Society of Petroleum Engineers
Drilling Systems Automation
Technical Section (DSATS)

International University Competition

Drillbotics™ Design Report - Phase 1

University of Houston
2019 – 2020

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Introduction

As the next generation of engineers, it is our responsibility to harness the technical insights and advancements of our predecessors and integrate them into modern solutions fit for today's challenges. Maximizing efficiency, increasing productivity and reducing risk are goals shared by all engineers throughout all time; it is the environment in which we attempt these goals that provide the new challenges and potential for innovation. Today’s environment is oversaturated by data, and therefore a modern approach must develop data driven solutions. A single rig can produce over a terabyte of data in a single day, and this data conveniently contains the solutions, and understanding we have been hoping to achieve. It is our responsibility to find means of collecting, understanding, and utilizing this data to change the industry from reactionary to preventative. Common drilling problems such as bit wear, stuck pipes and string failures reduce the efficiency and productivity of a drilling operation while increasing risk and deadtime. Common practice is to react to these hazards after they have occurred, but the data forecasts and warns of these problems, and we just didn’t notice. Within each rig’s data is the guide to its own automation, and we must understand what it is telling us before we can teach it to teach itself.

Our challenge is to design and build a miniature drilling rig to autonomously drill to specified targets. This requires designing and constructing a rig equipped with top drive motors, drawworks and mud pumps. We also must design means of directing the bit along a desired path. And finally we must design data collection and processing system to allow this rig to operate autonomously. If we are to push the industry towards automation we need to understand the data required to accomplish the base task while also considering what data could indicate a potential problem. By developing this understanding we will also develop a foundation for data acquisition and analysis that can be translated to industry.

This report will outline our major design considerations: the rig structure, the bottom hole assembly (BHA), sensors and data acquisition. While these are the main points covered in the report we also outline the drawworks, mud pump and hole cleaning. We have written software to design a well path given target locations. And finally we have included calculations performed and the equations used in our first iteration. As this is our first year to participate, we have made assumptions where necessary, knowing these may change as we build and test our design.

Safety

With any engineering problem safety is the number one consideration and each section will have its own safety consideration. First we will have all team members in necessary PPE: hard-hat, eye protection and ear protection. There will be an operation light to warn when rig is in operation and a hard stop button to shut down all operations if necessary. Considering the mechanical and moving parts hazards: our rig will encase any of these moving part hazards in plexiglass to prevent accidental contact. Considering the electrical and control systems: we will utilize a GFCI circuit breaker to prevent overloading damage to the circuit and protect from electrocution hazards. We will also have a multipurpose fire extinguisher on site, suitable for class A, B and C. Safety is the number one consideration therefore hard stops and failure criteria are specified for each aspect of the project. Further safety considerations maybe mentioned in subsequent sections.

The Rig Design

Our rig design mimics the iconic oil derrick. We wanted a sound structure to hold our top drive motor and guide it smoothly towards its target. The 2 hp top drive motor is mounted within a housing to ensure the center of gravity is directly over the bit. The draw works is connected to the motor housing which is guided by two rails attached to the inside of the derrick. The size of the derrick allows for a 30+ inch stroke length plus the pulleys, connections, and sensors we required. The rails are heavy duty, ball bearing, drawer slides that provide a secure fit and a smooth track, for the motor housing to travel without risk of jamming. The derrick and table are made of welded 2-inch square steel tubing providing exceptional stability, enabling the derrick to be used in many years and competitions to come. We wanted the ability to maneuver the rig over the provided rock sample (12”x24”x24”) while also leaving room for much larger rock samples in the future. Finally, as the size of the rig kept increasing as we took more included more features, we decided to allow the derrick and table to be detachable for ease of transport.

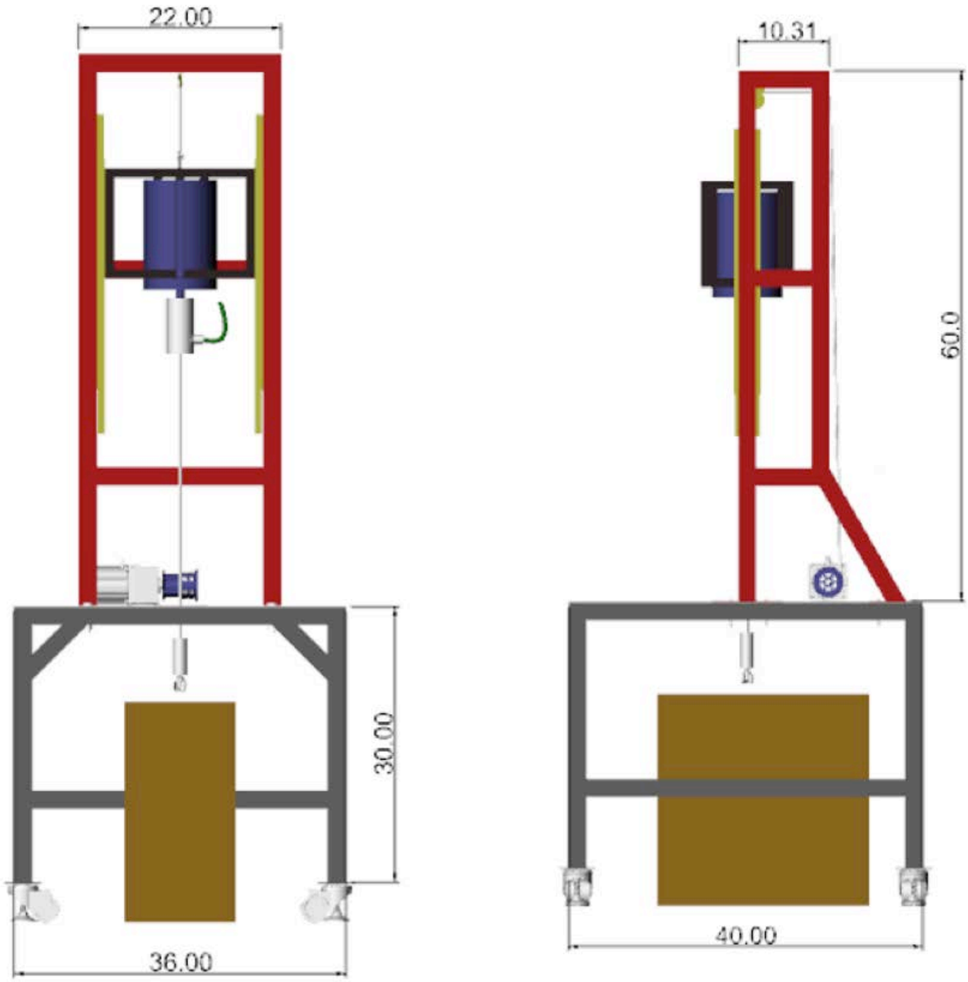


Fig. 1: Shows main components and dimensions of the rig design

Further design and materials considerations are described below, some will have to be tested and compared before final decisions are made. For example, we believe that the 30+ inch stroke length will provide enough length to push the bit entirely through the sample and contact desired targets. The suggested drill string is 3/8 diameter (.375”) aluminum with an ID of 0.277” and 36” length, though we may use a shorter length if we can. Also, we are considering a steel drill string of the same dimensions depending on our buckling limit calculations. Vertical movement of the top drive will be governed by a winch and pulley draw works. This wench is just a second motor and spool attached to the table (i.e. Rig floor). Steele cable will be run from the spool through two pullies attached to the top of the derrick and connect to the top of the motor housing, not the motor directly. There will a S-beam load cell weight sensor to measure the hookload, where the cable meets the motor housing. We will be using plexiglass sheets as the top of the rig floor as well as around certain parts of the table and derrick. This will provide an initial means of protection while allowing for full transparency. A removable rotary table(guide) will be placed in the center of the table to provide an additional means of stability at the drill floor. Finally we will add clamps to the table's cross members to lock the rig and sample in place. Notice the wheels can be locked(wrenched) into place and allowing table to be leveled.

Fluid circulation system

Drilling fluid selection

The choice drilling fluid for the project is water. For the preliminary design, a specific gravity of 1.04 and viscosity of 1.0cp are assumed. Changes will be made depending on preliminary tests on the cuttings transport efficiency of the fluid. This is especially critical for the deviated hole section, where cuttings build up is often reported. Temperature and Heat losses are assumed to be negligible for the system.

