Application of Plungers in Gas Wells Producing Liquids with High Downhole Critical Rates

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Introduction:
It is recognized in the industry that it is wise to have AL in place before liquid loading is expected for a number of reasons. These reasons include no production loss when the well drops below critical, convenience as the rig may/may not be available when the well drops below critical later, and in some cases some uplift is observed when installing plunger other AL before the rate drops below a calculated predicted critical. The discussion concerns installing plunger at in wells with high predicted downhole critical rates. The calculated downhole critical rates are high compared to surface values and even higher when corrections for angle to critical are included.

Discussion:

The wells in discussion here concerning plunger applications are in the Barnett Shale in N Central Texas. The field has been producing since late 1990's. The wells have an average true vertical lateral depth of 6700-8500 feet.

The discussion centers around concerns about how early plunger should be used when looking at the calculated critical velocity, the shape of the tubing performance curve and the production records.

FIRST WELL: Brown #1,

<u>Plunger type:</u>
9" sleeve and tungsten ball
Tungsten ball: 0.5 lbs.
<u>Tubulars:</u>
Bumper spring set at 7612' @ 54 degrees
EOT 7871' @ 72 degre

Survey

MD	TVD	Angle
0	0	1.1
23	23	1.1
105	105	1.1
707.3	705.9	6.8
795.9	793.9	7.1
7015.1	6971.3	2.5
7432.1	7375.1	21.5
7610.9	7511.6	54
7837.9	7613.7	70.5
7871.4	7624.5	71.7

2 3/8's tubing
<u>WHT</u>
70 degrees
<u>BHT</u>
189 degrees
<u>WHP</u>
Tubing 93 psi
Casing 333 psi
<u>BPD/Mscf/D</u>
40.7 bbl/day (37.5 water, 3.2 oil)
~780 Mscf/D before plunger installed from graph below
<u>Fluid Gravities</u>
1.06 /55, Water/Oil

The below chart/s show the daily gas production (Figure/s 1). The yellow line marks the date, May 28, 2000, on which a plunger was installed the plunger due to liquid loading. At the time of the install, the well was producing as a rate of 0.78 MMscf/D., which increased to almost 1 MMscf/D post install. About a month later there was a temporary drop in production due to plunger issues that were quickly resolved.

Given a wellhead pressure of 93 psig, Figure 2 shows the flowing pressure across the depth of the tubing string to the EOT at 7871' when the plunger was installed. It looks like from field data that loading started at maybe 900 but we will see if loading is predicted at 780 Mscf/D by existing correlations.

The wells discussed in this data set are horizontal wells. Typically the tubing is run into the curve section to an inclination of 60-80 degrees. To account for this deviation, the critical flow rate must be further adjusted.
Figure 3 shows a plot of an industry correction for deviated well. It shows for a well with a deviation or ~35 degrees the required critical could be 35% greater than whatever predication is used (i.e. Turner or Coleman for example)

The relationship plotted in Figure 4 is developed and discussed in SPE 115567, "Prediction and Dynamic Behavior of Liquid Loading Gas Wells" by Belfroid et al.

The procedure is to calculate the BHP at several depths (near the bottom), calculate the critical rate at each depth, corresponding pressure and temperature, and then correct the critical rate with the angle or deviation correction shown above in Figure 3. The procedure to calculate critical (and with angle correction shown below) is shown in Appendix A. To calculate the critical values a surface tension value is needed (Figure 4) of 6.27 dyns/cm.

A summary of pertinent parameters for this well are as follows:

Temp	MD	TVD	Angle	Pressure	Coleman	Turner	Coleman	Turner
DegF	feet	feet		psia	Critical	Critical	w Belfroid	w Belfroid
70	0.0	0.0	0.0	93	263	318	263	318
82	795.0	793.9	7.1	129	307	371	348	421
176	7015.1	6971.3	2.5	352	480	579	544	657
182	7432.1	7375.1	21.5	359	473	571	613	740
185	7610.9	7511.6	54.0	370	479	579	615	743
188	7837.9	7613.7	70.5	373	480	580	428	516
189	7871.0	7624.5	71.7	385	488	589	512	618

Since the critical rate is only 312 at the surface and the actual rate is 780 Mscf/D one might suspect that this well's calculations will not show loading. But after calculating downhole critical and correcting for the angle, the calculations show close enough to critical to warn about loading at this high rate.

Plotting rate and critical rate with depth and corrected with angle gives the following results (Figure 5) :

Program SNAP has some relatively new capabilities in this area. Shown in Figure 6 is a plot of critical velocity and actual velocity. Shekar is used for the critical calculations. It also is close to predicting loading at depth.

Reference for new technique is:
Shashank Shekhar, Mohan Kelkar, W.J. Hearn and L.L. Hain; 2017; "Improved prediction of iquid Loading in Gas Wells"; accepted for publication at SPE Productions and Operations.
The shape of the overall tubing performance curve is shown in Figure 7. From the shape of the overall TPC curve, it is indicated that the critical may be around 400 Mscf/D but in fact as shown above it is close to 800 Mscf/D at depth.

This section above has described the procedure for analysis and as such the following results do not have as much detail.

SECOND WELL

This next well analyzed, is Bowles #2.

Plunger type
9" Sleeve with Tungsten ball
Ball weight: 0.5 lbs.
Tubular Depth
Bumper spring set at 6607' @ 34 degrees
EOT 6803' @ 63 degrees
2 3/8 tubing

WHT/BHT
70/189 degrees
WHP/CHP
Tubing 76 psi
Casing 277 psi
Bbl/MMcf (when plunger was dropped)
52.5 Bbl/day / 780 MMcf/day 6.5 bopd, 46 bwpd
Fluid Gravities
1.11 Water
53.6 Oil

MD	TVD	ANGLE
200	199.5	0.81
2395	2375	8.66
3151	3119	11.9
4094	4060	4.81
5041	4997	1.06
6399	6361	20.64
6678	6682	57.9
6860	6706	71.63
7043	6741	91.4
7135	6736	91.6
7323	6744	92.9

The below chart (Figure 8) shows the daily gas production. The plunger was installed 9/29/2019. With the plunger an increase from 780 Mscf/D to 900 Mscf/D was shown but the well showed loading previously at 720 or less. The critical with angle correction for this case turns out below to be 690 so it shows compared to calculations to not loaded once again but it is close enough that it should warn of impending or in this case actual loading.

Calculations

The tubing performance curve (Figure 10) indicates the well is flowing above calculated critical when the plunger was dropped.

At 720 Mscf/D the bhp is ~380 psi. The critical corrected for deviation calculates to be 683 Mscf/D. This is lower than the actual rate when plunger installed so this prediction would tell you well is not loaded at this point. To further check the Shekar model results (Figure 11) are below which also shows no loading. So the Shekar prediction is a little low on predicting critical for this well.

