Society of Petroleum Engineers
Drilling Systems Automation
Technical Section (DSATS)
International University Competition
2020 – 2021

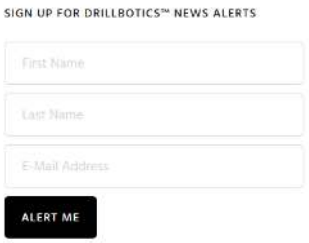
Drillbotics® FAQs

Revision 4: 8 February 2021

1. Introduction

This year marks the seventh competition for the title of Drillbotics® champion. Teams will build a virtual rig (Group A) or they may compete by building and operating a physical rig (Group B). Both will attempt to drill a directional well. Group A will virtually drill a full-scale well. Group B will receive a rock sample and drill a mini-well.

The Drillbotics committee wrote Guidelines for the competition, but there are inevitably some areas of confusion, which we hope to clarify here. These FAQs are a response to questions posed by various teams throughout the year and are updated as frequently as practicable. Updates will be posted on the Drillbotics.com blog, and it is the responsibility of each team to keep up to date, as these FAQs become an amendment to the Guidelines. Teams are encouraged to enroll to receive notification of new posts on the blog page www.Drillbotics.com/blog



This updated FAQ shows the latest revisions highlighted in yellow.

When asking a question, we want the student teams to please refer to the section and item number in the Guidelines concerning your topic so that we give the correct response.

2. *Frequently Asked Questions*

General information:

To those teams in Group B who failed to include certain items in their design reports we wish to offer you a chance to include the items before the judges meet next week. Not having these items will not disqualify anyone, but they may influence judges' considerations. To those teams who did include the information, thank you, it makes our job a lot easier. It lets us compare team assumptions and

Version	Date	Section	Description
2021.00	3 October 2019	All	Initial release
2021-01	23 Sept 2020	4.5	Removed restriction
2021-02	30 Sept 2020	Appx A Objectives & Appx C 1.6	Clarification
2021-03	28 Oct 2020	4.0, Appx A Objectives, Appx C	Able to compete? Drillpipe specs
2021-04	8 Feb 2021	3.3.3	Bit model

calculations. Note: giving us a table listing possibilities does not indicate that you made decisions on your assumptions. Please tell us what are the design limits that affected your choices?

We also look at the size and weight of your rig's design. Will it fit into a booth at the drilling conference? Did you provide information allowing us to estimate the cost of transport?

If you have not yet done so, please provide information per the Guidelines version 3 and FAQs Rev3:

Appendix page 26+ design notes and calculations

item 1.2.5.2.2 summary of ALL calculations in the format of 1.18.4.2

- Item C if it was included, where is your chart? (please list page number in case we missed it)
- Item E dimensions?
- Item F chargeable weight

We will make changes to the guidelines next year to make this more visible.

§3.2 Before drilling a well do we have to do planning to reach the target in the most efficient and safe way?

Yes

§3.2 How far apart (in meters) are the points in the directional plan? How many points in total? What is the approximate length of the well, inclination, azimuth? Do we decide ourselves about the drillstring geometry?

No additional target/trajectory information will be given outside of what is already provided in the guidelines. "The starting directional plan to hit the targets will not require wellbore inclinations in excess of 30° from vertical, 15° change in azimuth." Drillstring/BHA design is left up to each team.

§3.2 Do we have to drill a well, or just a section? Do we need to run casings, cement it etc?

The whole well will be drilled from spud to TD. Only the drilling operation is required to be modelled/executed. No casing, cement, logging, etc.

§3.3 Do we simulate a consolidated virtual rig to drill a well, or only model the 7 items mentioned in the guidelines? Do we also model drilling a well?

The end goal is for you to develop a virtual drilling model and a control model to drill a well virtually. The details in section 3.3 are some recommendations on what you will have to consider fit building the virtual drilling model. You and your team will have to determine what physics of the drilling process you want to model. But keep in mind that the competition challenge is to drill a directional well virtually to specified targets.