Pressure loss estimation

For the selected drilling fluid (water), pressure loss calculations are made with the assumption of single phase incompressible liquid flow. Pipes are assumed to be Aluminum and modeled as a drawn tubing for frictional pressure loss computations.

Standard formulas used for each calculation and the results are displayed in **Table 1** below.

Table 1: Formulas used for hydraulic computations

Parameters	Formula
$Reynolds\ number, N_{Re}$	$\frac{1.48 \times q \times \rho}{\mu \times D}$
Fluid velocity, $u\ (ft/s)$	$\frac{0.0119 \times q}{D^2}$
Annular velocity, $u\ (ft/s)$	$\frac{Q\ (gpm)}{2.448 \times (ID^2 - OD^2)}$
Annular mud weight, ρ_{ann}	$\frac{\left(Q \times \rho\ +\ V_c \times \rho_{cutt.}\right)}{(Q\ +\ V_c)}$
Volume of cuttings generated, V_c	$\frac{(1-\varphi) \times D_b^2 \times ROP}{24.49}$
Friction factor using the Chen approximation, f_f	$\left[-4\ log\ log\left\{\frac{\varepsilon}{3.7065} - \frac{5.0452}{N_{Re}}\ log\ log\left[\frac{\varepsilon^{1.1098}}{2.8257} + \left(\frac{7.149}{N_{Re}}\right)^{0.8981}\right]\right\}\right]^{-2}$
Frictional pressure drop, $\Delta p_{f.}(psi)$	$\frac{0.00518 \times f_f \times \rho \times u^2 \times L}{D}$
Kinetic pressure drop, $\Delta p_{kin.}(psi)$	$1.53 \times 10^{-8} q^2 \rho \left(\frac{1}{D_2^4} - \frac{1}{D_1^4}\right)$
Nozzle pressure drop, $\Delta p_b(psi)$	$\frac{8.3 \times 10^{-5} \rho \times Q^2}{C_d^2 \times A_n^2}$
Hydraulic Horsepower, $HHP\ (hp)$	$\frac{Q(gpm)\ \times\ P\ (psi)}{1714}$

Where q = flow rate, bbl/day

u = flow velocity, ft/sec

µ = fluid viscosity, cp

ROP = rate of penetration, ft/min

f_f = friction factor, dimensionless

L = Length, ft

A_n = Total nozzle flow area, in^2

V_c.= Cuttings generated, gpm.

Q = flow rate, gpm

ρ = fluid density, lb/cu.ft

D = characteristic or pipe diameter, in.

φ = porosity, fraction P = pressure, psi

Ɛ = relative roughness, dimensionless

C_D = Discharge coefficient, dimensionless

ρ_{cutt}. = Density of cuttings, lb/cu.ft

D_b = Bit diameter, in.

Using these formulas, pressure losses are estimated at the following nodes using the methods explained.

Surface pressure losses

- along hose losses

- gooseneck losses (i.e., hose-swivel junction)

Downhole pressure losses

- drill pipe losses
- bit losses

Annular pressure losses

- BHA-open hole annular losses
- Drill pipe-open hole annular losses

For all computations, the input used are summarized in **Table 2** while the results of the computations are presented in **Table 3**.

Table 2: Specifications for Pressure drop computations

Drilling fluid specifications	
Water viscosity, cp	1
Specific gravity	1.04
Density, lb/cu.ft	64.896
Drill pipe (DP) specifications	
DP ID, in	0.277
DP OD, in	0.375
DP length, ft	3
BHA specifications	
BHA OD, in.	1.1
BHA ID, in	0.277
BHA length, ft	0.833333
Bit specifications	
No. of nozzles	2
Nozzle ID, in	0.1
Total nozzle Area, sq.in	0.015708
Cd	0.95
Hole ID, in	1.5

Cuttings specifications	
Porosity, phi	0.3
SG of rock	2.65
Volume of cuttings, gal/hr	0.064312
ROP, ft/hr	1
ROP, ft/min	0.016667
Others	
Drawn tubing relative roughness	0.00005
Steel relative roughness	0.091
Hose ID, in	1
Hose L, ft	3
Swivel connection ID, in	0.277

Table 3: Pressure loss computations at varying pump rates

Surface Pressure losses							
Pressure losses inside hose							
Pump rate, gpm	1	2	3	4	5	10	20
Pump rate, bpd	34.286	68.571	102.857	137.142	171.429	342.857	685.714
Velocity, ft/sec	0.408	0.816	1.224	1.632	2.04	4.08	8.16
Reynolds number, Nre	3293.0	6586.0	9879.0	13172.0	16465.0	32930.1	65860.2
friction factor, f_f	0.3205	0.3050	0.2968	0.2914	0.2874	0.2758	0.2656
Friction pressure drop, psi	0.0538	0.2048	0.4485	0.7826	1.2060	4.6300	17.8340
Pressure losses at hose-swivel junction (gooseneck)							
Kinetic loss, psi	0.19708	0.78834	1.77376	3.15335	4.92711	19.7084	78.8338
Downhole Pressure losses							

Frictional losses inside drill pipe							
Velocity, ft/sec	5.31742	10.6348	15.9523	21.2697	26.5871	53.1742	106.348
Reynolds number, Nre	11888.	23776.	35664.	47552.	59440.	118881.	237762.
friction f, f	0.29328	0.28102	0.27456	0.27023	0.26702	0.25785	0.24987
Friction pressure drop, psi	30.191	115.726	254.370	445.079	687.175	2654.33	10288.8
Pressure drop across nozzles, psi							
Bit pressure Drop, psi	3.23329	12.9332	29.0990	51.7326	80.8323	323.329	1293.32
Annular pressure losses							
Annular mud weight, ppg	9.47359	9.08102	8.94467	8.87542	8.83351	8.7489	8.70619
Annular mud weight, lb/cu.ft	70.8621	67.9257	66.9058	66.3878	66.0744	65.4415	65.1220
Annular frictional loss across BHA							
Annular Velocity, ft/sec	0.39279	0.78557	1.17836	1.57114	1.96393	3.92785	7.85571
Reynolds number, Nre	1382.98	2765.96	4148.94	5531.92	6914.90	13829.8	27659.6
friction factor, f_f	0.34302	0.32468	0.31507	0.30868	0.30397	0.29048	0.27857
Annular losses across BHA, psi	0.04047	0.15323	0.33455	0.58270	0.89656	3.42714	13.1465
Annular frictional loss across Drill pipe							
Annular Velocity, ft/sec	0.19366	0.38732	0.58097	0.77463	0.96829	1.93658	3.87315
Reynolds number, Nre	1917.73	3835.46	5753.19	7670.93	9588.66	19177.3	38354.6
friction factor, f_f	0.33405	0.31687	0.30784	0.30184	0.29739	0.28468	0.27344
Annular losses across DP, psi	0.01226	0.04653	0.10171	0.17729	0.27293	1.04507	4.01519

From our computations, majority of our losses occur within the drill string. Observations showed that this is primarily due to the small pipe diameter to be used and the associated rise in frictional pressure drop for such diameters. From sensitivity studies, it is shown that a flow rate of 3gpm to 4gpm would satisfy the desired circulation goals, while keeping friction and associated stresses within optimal values.

Pump specifications

From the pressure drop calculations, the total pressure loss expected at different sections of flow loop are summarized in **Table 4** below.

Table 4: Cumulative sectional pressure losses

Pump rate, gpm	**1**	**2**	**3**	**4**	**5**	**10**	**20**
Surface losses, psi	0.250881	0.99313	2.22221	3.93599	6.13307	24.3384	96.6678
Drillstring losses, psi	30.19089	115.726	254.369	445.078	687.174	2654.32	10288.8
Bit losses, psi	3.23329	12.9331	29.0996	51.7326	80.8322	323.329	1293.31
Annular losses, psi	0.052733	0.19975	0.43625	0.75998	1.16948	4.47220	17.1617
Total losses, psi	33.7278	129.852	286.128	501.507	775.309	3006.46	11695.9

Based on these values, and a safety margin of 100psi, the pressure profile along the well is computed and summarized in Table **5** below. The extra pressure would compensate for unexpected parasitic pressure losses within the system.