THIRD WELL:
Acola #6

The plunger installed 2/7/20, date indicated by the dot in Figure 12. Two days before plunger was installed the well shut in due to well head repairs caused by sand. EOT is 7269'. Figures 12 and 13 show production records vs. time.

2 3/8's tubing
Bumper spring set in F nipple @7026'
WHT
70 degrees
BHT
189 degrees
WHP
Tubing 95 psi
Casing 415 psi
BPD/Mscf/D
95 bbl/day (95 water, 0.1 oil)

The "dot" rate is used to check for critical. (550 Mscf/D)

MD	TVD	ANGLE
6660	6638	7.51
6849	6819	24.09
6994	6904	30.26
7039	6980.6	42
7511	7172	79.63
7889	7195	89.62
7994	7196	90.11

Figure 14 shows a nodal system plot for this well.

At 700 Mscf/D the pressure is about 410
Corrected for angle critical is about 698 Mscf/D
Figure 15 shows critical velocity at depth (Shekar). It does indicate that the well is liquid loaded at depth.

FOURTH WELL: Cole #5

CP was about 440, TP was about 190 and Line (static) pressure was 170 when plunger was dropped. Fluid production was 25 BBL of water a day with no oil

Plunger: 9" sleeve with a Tungsten ball
Tubing: 2 3/8
Bumper spring is set in the X nipple at 8502 MD 8431 TVD at 51 degrees
EOT is 8658 MD 8513 TVD At 65.8 degrees.
WHT: 65 F. BHT is 189 F 16
Production data vs. time in shown in Figure 16.

The plunger was installed 12/19/17, date indicated by dot shown in Figure 17.. Daily production was 973mcf/day before then up to 1107mcf/day after install.

MD	TVD	ANGLE
6100	6099	0.76
7700	7699	1
7889	7888	4.8
8014	8012	8.4
8108	8104	15.6
8328	8303	36.1
8422	8376	43
8517	8439	52.4
8612	8492	61.4
8644	8507	64

At 973 Mscf/D the FBHP is calculated to be about 412 psia. The Turner corrected critical is calculated to be 716 but the flow is 937 Mscf/D. The Shekar model (Figure18) shows also no liquid loading so again predictions of critical are low compared to apparent actual conditions. From production one could argue that the actual critical occurs closer to 1050 Mscf/D.

Summary and Conclusions

In a presentation by D Green, Wellmaster, the following concept was introduced. Green shows a straight Line extention of the friction dominated portion of the J curve (Figure 19). He indicates that this is the point where a plunger can begin to work as the rate declines.

Although above critical, using Green's concept, the plunger could be dropped where the J curve starts deviating from the fully turbulent approximate straight line according to Green's concept (Figure 20) . This coincidently when the plunger was actually dropped. However stability is normally thought to be if you are to the left of the minimum of the tubing curve so some questions remain.

The results in the discussion show that predictions for critical are, in general, low compared to what is apparently actually happening.

The data definitely shows launching the plunger above the calculated critical gives good results. This is becoming industry practice but the calculation of critical is more complex than previously thought. The Green model or concept seems close to the rate where plunger was shown to be effective. Operators should not avoid putting in plunger before the rate drops to or below the calculated predicted critical as good results and increase production can result as shown here.

The critical calculations are not 100% accurate (for example the Turner predicts 20% higher than the Coleman). Based on these results conclusions about calculated critical is that loading apparently starts above the calculated critical. Perhaps as much as 10% higher compared to calculation results.. Further correlations of critical calculations compared to actual results should allow a workable rule to be established.

In general one should always put in AL somewhat early but these cases are more extreme. Based on this data even if calculations indicate above critical flow if data shows what appears to be loading one should test the use of plungers. Or in other words paying attention to recorded data seems more important than commonly used calculations concerning if the well is loaded or not but calculations are very convenient to use as a planning tool to anticipate when critical will occur.

Acknowledgements: The authors would like to thank BKV management for the right to publish and exchange thoughts with the industry with this paper.

APPENDIX A: EQUATIONS FOR CALCULATING CRITICAL FLOW

1. Density:

$$\rho_g = \frac{2.699\gamma_g P}{T z}$$

ρ	Density
P	Pressure
z	Compressibility factor
T	Abs temperature
σ	Surface tension
A	Area
L,g	subscripts for liquid , gas

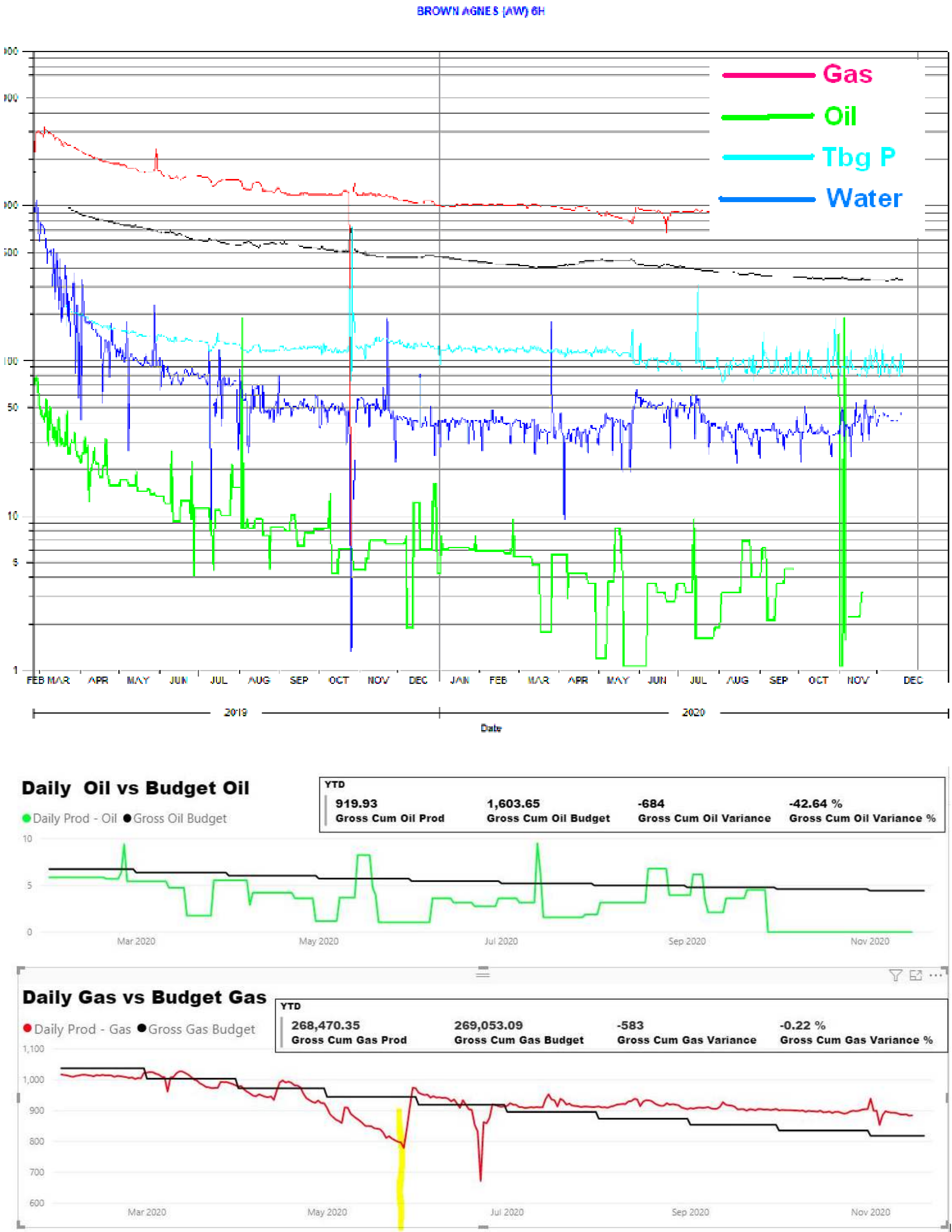
2. Critical Velocity:

Turner's Critical Velocity

$$U = 1.92 \frac{\sigma^{1/4}\left(\rho_L - \rho_g\right)^{1/4}}{\rho_g^{1/2}}$$

3. Turner's Critical Gas Flowrate:

$$Q = \frac{P\, T_{sc}\, A U}{1000\, P_{sc}\, z T} \times 3600 \times 24$$



Figures 1.a, 1.b and 1.c   Production data for this first well before/after the plunger launched

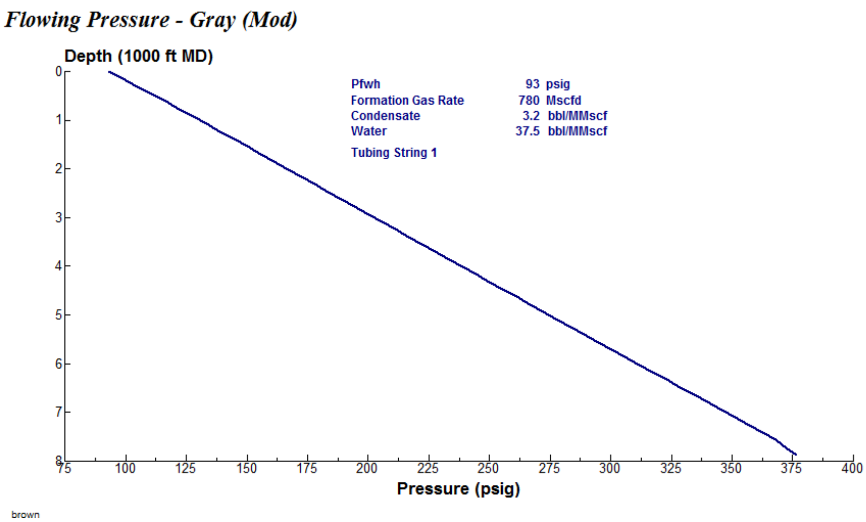


Figure 2: Calculated Tubing Pressure Profile Before Plunger launched. Well One

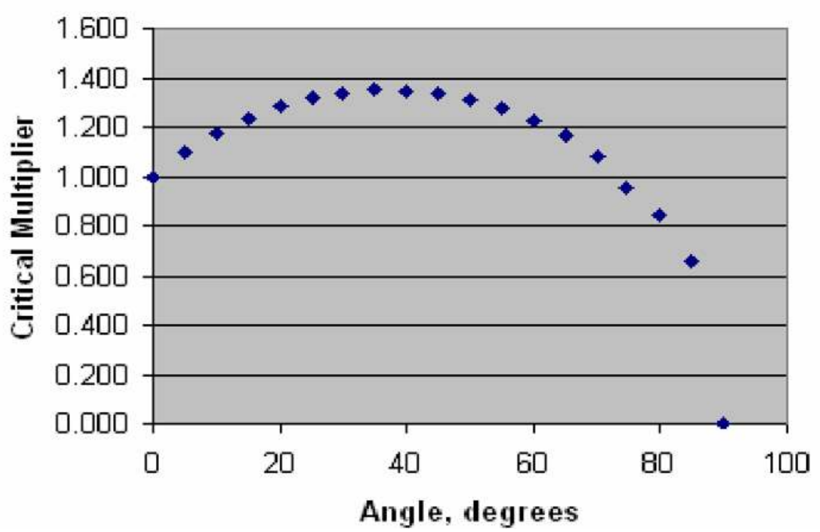


Figure 3: Correction to Critical for Well Deviation. In equation format it is: =(SIN(1.7*((90-Angle)*2*3.14/360)))^0.38/0.74067

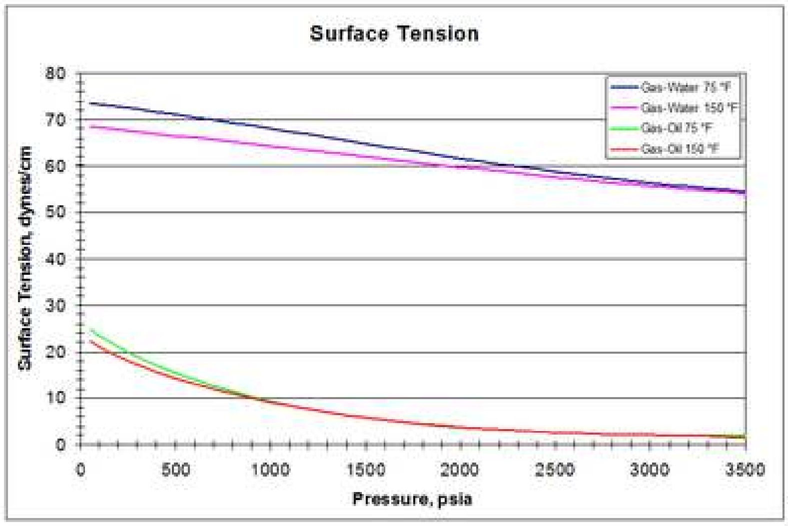


Figure 4. Typical surface tension values for use in critical calculations. (From R Sutton)

