MSc (Petroleum Engineering)

Project Report 2021/2022

Farid Hasanov

Establishing a new set of friction factors for liner running in complex wells using Wellplan software.

Heriot-Watt University

School of Energy, Geoscience, Infrastructure and Society

Institute of GeoEnergy

Supervisor – Haghighat Sefat, Morteza

Declaration:

I Farid Hasanov confirm that this work submitted for assessment is my own and is expressed in my own words. Any uses made within it of the works of other authors in any form (e.g. ideas, equations, figures, text, tables, programs) are properly acknowledged at the point of their use. A list of the references employed is included.

Signed: Farid Hasanov

Date: 04 August 2022

Acknowledgments

First of all I would like to acknowledge my project supervisor Haghighat Sefat, Morteza who assisted me with the preparation of this thesis, by guiding me and providing his valuable feedback.

I am grateful to Heriot-Watt University and its entire staff who assisted me during my long journey from the very first day as a student.

I would like also to highlight the company I am proudly employed at – the BP which was a sponsor of my entire study. Particularly I would like to mention my first team in the company where I have performed the very core of this project the calibration process for new injector well. Exactly there I have learned a lot about frictional forces, drag forces and Wellplan software, and now I can share my knowledge by writing this thesis.

Last but not least I would like to thank my entire family, especially my wife for their eternal support during my studies and for their understanding when I need to spend additional time in front of a computer.

Summary

Most of the oilfields in the world are mature fields in which drilling technology becomes more and more complicated with time. Every new drilled well requires a complex trajectory in order to avoid the anticollision, as well as the targets for those wells, which are located far away from the platforms. All this creates huge challenges mostly not to the drilling of such wells but to successfully casing off and cementing them. One of the benefits of running liner + tieback instead of a full casing string is that a shorter tubular creates less resistance while run in the hole. Another benefit is that it is easier to cement it. However, liner and tieback operation is more expensive and takes more rig time. One of such mature fields is ACG field located in the Caspian Sea. New planned well from this field required a complex analysis of liner running operation in order to achieve optimum centralization. This paper describes an effective method of derivation of new sets of friction factors required to run the liners or casings into complex deep wells. Wellplan software package has been utilized for this project. The theoretical background of friction and drag force will be provided in this thesis as well. As well the methodology of centralizer selection and their testing will be described in this paper as well. The procedure will describe the process of derivation of friction factors by calibration of the offset wells is also presented in this paper. Finally, a new method of averaging technique that has shown its effect in allowing to successfully drill and complete the well can be found here.

Contents

1 Aim and objectives

Azeri-Chirag-Gunashli (ACG) is the largest oilfield in the Azerbaijani sector of the Caspian sea. Located approximately 100km east of the capital city Baku ACG field is operated by the BP. The field can be subdivided into the Azeri and CDWG (Chirag-Deepwater Gunashli) areas. The platform of this project's interest is the third platform in the field which was installed in December 2005.

The reservoirs of the ACG field are young and prone to shale collapse, unstable formations and sanding issues. Given also the fact that the field is been on production for more than 15 years, depletion is taking place in the majority of the reservoirs, which in its term drives the wellbore stability issues.

In 2018 it was planned to deliver the three-zone water injector well with downhole flow control (DHFC) from the platform. This type of smart completion becomes more frequent nowadays. Downhole Interval Control Valves (ICV's) are controlled from surface and allow multiple zones selectivity, reduce water cut and gas cut, as well as minimize the intervention jobs, since no need to shift them with slickline. Such a well, requires a complex completion technology, however when injecting it can selectively pump water into the desired zone or combination of zones *(Fig.1).* At the time of being the well was to be the first three-zone injector with DHFC in the global portfolio of the company. The very chance to have a three-zone injection was dependent on the successful 9 5/8" production liner run to the bottom of the well, since it was important to land the casing bellow the lowest zone of injection to have access to all three zones.

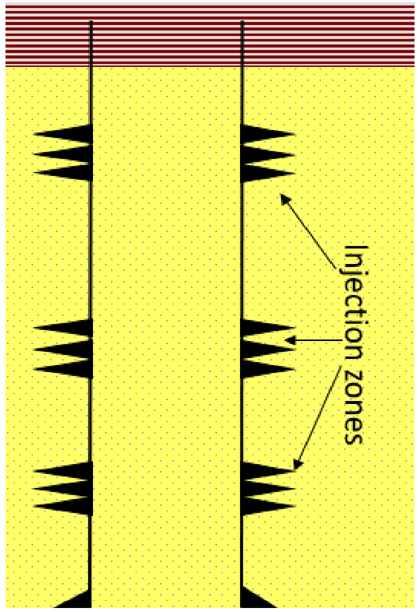

Fig.1 – Injection zones of typical DHFC well

One critical property of the injector wells is that such wells should have a low inclination at the target depth ~20°. This is driven by two factors:

- Non-optimal deviation can increase the near wellbore fracture tortuosity which in turn increases apparent fracture pressure observed at the wellbore
- Higher deviation wellbores can increase in the probability of inducing multiple fractures in the same sands which compete against each other and increase the apparent fracture pressure.

A low deviation wellbore is likely to create a longer intersection between fracture and wellbore and hence reduce near wellbore tortuosity and reduce risk of multiple fractures developing.

Having this factor as well as the large distance of the target from the platform (big step out), the trajectory for the well was “S” shaped (Fig.2). This complex trajectory comprising the build section, followed by a long tangent section and finally ending with a drop section poses another big risk for casing/liner running operations. As was mentioned above in order to get perforations across all the three zones it is important to land the production liner at the desired depth. Which is in turn dependent on the successful running of the previous intermediate string.

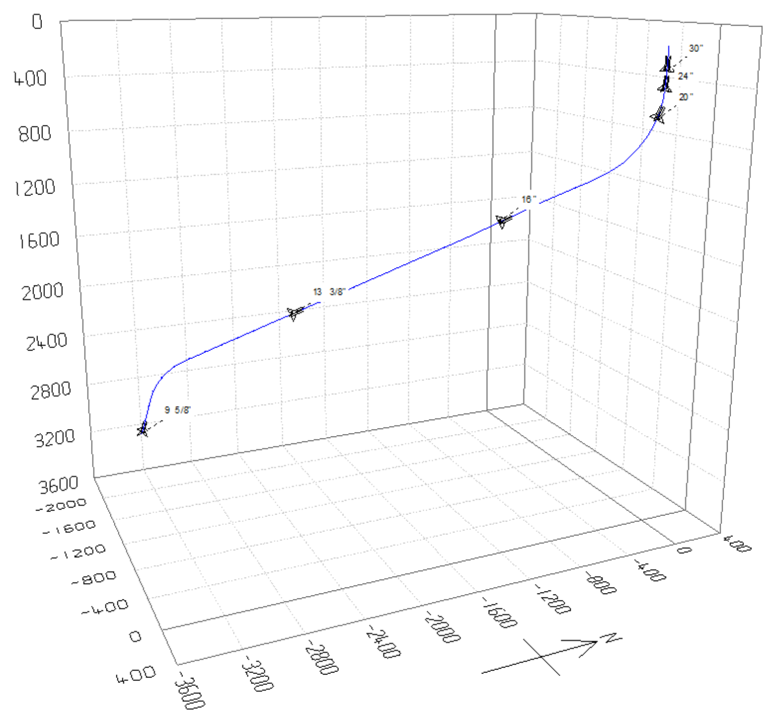

Fig.2 – Trajectory of the planned injector well

Another important aspect in the successful delivery of the well is zonal isolation. For the injection wells, it is critical to have good circumferential cement across the injection interval to avoid the crossflow between the injection zones. The good part of a successful cement job is the standoff of the casing, which is in turn dependent on the number of centralizers on the casing or liner. A high number of centralizers, however, leads to higher drag while tubular running and may compromise the ability to reach the bottom of the well. The team has faced a complex task in finding the optimal trade-off between good centralization and acquiring minimum drag force to be able to land the liner. The very selection of the liner + tieback instead of running the full casing string was done in order to reduce the drag while running in hole and ensure better cementing due to the less ECD and ability to move the liner.

