnection are well known.

[0084] In addition, certain aspects of the disclosed embodiments, as outlined above, may be embodied in software that is executed using one or more processing units/components. Program aspects of the technology may be thought of as "products" or "articles of manufacture" typically in the form of executable code and/or associated data that is carried on or embodied in a type of machine readable medium. Tangible non-transitory "storage" type media include any or all of the memory or other storage for the computers, processors or the like, or associated modules thereof, such as various semiconductor memories, tape drives, disk drives, optical or magnetic disks, and the like, which may provide storage at any time for the software programming.

[0085] Additionally, the flowchart and block diagrams in the figures illustrate the architecture, functionality, and operation of possible implementations of systems, methods and computer program products according to various embodiments of the present disclosure. It should also be noted that, in some alternative implementations, the functions noted in the block may occur out of the order noted in the figures. For example, two blocks shown in succession may, in fact, be executed substantially concurrently, or the blocks may sometimes be executed in the reverse order, depending upon the functionality involved. It will also be noted that each block of the block diagrams and/or flowchart illustration, and combinations of blocks in the block diagrams and/or flowchart illustration, can be implemented by special purpose hardware-based systems that perform the specified functions or acts, or combinations of special purpose hardware and computer instructions.

[0086] The above specific example embodiments are not intended to limit the scope of the claims. The example embodiments may be modified by including, excluding, or combining one or more features or functions described in the disclosure.

[0087] As used herein, the singular forms "a", "an" and "the" are intended to include the plural forms as well, unless the context clearly indicates otherwise. It will be further understood that the terms "comprise" and/or "comprising," when used in this specification and/or the claims, specify the presence of stated features, integers, steps, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, integers, steps, operations, elements, components, and/or groups thereof. The corresponding structures, materials, acts, and equivalents of all means or step plus function elements in the claims below are intended to include any structure, material, or act for performing the function in combination with other claimed elements as specifically claimed. The description of the present disclosure has been presented for purposes of illustration and description, but is not intended to be exhaustive or limited to the embodiments in the form disclosed. Many modifications and variations will be apparent to those of ordinary skill in the art without departing from the scope and spirit of the disclosure. The illustrative embodiments described herein are provided to explain the principles of the disclosure and the practical application thereof, and to enable others of ordinary skill in the art to understand that the disclosed embodiments may be modified as desired for a particular implementation or use. The scope of the claims is intended to broadly cover the disclosed embodiments and any such modification.

What is claimed is:

1. A method for optimizing coiled tubing string configurations for drilling operations, the method comprising:

determining a plurality of sections for a wellbore to be drilled along a planned trajectory through a subsurface formation;

determining physical properties of a coiled tubing string for drilling the wellbore along the planned trajectory, the coiled tubing string having a non-rotatable segment and a rotatable segment;

estimating a length of the rotatable segment of the coiled tubing string, based on the physical properties corresponding to the rotatable segment;

calculating a friction factor for the rotatable segment based on the estimated length of the rotatable segment;

estimating an effective axial force for one or more points of interest along the non-rotatable and rotatable segments of the coiled tubing string, based in part on the friction factor calculated for the rotatable segment,

upon determining that the effective axial force for at least one of the one or more points of interest exceeds a predetermined maximum force threshold, estimating an effective distributive friction factor for at least a portion of the non-rotatable segment of the coiled tubing string; and

redefining the rotatable and non-rotatable segments of the coiled tubing string for one or more of the plurality of sections of the wellbore to be drilled along the planned trajectory, based on the estimated effective distributive friction factor for the portion of the non-rotatable segment.

2. The method of claim **1**, wherein the effective-distributive friction factor represents a distribution of frictional drag forces over a selected length of the non-rotatable segment of the coiled tubing string along one or more of the plurality of sections of the wellbore.

3. The method of claim **1**, wherein the predetermined maximum force threshold is a predetermined maximum hook load.

4. The method of claim **1**, wherein the effective distributive friction factor is estimated for portions of the non-rotatable segment corresponding to lateral and curved sections of the wellbore along the planned trajectory.

5. The method of claim **1**, wherein the effective distributive friction factor is estimated for a portion of the non-rotatable segment corresponding to a lateral section of the wellbore along the planned trajectory.

6. The method of claim **1**, wherein the rotatable segment of the coiled tubing string includes a downhole motor and a bottom hole assembly, and the downhole motor is located upstream from the bottom hole assembly on the rotatable segment of the coiled tubing string.

7. The method of claim **6**, wherein the non-rotatable segment of the coiled tubing string extends from a surface of the wellbore and attaches to a proximal end of the downhole motor.

8. The method of claim **6**, wherein the downhole motor is a hydraulic motor.

9. A system for optimizing coiled tubing string configurations for drilling operations, the system comprising:

at least one processor; and

a memory coupled to the processor having instructions stored therein, which when executed by the processor, cause the processor to perform functions including functions to:

determine a plurality of sections for a wellbore to be drilled along a planned trajectory through a subsurface formation;

determine physical properties of a coiled tubing string for drilling the wellbore along the planned trajectory, the coiled tubing string having a non-rotatable segment and a rotatable segment;

estimate a length of the rotatable segment of the coiled tubing string, based on the physical properties corresponding to the rotatable segment;

calculate a friction factor for the rotatable segment based on the estimated length of the rotatable segment;

estimate an effective axial force for one or more points of interest along the non-rotatable and rotatable segments of the coiled tubing string, based in part on the friction factor calculated for the rotatable segment;

determine whether or not the effective axial force for at least one of the one or more points of interest exceeds a predetermined maximum force threshold;

estimate an effective distributive friction factor for at least a portion of the non-rotatable segment of the coiled tubing string, when the effective force for at least one of the one or more points of interest is determined to exceed the predetermined maximum force threshold; and

redefine the rotatable and non-rotatable segments of the coiled tubing string for one or more of the plurality of sections of the wellbore to be drilled along the planned trajectory, based on the estimated effective distributive friction factor for the portion of the non-rotatable segment.

10. The system of claim **9**, wherein the effective-distributive friction factor represents a distribution of frictional drag forces over a selected length of the non-rotatable segment of the coiled tubing string along one or more of the plurality of sections of the wellbore.

11. The system of claim **9**, wherein the predetermined maximum force threshold is a predetermined maximum hook load.

12. The system of claim **9**, wherein the effective distributive friction factor is estimated for portions of the non-rotatable segment corresponding to lateral and curved sections of the wellbore along the planned trajectory.

13. The system of claim **9**, wherein the effective distributive friction factor is estimated for a portion of the non-rotatable segment corresponding to a lateral section of the wellbore along the planned trajectory.

14. The system of claim **9**, wherein the rotatable segment of the coiled tubing string includes a downhole motor and a bottom hole assembly, and the downhole motor is located upstream from the bottom hole assembly on the rotatable segment of the coiled tubing string.

15. The system of claim **14**, wherein the non-rotatable segment of the coiled tubing string extends from a surface of the wellbore and attaches to a proximal end of the downhole motor.

16. The system of claim **14**, wherein the downhole motor is a hydraulic motor.

17. A computer-readable storage medium having instructions stored therein, which when executed by a computer cause the computer to perform a plurality of functions, including functions to:

determine a plurality of sections for a wellbore to be drilled along a planned trajectory through a subsurface formation;

determine physical properties of a coiled tubing string for drilling the wellbore along the planned trajectory, the coiled tubing string having a non-rotatable segment and a rotatable segment, the rotatable segment including a bottom hole assembly and a downhole motor located upstream from the bottom hole assembly, and the non-rotatable segment extending from a surface of the wellbore and attaching to a proximal end of the downhole motor;

estimate a length of the rotatable segment of the coiled tubing string, based on the physical properties corresponding to the rotatable segment;

calculate a friction factor for the rotatable segment based on the estimated length of the rotatable segment;

estimate an effective axial force for one or more points of interest along the non-rotatable and rotatable segments of the coiled tubing string, based in part on the friction factor calculated for the rotatable segment, the effective-distributive friction factor representing a distribution of frictional drag forces over a selected length of the non-rotatable segment of the coiled tubing string along one or more of the plurality of sections of the wellbore;

determine whether or not the effective axial force for at least one of the one or more points of interest exceeds a predetermined maximum force threshold;

estimate an effective distributive friction factor for at least a portion of the non-rotatable segment of the coiled tubing string, when the effective force for at least one of the one or more points of interest is determined to exceed the predetermined maximum force threshold; and

redefine the rotatable and non-rotatable segments of the coiled tubing string for one or more of the plurality of sections of the wellbore to be drilled along the planned trajectory, based on the estimated effective distributive friction factor for the portion of the non-rotatable segment.