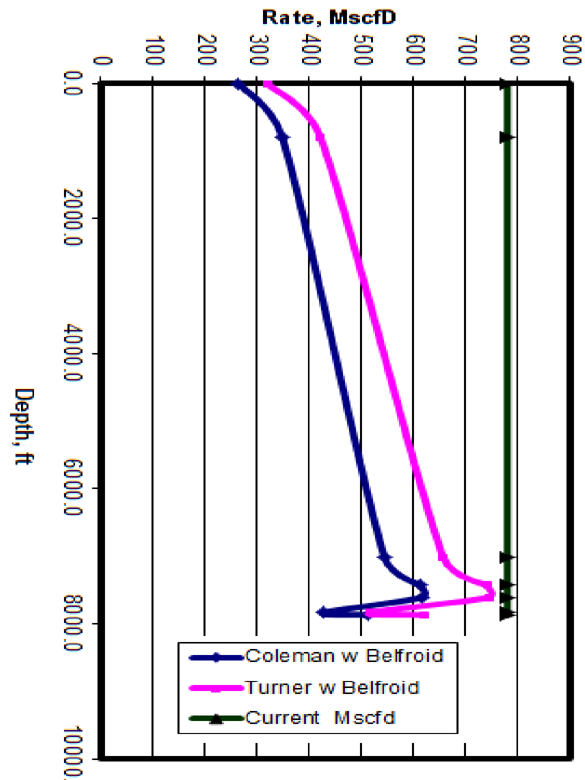


Figure 5: Downhole critical (Coleman and Turner) with Rate vs. Depth

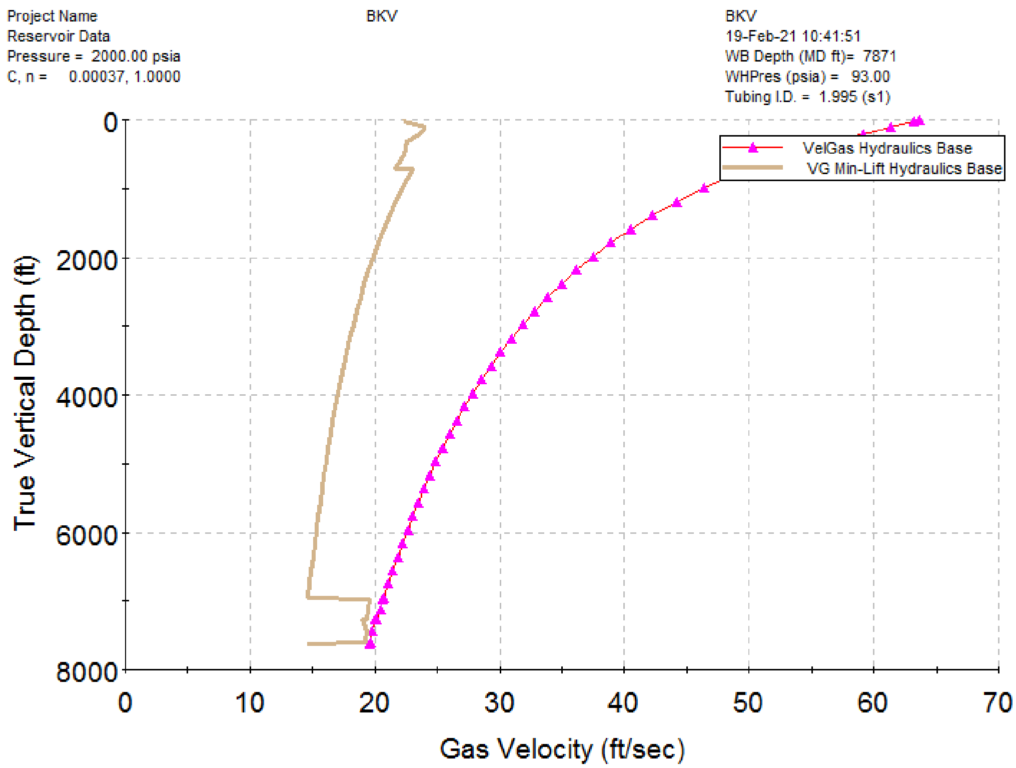


Figure 6: Critical and actual gas velocities from Shekar above (calculated by SNAP)