§3.3.3 What do you mean by saying that the drill bit model will be provided? What exactly will be provided?

```
function [ROP, ROPlateral, TOB] = rop_tob_drillbotics(formation_aggressivenss,
bit_aggressiveness_factor, WOB,RPM,Eff, D, CCS, side_force, side_cutting_factor)

%% This function predicts ROP, Lateral ROP of the bit, and Bit Torque
%  Output Variables, Units:
%  ROP, [ft/hr]  (axial ROP)
%  ROPlateral, [ft/hr] (lateral ROP)
%  TOB, [ft-lbs] (bit torque)

% Input Variables, Units:
% formation_aggressivenss, [ ] (drilling agressiveness, Torque/WOB ratio
%      which is heavily influenced by formation type.  based on paper by
%      Pessier and Fear in SPE 24584 (1992))  Contest will provide this.
% bit_aggressiveness_factor, [ ] (range from 0.7 for unaggressive bits to
%      1.3 for aggressive bits)  Contestants or contest will choose a bit
%      which will have an associated bit_aggressiveness_factor.
% WOB, [lbs]  (axial force on the bit)
% RPM, [RPM}  (revolutions per minute of the bit)
% Eff, [ ]  (drilling efficiency, usually 0.3 to 0.4)
% D, [inches]  (bit diameter)
% CCS, [psi]  (confined compressive strength of the rock)
% side_cutting_factor, [ ]  (scaling factor for side cutting aggressiveness
%      of the bit)

    mu = formation_aggressivenss*bit_aggressiveness_factor;

    ROP = (13.33*RPM.*mu.*WOB)*(Eff)/(D*CCS); % [ft/hr]; Derived from Teale MSE
concept (1965).

    TOB = D*(mu.*WOB)./36; % [ft-lbs]; Derived from Pessier and Fear, SPE 24584
(1992)

    ROPlateral = side_cutting_factor*side_force*RPM/(D*CCS); % [ft/hr]

End
```

§3.3.3 According to the Drillbotics 2021 Guidelines V3, the bit model is provided by you. But what are the input and output parameters of this model?

- Input: Formation Aggressiveness (provided by Contest), Bit Aggressiveness Factor between 0.7 and 1.3 (Contestants will select a bit with this value, which remains constant through the run.), Weight-on-Bit, Bit RPM, Drilling Efficiency (provided by contest, “Eff” = 0.35), Bit Diameter (“D”) (provided by Contest), Formation confined compressive strength (“CCS”) (provided by Contest according to a formation model/prognosis), Side cutting factor (provided by Contest, a constant value associated with a particular bit. Different bits are more laterally aggressive than others. Teams will either be assigned a bit with a particular Side cutting factor, or be forced to choose among bits with different side cutting factors.), Side force (provided by the Team’s drillstring model)

- Output: Axial Rate of Penetration, Lateral Rate of Penetration, Bit Torque
  mu = formation_aggressivenss*bit_aggressiveness_factor;

  ROP = (13.33*RPM.*mu.*WOB)*(Eff)/(D*CCS); % [ft/hr]; Derived from Teale MSE concept (1965).

  TOB = D*(mu.*WOB)./36; % [ft-lbs]; Derived from Pessier and Fear, SPE 24584 (1992)

  ROPlateral = side_cutting_factor*side_force*RPM/(D*CCS); % [ft/hr]

§3.3.4 and3.6.1 Is the planned trajectory going to be the whole well path that the well should follow, or are we going to receive only some target coordinates (e.g. HD, TVD, North, East) to reach? so, we can propose our own planned trajectory.

Only TVD/North/East target coordinates will be provided. It will be up to the teams how to design the trajectory to hit them.

§3.3.4 Should the steps of the virtual surveys are going to be in function of time or length?

- In the interest of simplicity (from an automation standpoint) it doesn't matter how the steps are done, however teams should ensure that the survey course lengths are appropriate for the dogleg severities being surveyed. It's typically recommended to not have survey intervals exceed 10m-13m (30ft – 50ft) in length for accurate wellbore placement. This should be considered in the control scheme if time-based survey intervals are being used.

§3.3.4 Do we have to simulate 3D or 2D model? And the guidelines mentioned that the trajectory will be given, what does it mean?

For Group A limit the scope to 2-D for both the steering model as well as the formation model for BHA/bit deflection behaviour.
Group B would still need to be able to drill in 3-D in case azimuth needs to be corrected to come back to hit the target(s).