18. The computer-readable storage medium of claim **17**, wherein the predetermined maximum force threshold is a predetermined maximum hook load.

19. The computer-readable storage medium of claim **17**, wherein the effective distributive friction factor is estimated for portions of the non-rotatable segment corresponding to lateral and curved sections of the wellbore along the planned trajectory.

20. The computer-readable storage medium of claim **17**, wherein the effective distributive friction factor is estimated for a portion of the non-rotatable segment corresponding to a lateral section of the wellbore along the planned trajectory.

* * * * *

SPE Western Regional Meeting

23–26 May 2016
ANCHORAGE, ALASKA, USA

SPE-180384-MS
Uphole Motor Technology

Oluwafemi Oyedokun, Texas A&M University, Robello Samuel, Landmark Graphics, Jerome Schubert, Texas A&M University

Society of Petroleum Engineers

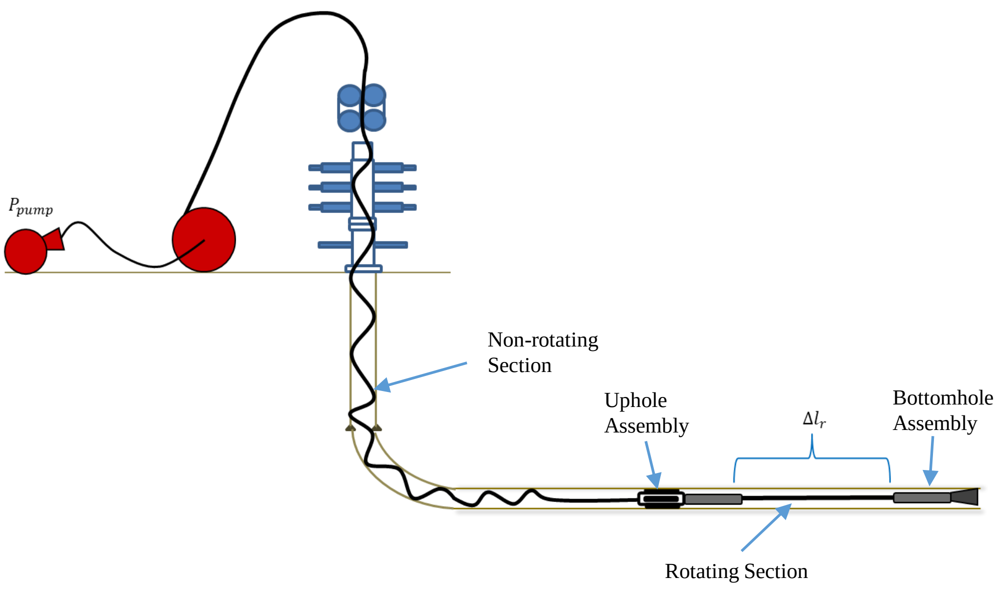
Presentation Outline

1. Background/Motivation
2. String Configuration
3. Rotating String Design
    a. Buckling Consideration
    b. Pump Constraint
    c. Whirling Check
    d. Other Constraints
4. Example Calculations
5. Further Works
6. Conclusions

Background/Motivation

- Significant extended-reach achievable
- Improved cuttings transport
- Inexpensive
  - Reduced standpipe pressure
  - No or little rig modification
- Viable? Highly probable

String Configuration



- Coiled tubing in the non-rotating section
- Coiled tubing or drillpipe in the rotating section
- Use of high torque uphole-motor
- Adjustable stabilizers in the uphole assembly

Rotating String Design

Design Constraints

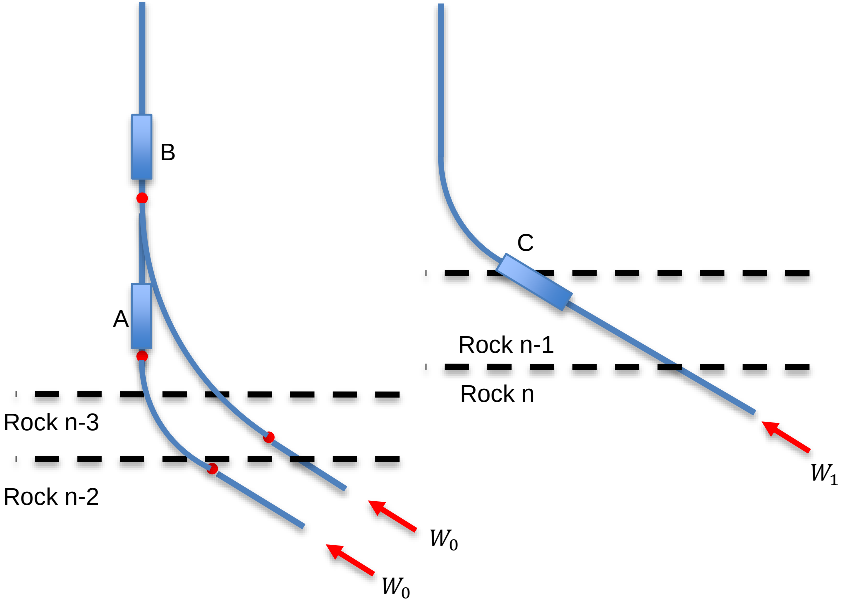
- No lateral buckling of the rotating pipe
- Limited pump pressure
- Assumed parasitic flow coefficients
- No whirling
- Injector Head Pulling Capacity
- Tubing Yield Strength

Design Variables/Parameters

- Constrained circulation rate
- Required uphole-motor configuration
- Minimum rotary torque
- Safe rotary speed
- Rotating pipe dimensions

Rotating String Design: Design Procedure

1. Determine the unit weight and diameter of the rotating pipe
   - Critical sinusoidal buckling load must be greater than maximum weight on bit
2. Locate where uphole-motor "experiences" maximum rotary torque
   - Where maximum weight-on-bit is applied
   - Kick-off point



Rotating String Design: Design Procedure

3. Specify the flow coefficients s, and K_L

4. Express the rotating length and pump pressure as functions of winding ratio and flow rate, and read-off n and $\dot{q}_m$ that satisfy the available pump pressure

5. Estimate other parameters:
   a. Rotating length
   b. Minimum rotary torque
   c. Pressure drop across the motor

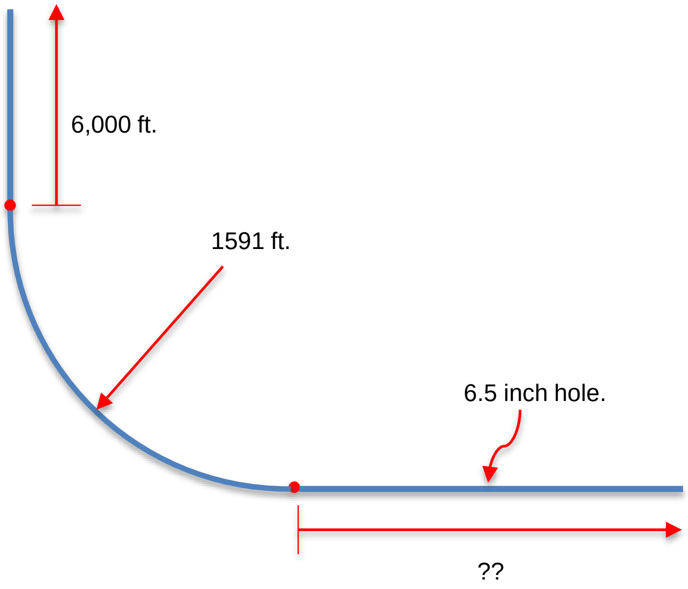
$$l_R(\dot{q}_m, n) = \frac{M_t - \mu r_p \int_{\beta_1}^{\beta_2} w_c R d\beta - M_{bit} - \mu \sin\varphi \sum_{j=1}^{N} w_{bp,j} l_j r_{p,j}}{\mu w_{bp} r_p \sin\varphi} + R(\beta_2 - \beta_1)$$

$$P_{pm}(\dot{q}_m, n) = K_L (l_R + n l_R) \left(\frac{\dot{q}_m}{\zeta} \right)^s + \alpha_2 \Delta p_m + \alpha_1 \Delta p_{mB} + \Delta p_b$$