Table 5: Pressure profile through well

Pump rate, gpm	**1**	**2**	**3**	**4**	**5**	**10**	**20**
Pump output pressure, psi	133.73	229.852	386.128	601.507	875.309	3106.46	11795.9
at hose-swivel junction, psi	133.476	228.859	383.905	597.571	869.176	3082.13	11699.3
Inside BHA above bit, psi	104.64	114.484	130.887	153.844	183.353	429.152	1411.82
BH from DP, psi	101.40	101.551	101.788	102.111	102.521	105.823	118.513
BH from Ann., psi	16.178	16.1166	16.0953	16.0845	16.0780	16.0648	16.0581
Pump HHP, hp	0.0780	0.26820	0.67584	1.40375	2.55341	18.1240	137.642

Using a 4gpm fluid rate, a pump capacity of 1.4hp would be enough for our design. Once selected, additional calculations such as a pump strokes, strokes per minute etc. computations would be made based on the specifications.

Safety

To minimize pressure losses due to fluid leakage, rubber seals are used at the hose-swivel junction to ensure a suitable fluid seal is created. A similar mechanism will be implemented at the BOP to be installed above the hole.

In addition, to maintain the pump rate and pressure desired, a pressure sensor would be used as a feed to automatically constrain the pump rate to meet the design pump output pressure.

Extra

Designs for hole cleaning, fluid rheology and solids handling at the surface are being considered. It is intended to use the Chien model for the hole cleaning design. However, this requires experimentally determined rheological parameters.

Also, solids handling at the surface will involve collecting the cuttings via a sieve while the fluid is recirculated to the pump. However, this is tentative as the volume requirements is not expected to be significant as to require flu recycling.

Mechanics of Drill Sting

Burst pressure

Drill string will tend to burst when the internal pressure at any point increases the bursting limit. Limiting pressure is given by

$$Py = \frac{2 * S_y * t}{Do}$$

Where

Py is burst pressure

Sy is yield stress

T is thickness

Do is OD of pipe

Ultimate Burst pressure is given by

$$Pt = \frac{2 * S_t * t}{Do}$$

Where St is ultimate yield stress

We calculated these values for our steel drill pipe

Burst and Tensile Strengths		
Given:		
Yield Strength	30000	[psi]
Ultimate Tensile Strength	70000	[psi]
thickness	0.049	[in]
OD =	0.375	[in]
Calculation:		

Internal Pressure at min Yield (Burst Pressure)		
Py =	7840	[psi]
Ultimate Burst Pressure		
Pt =	18293.3333	[psi]

Twist off

Condition of twist occurs when system is subjected to shear stress greater than the shear strength of the system. To calculate the maximum shear stress before failure and calculate the shear stress at the bottom of the drill string we employed following equations

$$\sigma_a = \frac{P_i r_i^2 - P_o r_o^2}{r_o^2 - r_i^2}$$

where

σ_a = stress in axial direction (psi)

p_i = internal pressure in the tube or cylinder (psi)

p_o = external pressure in the tube or cylinder (psi)

r_i = internal radius of tube or cylinder (in)

r_o = external radius of tube or cylinder (in)

$$\sigma_c = \frac{P_i r_i^2 - P_o r_o^2}{r_o^2 - r_i^2} - \frac{r_i^2 * r_o^2 * (P_o - P_i)}{r^2 * (r_o^2 - r_i^2)}$$

where

σ_c = stress in circumferential direction (psi)

r = radius to point in tube or cylinder wall (mm, in) ($r_i < r < r_o$)

maximum stress when $r = r_i$ (inside pipe or cylinder)

$$\sigma_r = \frac{P_i r_i^2 - P_o r_o^2}{r_o^2 - r_i^2} + \frac{r_i^2 * r_o^2 * (P_o - P_i)}{r^2 * (r_o^2 - r_i^2)}$$

where

σ_r = Radial stress

Maximum Torque Imparted by the system is given by

$$Tmax = \frac{\pi}{16} * \tau_{max} \frac{OD^4 - ID^4}{OD}$$

where

$$\tau_{max} = \sqrt{2 * \sigma_{ys}^2 - [(\sigma_a - \sigma_c)^2 + (\sigma_c - \sigma_r)^2 + (\sigma_r - \sigma_a)^2 * \frac{1}{6}}$$

Where tau max is the maximum shear before failure (twist-off). Sigma ys is yield stress for the material.

Maximum shear is limiting shear and is compared with Von Mises equivalent tensile stress under multiaxial loading condition is given by

$$\sigma_v = \sqrt{\frac{(\sigma_a - \sigma_c)^2 + (\sigma_a - \sigma_c)^2 + (\sigma_a - \sigma_c)^2}{2}}$$

Twist- off was calculated at the bottom of the drill string and we got the following result for fixed ROP of 1 feet/hr and RPM of 400 Von Mises shear was found under maximum shear.

Stress Calculations		
Given:		
Pi =	154	[psi]
ri =	0.1385	[in]
Po =	16.1	[psi]

ro =	0.1875	[in]
Yield Strength	30000	[psi]
Calculation:		
σ axial =	149.54	[psi]
σ hoop =	452.99	[psi]
σ radial =	-16.1	[psi]
τ max =	17319	[psi]
Torque max	6945	[psi]
Von Mises shear =	479.1046	[psi]

We will run stress behaviour throughout the drill string in our future calculations and generate stress profile. We will run sensitivity analysis on varying RPM, ROP, WOB and Friction (Side force).

Buckling

We are using Paslay buckling criterion to determine bucking in the drill string. Buckling force is given by

$$F_b = -F_a + P_i A - P_o$$

Where Fb is buckling force, Pi is internal pressure, Po is external pressure, Ai is area calculated with internal radius and Ao is area calculated by outer radius. Drill string will start to buckle if buckling force exceeds Paslay buckling force criterion given by

$$F_p = \sqrt{\frac{4EIwsin\alpha}{r}}$$

W is contact force of drill string, EI is the stiffness of the string and r is given by annular clearance

Bending Stress

Bending stress can be calculated using

$$\sigma_b = \frac{rEkM}{68754.9}$$

Where

E is the Modulus of elasticity, r is the radius of the pipe, K is dogleg severity and M is bending magnification factor. Bending stress were calculated considering the dogleg of 7.5feet/ 100 feet.

Bending Stress with Hole Curvature		
Given:		
OD =	0.375	[in]
ID =	0.277	[in]
Max DLS =	7.5	[deg/100ft]
E =	27000000	[psi]
Calculation:		
σ bi =	407.9513884	[psi]
σ bo =	552.2807604	[psi]

BHA Design

To comply with the Directional Drilling requirement and to hit the target up to 30-degree inclination, 15-degrees Azimuth and 10 inches of horizontal/ lateral displacement, a Push-the-Bit BHA that will achieve the desired dogleg will be built to achieve better build/drop rate.

The Push-the-bit configuration will include 10 inches rotary steerable section in BHA Assembly that will host the sensors in the upper annular housing and four steerable pads in the lower annular housing. This section of BHA will be stationary, isolated from the rotary parts by a slip Ring. Drilling will be implemented in rotary mode to minimize risks of stuck pipe. Directional drilling and rotary steerable mechanism will use 4 pad system that will push against the wall to provide required side force to steer the bit. Pads will be connected to Snail CAM (**shown in figure 2**) with a piston type setting. Cam will be operated by primary motor (In annular housing, lower end) that will control its motion. When operating on its amplitude (peak) pads will be fully open and touch the wellbore. We have been discussing to introduce a control system that will manage the amplitude of CAM so that it can control maxima and minima of piston.

