

Carlos:

I'm not sure where you get the data for the statements 1-8 that you propose are given as fact and yet I will bite since the first one seems fairly simple and explainable.

Perhaps the others aren't, yet as engineers, all of these issues shouldn't be too much for any one of us to understand with diligent study.

1. The lower the compressive force, more string is in tension, the greater will be the torque at surface. Why? Torque and Drag (T&D) are a function of mostly hole angle, dog leg severity (DLS), lateral force and friction factors. Lateral force is a strongly proportional to hang down weight because this forces the drill string into the side of the wellbore. Increasing the tension causes more of the drill string to make contact with the wellbore wall due to the increase in side force. Traditional equations include the weight of the pipe, DLS and the angle of the hole and a friction factor between hole and pipe contact. Friction factor is most likely variable enough along the length of the wellbore to be necessarily accounted for. For instance drill pipe against hole consisting of sand, shale and combinations, various OD and grades of drill pipe against various ID and grades of casing. Things that affect this contact aren't necessarily accounted for equally in every traditional equation and/or T&D software.

2. At constant rpm and increasing the tripping speed, the surface torque is reduced. Why? Ignoring the question of why are we tripping and rotating at constant rpm? Are we backreaming? Ignoring that and associated comments; acceleration causes fluctuations in forces and vibrations, both of which contribute to torque, of course often an overly aggressive bit results in surface manifestations of stick slip, rpm and torque spikes. There shouldn't be any torque while tripping so most likely you were thinking drag and wrote torque. Assuming that is correct, whilst tripping there is a change in the friction between the side of the hole and the drill string and it is a function of the velocity. Thixotropic muds aren't anything new and the fact that if pipe is left still the differential pressure gradient that exists just behind the wall cake begins to act on drill pipe this pressure works to pin the drill pipe to the side of the wall and this increases the force required to pull the pipe normal to that force as well. Also, moving pipe resists a friction factor that is much less than static pipe. Once pipe begins to move, its friction factor decreases from the highest, static friction factor, to the lower, dynamic friction factor, thus lowering the torque and drag seen on the rig floor. Note that the above explanation works, essentially for torque and drag and thus the confusion over whether

we are tripping or backreaming really matters little. Presented above are three completely different reasons for similar surface manifestations of decreasing torque and drag.

3. I have seen that the best rheological model to use and calculate an accurate SPP is yield power law. However, news papers have come up in drilling fluids and those use the power law model. The question is which model we should use and for slim hole (high annular velocities) which rheological model is the most appropriate?. Also can I say that the minimal viscosity I will experience in the system would be the plastic viscosity which is on the bit? [The Herschel-Buckley rheological model is close to exclusively used today for drilling in large holes and small.](#)

4. When I am calculating the pressure losses in the system, there are some sections in the annulus where the regime is transitional flow. Which formula should I use for pressure losses calculations? I have seen formulas for turbulent flow and for laminar flow. Using power law or yield power law the formulas change a lot from turbulent to laminar flow. If I calculate it assuming turbulent flow, how much is I over calculating the pressure losses at those sections? [Use the Herschel-Buckley model and in places where you're not sure of the flow regime you're going to have to be diligent and yet decide. For Herschel-Buckley perhaps there are three formulas for each flow regime because transition is considered the third. So it is simply a matter of calculating the flow regime you are in and applying the appropriate formula.](#)

5. I wish to model a well control situation in a ultra deep water where the fluid expected is oil + gas at surface (when the influx is present the fluid is oil only but once the pressure is below the bubble point the gas will be present as the fluid is going up). How can I model the kick tolerance for this specific situation? The fluid I am using SBM and the temperature at sea bed is very low so that the rheological properties is very high. [The traditional calculations for kick tolerance for a shut in situation is fairly straight forward if the bubble point is lower than the wellbore conditions below the last casing shoe. Of course if the bubble point is higher than the difference in the reservoir pressure minus the footage below the last casing shoe times the mud weight to balance the reservoir pressure minus the fracture gradient at the last shoe x 12/231 then you will have gas above the shoe or below if the shoe breaks down yet things will remain simple for a static model, shut in kick tolerance calculation. If you want to use a kick simulation for your kick tolerance calculation and include multi-phase flow with multiple](#)

fluids then there are many software programs on the market to accomplish that and yet probably not the forum to go into those or name them all.