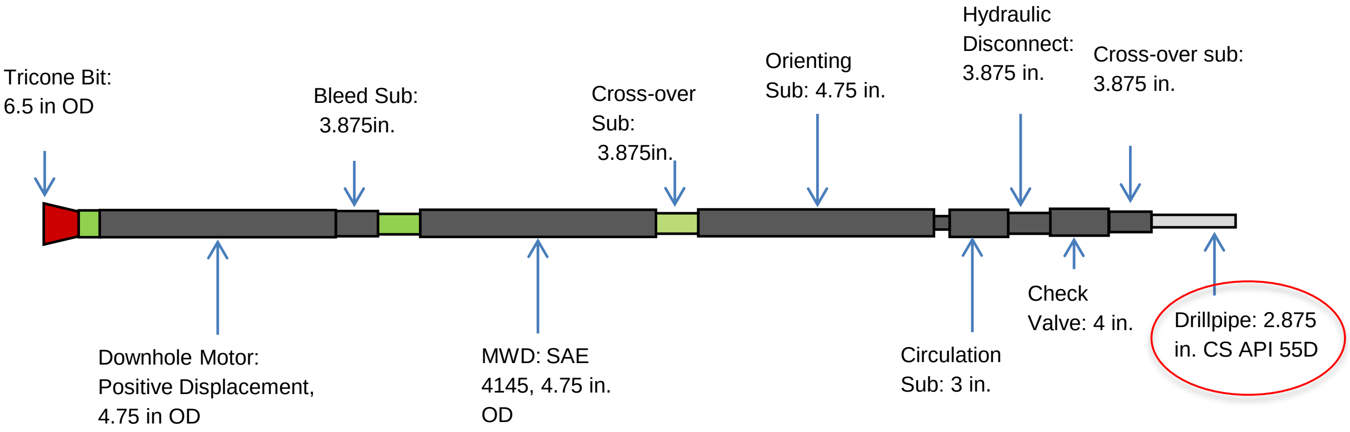
Example Calculation -1: Large Hole Drilling with CT

Parameter	Value	Parameter	Value
Friction Factor	0.3	Constant	$4e-5$
Mud Weight	10 ppga	Flow Ratio,	1
Density of Steel	65.5ppga	Flow Ratio,	1
Max.Weight on Bit	8000lbf	PDM Power Output	40hp
Turbulence Index, s	1.75	Flow Coefficient,	0.1
Constant	0.01	Constant	5252
Bit Rotary Speed	200rpm	Uphole-Motor Rotor Speed	20rpm/40rpm

Available pump pressure is 7000 psi

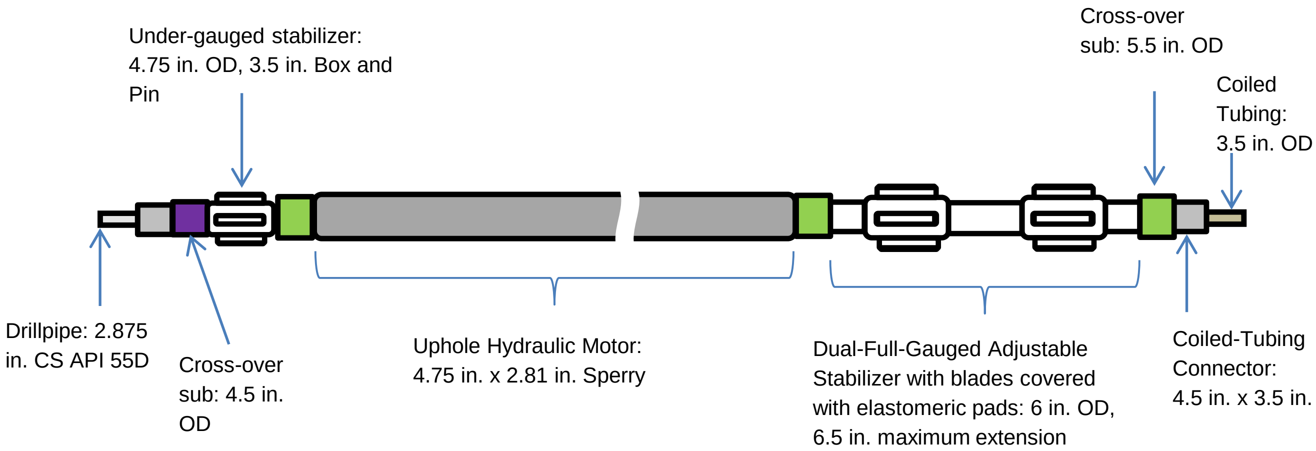


Example Calculation-1



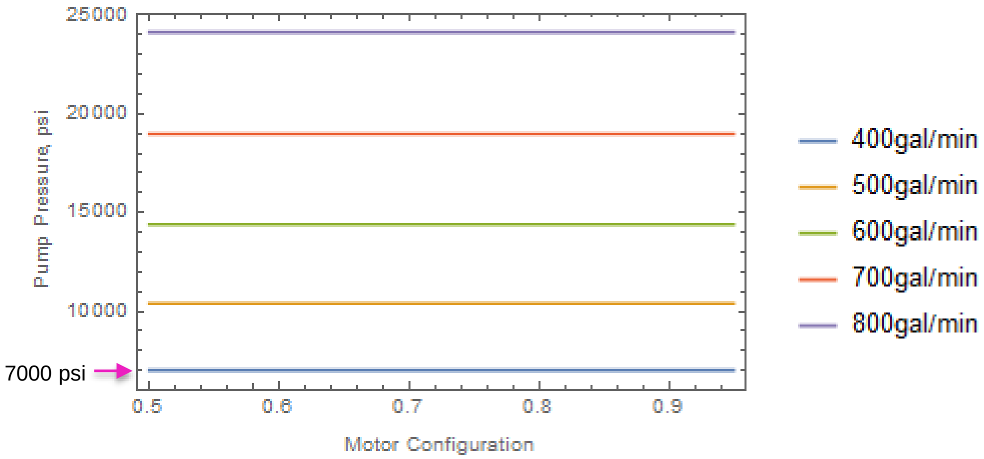
Bottomhole Assembly

Example Calculation-1



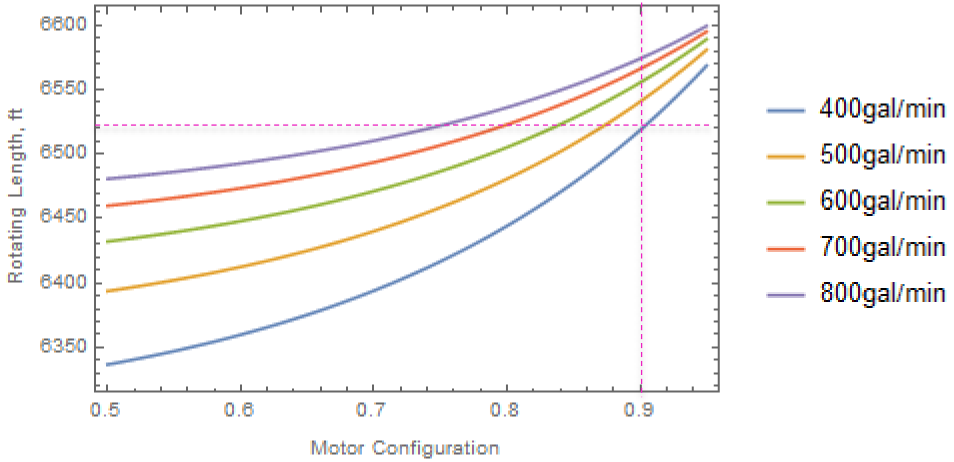
Uphole Assembly

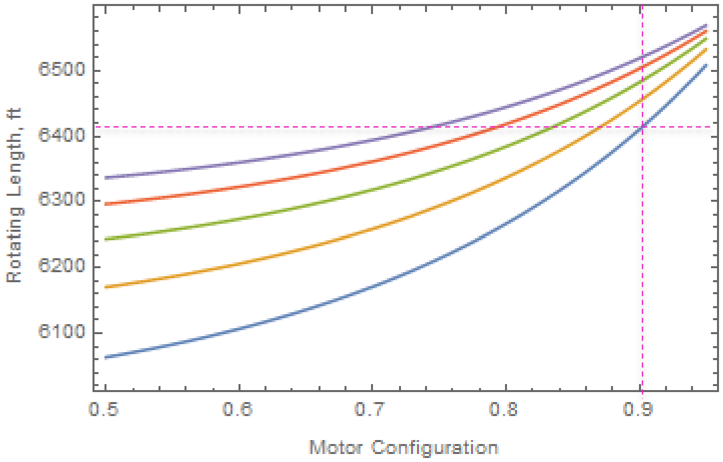
Example Calculation-1



Pump Pressure Variation with Winding Ratio and Flow Rate, $N_m =$ 20 RPM or 40 RPM