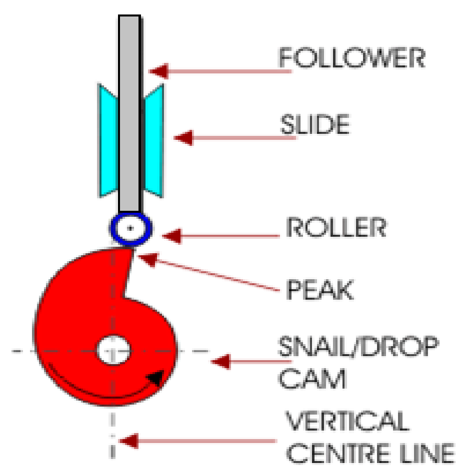


Fig. 2: Snail CAM

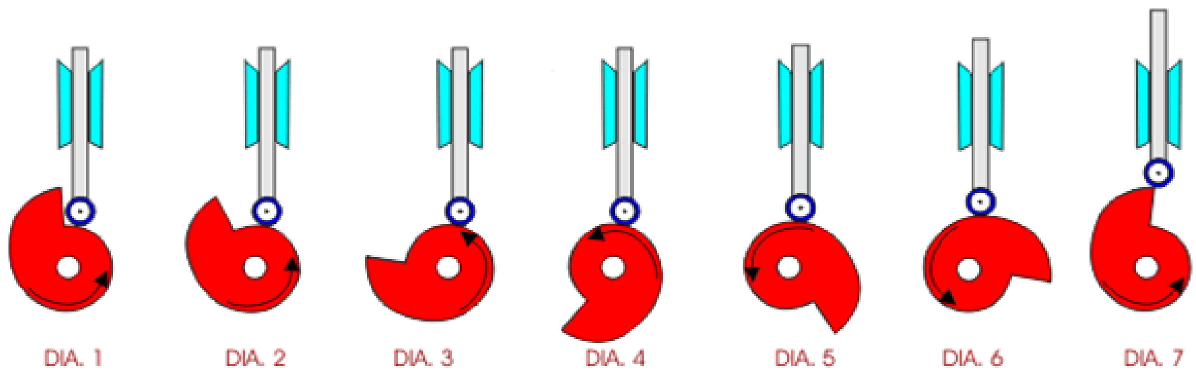


Fig. 3: working of Snail CAM

Basic design of push the bit system will induct pulley and fulcrum configuration. A 2.5-inch-long Stabilizer will act as the fulcrum point and pad will act as variable effort point shown in the figure below. While drilling directionally pad will open against the wall and provide a side force, and relatively a side force will act on stabilizer and on the drilling bit.

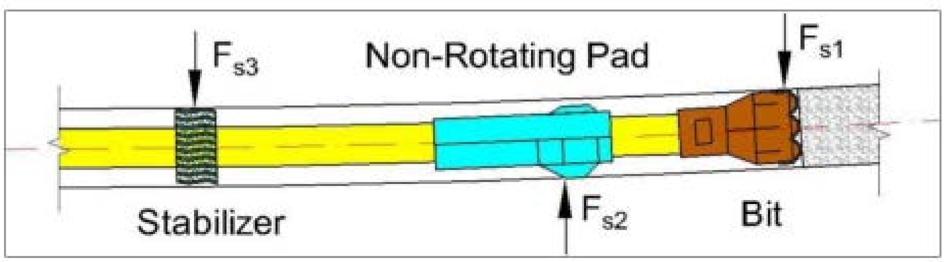


Fig. 4: Free body diagram of Push-the-bit setting

To understand the DLS created by this assembly we are referring to a SPE paper written by Dr Rebello Samuel and Mr Yuan Zhang ("*Analytic Model to Estimate the Directional Tendency of Point and Push the bit" SPE 174798 MS*).

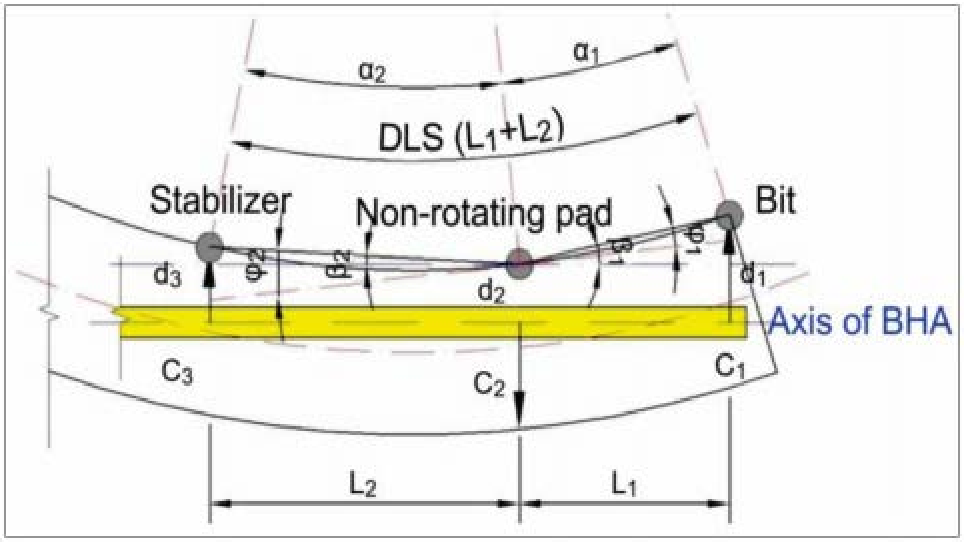


Fig. 5: DLS by push-the-bit mechanism

In the figure above C1, C2, C3 are contact points of Bit, Pad and stabilizers respectively. L1 is length between bit and the pad, L2 is length between stabilizer and pad. It the model it is assumed that C1, C2, C3 is part of the circle and a tangent is drawn through point C2. Angle between the tangent and the chord line is given by Φ1, Φ2 and the angle between the chord line and axis of BHA is β1, β2. Small Angle subtended by pad and stabilizer is α2. Angle between pad and bit is α1. So, the total dogleg is given by

$$DLS = \frac{\alpha_1 + \alpha_2}{L_1 + L_2}$$

And it is given that $$\emptyset_1 + \emptyset_2 = \beta_1 + \beta_2 = \frac{\alpha_1+\alpha_2}{2} = \frac{d_2-d_1}{l_1} + \frac{d_3-d_1}{l_2}$$

