PRACTICAL PRODUCTION AND ARTIFICIAL LIFT SPREADSHEET TOOLS

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INTRODUCTION:
This paper discusses and provides a number of routines codified in practical spreadsheets that production engineers and operating personnel will be able to use to do calculations helpful for visualizing, analyzing and evaluating common production problems/scenarios. Using these spreadsheets will save time and increase the user's effectiveness in handling various production challenges and Artificial Lift situations.

ROUTINE 1: CRITICAL VELOCITY FOR GAS WELLS AT P AND T
The flowrate required to lift liquids to surface in a gas well (Critical Rate) varies with pressure. This is important as the Critical Rate at depth may be higher than at surface. Therefore, liquid loading may be occurring at the bottom of the wellbore despite having sufficient rate as measured at surface. This application determines the critical rates, using both the Turner and Coleman correlations[1,2], at various pressures. Please note that Coleman and Turner's work is based on calculating critical rate from surface pressure, however you can refine your results by inputting BHT and BHP[3] from Routine 4 below.

ROUTINE 2: TURNER-COLEMAN CRITICAL VELOCITIES WITH DEVIATION CONSIDERED
There are many formulations of critical gas velocity in the literature. The methods of Turner and Coleman are two of the most commonly used formulations. Turner was the first finding critical by balancing weight of liquid droplet against the upward drag from the gas production. Coleman did a later study and developed a new formulation for lower pressure wellhead pressures. The formulas were similar. The Turner gives a higher critical velocity than the Coleman. The Coleman may be more accurate for lower WHPs' but to be conservative, many still use the Turner for critical velocity calculations. Hole angle can also affect the critical velocity. The critical is adjusted upward by a Shell correlation up to about 35 degrees and for steeper angles the critical velocity begins to adjust to lower values. This correlation chart in the SS and the value of the adjustment is included in the calculations. If the user puts in the bottom hole temperature and pressure and the adjust for deviation, then a fairly accurate value of the critical velocity (depending if you like the Turner or Coleman best) can be obtained.

ROUTINE 3: OIL WELL GAS LIFT PERFORMANCE

This application calculates the Flowing Bottomhole Pressure using the Hagedorn and Brown multiphase flow correlation with a simple Vogel IPR to do nodal analysis. Hagedorn Brown is a multipurpose correlation routine but is found to work very well for many oil well gas lift applications. Inputs required include well test pressure, rate and temperature; fluid specific gravities and flow path parameters. Results show how much different amounts of lift gas will help (or hurt) your oil well including a plot of the most commonly used gas lift optimization parameter, BOPD/MCFD Injected. This spreadsheet can be very useful if you do not have (or cannot access) nodal analysis software which can be costly.

ROUTINE 4: CALCULATE GAS WELL BHP

The Gray correlation[4] is used in this routine to calculates the flowing bhp in gas wells. When free water is present in the well, the resulting pressure gradient in the well is increased. Gray published this method for calculating the pressure drop resulting from the flow of gas and water. This correlation is designed for flowing gas wells and calculates accurate pressure profiles when liquid production is below 200 bbl/MMSCFD. Please note these resulting downhole pressures can be used in critical rate calculations in Routine 1.

ROUTINE 5: GAS ASSISTED PLUNGER LIFT

GAPL (gas assisted Plunger lift) is a method where gas is either constantly or intermittently injected down the casing to provide sufficient gas volume to operate Plunger Lift. Some plunger lift installations don't have enough formation gas to cycle the plunger, then the operator can inject high pressure gas into the annulus of well so the Plunger in the well can cycle. One rule of thumb to successfully operate a plunger in a well requires 400 scf/ (bbl of liquid/1000 ft of depth) to operate. Gas required to operate plunger lift is determined using Foss and Gaul[5,6] calculations so there are two methods to calculate the gas needed to be injected. The user would decide with method gives the best operation from use of calculations.

When a plunger well cycles successfully with a given slug or liquid slug size, the well must build to a casing pressure max during the off time. This PCmax is calculated by the Foss and Gaul Method. If the well cannot build to this required pressure during off time, one can visualize injecting gas during the off cycle or continuously so the well reaches a casing pressure equal to or above the required PCmax so the well can operate. This could be from trial and error or this SS could be used to narrow down the amount of gas needed to be injected to get the plunger well cycling again.

GAPL is widely used to continue to use plunger lift even though the well is weakening with time. These calculations could also be used for PAGL (Plunger Assisted Gas Lift) where a plunger is dropped to assist liquid recovery from gas lift wells at lower gas lift injection rates as liquid production declines.

Another not related method is to use two plungers in the one well where a plunger cycles up and down in the top portion of the well and other cycles up and down in the bottom portion of the well. Since the well can be considered to now allow some of the gas above the bottom plunger to help lift the top plunger (and liquid slug) and the two plungers share the liquid load, the two-plunger method is an alternative to the GAPL. The two-plunger method requires a lot of wireline work and the GAPL requires a gas lift source.

ROUTINE 6: PLUNGER PERFORMANCE WITH TIME USING DECLINING IPRS'S

This routine determines operating range of plunger lift on wells as IPR declines.