Example Calculation-1

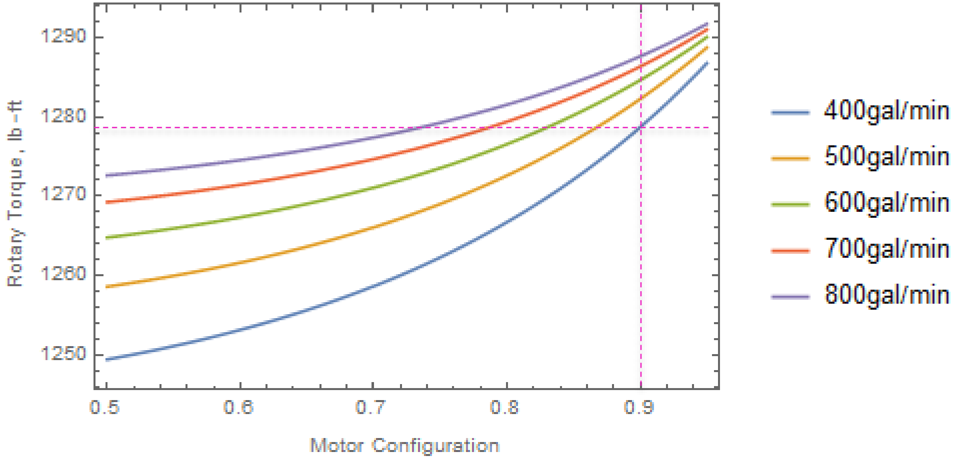


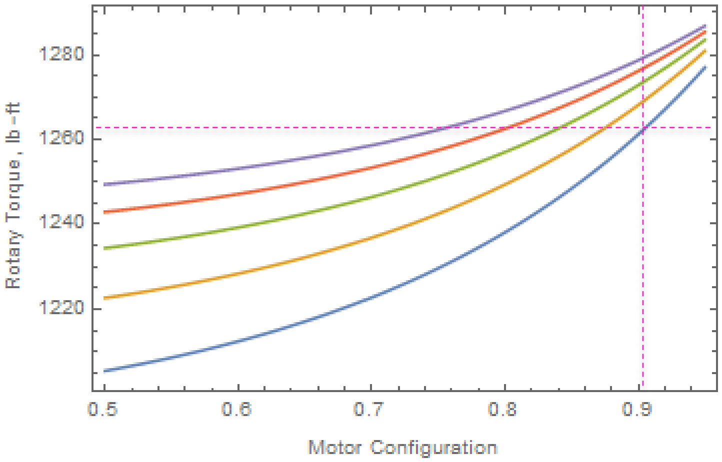


Required rotating length for 20 RPM rotary speed is 6,520 ft.

Required rotating length for 40 RPM rotary speed is ~6,420 ft.

Example Calculation-1

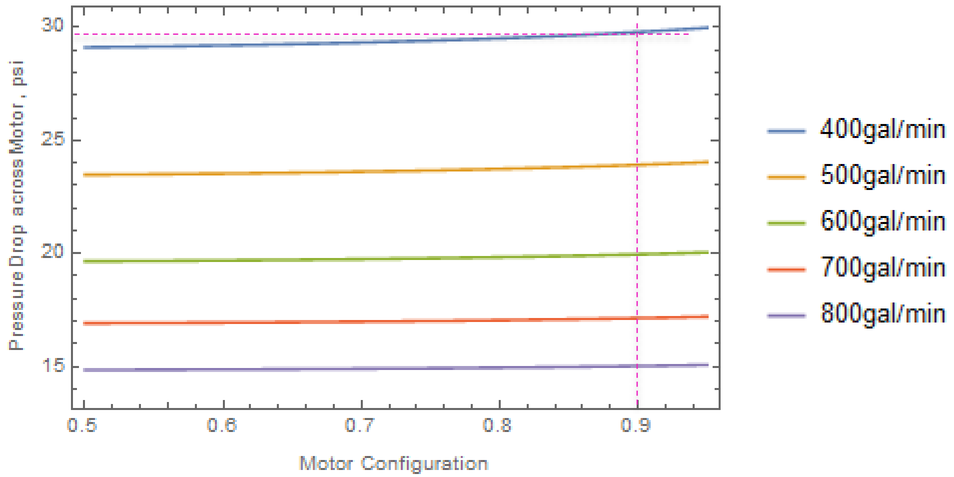


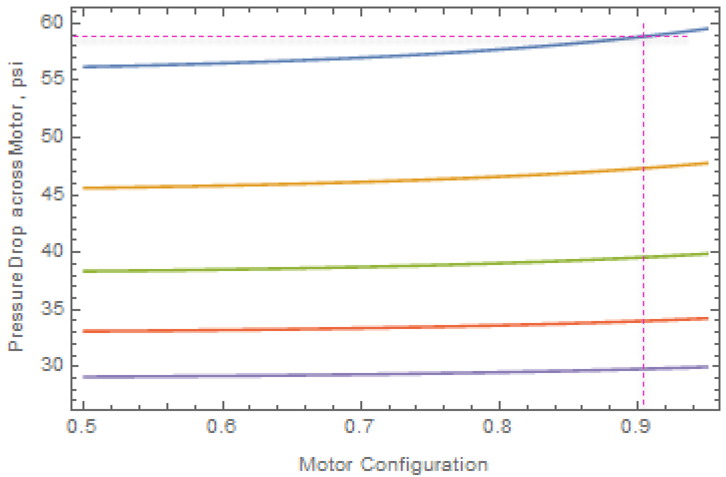


Minimum rotary torque for 20 RPM rotary speed is 1278 lbf-ft.

Minimum rotary torque for 40 RPM rotary speed is 1262 lbf-ft.

Example Calculation-1

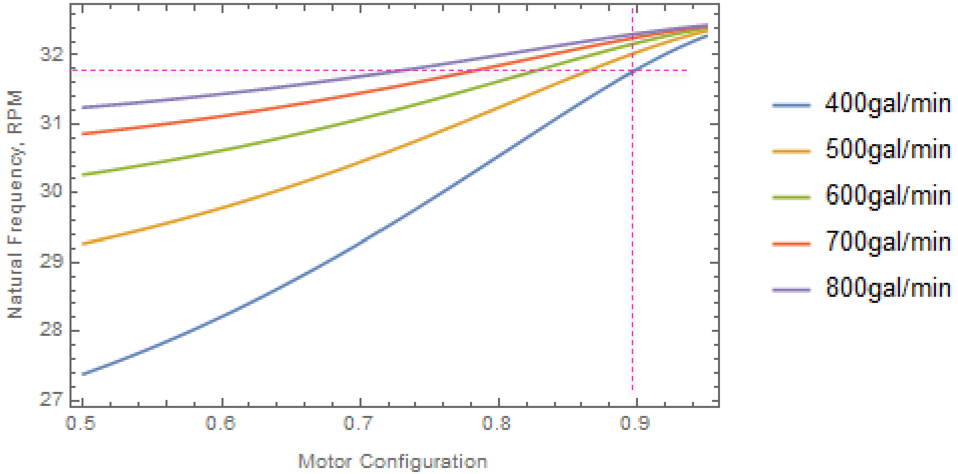


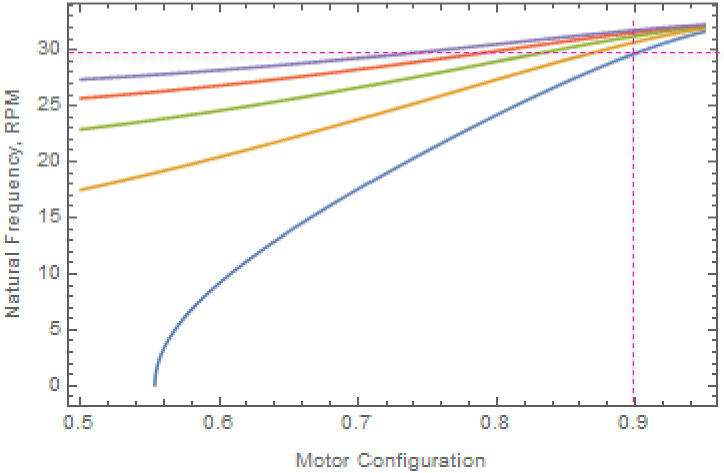


Pressure drop across uphole-motor for 20 RPM rotary speed is 29.5psi.

Pressure drop across uphole-motor for 40 RPM rotary speed is 59 psi.