That gives

$$DLS = \frac{2 * (\frac{d_2 - d_1}{l_1} + \frac{d_3 - d_1}{l_2})}{l_1 + l_2}$$

Project BHA Design

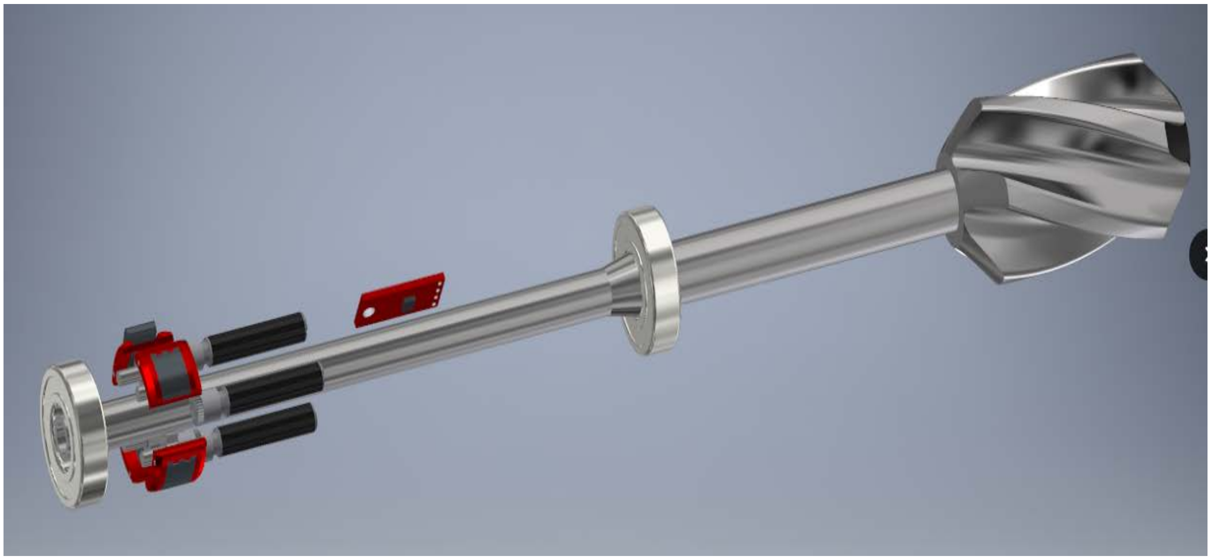


Fig. 6: Internal view of Steering device

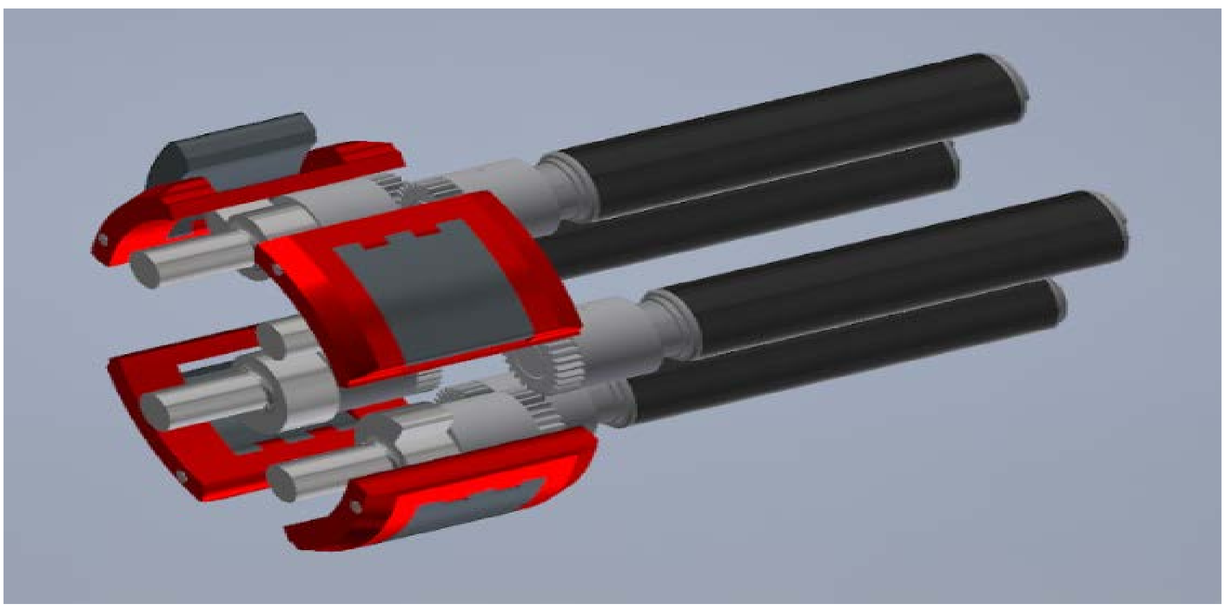


Fig. 7: Primary motor, Snail CAM, PAD

Pads will be pushed outward by Snail CAM controlled by 2 phase DC stepper motor, with 256:1 planetary gear built. Motors will be controlled by control system and powered when needed.

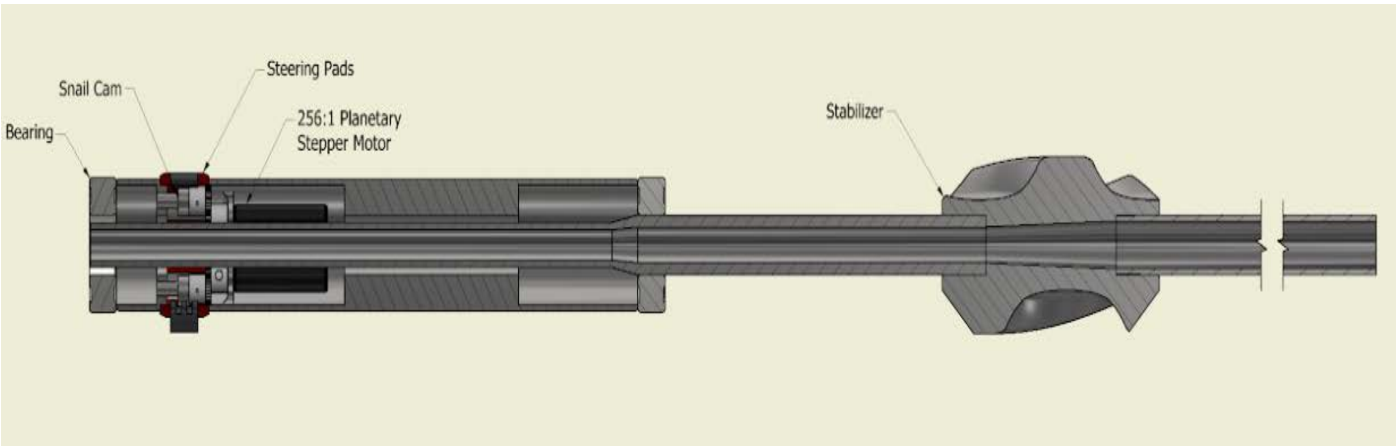


Fig. 8: Sectional view of BHA

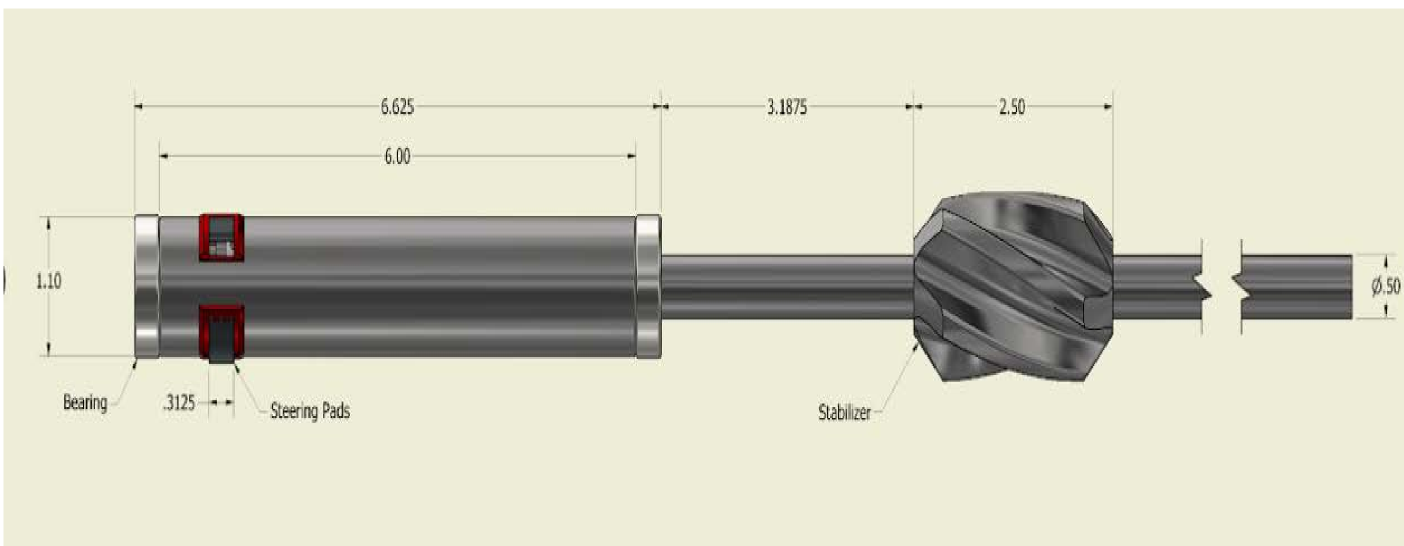


Fig. 9: Side view of BHA

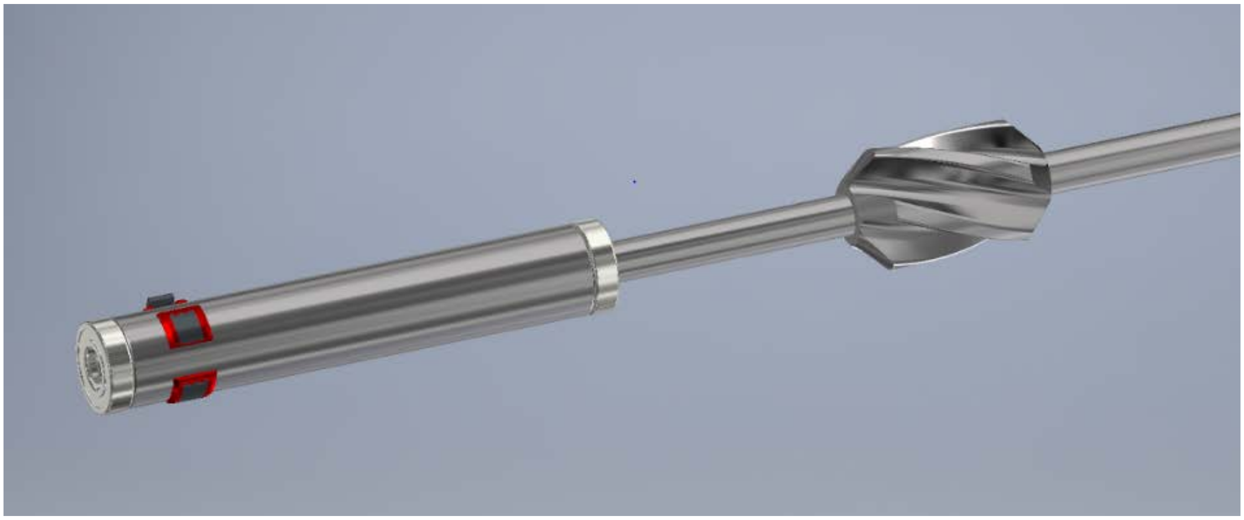


Fig. 10: General view of BHA

Pads will open for any build or drop needed. Opening and closing of pad will be determined by inclination and azimuth needed.