The size of the slug to be lifted is input and the time required for the steps of one cycle as well as the cycles/day is calculated. Then the total production per day is calculated along with the max and min production per day. With the input of IPR data, the ranges of operation of the current IPR are calculated and then it is shown on declining IPRs. This shows the approximate range of liquid plunger production as reservoir pressure declines.

ROUTINE 7: PLUNGER FALL VELOCITY[7,8]

Plunger fall velocities for various plungers have been measured in many different wells in the field and measured in a large scale well simulator. A new theoretical plunger fall velocity model has been developed. The measured fall velocity at a specific pressure and temperature is used to calibrate the model, and then the model can be used to calculate fall velocity at other conditions for the same plunger or used to show how changing a feature like plunger weight can impact fall velocity.

During the plunger cycle, enough time must be set aside when the well is shut-in for the conventional plunger to fall to bottom through the gas and through the liquid that can be on bottom. The General Plunger Fall Model, $V = C / \sqrt{\rho}$, equates plunger fall velocity to be inversely proportional to a constant multiplied by the square root of the density of the gas the plunger falls through. A measured fall velocity at a specific pressure and temperature is entered in the routine to determine the constant C. It is found that pressure greatly affects fall velocity with low pressure wells allowing the plunger to fall fast. When the required data is input, a plot Is generated of the fall velocity vs pressure. This predicted data has been compared to field data by Echometer and others and the predications are found to be accurate.

ROUTINE 8: PLUNGER RULE OF THUMB PROGRAM[6,9]

This program jointly from Echometer and PltechLLC can give the user insights into optimizing the plunger lift cycle. If CP and TP at the end of shut-in period are input the program calculates the bbls of liquid to lifted on the particular cycle. Then using the methods of Foss and Gaul, the CP value needed to lift the slug is calculated. The plunger fall velocity in gas and liquid is input to get the min shut in time. Using the max cycles per day the production can be estimated. Other features are indicated in the input/output below. This routine should help the user set the cycle and see what's possible from the plunger well. It has a "what if" feature that allows the user to input the slug size without inputting the CP and TP to see what effects on slug size on required CP and production.

These rules-of-thumb algorithms have been translated into mathematical equations as discussed in references 6 and 7. The calculations allow the operator to estimate the rise velocity of the plunger, the liquid slug size per cycle and time period intervals for the plunger cycle. The algorithms are used in this routine to calculate timings for events during the plunger lift cycle and the times are compared to key events determined from measurements acquired at the well. Using the measured tubing and casing pressure and plunger location during the cycle along with other well parameters as inputs into the spreadsheet helps the operator to verify the plunger lift system is operating as desired. Both measured plunger lift performance data and calculations from the algorithms guide the operator to effectively analyze, adjust and optimize the plunger lift installation. This Rule-of-Thumb routine has received wide use in the industry and parts of it have been included in companies data collection and automation system.

ROUTINE 9: CALCULATE DOWNHOLE SRP PUMP CLEARANCE VS P AND T[10]

Downhole sucker rod pump clearance changes from shop conditions to bottom hole conditions due to bottomhole pressure and temperature that the pump components are subjected to. This routine uses equations to estimate the change in dimensions of the plunger and barrel of top and bottom hold down pumps at bottomhole pressure and temperature conditions. The approach uses one equation for cylinder dimension changes with pressure with appropriate inputs for the internal and external pressure (or average pressure) for the upstroke when slippage is important and has an effect on the total production. Examples are given for thin and heavy wall pumps at a variety of depths, pressures, and temperatures. Corresponding production rates for the calculated downhole pump dimensions are given. Top hold down pumps (THD) react differently than bottom hold down pumps (BHD). This routine calculates the changes in clearances for both types of pumps at bottom hole conditions compared to surface conditions. The results affect pump slippage which increases with more clearance and decreases with less clearance. Many will calculate leakage using the surface clearance but to be more accurate, you can use this routine to estimate the change in clearance due to pressure and temperature at bottom hole conditions.

ROUTINE 10: CURRENT AND PROPOSED FATIGUE SR ANALYSIS

Allowable sucker rod loading has been calculated for many years using the Modified Goodman Diagram. The Modified Goodman Diagram is used to design sucker rods to operate under cyclic loading with a fatigue life of 10 million cycles. The rods are considered to not be overloaded if they cycle within the load limits but are considered overloaded and should fail due to fatigue, if they exceed the maximum limit during cycling. The Modified Goodman Diagram, MGD, method achieves a long rod life by restricting the maximum allowable cyclic stress range to ¼ or 25% of the tensile strength of the sucker rods. Actual rod life performance installed in all well has proven the ¼ factor is extremely conservative, where sucker rods designed using MGD will never have a fatigue failure in an infinite number of cycles. Beginning in 1998-2000 time period operators started using a SF (service factor) greater than 1 to increase the allowable stress range limits. Typically, in the past an operator would not want to use a SF of greater than one. Both cyclic fatigue laboratory testing and studying beam pump operations showed that the MGD is exceeded in operation indicating the MGD is too conservative. As a result, a new API method was developed with an allowable cyclic stress range to 1/2.8 or 35.7% of the tensile strength of the sucker rods. This allows use of smaller rods (less costly) without being overloaded in some cases. This method has not been fully issued as a new approved method of analysis. In some cases, however, recognizing the new method, designs are now made with SF’s of over 1 since the new method has yet to be fully recognized.