1.1 Current methodology

Across the ACG field the friction factors selection was mostly performed upon the historical data. For some cases when complicated casing job was expected calibration was taking place, however the scale of the job as well as the final friction factors derivation i.e., averaging, was different from this project.

For this particular well, historical friction factors meant that either centralization should be compromised, or the liner may get stuck halfway through the open hole. Therefore, it was decided to perform an effective calibration job across the field by analyzing ~20 wells to get the optimum friction factors for 16”, 13 3/8” and 9 5/8” liner running simulations.

2 Literature review

Several research projects were reviewed prior to the initiation of this job. It was necessary to find a similar group of people who have faced the challenges of liner or casing running into the deep “S” shaped well. The research has indicated a few papers of interest where group of researchers have utilized the Wellplan software to calculate the torque and drag while operations. Most of the papers were describing the utilization of the WellPlan software to estimate the torque and drag while drilling complex, especially horizontal wells [1], [2]. In those papers good theoretical information was provided as well which helped to better understand the drag forces while running the tubular into the well. Alamen Faisal et al; [2] has described the methods of the selection of a friction factors while drilling the horizontal wells, however no information on estimation of those while running the casing were provided in their research. As well in their paper there was no data on the derivation of the aforementioned friction factors and averaging those to get a final set of FF's for future projects. Another research was done by the Professor Mesfin Belayneh from the University of Stavanger [3] which described the usage of the WellPlan to undercome the drilling challenges. The paper is mostly concentrated on the physics of drag and implementation of the simulation by using the modeling.

3 Theoretical background

3.1 Friction. Static and dynamic friction

It is easier to slide over a smooth surface than a rough one. Microscopic examination of even the smoothest looking surface shows that it is in fact very rough. This means that are between those two objects intermolecular forces are occurring and exactly those forces are contributing to what we are calling friction.

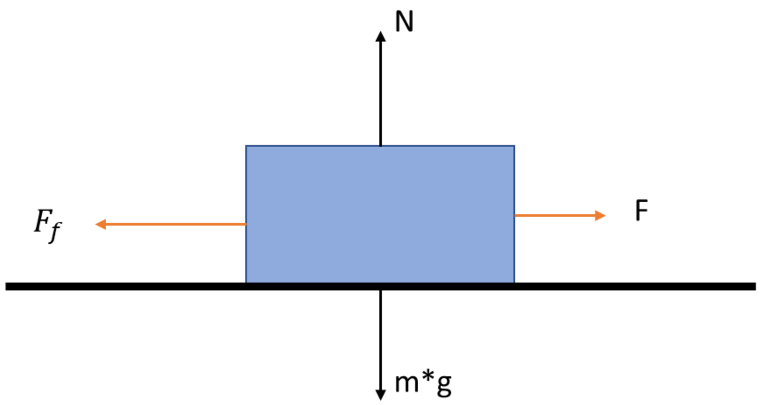

Fig.3 – Force diagram of body sliding on the flat surface

If we place an object on the surface as shown in the *Fig.3* and apply the force F to pull the object the following will take place. The other force is known as force of friction F_f will emerge and it will pull to the opposite direction to the pulling force F. At the very beginning while F is low the body will not move. At some point of a time when F increased enough the object will start moving. This is when we say that pulling force F equals to the static force of friction. After this moment when the object will slide over the surface with lower force F than in the beginning is required to keep the object in motion. This is when we say that pulling force F is greater than the dynamic friction force. I.E. more force is required to start the object movement rather than to keep the same object in motion. [4]

3.2 Normal force

Normal force as shown by letter N in the figure is the force perpendicular to the surface on which the body slides. If the body lies or slides on the horizontal plane the normal force compensates the force of gravity.

3.3 Friction factors

As per mechanics friction factor also called the coefficient of friction is the dimensionless unit that shows the relationship between the force of friction, occurring between two objects, and the normal reaction force between those objects. Friction factors are intended to represent the roughness between two steady moving surfaces. [5]

The friction factors are denoted by the Greek letter μ and can be easily calculated by usage of the following formula:

$$F_{friction} = \mu * F_{normal}$$

Friction factor depends on:

- The type of two materials
- Roughness of material's surface
- Availability of lubricant between those objects

However, all that was mentioned above is a good representation for the case when two bodies are moving adjacent to each other, or single body is sliding on some surface. The conditions in the wellbore is much more different that the aforementioned cases. The friction between the borehole and any tubular in the well (drillstring, casing, tubing) is a complex system and hence here the friction coefficients are representing a variety of factors. The magnitude of friction factors can depend on but not limited to the following [6]:

- Type of rig operation
- String size stiffness, weight
- Hole diameter, annular clearance
- Mud system (lubricity, viscosity)
- Contact area (metal to metal, metal formation)

Also, an important aspect is that in Wellplan the friction factors can be various for running in hole, pulling out of hole and rotating operations.

3.4 Sideforce

In the example of body laying or sliding over some surface the term Normal force was described. The geometry of the well, however, is much more complex and cannot be easily represented by the term used in for the surface objects. In the borehole the normal force is called sideforce; the force that exerted by the borehole onto the string.

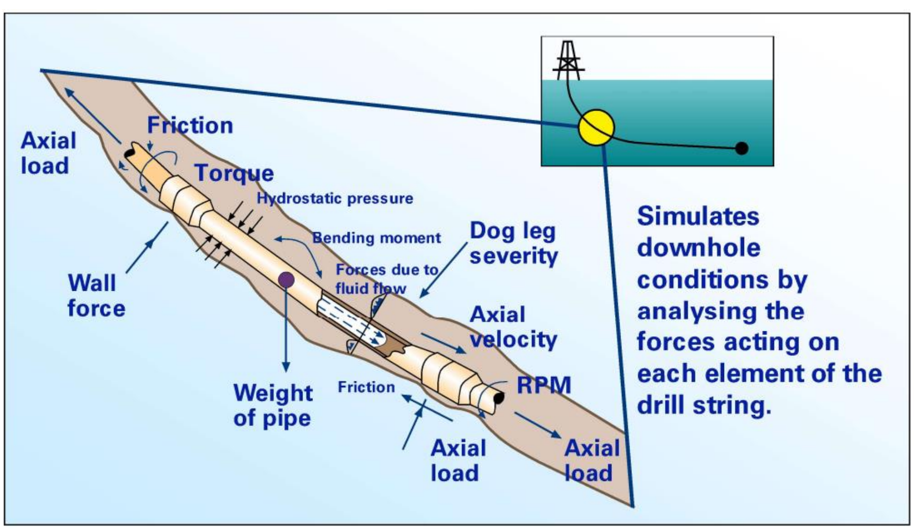

Fig.4 – Forces acting on a drillstring while drilling [10]

If we will take a small segment of the drillstring upon the inclined hole the force diagram can be simplified as per image below:

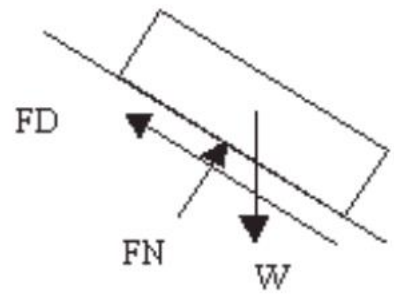

Fig.5 – Simplified force diagram of an element of the drillstring [9]

Where:

F_N= Normal Force or Sideforce

F_D = Drag Force

W = Weight of segment

Here no motion takes place. The normal force or sideforce is acting perpendicular to the sliding surface as was mentioned above. Gravity acts vertically downwards. Another force, the drag force, is also acting on the segment. The drag force always acts in the opposite direction of motion. The body (segment of a string) does not slide down exactly because of the drag force. The magnitude of the drag force depends on the normal force, and the coefficient of friction between the bodies. Therefore, it is important to understand the concept of the sideforce since it has a direct influence on the drag. [7]

For such type of an example the sideforce can be calculated by

$$F_N = \sqrt{(F_T \Delta\alpha Sin(\Phi))^2 + (F_T \Delta\theta + WLSin(\Phi))^2}$$

Where:

F_N= Normal or side force

F_T = Axial force at bottom of section calculated using Buoyancy Method

Δα = Change in azimuth over section length

Φ = Average inclination over the section

ΔΘ = Change in inclination over section length

L = Section length

W = Buoyed weight of the section

The above formula is a primary one which is used by the WellPlan's Soft String model (will be described later) to calculate the drag and allow the safe passage of the tubular into the well.

3.5 Soft string model

In the Wellplan software package, two types of torque and drag modeling are available. Those are the soft string model and the stiff string model. As per the best practices the usage within the BP is the soft string model. In this type of a model, the drillstring (casing, tuning) is considered to be flexible and treated as a huge flexible cable with no associated bending stiffness. Since there is no bending stiffness, there is no standoff between the string and borehole walls. [7] Therefore, the workstring is assumed be in constant contact with the walls of the wellbore. Loads on the string result solely on the combined effects of gravity and frictional drag; the later one is a product of normal force and coefficient of friction.[9]

The stiff string model is dividing the tubular into the equal components and computed the sideforce of each component. Unlike the soft string model it considers the stiffness of each segment, therefore, allowing some parts of the string not to be in the contact with the borehole. Despite the fact that stiff string model was developed after the soft string and considered to be more modern, the actual field observations demonstrated that data is inclined to match the soft string rather than stiff string [11]. Despite of that, the historical simulations and the entire of drilled wells for the ACG field was performed by the usage of soft string mode. Those two reasons he influenced the selection of this model for the project described here.

4 Boundaries

4.1 Drag force in the well

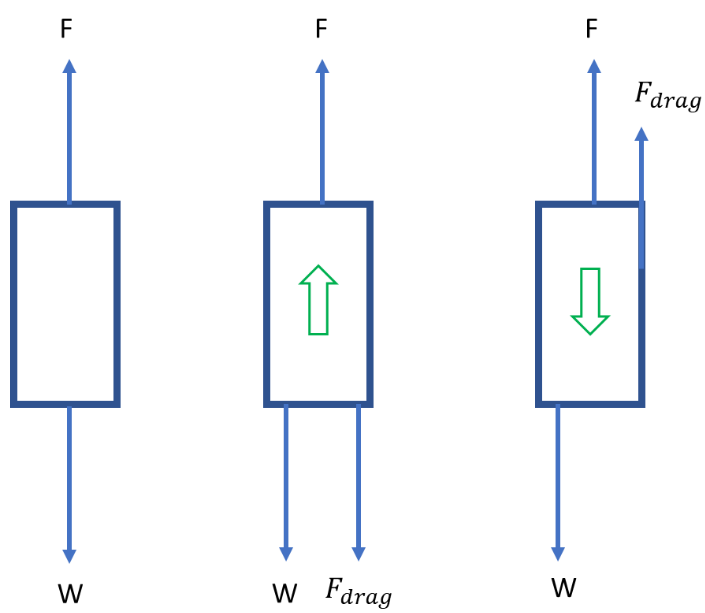

Fig.6 – Neutral weight, upweight and downweight

When a tubular is suspended in the well the force which required to suspend it *(F in Fig.6 left)* equals to the weight of the string multiplied by the buoyancy factor (buoyed weight). If the tubular will be run into the vertical hole the pick up weight (upweight) will be almost the same as the slack off weight (downweight) and is equal to the buoyed weight of the string. However, if the hole is inclined and tubular touches the borehole then the weights are different due to the drag force. As was mentioned the drag act opposite to the direction of the movement; when the pipe moves up drag force is the opposite and the resultant suspension force is *buoyed weight of tubular (W) + drag (F_{drag}). (Fig.6 middle)* Correspondingly when the pipe is moved down the force F is *buoyed weight of tubular (W) – drag (F_{drag})*. (F*ig.6 right).* The suspension force F is represented by the hookload indicator – Weight on Hook at the rigsite.

4.2 Yield and tension

Tensile strength it the force needed to pull a tubular until the point where it breaks. It also can be called the maximum force which pipe body can hold. Yield stress also called yield point is the point at the Stress x Strain curve *(Fig.7)* at which the tubular starts to deform plastically. Yield stress is a stress level at which a material can withstand the stress before it is deformed permanently [10].

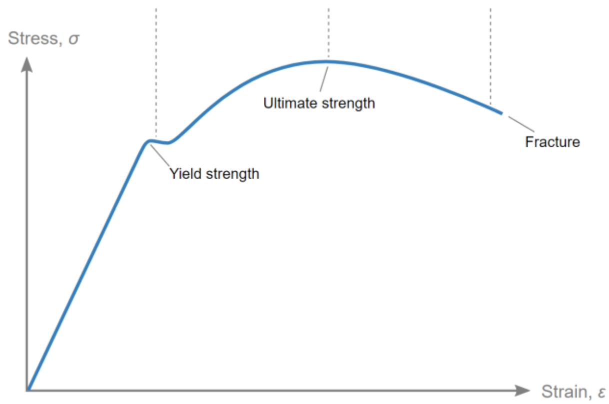

Fig.7 – Stress x Strain curve [8]

In drilling once the yield point is reached the tubular will be continuously deformed until it will fully part. Therefore, the limiting boundary for the tension is not the tensile limit of the tubular but the yield stress.

4.3 Compression and buckling

The limit of the compression is called buckling. There are two types of buckling which may occur in the tubular – sinusoidal buckling and helical buckling.