Example Calculation-1

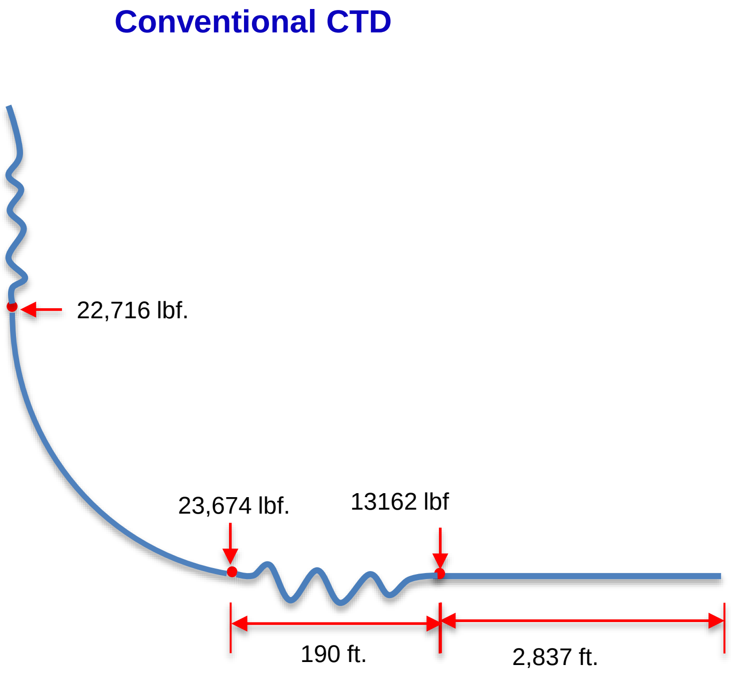


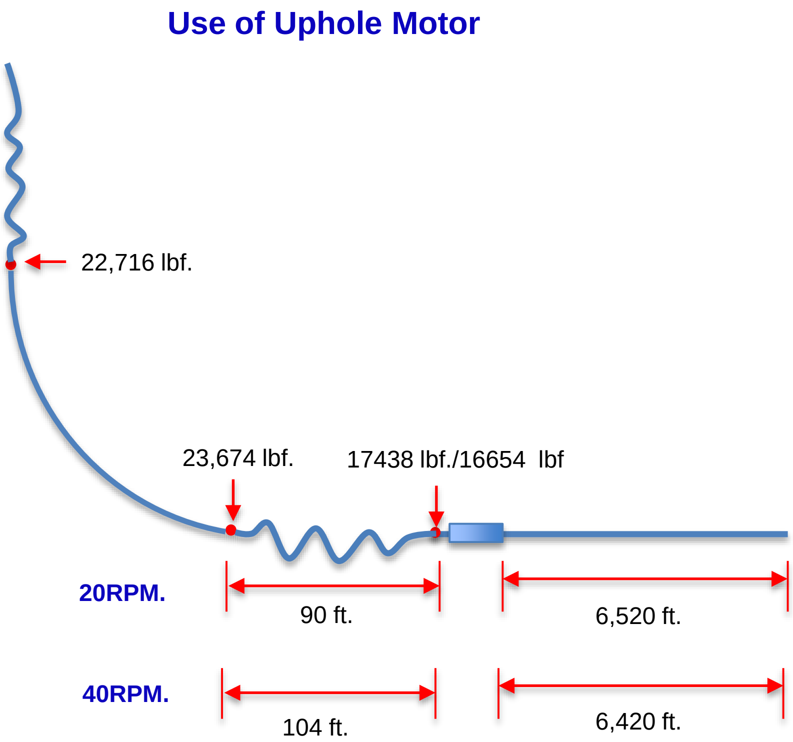


Rotating the string at 20 RPM will cause no whirling; critical speed is at 31.8 RPM

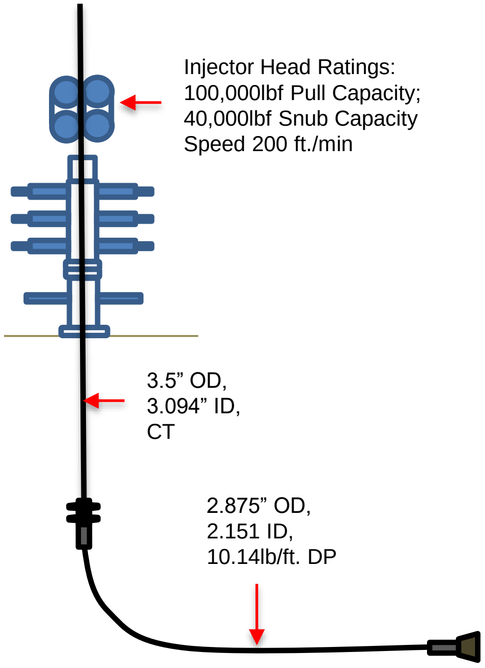
With a rotor speed of 40 RPM, the speed should be stepped down below the critical speed of 30 RPM

Example Calculation-1





Example Calculation-1: Injector-Head Pulling Capacity



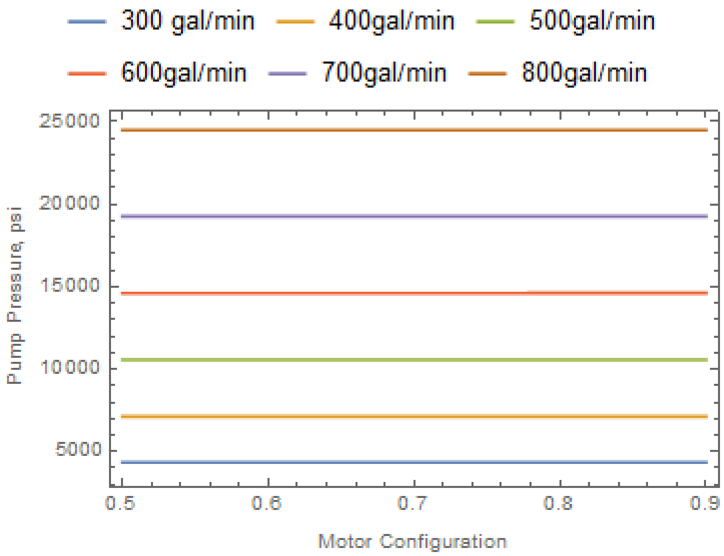
String Component	Unit Weight (lb./ft.)	Component Length (ft.)	Component Weight (lbf.)
Bottomhole Assembly	-	78.31	2,680.30
Rotating DP	10.14	6520.00	66,112.80
Uphole Assembly	-	62.73	4,473.18
3.5" OD CT	7.199	7681.00	55,295.52
Total		**14,342.04**	**128,561.5**

Failed!

Re-select the CT and DP, choose lighter tubulars

Example Calculation-1: Re-design

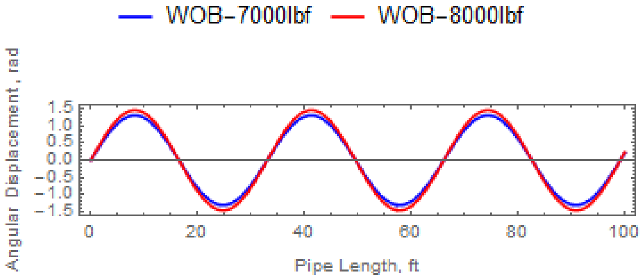
Tubular	Unit Weight (lb./ft.)	Outer Diameter (in.)	Inner Diameter (in.)	Critical Helical Buckling Load (lbf.)	Critical Sinusoidal Buckling Load (lbf.)
CT	4.541	2.875	2.563	6,884.18	4,696.99
DP	6.16	2.875	2.441	9,142.85	6,464.97



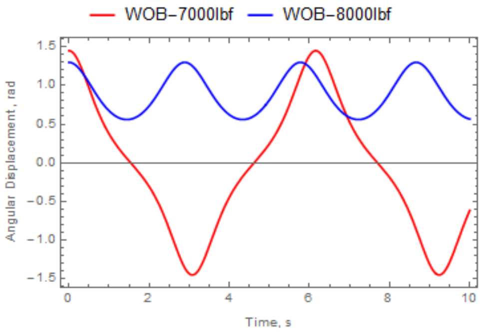
Allowing for sinusoidal buckling of the drillpipe (WOB is 8,000 lbf.)