API’s recommended practice in the past has been to reduce the limit by a using a SF less than 1 for rods being used in a corrosive and salt water environment. The issue is no sucker rods made today are corrosion resistant, some grades are more tolerant of corrosion, but none are resistant. All rod grades are susceptible to corrosion (i.e., pitting, corrosion fatigue, corrosion abrasion, erosion corrosion, sulfide stress corrosion, etc.). Using service factors less than 1 to de-rate rod loading for corrosion is not recommended because SF<1 forces the operator to design with larger diameter rods, not always possible, or higher tensile strength sucker rods, which are more susceptible to corrosion pitting.

A comparison of using the MGD and the new proposed API method is done in this routine. One can see for instance when a SF of over 1 is used, when stress may be acceptable with the new method and when the new method would say the rods are overloaded.

<u>ROUTINE 11: VISUALIZE PUMP DYNO CARD LOAD WITH INCOMPLETE FILLAGE</u>

Incomplete pump fillage is often associated erroneously with a “pumped-off well”, meaning that the pump displacement exceeds the production capacity of the reservoir, ignoring the fact that there are two other causes of partial liquid fillage: gas interference and the presence of a flow restriction or excessive pressure drop at the pump intake. The result of a misdiagnosis is to incorrectly set the mode of operation of pump-off controllers, variable speed drives or timers thereby losing significant amounts of production. One of the main causes of inefficient rod pump operation is incomplete liquid fillage since this causes a reduction of the effective plunger stroke thereby reducing displacement at pump.

Assuming that the standing valve is operating normally and there are no restrictions to fluid flow from the wellbore into the pump, the pressure inside the pump barrel during the upstroke is slightly less than the pump intake pressure by the frictional pressure losses due to the flow. These losses are generally of the order of 5 to 10 psi for water and low viscosity oils. The pump intake pressure is determined by the pressure that exists in the annulus at the depth of the pump seating nipple and is directly related to the gas-free liquid pump submergence and the casing head pressure. The pump discharge pressure is the pressure that exists at the bottom of the tubing and is equal to the sum of the tubing head pressure plus the pressure due to the column of fluid in the tubing down to the top of the traveling valve. The tubing fluid is a mixture of oil, water and gas and its gradient is normally computed from the density of the produced oil and water mixed in proportion to the well test water-oil ratio.

This routine allows pump dyno cards to be visualized vs. discharge pump pressure. This is of assistance when trouble shooting a well and also when showing or teaching how a pump dyno card height changes with discharge pressure.

ROUTINE 12: MAX RATE FROM PUMPING USING IPRS

In addition to calculating the inflow performance of a well using the Vogel, Petkovich (Backpressure) and Productivity Index methods, this application determines the minimum expected pressure at the pump depth which equals the weight of a column of gas plus the surface pressure. This will result in a better estimate of the maximum expected production rate one can expect from the well. A single well test (production rate at the estimated bottomhole test pressure) is required in addition to an estimation of the static reservoir pressure.

ROUTINE 13: SRP PUMP SPACING

This routine estimates the amount of rod lift or spacing when setting a pump so it will not hit down when it starts to pump and the rods extend in length as the pump is loaded and pumping begins. This is for steel rods, with an anchor and is an estimate. Add some extra to the answer for a safety factor.

The program would be more accurate if the extension of the bottom of the rod were predicted by a wave equation but for now an approximate value is used from an earlier method of rod design which is shown in a separate tab.

One should monitor how well the program predicts reality but it has been showing to give good estimates.

Industry rules for steel rod spacing are for steel rods 24” spacing for wells up to 4000 ft deep and then an additional 6 inches for each 1000’ in depth. For FG rods rod spacing (RPS = (.9*FL/1000) + (2*SND/1000).

Other approximate rules may exist. Industry may err on the high side for safety, but this will limit gas compression ratio in the pump and could result in premature gas interference.

ROUTINE 14. ESPS PERFORMANCE WITH IPR AND GAS

This routine estimates the lowest pump intake pressure that an ESP can achieve based on the gas separation that is used, natural, rotary or tandem. As the intake pressure drops, the gas volume fraction at the ESP intake increases and the pump will reach a point when it falls off its operating curve due to its inability to handle the gas. This limit can be estimated based on the Dunbar[11] factor which is calculated based on the GOR and fluid characteristics. This estimate is very useful in explaining why ESP’s cannot achieve low intake pressures in high GOR wells.

ROUTINE 15. GAS WELL GAS LIFT

Gas wells can flow until the gas rate drops to low values (below critical) and then they will load up and flow at a lower rate or quit flowing. One can try a small tubing (velocity string), plunger lift, pumps or chemicals. Or one can gas lift the gas well which can be thought of as adding gas to the produced gas stream with a gas lift system to get the well producing at a high rate again.