When local compression in a string reaches a certain critical level, the string buckles and starts to snake along the low side of the hole. This state is known as the sinusoidal buckling. If further force is applied the amplitude of snake grows and string now turns to something of a helix shape. In this state the string coils up against the wall of the borehole into what is known a helical buckling *(Fig.8).*

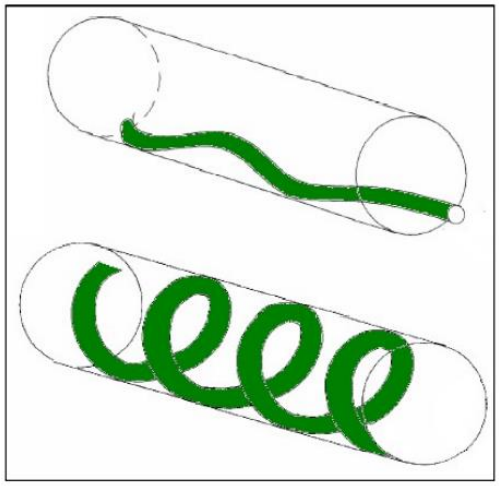

Fig.8 – Sinusoidal and helical buckling of a drillstring [9]

Once buckling has occurred, there is an additional side force due to increased contact between the wellbore and the work string. In sinusoidal buckling, no additional side forces occur. In helical buckling mode, additional side forces are occurring. Therefore, the sinusoidal buckling can be tolerated, but helical buckling is to be avoided all the time. [11]

5 WellPlan Software

Wellplan software provides comprehensive well engineering toolkit and has a number features to analyze various aspects of well planning. For the ACG field the most widely used areas are hydraulics and torque and drag analysis. One of the strongest sides of the Wellplan is that it allows a top-down analysis, which uses surface parameters to understand the forces acting along the string, from top to the bottom of the well. It is also important to mention that most of the recent wells drilled in the region have been planned by using the Wellplan software, therefore the models used for casing and liner running operations were available for analysis. This provided easy access to the historical friction factors and enabled the calibration process.

5.1 Input data

In this part the data which is input to the WellPlan model will be listed. Those data acts like the variables of the equation used by the soft string model to obtain the end results – simulation output.

5.2 Trajectory (Wellpath)

It is obvious that trajectory of the well has its impact on the drag and toque and should be taken into the consideration. The first input into the WellPlan model is the Datum also called as well reference point. From that point all the following surveys along the trajectory are calculated. In the trajectory panel MD, Inc and Azimuth are entered for every next survey point. Wellpath calculations use the Minimum Curvature method. The Tortuosity section adds tortuosity to planned data to "roughen" the smooth curve into a more realistic path.

5.3 Hole Editor panel

The Hole Section Editor panel is used to define the wellbore profile and inner configuration of the well. The main inputs of interest in this part are: Length and inner diameter of previous casing and open hole length, size and overall geometry. It is important to input the geometry of the hole, meaning underreamed sections as well as not reamed “pilot” hole.

The very topic of this paper – friction factors are also input in this panel. FF can be chosen for every hole section as per the geometry of the well or separate FFs for the cased hole and open hole dependent on the type of operation. In general, 6 types of operations are present in the WellPlan which can have separate friction factors. Those are:

- Tripping in – used to calculate the drag and torque of tubular while it is lowered into the well.
- Tripping out – used to calculate the drag and torque of tubular while it is pulled out of the well.
- Rotating on bottom – used to simulate the drilling conditions.
- Slide drilling – used to mimic high weight on bit and no rotation of the string at the surface. Slide drilling is mostly used when drilling with positive displacement motor.
- Back reaming – used to simulate the backreaming operations as the name suggests. Checks for the tubular ability to withstand torque and overpull applied simultaneously.
- Rotating off bottom – used to simulate the neutral conditions and buoyant weight of the tubular.

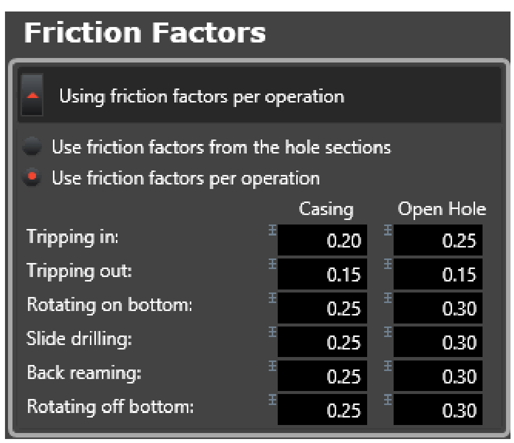

Fig.9 – Wellplan snapshot of a friction factors input tab

Out of those six, only 3 are interesting for our study. Out of those Tripping in and tripping out are required to estimate the drag while casing running and are the primary concern of this paper. The rotate of bottom will be used only as a benchmark to estimate the neutral weight.

Generally, it is recommended to use friction factors per operations rather than per hole section, since it easier to get a benchmarks for calibrations, since it is good practice to regularly take up and down weights.

5.4 String data

Here we populate all the data for the tubular to run into the well. For the torque and drag modeling the important parts are located under the "Mechanical" tab; outer and inner diameter doesn't influence the result of the calculations.

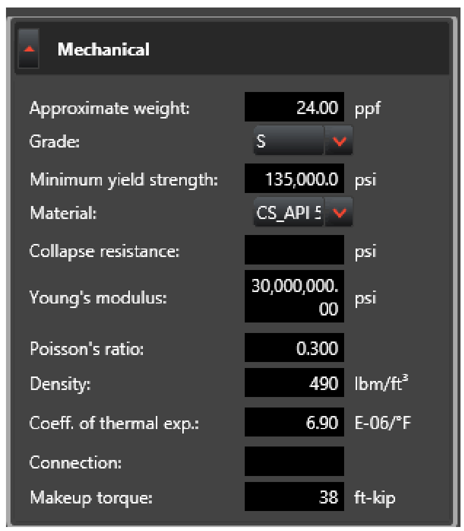

Fig.10 – Wellplan snapshot of a mechanical pipe properties tab

As well here the Stand of devices – the centralizers data is populated.

The centralizers are the most important area of this entire study. They are creating the majority of the drag. The data about the centralizers are populated in the "Standoff devices" tab of the

"String Editor" panel. The centralizers with their respective forces will be described below more broadly.

5.5 Centralization

Two types of centralizers are known within the oil and gas industry. Those are the rigid ones and bow-spring ones *(Fig.11).* The bow-spring centralizers have flexible bows which are pushed inwards when run into smaller diameter pipes. The rigid centralizers have bows that are either not flexible or have very limited flexibility. Those are mostly used in casing/casing overlaps to ensure some spacing between the metal parts.

Fig.11 – Soft bow and rigid centralizer. Courtesy of https://www.zs-oilfieldequip.com/

The Wellplan software also uses the same approach; the type of centralizer can be selected when entering the standoff device data.

Under the standoff device panel *(fig. 12)* the general information, like length for centralizers placing and frequency are populated.

The mechanical part input area requires the Actual OD, Effective (maximum compressed) OD, unit weight and length to be filled.

Below that are the most critical part of the drag simulation is located. This includes the Starting force, running force, and restoring force of the centralizer.