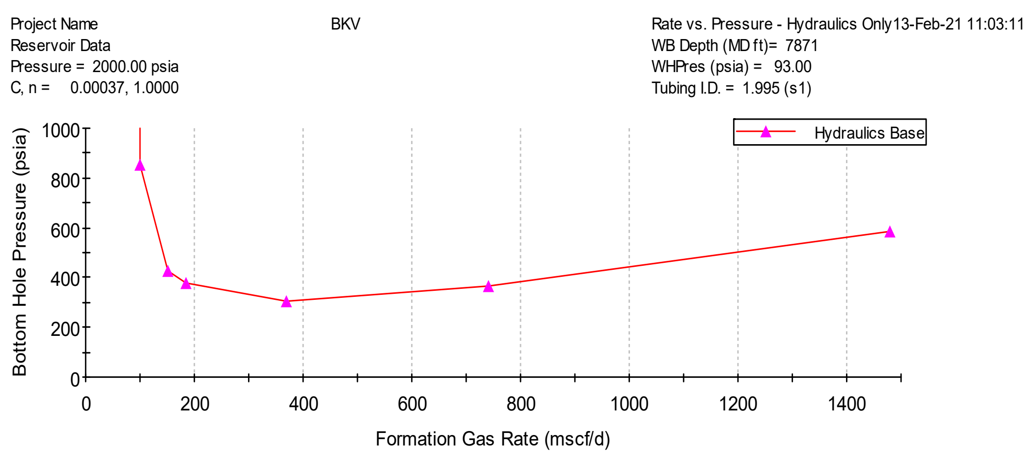


Figure 7: Tubing Performance Curve

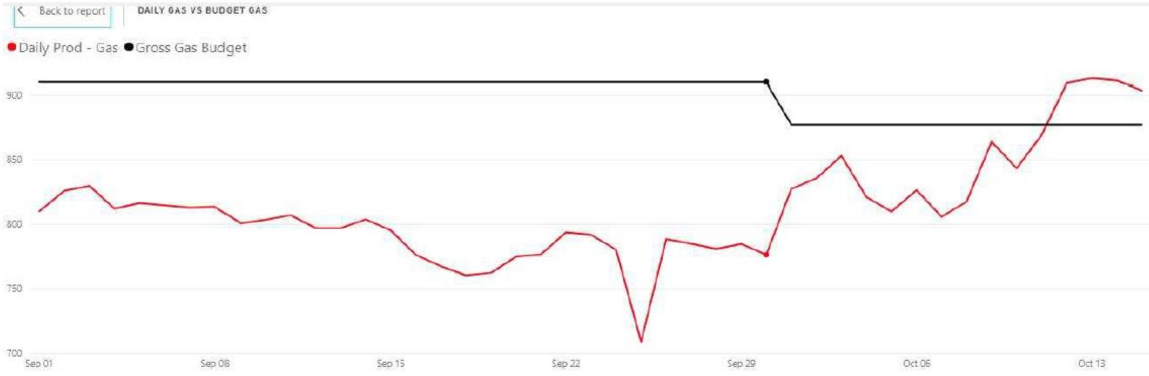


Figure 8: Production vs time. Well two

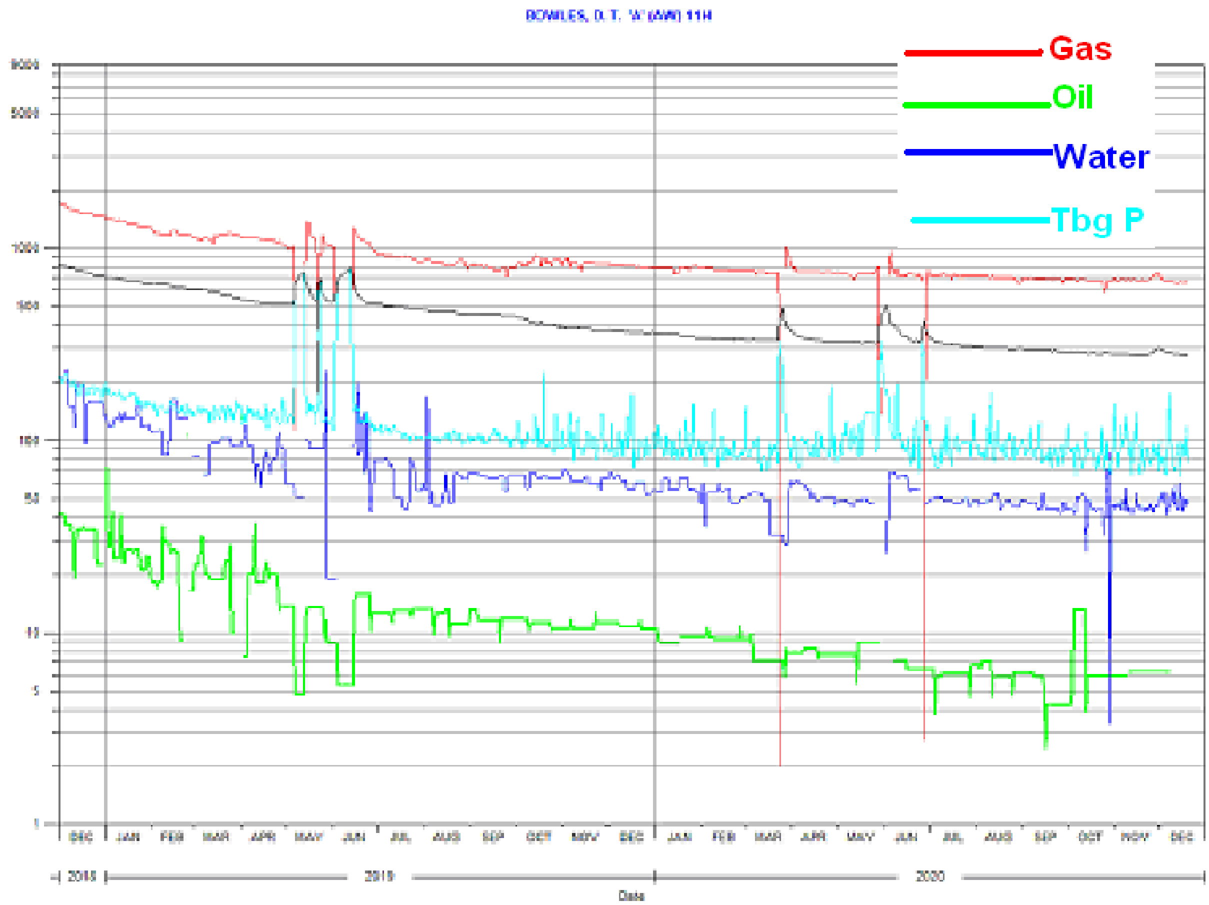


Figure 9: Additional production data. Bowles Well