This routine shows what the tubing performance curves look like when gas is added and adding gas to the stream may increase production up to a point and when too much gas is injected friction will cause the gas injection to have diminishing returns on the production. The nature of the tubing performance curves is summarized in a Gas-In/ Oil (or liquid) -out curve. The peak production on the gas-in/liquid-out is the maximum production that can be obtained for the descriptive input for a particular case assuming no limits on lift gas available. The gas-in/liquid-out is used throughout the gas lift industry for gas lift with oil wells and in this case for gas wells as well. Once the rate of gas is determined, then the well can be worked on further with other programs to space and pressure a string of gas lift valves to achieve the production selected from the gas-in/oil-out curve. The Gray multiphase flow correlation is used which works well for many gas wells producing some liquids.

This routine also serves to estimate performance from lower surface pressure or smaller tubing.

ROUTINE 16: GAS LIFT PRESSURE TRAVERSE ANALYZER

A pressure/temperature survey run in a gas lift well is a critical tool to diagnose performance and make production improvements. This application takes information from a pressure/temperature survey, plots it with valve parameters to identify which valves are taking gas and determines the amount of gas being injected.

ROUTINE 17: GAS LIFT VALVE PERFORMANCE

The performance of a gas lift valve is calculated and illustrated by plotting the flow through the valve vs. the ratio of Pt/Pc. Curves for different values of Pc are plotted. It shows that for the higher Pc values, the valve approaches fully open and the pressures push more through the valve.

REFERENCES

1-Turner, R. G. et al., “Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells,” Journal of Petroleum Technology, Nov. 1969.

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4- Gray, H.E.: “Vertical Flow Correlation – Gas Wells,” User’s Manual for API 14B Surface Controlled Subsurface Safety Valve Sizing Computer Program, 2nd ed., Appendix B, API, Dallas, TX, (June 1978)

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6- Rowlan, Lea, J.F., McCoy, J.N, “Modified Foss and Gaul Model Accurately Predicts Plunger Rise Velocity”, 2009 SPE 120636, POS Oklahoma City, Oklahoma, USA, 4–8 April 2009

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8-O.L. Rowlan, O.L., McCoy, J.N., Lea, J.F., Nadkrynechny, R., Cepuch, C.,” Measured Plunger Fall Velocity Used to Calibrate New Fall Velocity Model”, SPE-164495-MS, Production and Operations Symposium Oklahoma City, Oklahoma, USA, 23−26 March 2013.

9-Lea, J F, Rowlan, O. L., and McCoy, J. N., “Measurement and Calculation of Key Events During the Plunger Lift Cycle”, SPE 110829, for presentation at the 2007 SPE Annual Technical Conference and Exhibition held in Anaheim, California, U.S.A., 11–14 November 2007

10-Lea, J.F., Brock, M. “Down Hole Pump Slippage”, SWPSC 2019, Lubbock, TX
11 - Dallas.Dunbar, C. E.: Determination of proper type of gas separator, SPE Microcomputer Users Group Meeting, Long Beach (1989)

FIGURES:

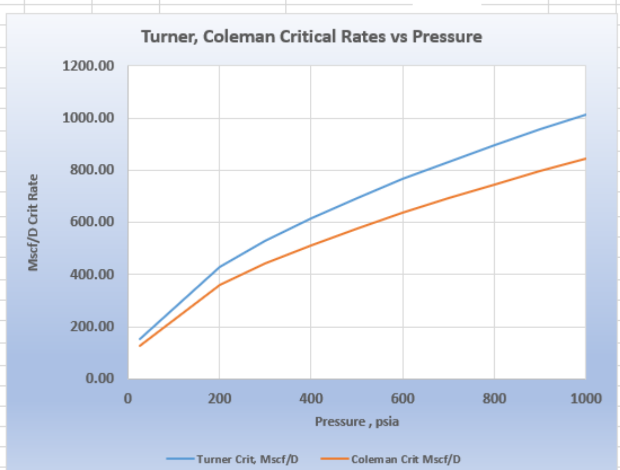
Output Figure for Routine 1: Critical Velocity for Gas Wells at P and T

Inputs in Yellow

	Line Pressure	191		1316.75	kPA
	Input Temperature	120 °F		48.89	C
	inut Gas Gravity	0.72 Air =1			
	Calculated Z Factor	0.974			
	Input Liquid Density	67	60	1.07	SpGr
	Input Surface Tensio	60 dyne/cm			
	Input Tubing ID	1.995 in		50.67	mm
ID's	3.958	2.992	2.441	1.995	1.751

Results

Calculated Criticals	Turner's	Coleman's
Gas Density, lbm.cu f	0.661	0.661
Critical Velocity for G	18.68	15.57
Critical Flowrate (MS	420.35	350.28
Critical Flowrate (E^3M	11.90	9.91
Critical Flowrate (M^3/	11895.86	9912.84



Output Figure for Routine 2: Turner Coleman Critical Velocities with deviation considered

Inputs in Yellow

Pressure	311	2144.03	kPA
Input Temperature	189	87.22	C
inut Gas Gravity	0.72		
Calculated Z Factor	0.972		
Input Liquid Density	69.2	1.11	SpGr
Input Surface Tension	67		
Input Tubing ID	1.995	50.67	mm
Input angle	63		

Results below (also see tab "Plot")

Calculated Criticals	Turner	Coleman
Critical Velocity (ft/s)	16	13
Critical Flowrate (MScf/D)	527	437
Critical Flowrate (E3M3/D)	15	12
Critical Flowrate (M3/D)	14927	12361
Angle correction factor	1.190	
Criticals corrected for Angle	628	520