We want your model to be flexible enough to drill the well to the targets specified just prior to the contest date.

§3.5 In the guidelines, regarding the coding aspect of the competition, we would like to inquire about the type of programming language to be used for this competition.

Whatever you prefer.

§4.0 **Is it possible for our team to participate in Drillbotics-2021 if we got our master's degrees this August? We were not able to compete because of the cancelled tests.**
No. Unfortunately, the competition is only for current students. It would not be fair to the other teams to allow graduates to compete. Teams that had to drop out of the 2020 contest due to the pandemic will be allowed to participate for the purpose of learning but will not be considered for any of the prizes.

§4.5 **What if a school wants to enter more than one team in a group?**

Did read: A university may sponsor more than one team but must submit only one team/design for Phase II evaluation.
Revised: A university may sponsor more than one team in a group and may enter a team(s) in one or both groups.

Appendix A: Objectives **Does this mean a requirement of 30° inclination and 15° change in azimuth between each target in the trajectory, or are these values the total displacement required from the start to the end of the trajectory?**

The max displacement/inclination/azimuth are total/accumulated from the start to the end of the well path.

Please note: We want teams to be prepared to drill any given trajectory within the specified parameters, so we will not provide the coordinates in advance of the test.

Appendix A: Objectives
The referenced aluminum material may not be able to meet the trajectory requirements without going into plastic deformation.

Yes, this is a difficult engineering problem. Teams must deal with multiple constraints like those faced by practicing drilling engineers designing difficult wells. Each team should design their own well trajectory plan after receiving competition targets. Their systems should autonomously determine the trajectory, taking into consideration the physical limitations that they have defined for their specific system. If a team feels that their system will not be able to hit the targets, the plan should be designed to get as close to the targets as possible. Judges will assess your assumptions and calculations to see how well you understand the issues. Be sure to explain what testing was done to confirm your assumptions.

Teams should consider whether their model assumes that the pipe will be subject to the same radius of curvature as the well trajectory. Consideration should include drill pipe, connections and BHA (versus one continuous section of drill pipe). What are the external bending moments and forces? How will this affect stress/strain? The pipe clearance from the wellbore wall may allow it to have a less severe bend and the connection points would also influence the stress/strain of the pipe body. Another question is whether plastic deformation should be allowed?

Appendix A: Objectives

What information about the lithology will be provided: type, pore/fracture pressure, UCS?

For Group A, expect formation aggressiveness and CCS to be functions dependent on bit depth (TVD). Note CCS versus UCS. Teams should explain their conversion calculations. For Group B, we will advise teams of the rock properties after the we purchase the rock next spring. Teams should expect more than one formation.

Appendix A: 1.3.3 We are planning to install a riser, consisting of a pipe with a flange, on top of the rock sample. We did not intend to remove it after the pilot hole is drilled but want to use it further while drilling the entire well. The riser should supply a flow conduit and stabilize the drill string, especially when most of the BHA is still above the rock. It is not intended to apply any lateral forces and the riser is not part of our the steering process. By reading the mentioned Appendix items again and considering your email, I understand that this approach is a valid option and still within the guidelines. Is that correct?

Yes, as long as you do not use it to steer. Previously some teams were trying to steer from above the rock's surface.

Appendix A: 1.5.1 We wonder when we can order the bit you will provide and how long it will take to deliver?

The Drillbotics Committee will notify all Group B teams of the availability of the bit. Typically, they are available about the middle of April, but it will depend on Baker Hughes' production schedule. Note that teams will only receive one bit, so they must balance testing versus bit wear/damage of the bit used during the test.

Appx C §1.6 Is it possible to cut the drill pipe in more parts and then use joints to connect it?

No, this would artificially strengthen the drillstring. We want you to deal with the drillstring dynamics via your control software.

Appx C §1.6 Do we have to use aluminum tubing?

We refer you to section 1.6 of the Guidelines regarding the use of aluminum tubing (pipe) and specifically to 1.6.1 to substitute steel pipe. Teams may choose durability over flexibility, and we ask that you explain your choice in your design report.

Also refer to the question above about aluminum pipe and plastic deformation.

-End-