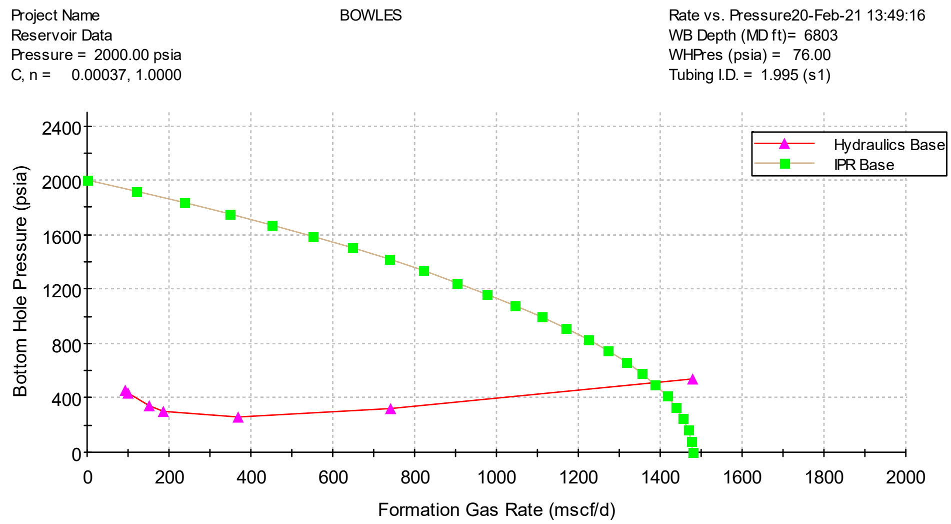


Figure 10: Tubing Performance Curve shown with an IPR

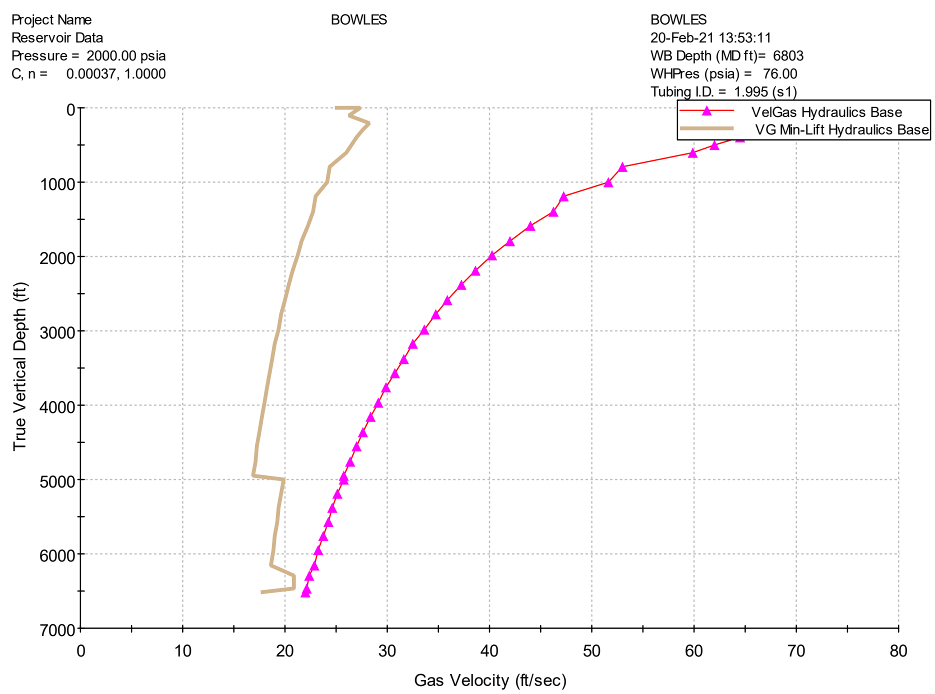


Figure 11: Shekar mode predications for Bowles Well

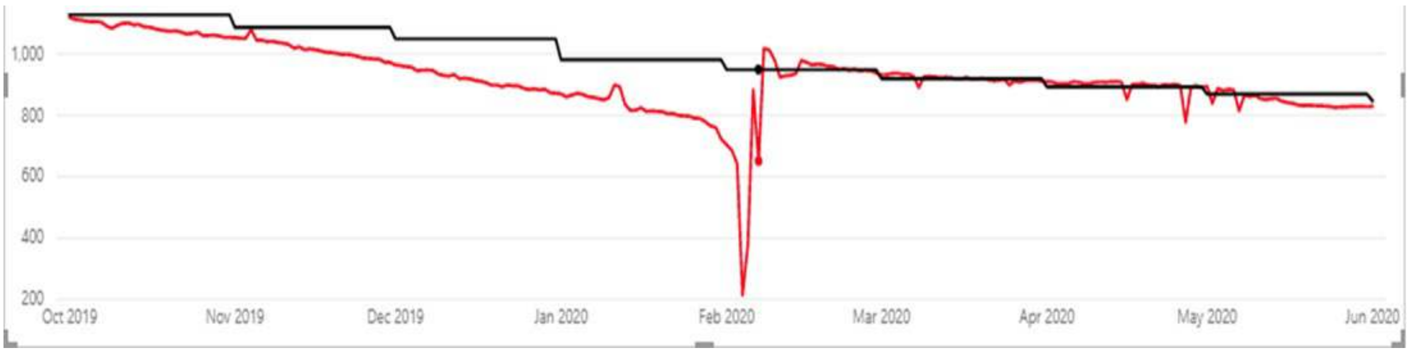


Figure: 12: Production vs Time: Acola Well.