Z FACTOR CALCULATION

Gas Gravity	0.71	
Calculate Ppc	667.92	
Calculate Tpc	388.68	
Input Mole fraction H2S	0.00	
Input Mole Fraction CO2	0.00	
Calculate A	0.00	
Calculate e	0.00	
Calculate P'pc	666.70	
Calculate T'pc	388.68	
Temperature , F	189.00	F
P, Psia	311.00	psia
Calculate Tpr	1.67	
Calculate Ppr	0.47	
Calculate A	0.50	
Calculate B	0.12	
Calculate C	0.06	
Calculate D	1.00	
Calculate Z	0.972	

Output Figure for Routine 4: Calculate Gas Well BHP

Flowing Well

Well Name		Producer-1
Surface Flowing Pressure	psia	100
Surface Flowing Temperature	deg F	100
Bottomhole Flowing Temp.	deg F	150
Tubing ID	in	1.995
Tubing Depth	ft	11000
Roughness (Optional)	in	0.00091

Well Fluid

Gas Rate	MMscf/d	1
Condensate	stb/MMscf	100
Water	stb/MMscf	100
Gas Gravity (Air = 1.0)		0.72
Condensate Gravity	API	59
Water Gravity (Fresh = 1.0)		1.03

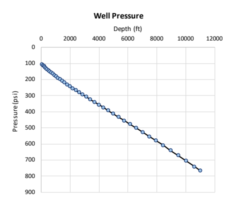
Impurities (Mole Fraction)

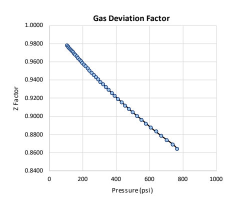
N2	frac.	0
CO2	frac.	0
H2S	frac.	0

CALCULATE

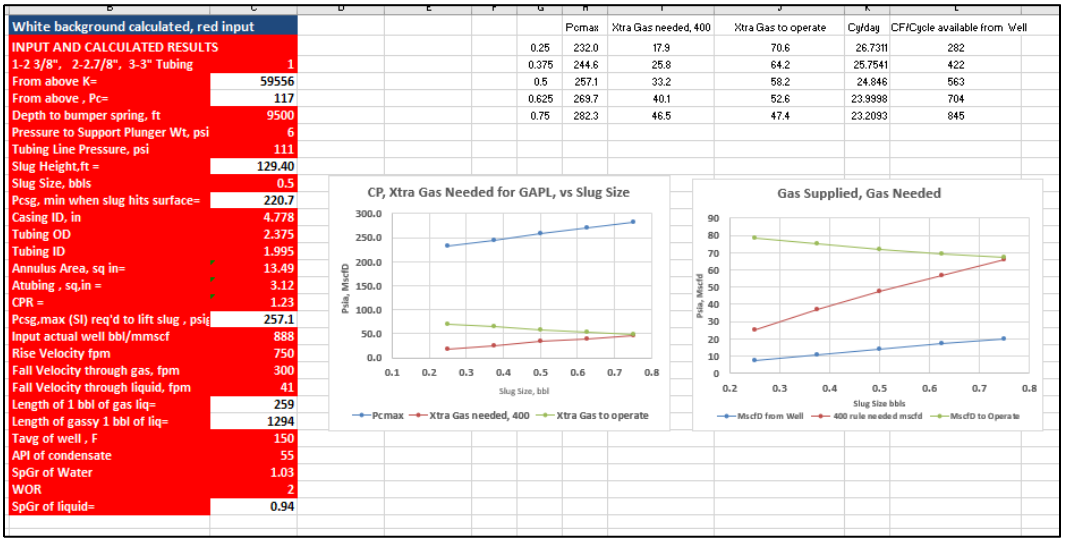
FBHP at Tubing Depth 766 psia

Depth (ft)	Pressure (psi	Z	Tc (deg. R)	Pc (psi)	YR
54	105	0.9780	418.7759	663.3627	0.1545
113	110	0.9769	418.7105	663.3727	0.1622
176	116	0.9758	418.6474	663.3824	0.1703
243	122	0.9746	418.5840	663.3921	0.1789
316	128	0.9733	418.5211	663.4017	0.1878
395	134	0.9720	418.4599	663.4111	0.1972
480	141	0.9706	418.4005	663.4202	0.2070
572	148	0.9692	418.3432	663.4289	0.2174
671	155	0.9677	418.2887	663.4373	0.2283
778	163	0.9661	418.2373	663.4451	0.2397
893	171	0.9644	418.1898	663.4524	0.2517
1017	180	0.9627	418.1467	663.4590	0.2642
1150	189	0.9609	418.1087	663.4648	0.2774
1293	198	0.9590	418.0765	663.4698	0.2913
1446	208	0.9570	418.0508	663.4737	0.3059
1610	218	0.9550	418.0325	663.4765	0.3212
1785	229	0.9528	418.0224	663.4781	0.3372
1973	241	0.9506	418.0213	663.4782	0.3541
2173	253	0.9482	418.0303	663.4768	0.3718
2386	265	0.9458	418.0504	663.4738	0.3904
2612	279	0.9433	418.0825	663.4689	0.4099
2853	293	0.9407	418.1276	663.4620	0.4304
3109	307	0.9379	418.1870	663.4529	0.4519
3379	323	0.9351	418.2618	663.4414	0.4745
3666	339	0.9321	418.3530	663.4274	0.4983
3968	356	0.9291	418.4620	663.4107	0.5232
4286	373	0.9259	418.5899	663.3912	0.5494
4622	392	0.9226	418.7380	663.3685	0.5769
4974	412	0.9192	418.9076	663.3425	0.6057
5344	432	0.9157	419.1000	663.3130	0.6361
5731	454	0.9120	419.3165	663.2799	0.6679
6136	476	0.9083	419.5584	663.2428	0.7013
6559	500	0.9044	419.8273	663.2017	0.7364
6999	525	0.9004	420.1244	663.1562	0.7733
7458	552	0.8963	420.4513	663.1061	0.8120
7934	579	0.8921	420.8095	663.0513	0.8527
8429	608	0.8878	421.2005	662.9914	0.8954
8941	639	0.8833	421.6260	662.9262	0.9403
9470	670	0.8787	422.0877	662.8555	0.9874