Required pump pressure is 4,800 psi

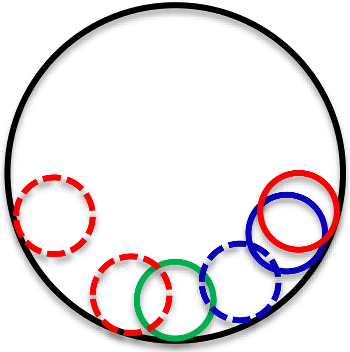
Example Calculation-1: Snaking Motion of DP



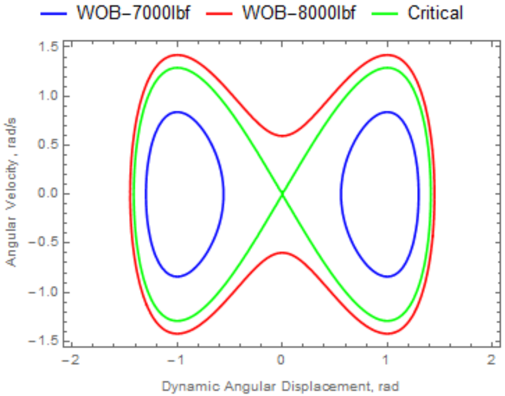
Static Post-Buckling Configuration of the Drillpipe



Dynamic Displacements

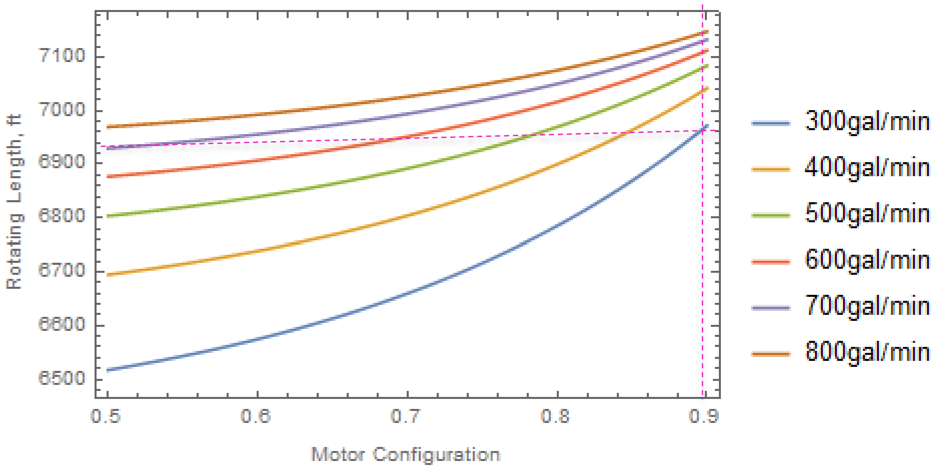


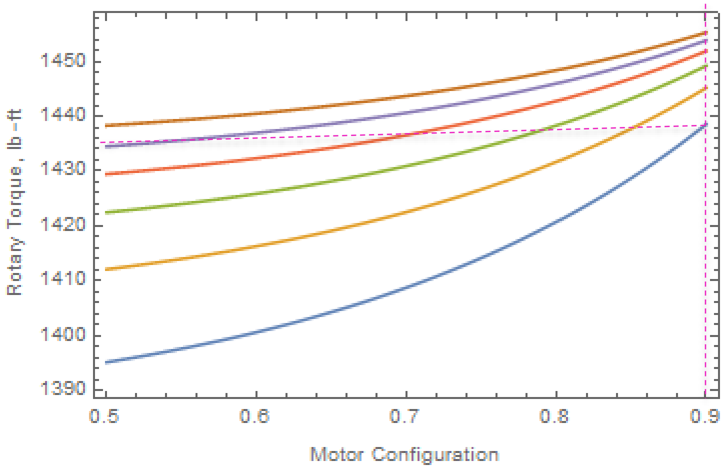
Dynamic Lateral Displacements of DP



Phase Diagram

Example Calculation-1

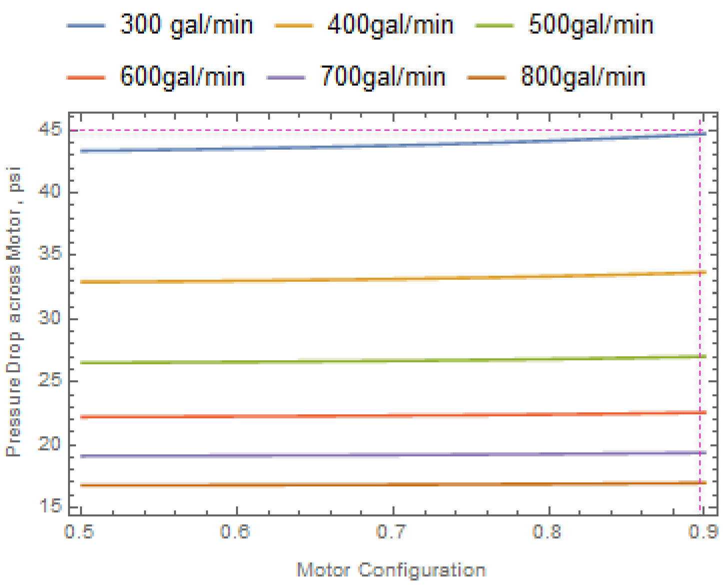




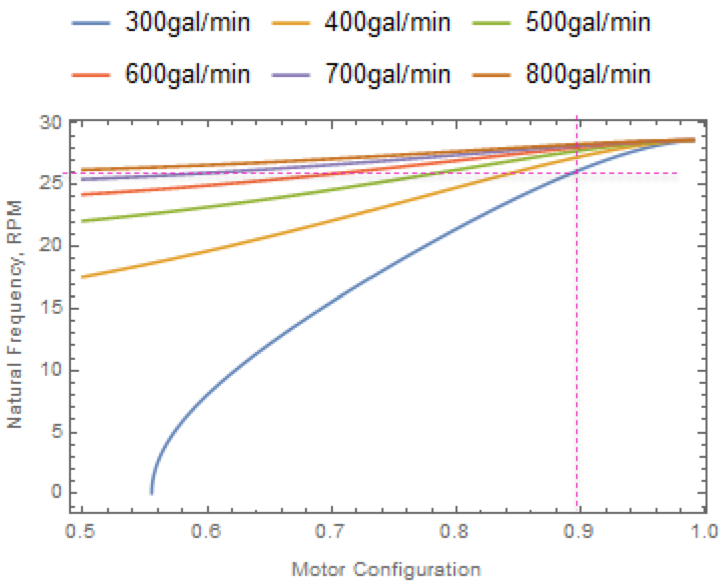
Reduced circulating rate, 300 gal/min, rotating length is 6,940 ft.

Required rotary torque is 1436 lb.-ft.

Example Calculation-1

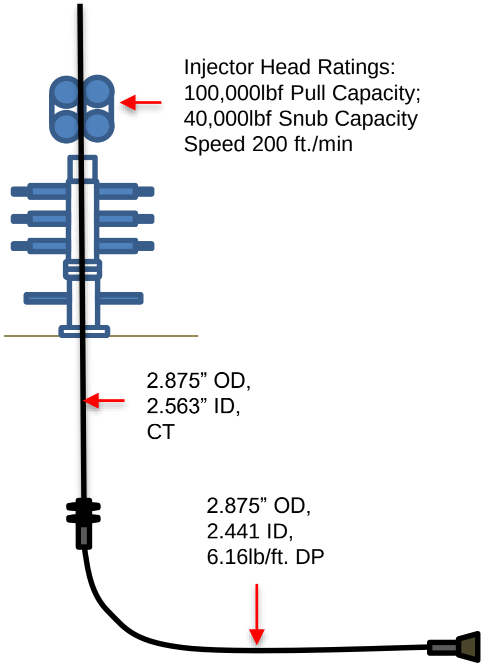


Uphole Motor Pressure Drop is 45 psi



Critical Rotary Speed is 26 RPM

Example Calculation-1: Injector-Head Pulling Capacity



String Component	Unit Weight (lb./ft.)	Component Length (ft.)	Component Weight (lbf.)
Bottomhole Assembly	-	78.31	2,680.30
Rotating DP	6.16	6940.00	42,750.40
Uphole Assembly	-	62.73	4,473.18
2.875” OD CT	4.541	7591.00	34,470.73
Total		**14,672.04**	**84,374.21**

Passed!