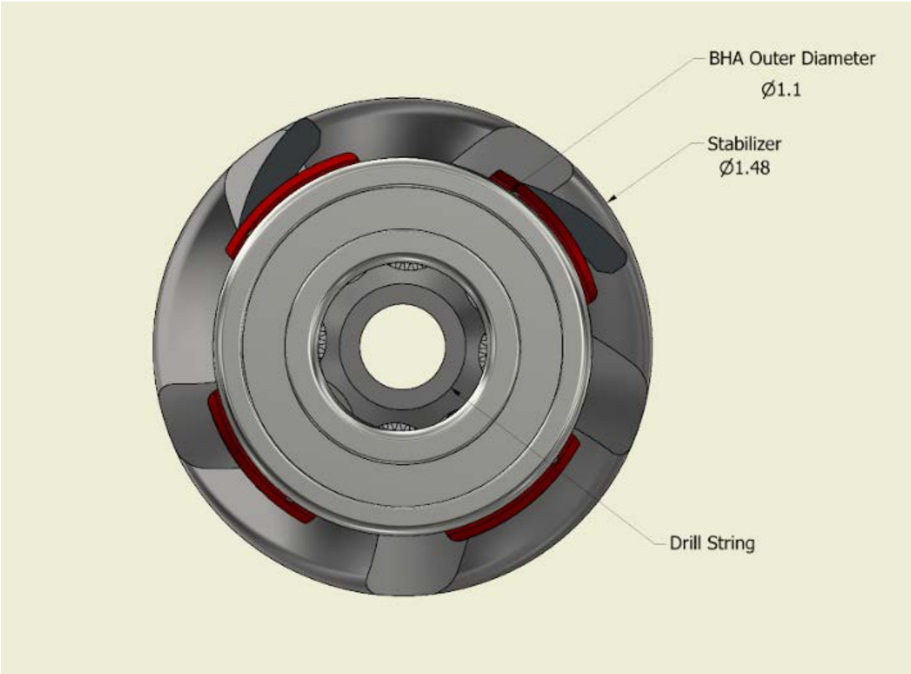


Fig. 11: Top view of BHA

An in-house software program (already developed, discussed in controls) will trace the correct position of BHA and guide it to return on designed well path if deviated from the original plan. Program automatically design the well path based on target coordinates.

Control System

Sensors

We have identified several key parameters to measure ensuring effective performance. These sensors will monitor the drilling process and control its operations.

Weight on Bit

WOB is a major parameter to not only measure but control, to do so we'll use an S-Beam Load Cell shown in **Fig. 12**. The Load Cell will be placed between the Top drive housing and the hoisting cable along with vibration dampening pads to improve the accuracy of WOB measurements.

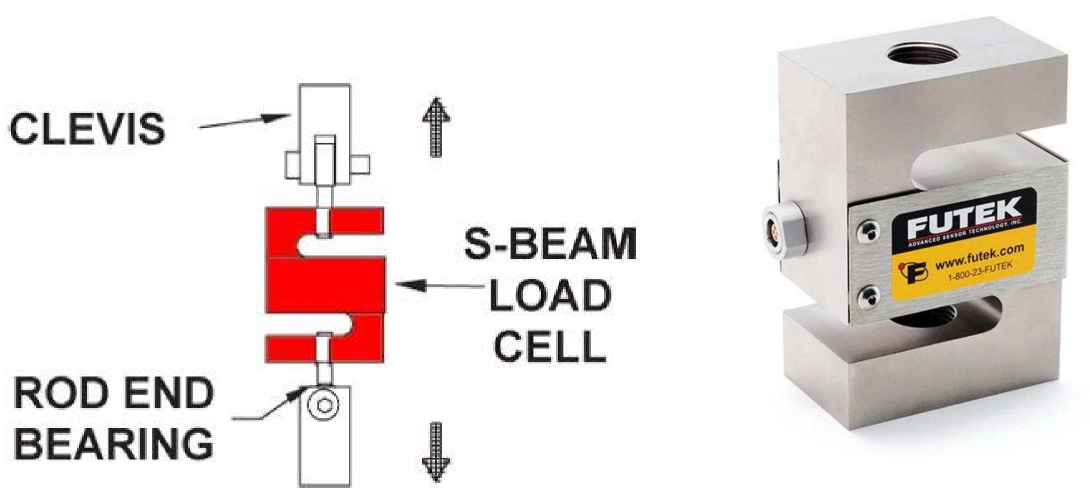


Fig. 12: WOB Sensor

Downhole

The downhole sensor will be a 9-Axis IMU, shown in **Fig. 13**, located in the BHA, will be used to measure the acceleration, azimuth, inclination, and orientation of the steering mechanism. The acceleration will be used to provide ROP, with the provided directionality making this the most important sensor.

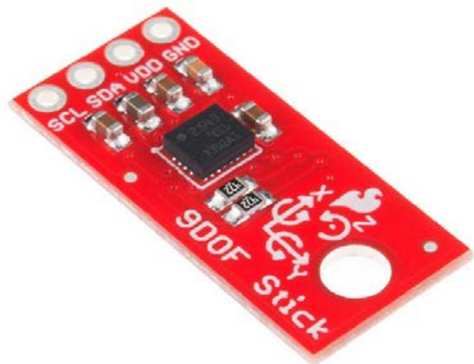


Fig. 13: Downhole Sensor

Rate of Penetration

ROP will be measured using the accelerometer from the downhole sensor. In addition to that, a Sharp IR Proximity Sensor shown in **Fig. 14** will be used to provide ROP and confirm the accelerometer data. The IR Sensor will provide the measured depth, which in combination with the known well path will provide ROP. This secondary measurement is taken as a result of the accelerometer's potential inaccuracies in high vibration environments.

Fig. 14: ROP Sensor

<u>RPM & Torque</u>

For measuring RPM and torque, we'll be using a variable frequency drive shown in **Fig. 15**. This controls the motor by varying the voltage and frequency. Based on the voltage and frequency output from the VFD, the RPM and torque can be calculated for the top drive motor.

Fig. 15: RPM & Torque Sensor

Flow

To ensure continual clearance of drilling chips we're using a flow meter, shown below in **Fig. 16**. The flow meter will measure the volume of drilling fluid traveling through, allowing for the proper adjustment of the mud pump.

Fig. 16: Flow Sensor

Vibration

To measure the vibration of the drill string and the drill rig, two accelerometers shown below in **Fig. 17** will be placed on the top drive housing and the drill rig frame. Additionally, the accelerometer in the IMU downhole will also provide vibrational data for the BHA. These data points for vibration will be used to detect and prevent drilling faults.

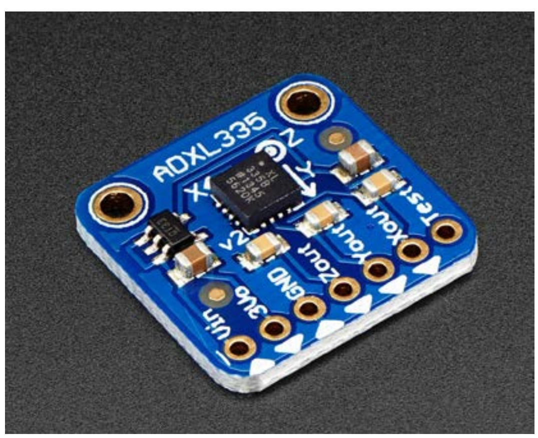


Fig. 17: Accelerometer Measuring Vibration

Limit Switch

The final sensor used will be the limit switches shown in **Fig. 18**. These will be used as a safety precaution to shut down the rig once the top drive reaches the limit of its travel.This would be applicable during improper tracking of the top drive's position.

Fig. 18: Limit Switch

Sensor Positions

The sensor's position and placements are shown in **Fig. 19** below.