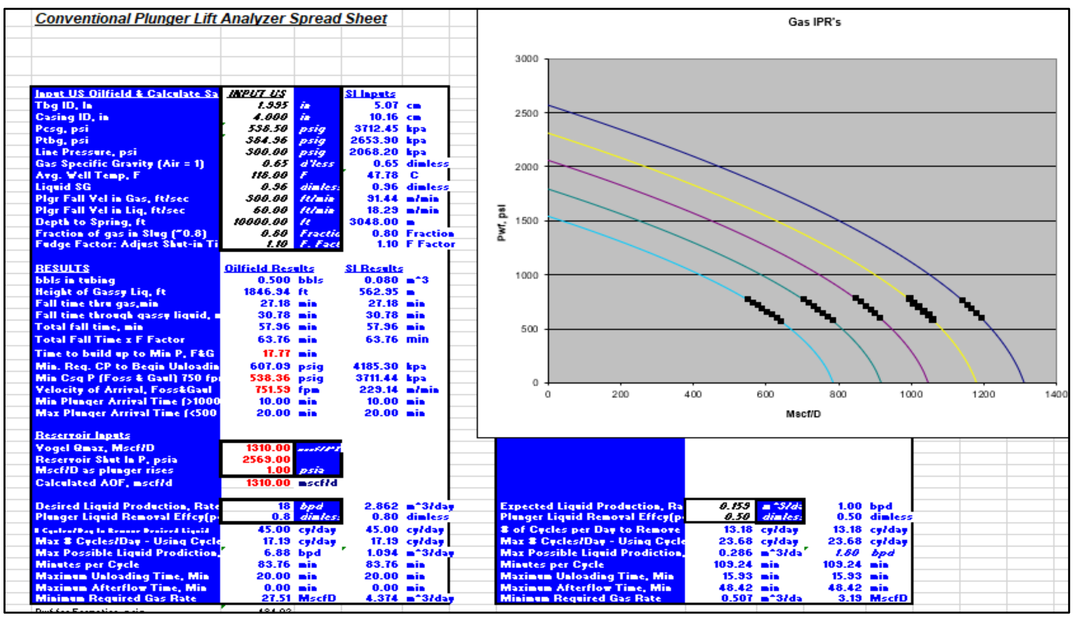
Output Figure for Routine 5: Gas Assisted Plunger Lift



White background calculated, red input	
INPUT AND CALCULATED RESULTS	
1-2 3/8", 2-2.7/8", 3-3" Tubing	1
From above K=	59556
From above , Pc=	117
Depth to bumper spring, ft	9500
Pressure to Support Plunger Wt, psi	6
Tubing Line Pressure, psi	111
Slug Height,ft =	129.40
Slug Size, bbls	0.5
Pcsg, min when slug hits surface=	220.7
Casing ID, in	4.778
Tubing OD	2.375
Tubing ID	1.995
Annulus Area, sq in=	13.49
Atubing , sq,in =	3.12
CPR =	1.23
Pcsg,max (SI) req'd to lift slug , psig	257.1
Input actual well bbl/mmscf	888
Rise Velocity fpm	750
Fall Velocity through gas, fpm	300
Fall Velocity through liquid, fpm	41
Length of 1 bbl of gas liq=	259
Length of gassy 1 bbl of liq=	1294
Tavg of well , F	150
API of condensate	55
SpGr of Water	1.03
WOR	2
SpGr of liquid=	0.94

	Pcmax	Xtra Gas needed, 400	Xtra Gas to operate	Cy/day	CF/Cycle available from Well
0.25	232.0	17.9	70.6	26.7311	282
0.375	244.6	25.8	64.2	25.7541	422
0.5	257.1	33.2	58.2	24.846	563
0.625	269.7	40.1	52.6	23.9998	704
0.75	282.3	46.5	47.4	23.2093	845