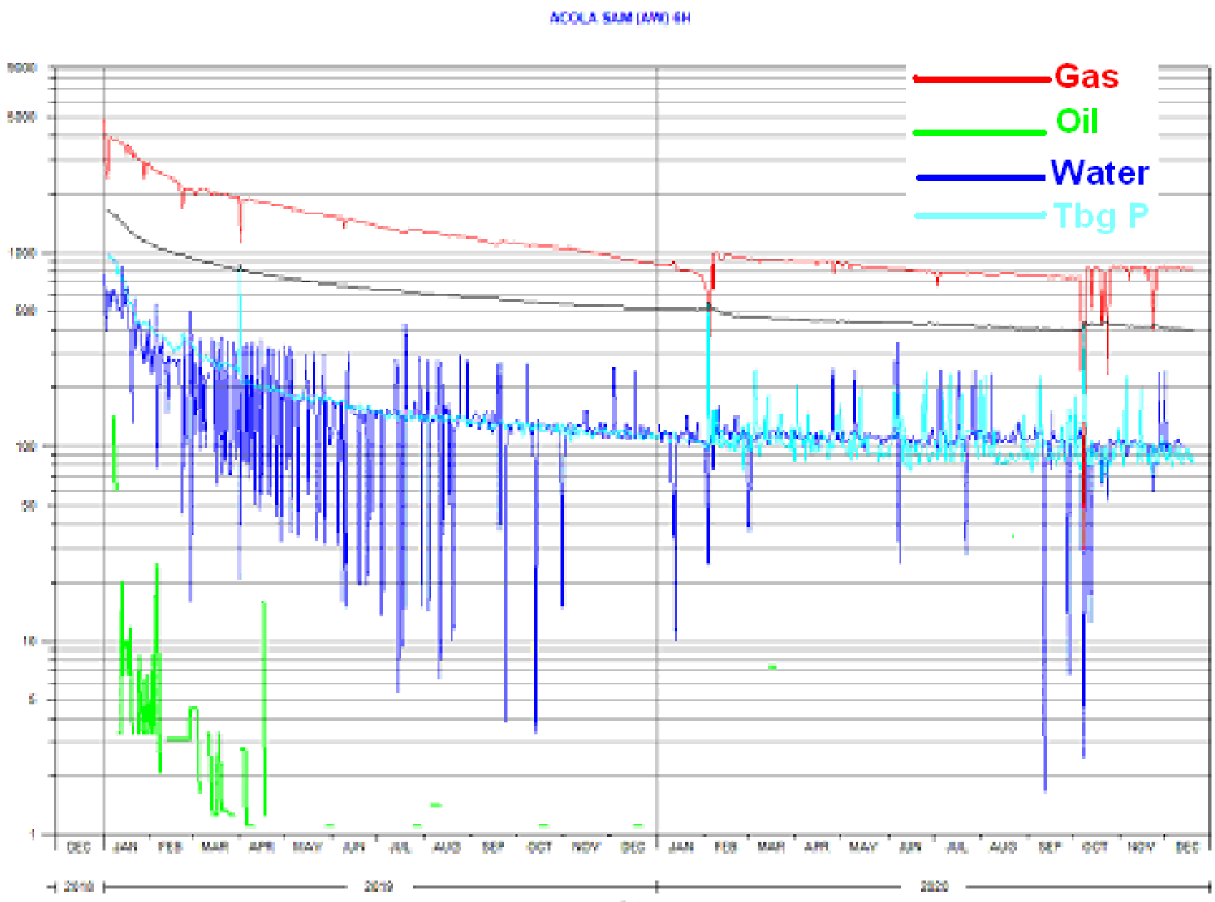


Figure 13: Additional production data: Third Well

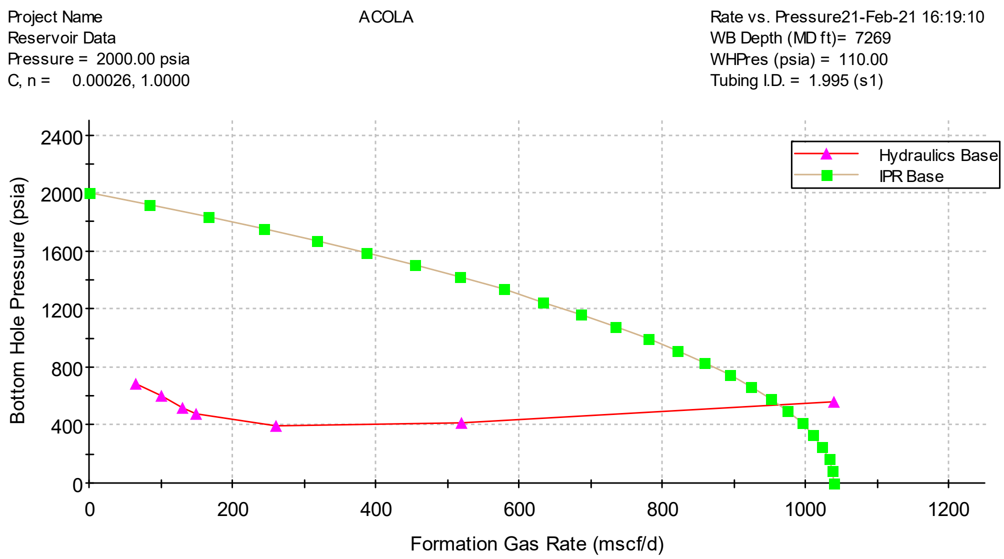


Figure 14. Tubing Performance Curve for Acola Well

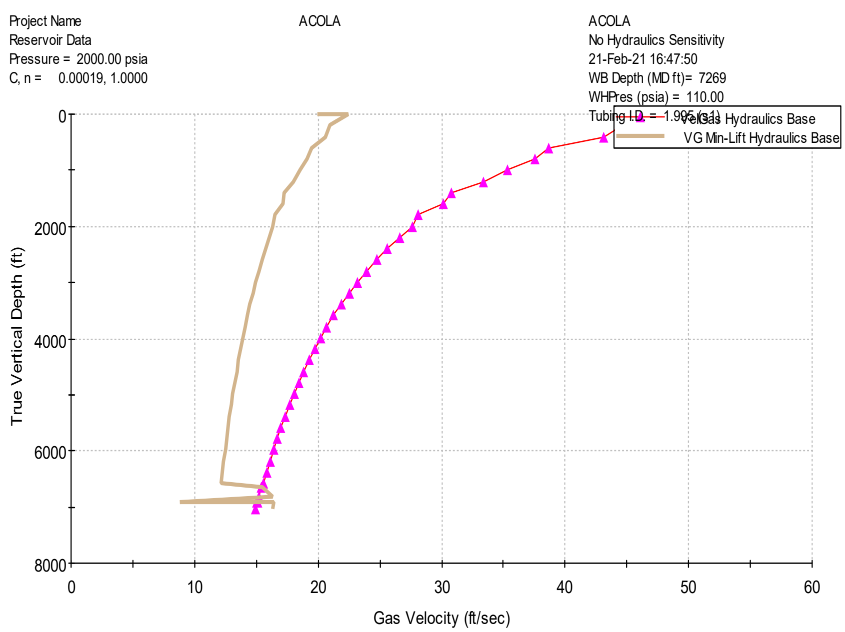


Figure 15: Shekar results for Acola Well

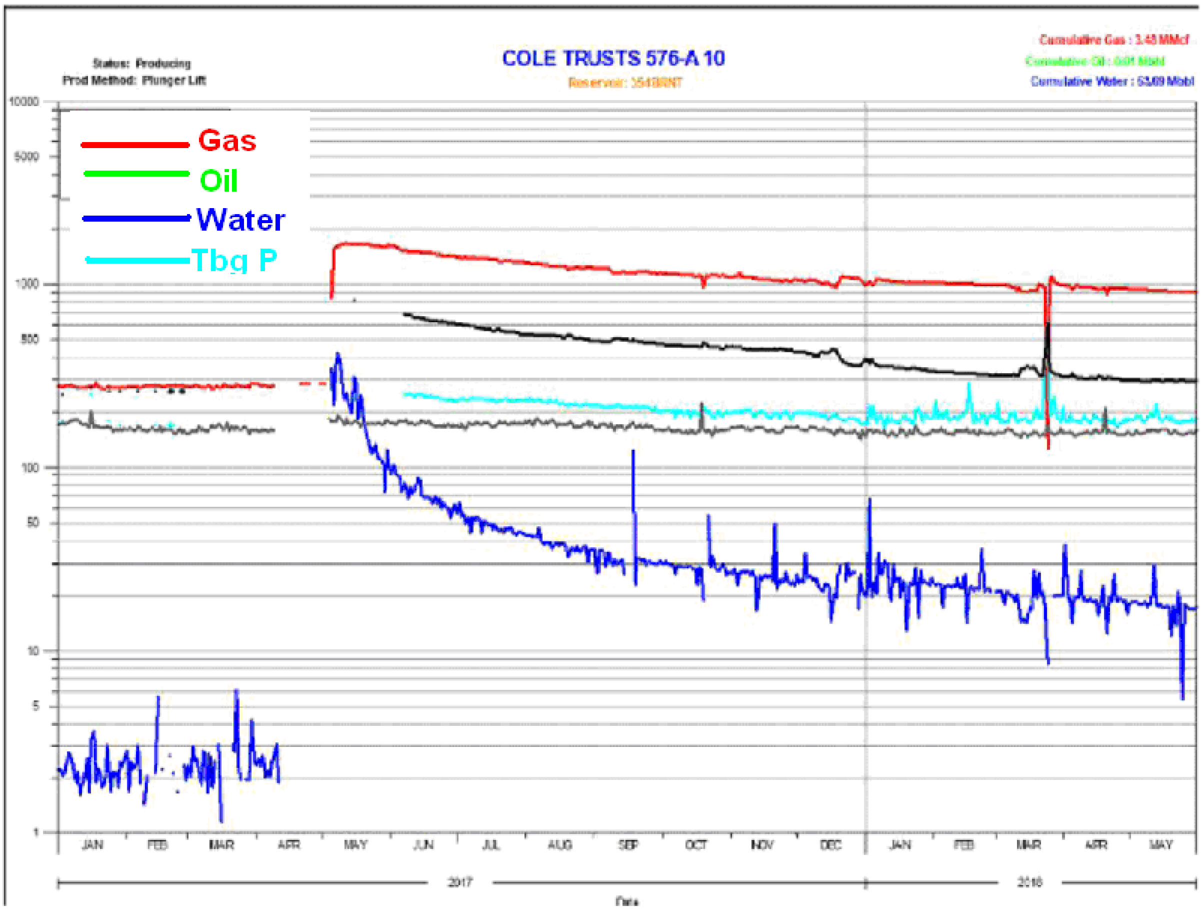


Figure 16: Production data: Cole Well

Figure 17: Gas Production: Fourth Well.