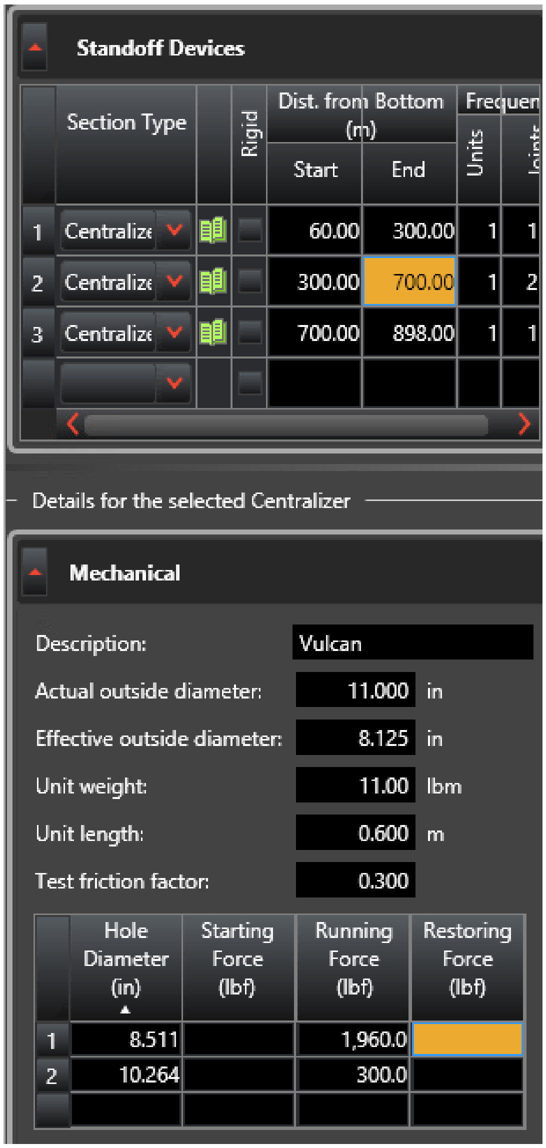

Fig.12 – Wellplan snapshot of a Standoff devices panel

Starting force specifies the force required to move the centralizer into the wellbore. This is simply a compressive force which requires to push the centralizer into the wellbore. Since this moment of pushing happens only ones the data in the starting force area doesn't has any effect on the drag results. Exactly for that reason the starting force area is empty on Figure 12.

Running force is the force that is required to move the centralizers through the wellbore. The running force is required for the calculation of a drag force.

Restoring force – is the force centralizer's springs exert in response to an applied compressive force. This is required for the cementing purposes only and is not a part of torque and drag normal analysis.

The forces mentioned above are acquired from the special casing bow-spring centralizers testing, which goes under API SPEC 10D [13].

The starting and running forces are measured while a single test. Two vertical pipes are used for this test. The centralizer is rigged up onto the inner string, which is, in turn, lowered into the outer string. The outer string should be the same ID as the wellbore the centralizer will be run into. Force is applied to insert the centralized inner pipe into the upper pipe. The maximum force seen during the insertion is starting force reading for the specified hole size. Hole size is equal to the ID of the outer pipe as described above. Then the test continues by sliding the inner pipe inside the outer pipe with even velocity. The required force reading at this moment is the running force of the centralizer.

The restoring force test is done by the utilization of inner and outer pipes as well, however, now the test assembly is horizontal. External load is applied on the side of the outer pipe. The magnitude of the load equals the force which is required to push the centralizer's bow inwards at 67% of its original OD. The test is repeated from various points on the outer pipe to determine the average restoring force at 67% deflection.

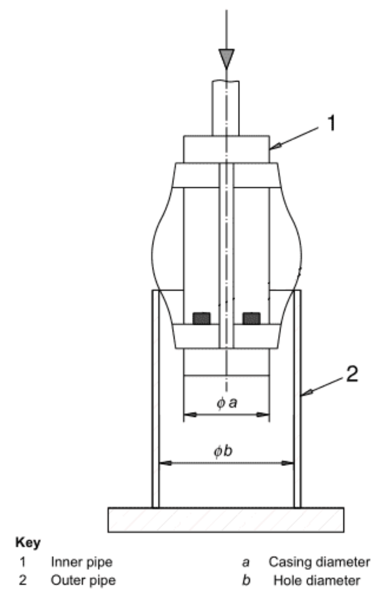

Fig.13 – Centralizer's test on running and starting forces. Courtesy of https://www.drinol.com/.

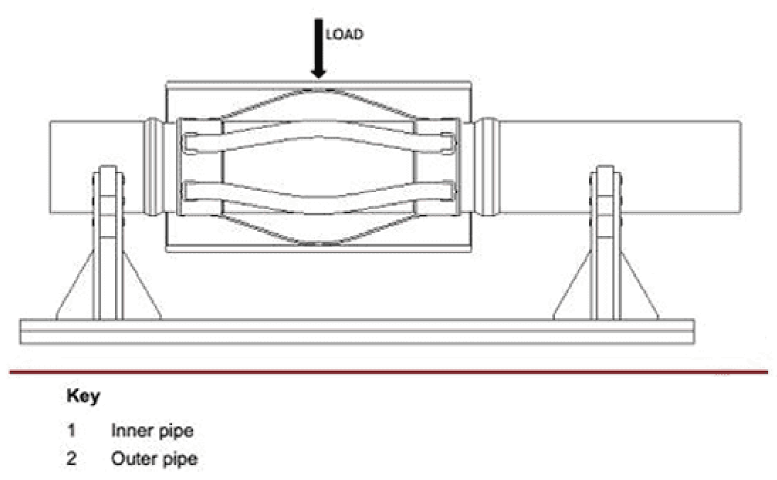

Fig.14 – Centralizer's test on restoring forces. Courtesy of https://www.drinol.com/.

Having input the results of the test into the Wellplan software the following Force plot is produced

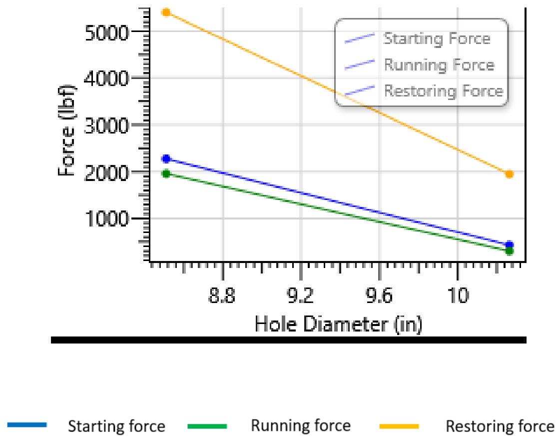

Fig.15 – Wellplan snapshot of a Standoff devices Force plot

The software then interpolates the force lines to the required cased and open hole as was populated in the Hole section panel.

5.6 Fluids panel

In real world properties like viscosity or lubricity of the fluid has influence on the drag force. In the WellPlan however, for the torque and drag calculations only the mud weight is required in order to calculate the buoyed weight of the assembly. The elements of the fluid rheological properties are incorporated into the friction factor.

5.7 WellPlan output

All the aforementioned input data is used by the software to calculate the output. To ensure the success of casing running into the well the drag needs to be calculated. However, the end-users (engineers, offshore personnel) cannot monitor the drag in real-time. What we do see while running the liners is a Weight on Hook – WOH. Deeper the depth of the casing in the well more will be the WOH and since most of the wells are inclined the Up weight will be higher than the Down weight. The job of the driller and offshore team is to ensure that up weight stays bellow the yield stress limit and down weight stays above the buckling limit.