Output Figure for Routine 6: Plunger Performance with Time



Conventional Plunger Lift Analyzer Spread Sheet

Input US Oilfield & Calculate Sa	INPUT US		SI Inputs	
Tbg ID, In	1.995	in	5.07	cm
Casing ID, in	4.000	in	10.16	cm
Pcsg, psi	538.50	psig	3712.45	kpa
Ptbg, psi	384.96	psig	2653.90	kpa
Line Pressure, psi	300.00	psig	2068.20	kpa
Gas Specific Gravity (Air = 1)	0.65	d'less	0.65	dimless
Avg. Well Temp, F	118.00	F	47.78	C
Liquid SG	0.96	dimless	0.96	dimless
Plgr Fall Vel in Gas, ft/sec	300.00	ft/min	91.44	m/min
Plgr Fall Vel in Liq, ft/sec	60.00	ft/min	18.29	m/min
Depth to Spring, ft	10000.00	ft	3048.00	m
Fraction of gas in Slug (~0.8)	0.80	Fractio	0.80	Fraction
Fudge Factor: Adjust Shut-in Ti	1.10	F. Fact	1.10	F Factor

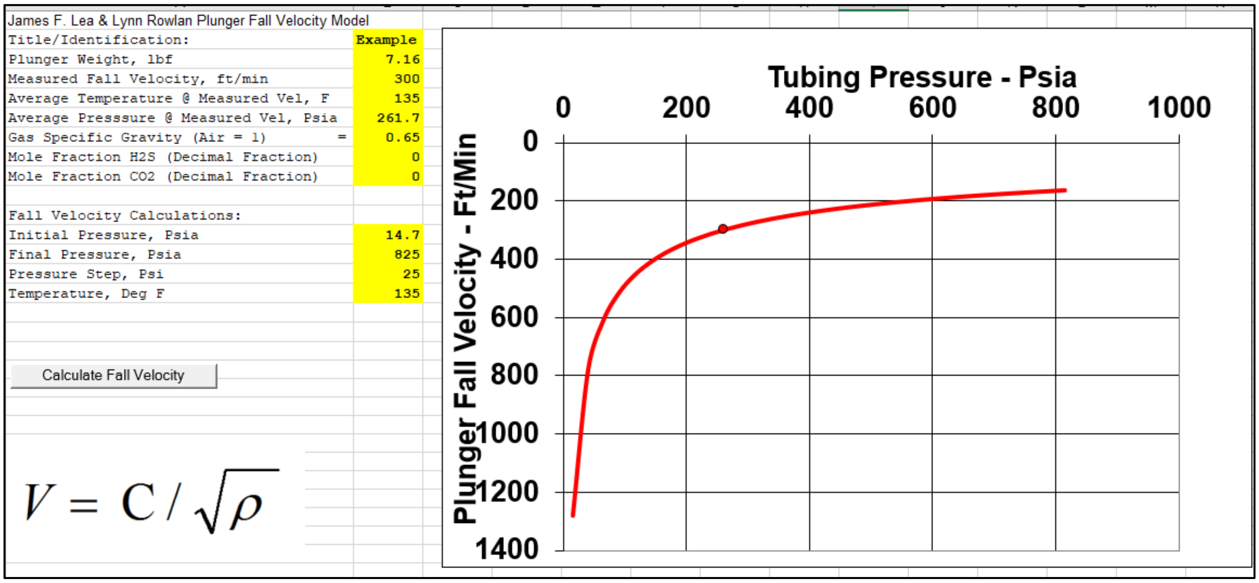
RESULTS	Oilfield Results		SI Results	
bbls in tubing	0.500	bbls	0.080	m^3
Height of Gassy Liq, ft	1846.94	ft	562.95	m
Fall time thru gas,min	27.18	min	27.18	min
Fall time through gassy liquid, m	30.78	min	30.78	min
Total fall time, min	57.96	min	57.96	min
Total Fall Time x F Factor	63.76	min	63.76	min
Time to build up to Min P, F&G	17.77	min		
Min. Req. CP to Begin Unloadin	607.09	psig	4185.30	kpa
Min Csg P (Foss & Gaul) 750 fp	538.36	psig	3711.44	kpa
Velocity of Arrival, Foss&Gaul	751.59	fpm	229.14	m/min
Min Plunger Arrival Time (>1000	10.00	min	10.00	min
Max Plunger Arrival Time (<500	20.00	min	20.00	min

Reservoir Inputs		
Vogel Qmax, Mscf/D	1310.00	mscf/PD
Reservoir Shut In P, psia	2569.00	
Mscf/D as plunger rises	1.00	psia
Calculated AOF, mscf/d	1310.00	mscf/d

Desired Liquid Production, Rate	18	bpd	2.862	m^3/day
Plunger Liquid Removal Effcy(p	0.8	dimless	0.80	dimless
# Cycles/Day to Remove Desired Liquid	45.00	cy/day	45.00	cy/day
Max # Cycles/Day - Using Cycle	17.19	cy/day	17.19	cy/day
Max Possible Liquid Prodiction,	6.88	bpd	1.094	m^3/day
Minutes per Cycle	83.76	min	83.76	min
Maximum Unloading Time, Min	20.00	min	20.00	min
Maximum Afterflow Time, Min	0.00	min	0.00	min
Minimum Required Gas Rate	27.51	MscfD	4.374	m^3/day