6. I would like to know the effect of the packer OD in torque and drag when I running it along with screens. A packer with diameter of 5.88 did not have buckling but once the packer diameter was increased to 5.9 the model showed me buckling. How can I explain that with minimum change in OD buckling becomes significant? Logic isn't always clear to intuitive thinking, and the term for it is counter-intuitive. One minute you are 20 years old and a second later you are 21? I aged a year in one second? Well, if your perspective is one second before your 21st birthday. If your packer OD results in loading that is very, very close to buckling and you make it just enough bigger though a tiny amount, it now buckles...you were at the tipping point and you see the analogy. If you are drilling, the buckling is significant, because rotating buckled pipe or rotating with buckled casing can cause much damage and yet if you are running a packer I'm not sure if a small amount of compressive force above a packer, as long as it moves downhole and you set it at the depth your planning to, is a huge deal. Once you run and set the packer and the tubing, do so with enough tension to avoid tubing movement/buckling during production. If your question was merely as to the cause and effect of an increasing diameter of packer to the buckling, then note that the larger OD packer is a tighter fit running into the production casing. The tighter tolerances cause a higher net compressive force acting up at the packer. This compression is transferred to the tubing above the packer and is the cause of buckling at higher loads. I'm not sure of exactly what design phase you are in on this question, tubing movement/buckling, or simply running a packer to be set at depth.

7. For casing setting, normally people use bottom up. Under what condition I should design top to bottom, in exploratory wells? More important than method of design may be the concept of precision and accuracy. Inaccuracy should never be accepted because of imprecision and imprecision should never be acceptable because of inaccuracy. How many times have we been bullied into rounding our calculations because precision to a foot is deemed to be insignificant compared to a well miles deep? Perhaps in some instances this is okay, yet in casing setting depth it isn't, in my opinion. If the well is expendable and not considered to be viable for production you will simply set casing every time you have no other choice, because of hole conditions and/or lack of kick tolerance, and be left with whatever hole size you're left with at TD. One thing to be certain that is probably neglected in some instances is the effect of reduced fracture

gradients in sands, and if they are too close to the shoe, they may be below the LOT at the shoe. In offshore wells, highly permeable sands with low friction angle sand grains exist that have much lower shear failure and this may require that you stop drilling before reaching your planned shoe. Another reality that can be neglected is that typical underreamed holes will leave you with anywhere from a 100' to a 160' pilot hole, and in deepwater projects, unless your willing to spend another \$1,000,000, on average, to trip, run your reamer close to the bit, trip back in hole and drill back to bottom, your left with a fracture gradient 100'-160' less than the plan. This is where precision and accuracy are needed. Even if you do make a special trip to ream, you will still leave 15' or so, depending on how close you can put your reamer to the bit after laying down measurement tools. Also if it is a long string landed in the wellhead, there will be another 30' needed to compensate for spacing and heave of the rig, and with a liner this will still be a minimum of perhaps 5'-7'. Therefore you have to drill a hole on a plan to have the margin below the fracture gradient of the previous shoe and above the pore pressure of the deepest penetration. Yet, you give back the fracture gradient equivalent of 22' on the low end and almost 200' on the high end depending on the details of the above mentioned specifics. Designing casing setting depths for production you typically want a minimum hole size and yet you may have minimum options for contingencies in case you're forced to set one string or more early. Therefore accounting for everything is vital and key to success and losing 200' of hole and its equivalent in increased fracture gradient in the planning phase, is unacceptable. You can't close your eyes to these facts and hope they go away, yet must recognize and plan for this loss of hole in the design phase. If your well plan has 7 casing strings and you lose 100' each hole section you've lost 700' of fracture strength and you now can't get the required hole size to TD. Precision and accuracy are required and rounding won't work. Whether top/down, or bottom/up, getting the casing seats in the right place to minimize pressure differentials, time in problem hole sections, and case off other issues like directional sections, is the prime importance.

8. Have someone design fiberglass casing. If so, which parameters should be had into account compared with a standard tubular? Parameters: Need, cost, life-cycle loads, strength of material, special corrosion resistance, flow assurance advantages, other special functionality and availability.