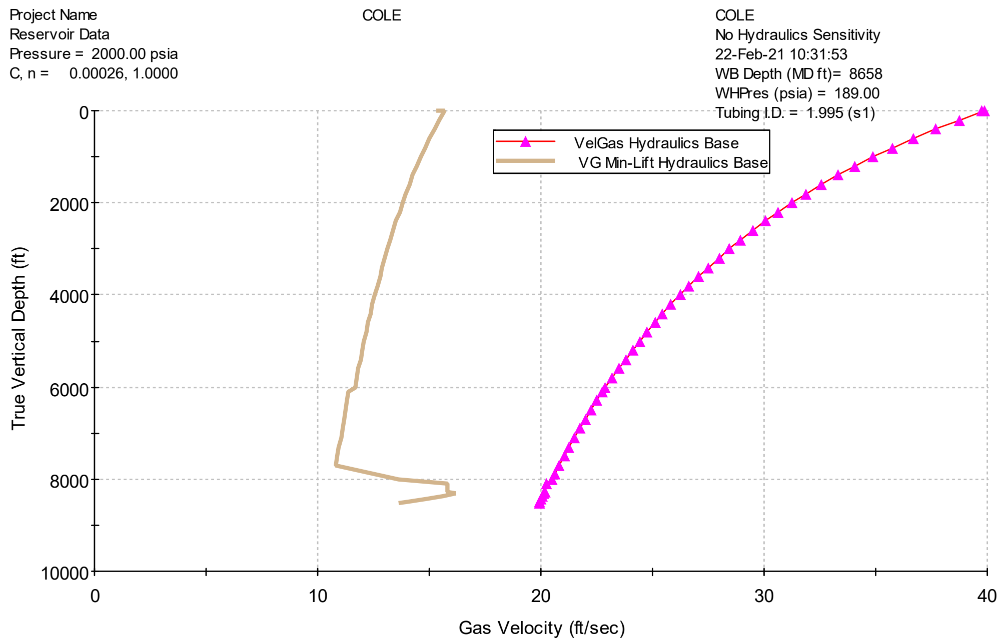


Figure 18: Shekar results for Cole Well

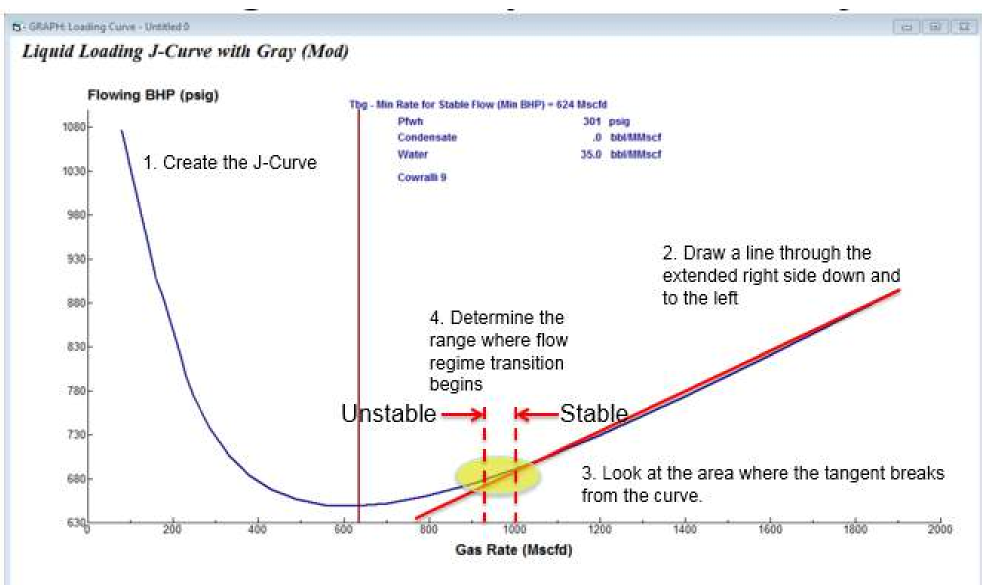


Figure 19: When J curve deviates from Friction dominated portion (After Green)

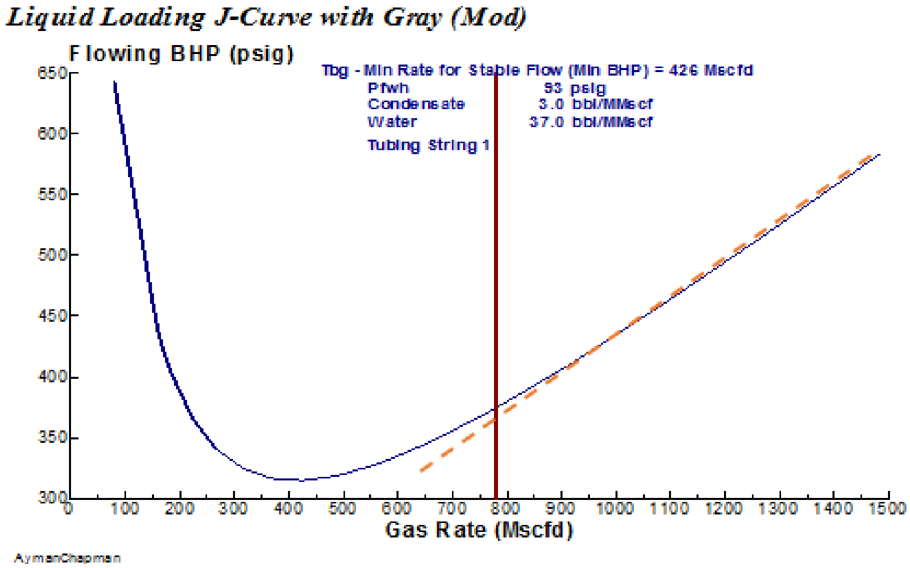


Figure 20: Applying the concept in Figure 20 to Well One