Example Calculation-1: Check on Tubing Yield Strength

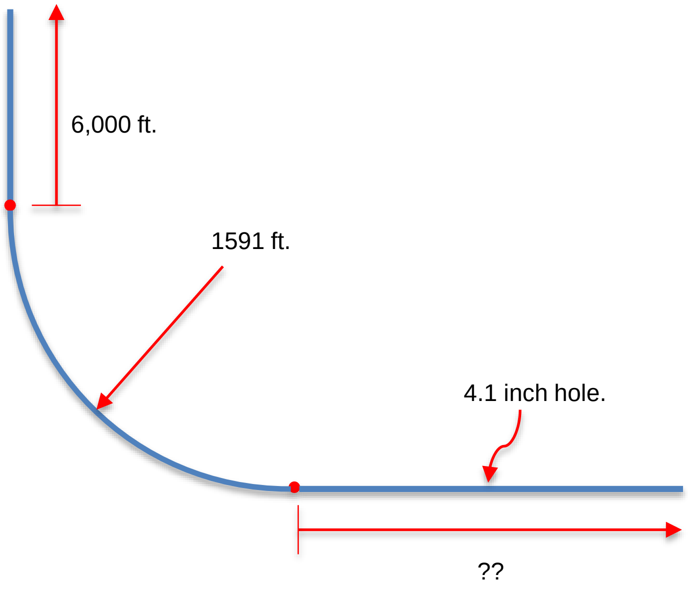
DIMENSIONS (Inches)				NOMINAL WEIGHT (lbs / ft)	TUBE BODY LOAD (Lbs.)		INTERNAL PRESSURE (psi)	
O.D. SPECIFIED	WALL SPECIFIED	WALL MINIMUM	I.D. CALCULATED		YIELD MINIMUM	TENSILE MINIMUM	HYDRO TEST 90%	INTERNAL YIELD MIN.
2.875	0.156	0.148	2.563	4.541	119,900	129,300	8,300	9,200
	0.175	0.167	2.525	5.059	133,600	144,000	9,300	10,400
	0.190	0.180	2.495	5.462	144,200	155,500	10,000	11,200
	0.204	0.195	2.467	5.834	154,100	166,000	10,900	12,100

$$\sigma_{VME} = 83{,}995.4 \text{ psi}$$

Passed!

Example Calculation-2: Small Hole Drilling with CT

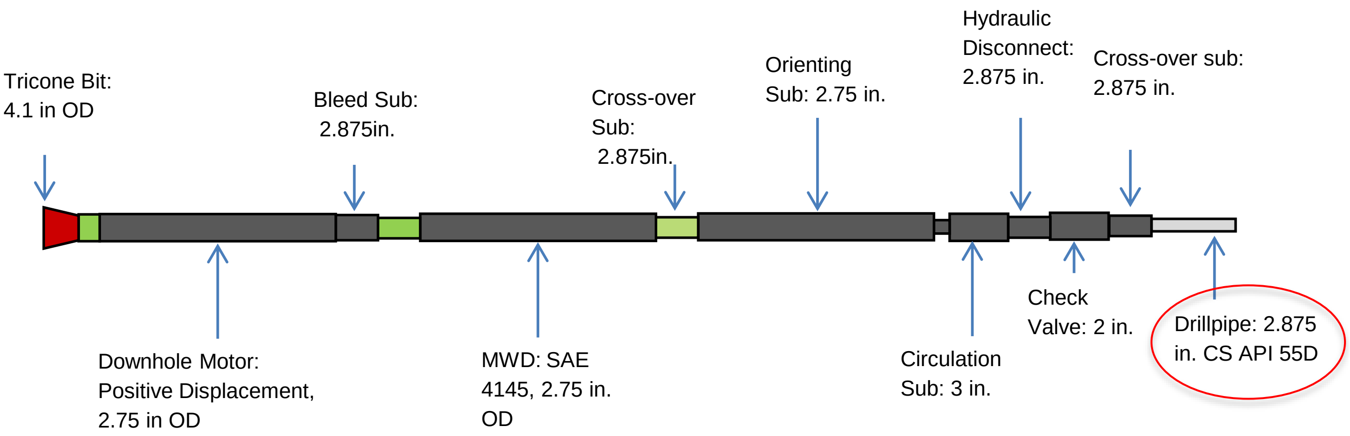
Parameter	Value	Parameter	Value
Friction Factor	0.3	Constant	$4e-5$
Mud Weight	10 ppga	Flow Ratio,	1
Density of Steel	65.5ppga	Flow Ratio,	1
Max.Weight on Bit	8000lbf	PDM Power Output	40hp
Turbulence Index, s	1.75	Flow Coefficient,	0.15
Constant	0.01	Constant	5252
Bit Rotary Speed	200rpm	Uphole-Motor Rotor Speed	20rpm/40rpm



Available pump pressure is 7000 psi

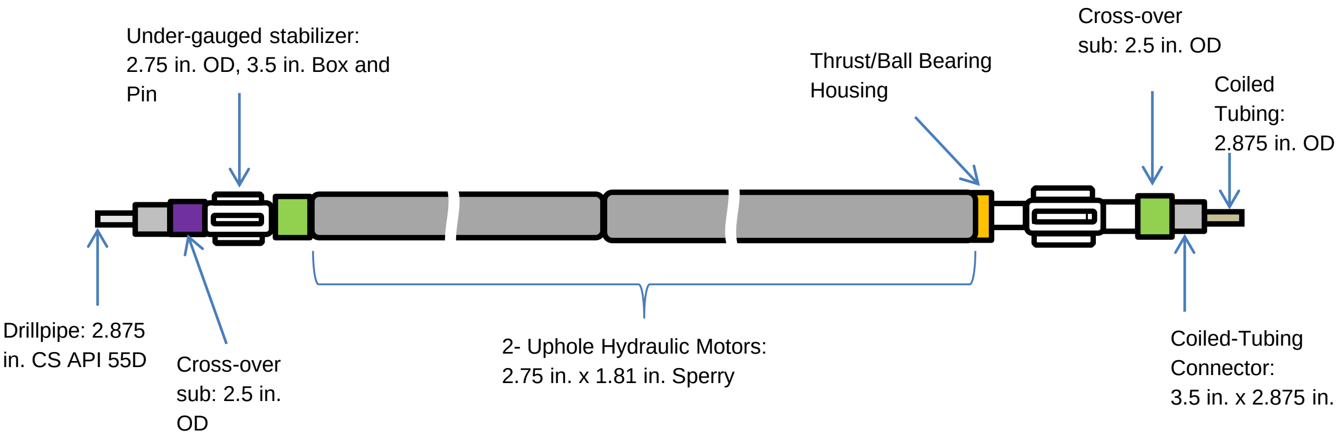
Use two uphole motors in reverse operations.

Example Calculation-2



Bottomhole Assembly

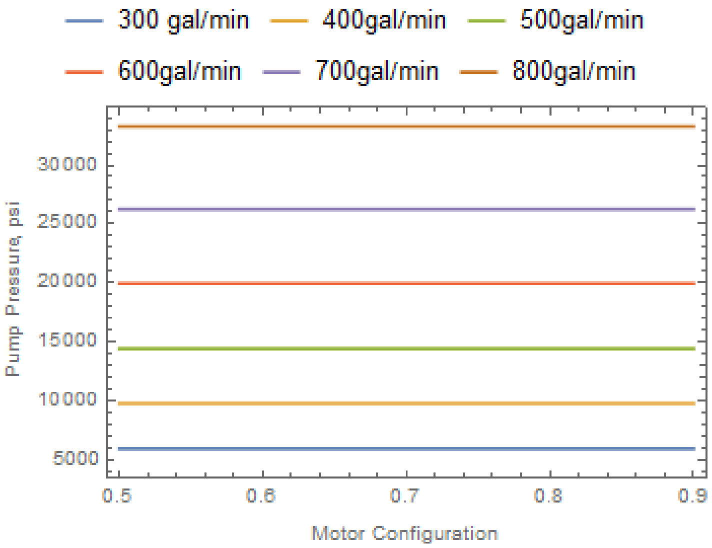
Example Calculation-2



Uphole Assembly

Example Calculation-2

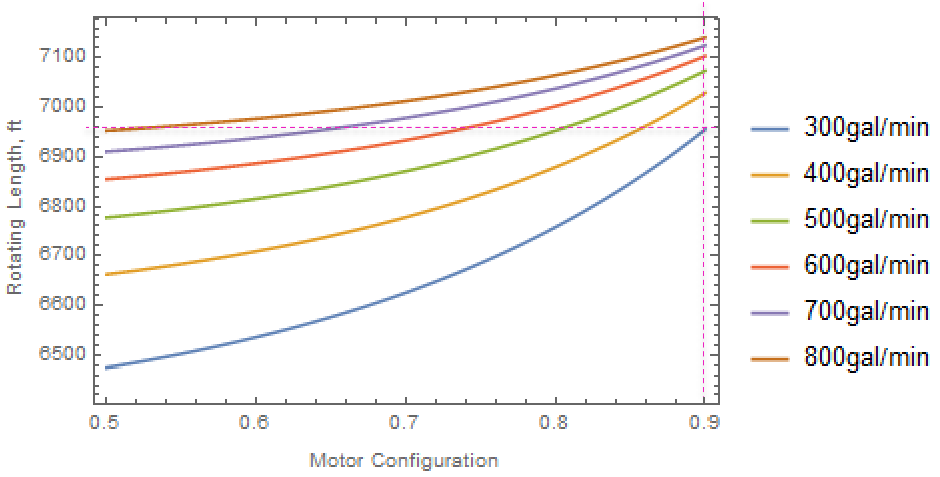
Tubular	Unit Weight (lb./ft.)	Outer Diameter (in.)	Inner Diameter (in.)	Critical Helical Buckling Load (lbf.)	Critical Sinusoidal Buckling Load (lbf.)
CT	4.541	2.875	2.563	11,426.70	8,079.90
DP	6.16	2.875	2.441	15,198.40	10,746.90