A simple example of the WellPlan simulation output is sketched below:

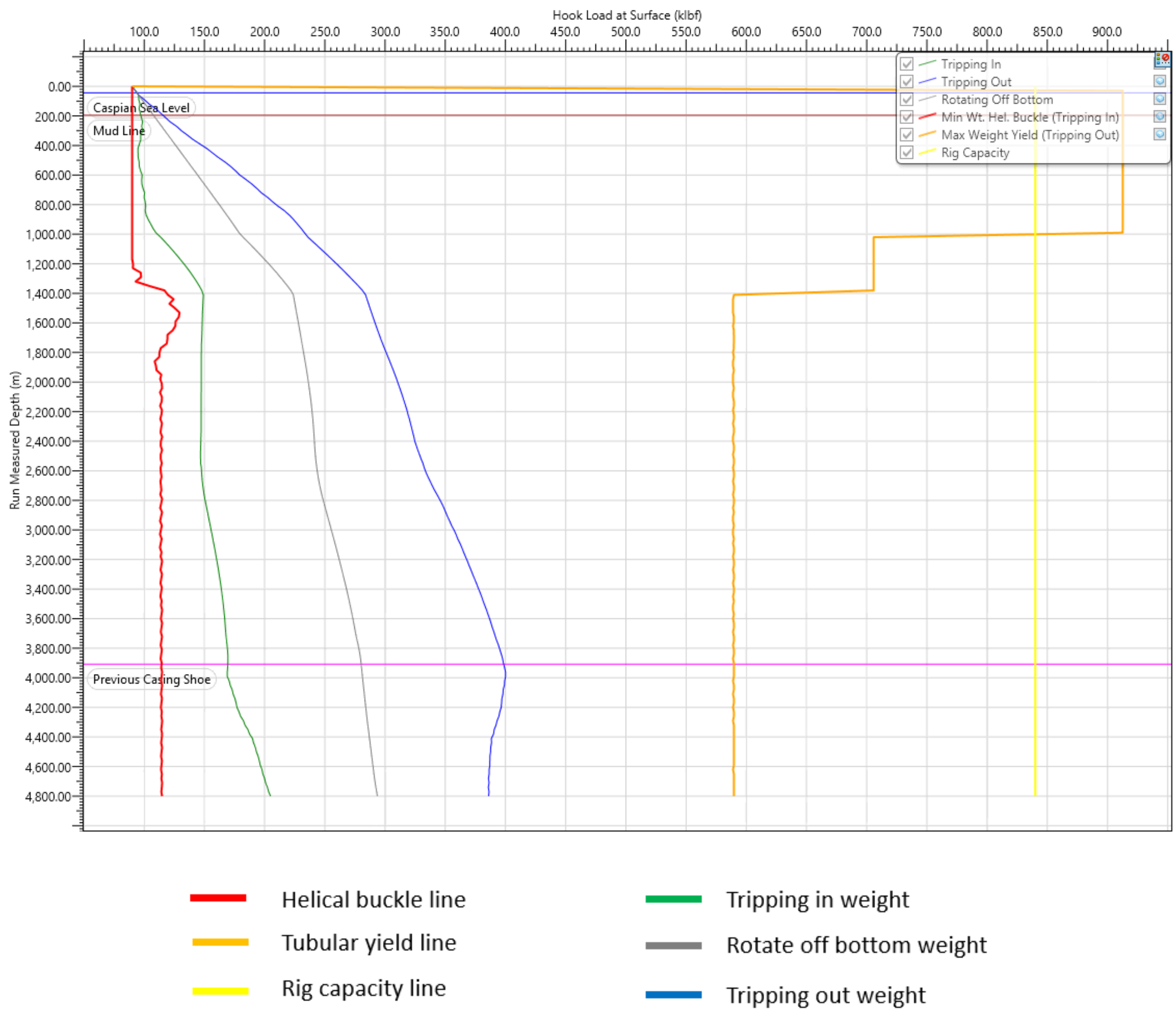

Fig.16 – Example of liner running Hookload chart on Wellplan (ver.3)

The red line to the left of the green trip in line represents the helical buckling limit. The orange line on the right of the blue trip out line is the weight after which the tubular yield will take place. Also additional limit line (yellow) – the rig or traveling block limit may be put into the simulation. The grey line represents the neutral rotate off bottom weight.

6 Data summary

As was mentioned for the injector well it is critical to find an optimum tradeoff between the zonal isolation requirement and successful liner run operations. For this the number of centralizers needs to be coherently selected. And finally for that reliable friction factors need to be used. The aim was to create a field-wide database of friction factors which can be used for current well and for future injector wells. Available data to perform the project are the centralizer data - running forces and restoring forces as was described before, and previously drilled – offset wells.

6.1 Candidate wells

It is important to wisely select the candidates for the calibration process. Several aspects should be taken into consideration while doing that:

- If the well is planned to be cased off by liner + tieback, exactly the same type of wells should be used for calibration. Respectively if the full casing string is to be used, similar offsets are to be considered.
- Trajectory. It is desirable to select candidates with similar trajectories (mostly injector wells). High step out and long drilling depth were important.

- Section length of the candidates to be similar to the planned well.
- Fluids used should be similar. For example if the same tubular is run in one well in seawater or oil based mud (OBM) the model with OBM will have lower friction factors. This is due to the fact that OBM has better lubricity, but the lubricity is not an input parameter into the Wellplan model, therefore it is captured by the friction factor's magnitude.
- Centralization strategy should also be like the planned well.

Another important aspect is the usage of Wellplan software is consistency. It is obvious that if the calibration process is done with the same centralizers but using different running forces for every well, this will result in wrongly calibrated friction factors. Industry knows the cases where same centralizers, but from different batches have strong variation in running forces. Such cases are usually flagged up with the manufactures and a new batch of centralizers are ordered. Therefore, it is critical to choose offsets that besides of having similar centralization strategies also use the same running forces both for the calibration and for the final modeling. Saying that it is worth mentioning that modeling a new case with brand new centralizers, which were not run in the region before, is a complicated and risky process. For such a case the most conservative friction factors are recommended to be used.

7 Workflow

The first job is to acquire the actual weight that was seen while running a liner. The best source for that is recorded data from a mudlogging company or from the rig sensor. The UTG files for the entire time from starting liner or casing run until a point when tubular tags the bottom of the hole is taken and weight on hook is plotted against the bit depth. The chart of this is a continuous line and from it, several points of the trip in and trip out should be taken.

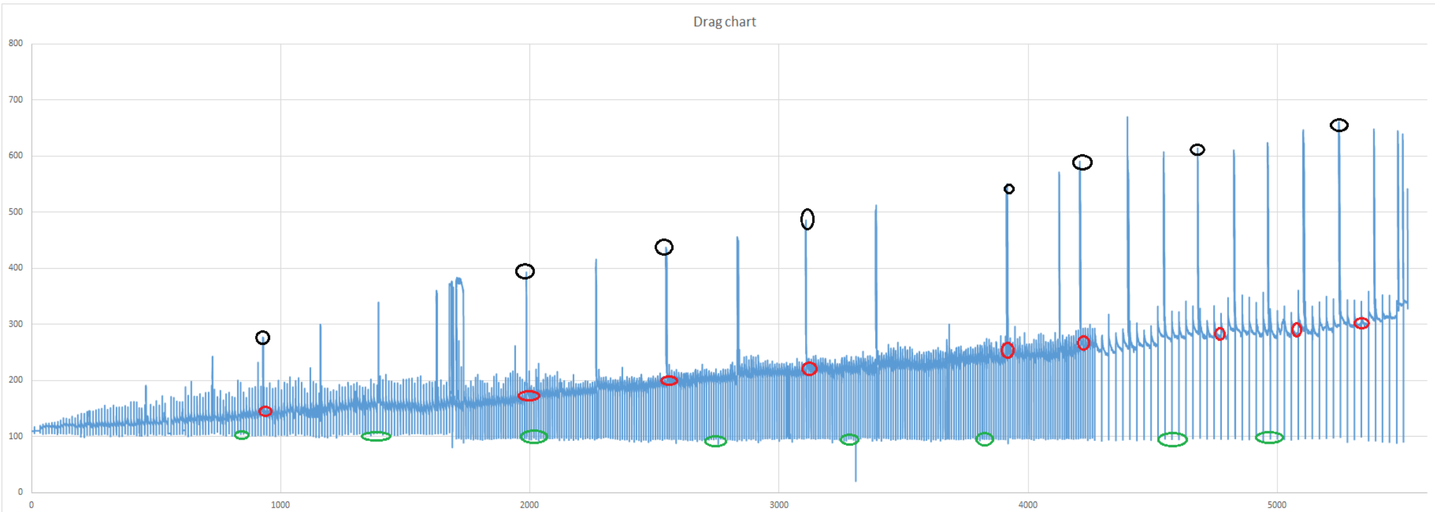

Fig.17 – Plot of actual weights while 9 5/8" liner running operations

The image above is an example of actual weight on hook seen while liner running. The black circles are representing the trip out weight taken at several depths. The red circles are trip in weight. It is important to understand which value corresponds to the tripping in weight. At this chart the lowest weights ween are shown in green circles, those are the movement of the empty block and should not be accidentally corresponded as trip in weight of the entire string.