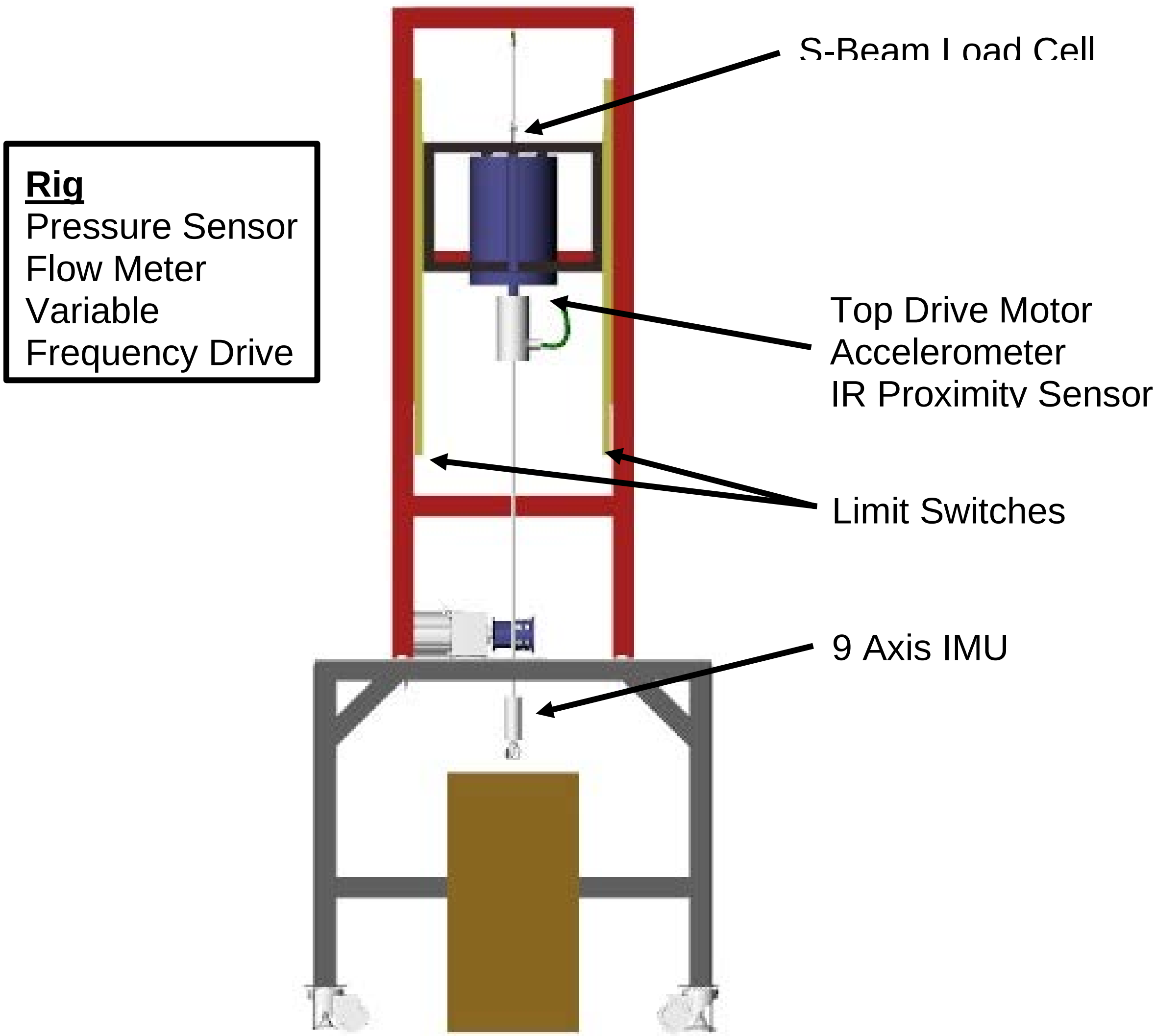


Fig. 19: Sensor Placements

Data Acquisition System

Data acquisition is a very important aspect of autonomous drilling. Proper data collection is necessary to correctly adjust the drilling parameters. In the control system, sensors serve to measure physical properties and converts them into electrical signals such as voltage or current. The Data acquisition device serves to process the data and transfer it to a host computer. It does this with various components, being an Analog-Digital converter (to convert various data inputs into a single readable form for the computer), a Signal Conditioner (which amplifies signals and filters out noise), and a computer bus (which serves as an interface with the host computer). The overall structure of this process is shown below in **Fig. 20**.

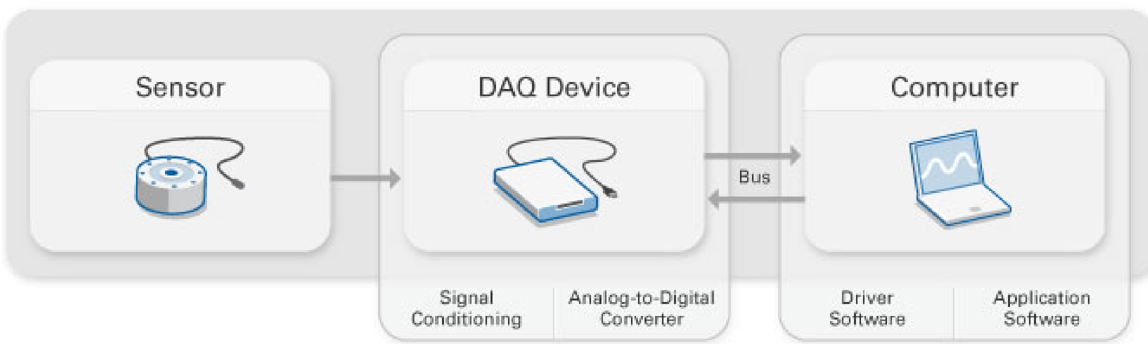


Fig. 20: Data Acquisition System

For the data acquisition, we'll be using Ni USB-6351, shown in **Fig.21**, which is compatible with voltage inputs, temperature inputs, counter inputs, quadrature encoder input, waveform output, timer output, and digital I/O. However, in our application only the voltage and digital I/O will be required. This configuration was chosen due to its compatibility with LabVIEW, as well as it's effectiveness.

Fig. 21: Data Acquisition Device

Data output from the Data Acquisition System will be sent to LabView and displayed on the GUI. An example of the GUI and the information displayed is shown in **Fig. 22**.

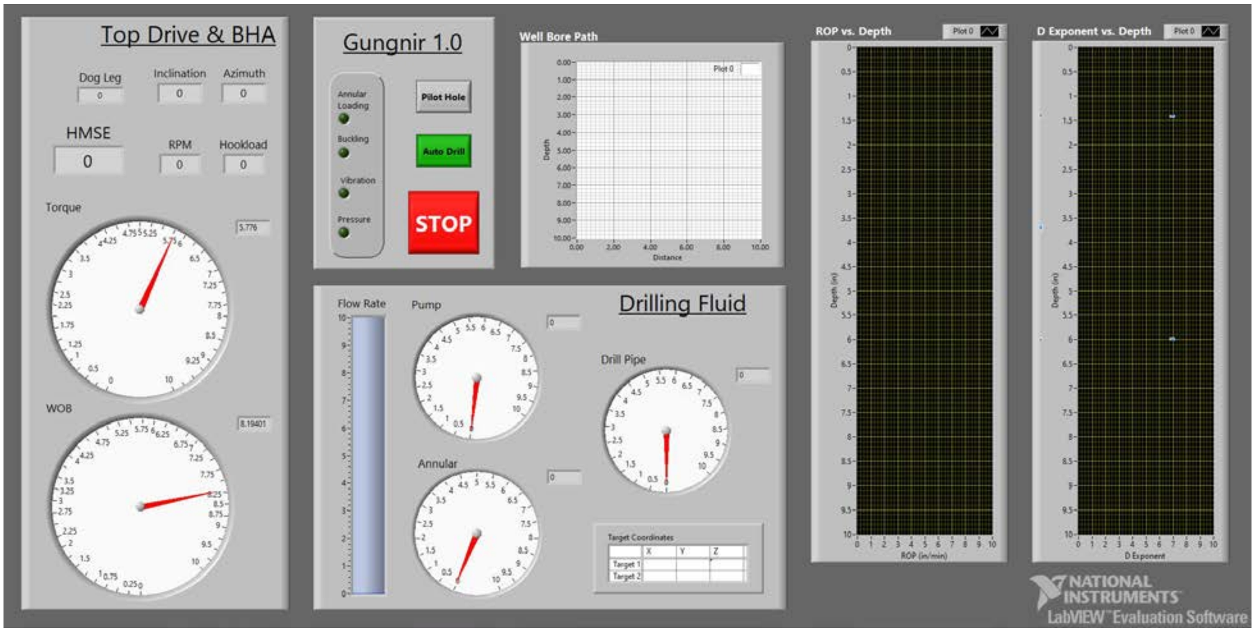


Fig. 22: Graphical User Interface

Control Algorithm

The system will use IR Proximity sensors to measure the vertical position of the top drive. Rate of Penetration can be calculated from this data, whereby RPM and WOB can be incrementally increased. For the algorithm driving controller, we'll utilize a PID loop.