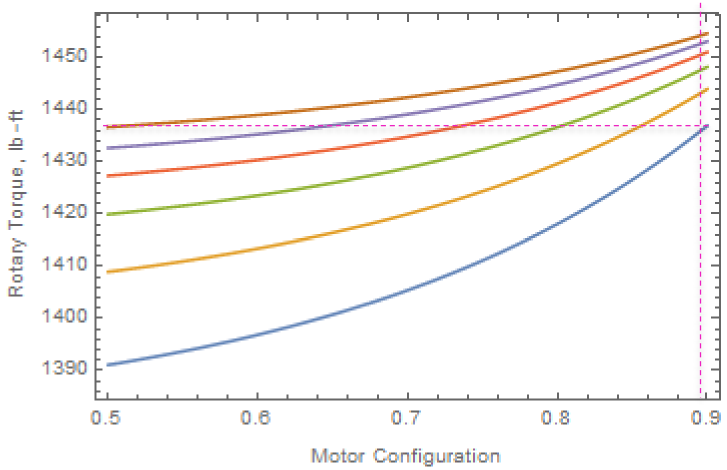


No sinusoidal buckling of the drillpipe (WOB is 8,000 lbf.)

Required pump pressure is 5,200 psi

Example Calculation-2

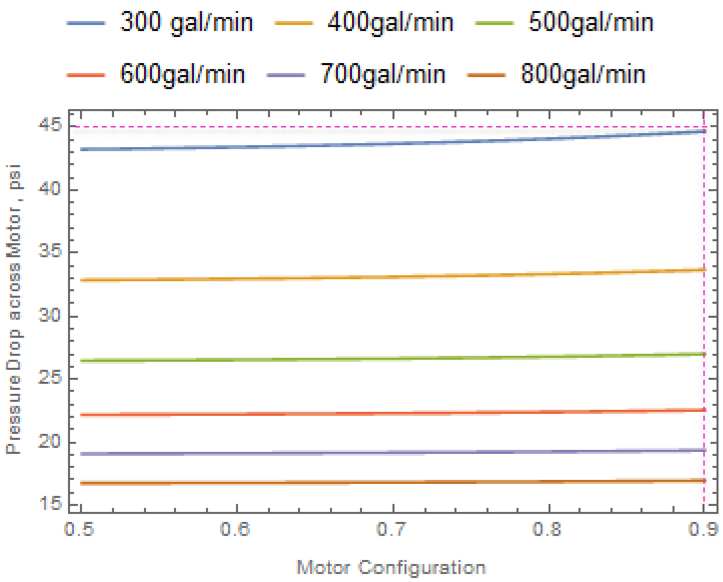




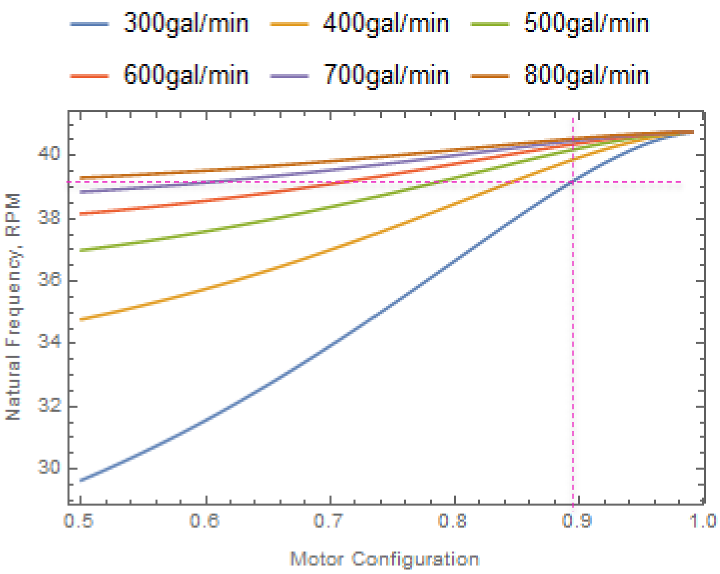
Circulating rate, 300 gal/min, rotating length is 6,960 ft.

Required rotary torque is 1436 lb.-ft.

Example Calculation-1

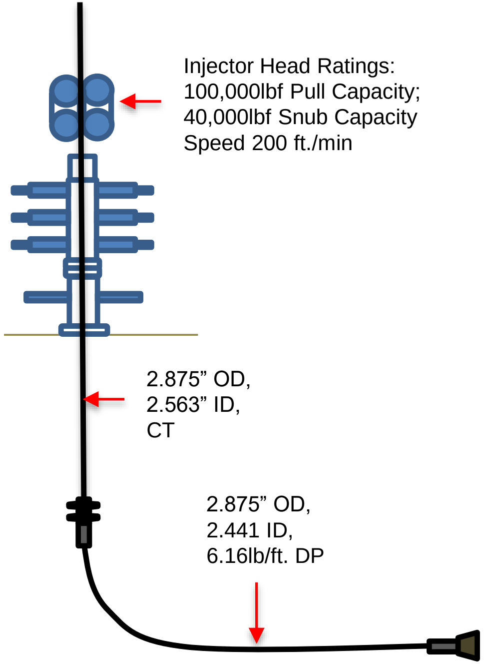


Uphole Motor Pressure Drop is 45 psi



Critical Rotary Speed is 39 RPM

Example Calculation-1: Injector-Head Pulling Capacity



String Component	Unit Weight (lb./ft.)	Component Max. Length (ft.)	Component Max. Weight (lbf.)	Comp. Req. Length (ft.)	Component Req. Weight (lbf.)
Bottomhole Assembly	-	78.31	2,480.30	78.31	2,480.30
Rotating DP	6.16	6,960.00	42,873.60	6,960.00	42,873.60
Uphole Assembly	-	62.73	4,273.18	62.73	4,273.18
2.875" OD CT	4.541	11,537.24	52,390.61	11,000.00	49,951.00
Total		**18,638.27**	**102,017.39**	**18,101.04**	**99,578.08**

Passed! But with higher safety margin, the CT length can be reduced

Example Calculation-2: Check on Tubing Yield Strength

DIMENSIONS (Inches)				NOMINAL WEIGHT (lbs / ft)	TUBE BODY LOAD (Lbs.)		INTERNAL PRESSURE (psi)	
O.D. SPECIFIED	WALL SPECIFIED	WALL MINIMUM	I.D. CALCULATED		YIELD MINIMUM	TENSILE MINIMUM	HYDRO TEST 90%	INTERNAL YIELD MIN.
2.875	0.156	0.148	2.563	4.541	119,900	129,300	8,300	9,200
	0.175	0.167	2.525	5.059	133,600	144,000	9,300	10,400
	0.190	0.180	2.495	5.462	144,200	155,500	10,000	11,200
	0.204	0.195	2.467	5.834	154,100	166,000	10,900	12,100

$$\sigma_{VME} = 96{,}868.7 \text{ psi}$$

Passed!

Further Works

1. Compatibility with articulated tractor and
   other mechanically operated extended-reach techniques

2. Collaboration with industry partner(s) for field testing

Conclusions

1. Relatively inexpensive technology
2. Significant lateral extent achievable
3. Applicable to small hole CT drilling; use caution with large-hole drilling
4. Increase fatigue life of CT
5. Combine with other extended-reach techniques
6. Although no experiment has been done, its viability is highly probable

Thank You