Then those several up and down weights are input in the Wellplan into the actual values tab. The calibration process is done to find the optimal friction factors while simulating the casing or liner well on the already drilled historical well. Having the actual weights shown as dotes in Wellplan output and simulated weights shown as straight lines *(fig. 18)*, the engineer's job is to adjust the friction factors until the simulation weights are aligned with the actual weights, i.e.

lines are overlaying the dotes. One example of such a job match can be seen in the snapshot below:

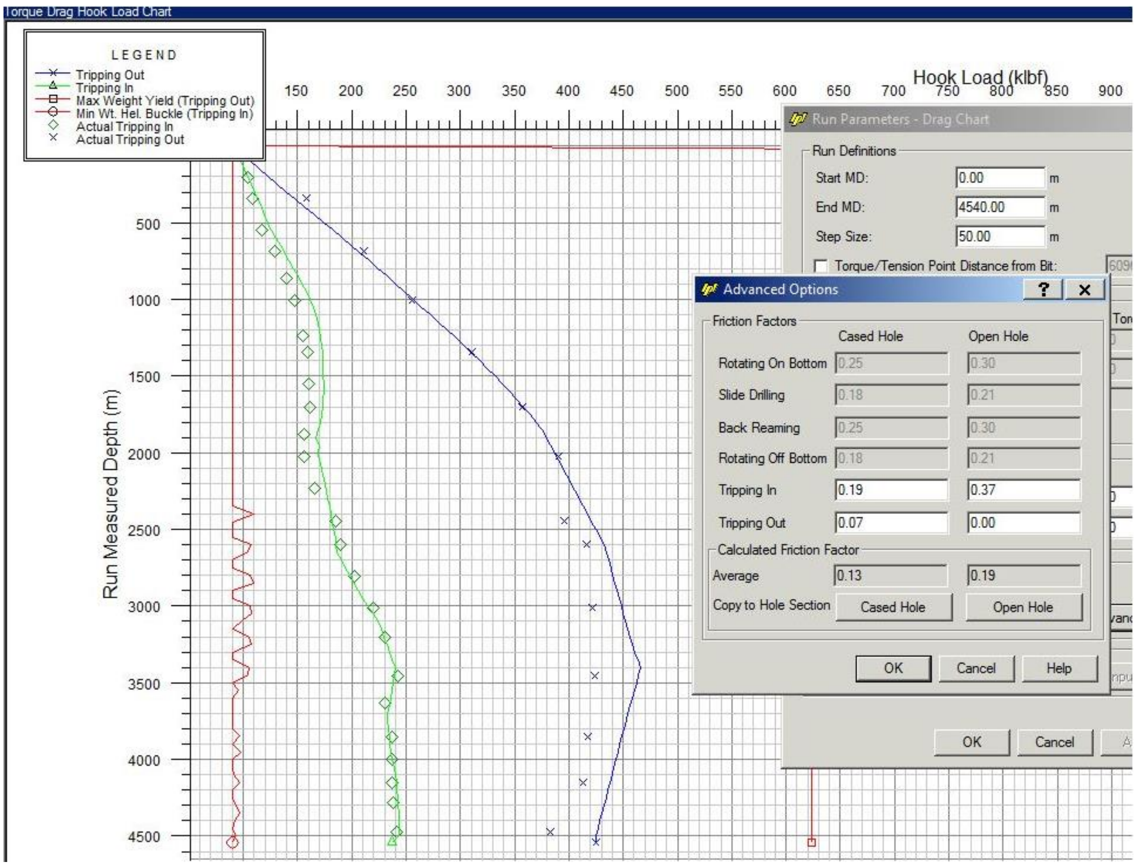

Fig.18 – Calibration of friction factors by actual weights in Wellplan (ver. 2)

This particular case shows that for this well the Tripping out friction factor for the OH section was very small close to zero. Sometimes while doing a calibration an engineer should find an optimal solution. For example, in the image above the trip out open hole friction factor wasn't exactly calibrated, this sacrifice was done in order to have the precise match of the cased hole friction factor. The cased hole is accounted for the highest created drag, and it is important to calibrate this FF first.

For the sake of seeing the entire picture the actual work of the calibration was plotted against the simulated weight on the excel spreadsheet to produce a drag chart.

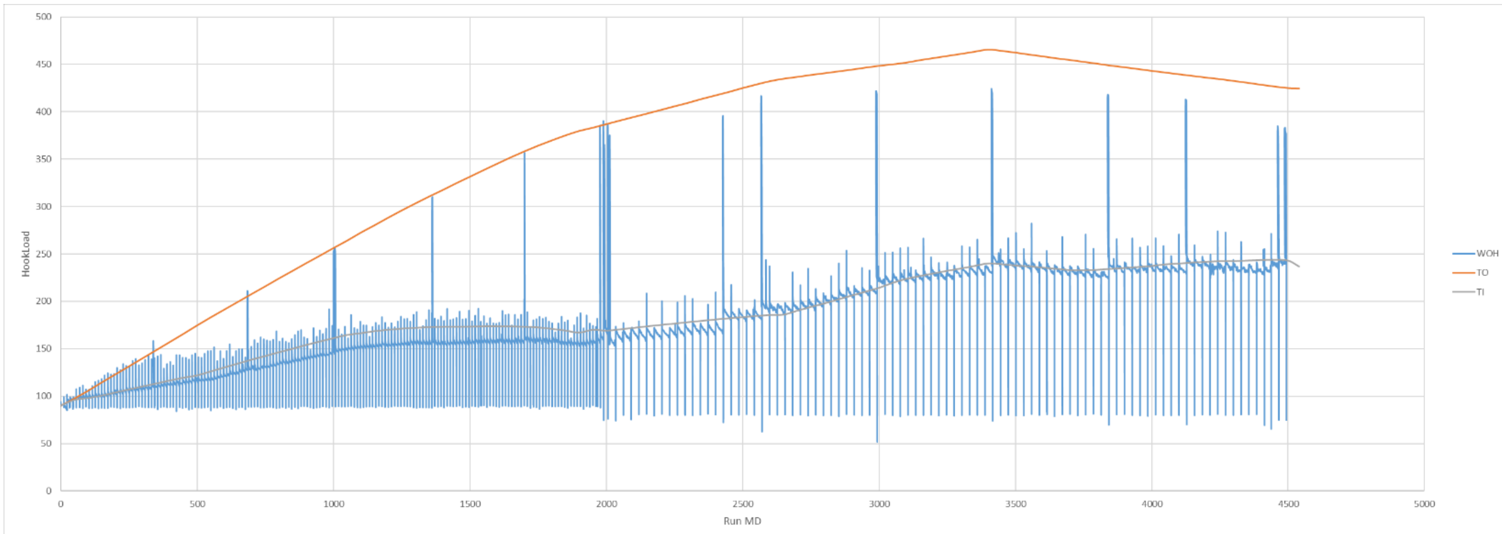

Fig.19 – Calibrated drag chart of 9 5/8" liner running operation

On the drag chart above compared to the *Figure 17* we can see two additional lines: Orange line - Trip out weight as it was produced by the Wellplan simulation and grey line – Trip in weight as it was produced by the Wellplan simulation

It is also important to mention that the calibration process should not be limited to matching the lines only. There are always some areas where simulated weights cannot be matched with the actual weights and some compromises should be made. A good practice, for the cases when tubular had some hung-up points or even got stuck while in an open hole, is to match only the cased hole part of the outputs i.e. calibrate the cased hole FF's only.