The system will begin by increasing weight on bit to initiate the drilling process. Subsequently, weight on bit will be gradually increased while measuring the rate of penetration. This will serve to find the optimal weight on bit (known as the Founder Point) for maximum rate of penetration for a given RPM.

Similarly, optimum RPM will be found the same way. Using the optimum weight on bit, RPM will gradually be increased while monitoring the rate of penetration to find the optimal drilling parameters.

Furthermore, testing will be done to find failure points from the weight on bit and measured vibration. This way during drilling operations if these parameters are reached with a safety factor, then the drilling will be stopped.

Trajectory Control

We have created a program that builds a well path given surface and target location. This program can either be given a desired BRA and target inclination or choose these values for itself within our BHA's allowable BRA. This program creates the theoretical well path we hope to achieve. Though in reality the wellbore typically deviates so we have an algorithm that continuously checks the true position of the bit provided by the gyroscopes in the BHA. If the location of the BHA indicates the bit is off target the program finds what change is required to correct the deviation and return to target. In this way we have a means of autonomously drilling to target. The decision criteria for correcting the well path are related to all the data produced by the rig throughout the process.

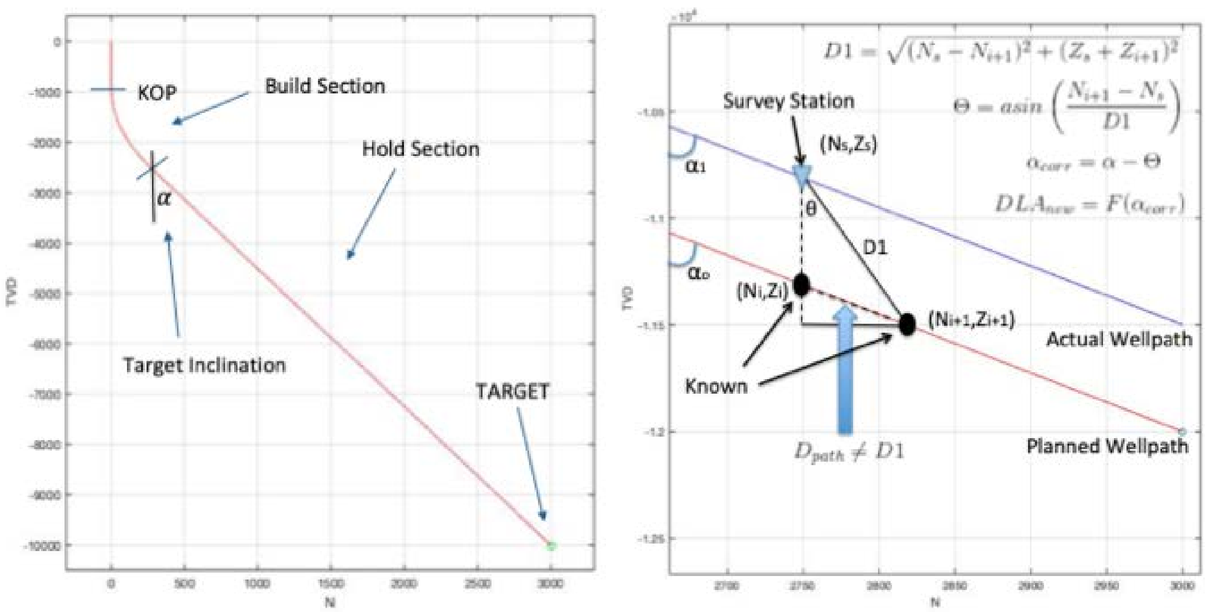


Fig. 23: (a) Example output of wellpath program (b) Theory behind wellpath correction

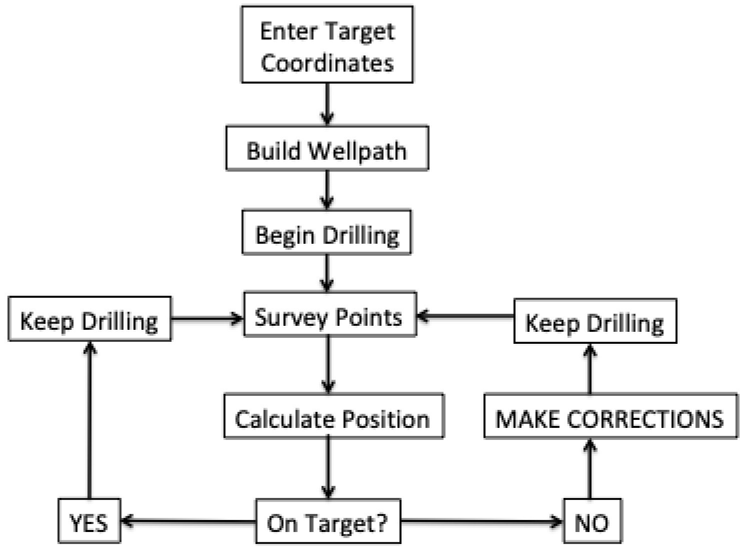


Fig. 24: Depicts the Drill-to-Target workflow

Appendices

Appendix A - Team Biographies

Austin Williams

- MS Petroleum Engineering, University of Houston (Dec. 2020)
- BS Geophysical Engineering, Colorado School of Mines (2016)

Abhishek Raj

- MS Petroleum Engineering, University of Houston (Dec. 2019)
- BS Chemical Engineering, BMSCE (2017)

Lotanna Ohazuruike

- PhD Petroleum Engineering, University of Houston (May, 2021)
- MSc Petroleum Engineering, University of Port Harcourt/IFP School (2016)
- BTech Petroleum Engineering, Rivers State University (2013)

Brandon Le

- BS Mechanical Engineering, University of Houston (May, 2023)

Erika Andrade

- BS Petroleum Engineering, University of Houston (May, 2020)

Usman Hussain

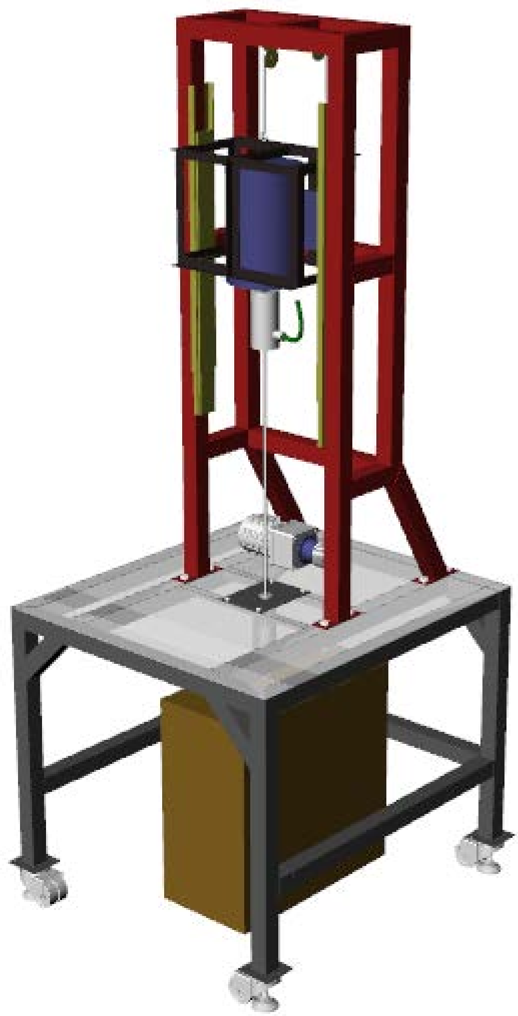
- BS Mechanical Engineering, University of Houston (May, 2023)

Appendix B - Project Finances

Project estimates at this phase are estimated as follows.

S.No	Section	Projected Cost ($)
1	Structure	500
2	BHA	1,500
3	Control/Sensors	3,000
4	Fluid System	300
5	Miscellaneous	700
6	Total	7,000

Transportation costs are not included as a brand new rig is to be constructed. In addition, as the team resides in Houston, this is expected to be minimal.



Thank you for your time and consideration!