8 Calibration outcome

The calibration process was repeated for several wells and for several liner strings. In order to reach all the injection zones not only 9 5/8” liner + tieback but also all the previous strings (13 3/8” and 16”) should run until the prescribed depths. The summary tables will show the optimum derived FF’s across the field for every liner size.

16" liner FF calibration results					
	CH TI	CH TO	OH TI	OH TO	Section length, m
Well A	0.25	0.11	0.47	0.11	1210
Well B	0.3	0.24	0.17	0.06	952
Well C	0.33	0.38	0.36	0.77	1032
Well D	0.27	0.22	0.3	0.13	952
Well E	0.38	0.25	0.33	0.08	746
Average	0.306	0.24	0.326	0.23	
W. Av	0.3	0.235	0.334	0.239	

Table 1 – 16” Liner calibrated Friction Factors

13 3/8" liner FF calibration					
	CH TI	CH TO	OH TI	OH TO	Section length, m
Well A	0.3	0.03	0.25	0.01	1088
Well B	0.3	0.12	0.19	0.01	1389
Well C	0.24	0.2	0.16	0.14	2222
Well D	0.31	0.11	0.19	0.01	1108
Well E	0.34	0.27	0.13	0.1	1481
Well F	0.27	0.08	0.34	0.08	1294
Well G	0.13	0.18	0.4	0.08	1338
Well H	0.18	0.17	0.48	0.14	1425
Average	0.259	0.145	0.268	0.071	
W. Av	0.256	0.154	0.26	0.08	

Table 2 – 13 3/8" Liner calibrated Friction Factors

9 5/8" liner FF calibration					
	CH TI	CH TO	OH TI	OH TO	Section length, m
Well A	0.19	0.07	0.37	0.01	1924
Well B	0.08	0.05	0.49	0.4	2850
Well C	0.14	0.1	0.5	0.55	2723
Well D	0.17	0.11	0.28	0.16	2133
Well E	0.2	0.1	0.53	0.25	1599
Well F	0.13	0.09	0.38	0.2	2152
Well G	0.15	0.11	0.41	0.22	1986
Well H	0.14	0.1	0.4	0.28	2285
Average	0.15	0.091	0.42	0.259	
W. Av	0.145	0.09	0.423	0.278	

Table 3 – 9 5/8" Liner calibrated Friction Factors

After a broader discussion within the team it was decided not to use the simple averaging technique but to attempt to perform the weighted averaging of the resultant friction factors. The best selection for the weights has fallen onto the section length. The weighted averages are shown in as the red digits in the bottom row of the tables.

The calculation method of averaging is the following:

$$FF_{av} = \frac{FF_{w1} * SL_{w1} + FF_{w2} * SL_{w2} + \cdots + FF_{wn} * SL_{wn}}{SL_{w1} + SL_{w2} + \cdots + SL_{wn}}$$

Where:

$FF_{av} - average\ friction\ factor\ (weighted)$

$FF_{wn} - Friction\ factor\ which\ resulted\ from\ the\ calibration\ of\ n^{th}\ well$

$SL_{wn} - Section\ length\ of\ n^{th}\ well$

9 Results

Having performed that thorough assessment we were prepared to the liner running operations. The most complicated job was running of 9 5/8” liner due to the tight tolerances between trip in weights and buckling limit as well as trip out weight and tubular yield limit.

Despite all the challenges the team managed to successfully run all the liner strings. Another important aspect is that 9 5/8” liner was successfully cemented as well. Good zonal isolation across the entire perforation interval was achieved. This allowed completions team, to run the tubing conveyed perforation guns and perforate all 3 intervals. After successful injectivity test the well was handed over to the production team.

Delivery of the three-zone injection allowed to achieve the effective waterflood of each individual layer. This in terms maximized water injection recovery factor and sweep efficiency of every producing unit by allocating the targeted injection rate to every formation. Overall, the well described in this simulation was the first well in its type and was a good benchmark for the following DHFC wells.

10 Discussions

The on-spot benefit of the performed job was increase in the production due to the successful injection as it was described in the previous section of this paper. As well, the acquired calibration data as well as the new friction factors were shared across the drilling engineering community. The results of the study have demonstrated that historically used friction factors for liner running were conservative. After the successful run of all three liner strings into the well of interest, drilling engineering community of the region became more confident in using more optimistic friction factors. As well the weighted averaging technology was accepted and became a recommended one to be used within the region. A database was created which is enlarged after every new drilled well. Until today the engineers are referring to the calibration method performed and to the utilization of the weighted averaging method while planning complex water injector wells. There were some discussions whether simple arithmetic average or weighted average method should be used. The community came to a conclusion that for less complex wells the simple averaging technique looks more appealing, since it is faster to perform and consumer less man/hours. However when complex wells, as was described in this project, to be drilled the weighted average method with justified weights is required.

11 Conclusions

To finalize this project it is worth mentioning that establishing new sets of friction factors in a periodic manner, to tackle the complex liner or casing running scenarios is a recommended practice. Below some instructions how to initiate the calibration process.

1. Establish the list of candidate wells. Ideally those to have similar trajectory, casing sitting depths and centralization to the planned well. Also, it is important to check the liner running reports for those wells to ensure that no complications have taken place which may mislead the FF derivation process (e.g. extreme tight spots, hung ups, stuck tubular).
2. Check for the data validity. Ensure that Wellplan model of the candidate wells matches the actual data in terms of lengths, centralization plan, centralizer forces, mud weight etc.
3. Record the actual weights occurred while casing or liner running. Those can be taken from UTG reports of mudlogging company or from digital data of hookload indicator. Data can be directly input into the Wellplan or plotted with usage of software like MS Excel.
4. Adjust the friction factors in the model until the simulated trip in and trip out weights are matching the actual ones.

5. Record the resultant friction factor.
6. Repeat for all the candidates.
7. Average the resultant friction factors. Average can be a weighted one or simply an arithmetical one.
8. Apply the averaged FFs to the planned well
9. After the operations, recalibrate the Friction factors of the newly drilled and cased hole to add to the database.

12 Suggestions for further work

Further research is needed to establish another way of averaging bigger datasets of friction factors. Researchers in this area should use new weights for the optimal friction factor derivation. A good strategy may be creation of a new weight sets which are drawn from the centralization strategy. For example, running forces multiplied by the centralizer spacing (1 unit per 1 joint, 2 units per joint etc.) may act as a new weight for weighted average friction factors derivation. More simple approach may be weighting by the dogleg severity or sail angle (inclination of a tangent section).

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