Expected Liquid Production, Ra	0.159	m^3/da	1.00	bpd
Plunger Liquid Removal Effcy(p	0.50	dimless	0.50	dimless
# of Cycles per Day to Remove	13.18	cy/day	13.18	cy/day
Max # Cycles/Day - Using Cycle	23.68	cy/day	23.68	cy/day
Max Possible Liquid Prodiction,	0.286	m^3/da	1.60	bpd
Minutes per Cycle	109.24	min	109.24	min
Maximum Unloading Time, Min	15.93	min	15.93	min
Maximum Afterflow Time, Min	48.42	min	48.42	min
Minimum Required Gas Rate	0.507	m^3/da	3.19	MscfD

Input and Output Figure for Routine 7: Plunger Fall Velocity



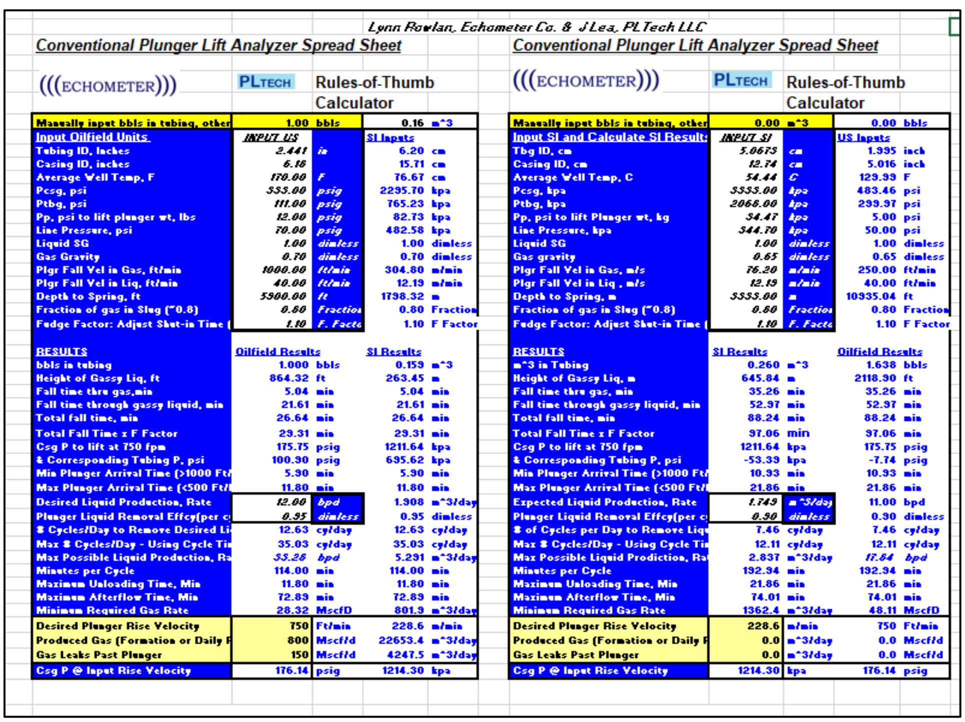
James F. Lea & Lynn Rowlan Plunger Fall Velocity Model

Title/Identification:	Example
Plunger Weight, lbf	7.16
Measured Fall Velocity, ft/min	300
Average Temperature @ Measured Vel, F	135
Average Pressure @ Measured Vel, Psia	261.7
Gas Specific Gravity (Air = 1) =	0.65
Mole Fraction H2S (Decimal Fraction)	0
Mole Fraction CO2 (Decimal Fraction)	0
Fall Velocity Calculations:	
Initial Pressure, Psia	14.7
Final Pressure, Psia	825
Pressure Step, Psi	25
Temperature, Deg F	135

Calculate Fall Velocity

$$V = C / \sqrt{\rho}$$

Output Figure for Routine 8: Plunger Rule of Thumb Program



Lynn Rowlan, Echometer Co. & J Lea, PL Tech LLC

Conventional Plunger Lift Analyzer Spread Sheet

(((ECHOMETER))) PLTECH Rules-of-Thumb Calculator

Manually input bbls in tubing, other	1.00	bbls	0.16	m^3
Input Oilfield Units	INPUT US		SI Inputs	
Tubing ID, Inches	2.441	in	6.20	cm
Casing ID, inches	6.16		15.71	cm
Average Well Temp, F	170.00	F	76.67	cm
Pcsg, psi	333.00	psig	2295.70	kpa
Ptbg, psi	111.00	psig	765.23	kpa
Pp, psi to lift plunger wt, lbs	12.00	psig	82.73	kpa
Line Pressure, psi	70.00	psig	482.58	kpa
Liquid SG	1.00	dimless	1.00	dimless
Gas Gravity	0.70	dimless	0.70	dimless
Plgr Fall Vel in Gas, ft/min	1000.00	ft/min	304.80	m/min
Plgr Fall Vel in Liq, ft/min	40.00	ft/min	12.19	m/min
Depth to Spring, ft	5900.00	ft	1798.32	m
Fraction of gas in Slug (~0.8)	0.80	Fraction	0.80	Fraction
Fudge Factor: Adjust Shut-in Time (	1.10	F. Facto	1.10	F Factor
RESULTS	Oilfield Results		SI Results	
bbls in tubing	1.000	bbls	0.159	m^3
Height of Gassy Liq, ft	864.32	ft	263.45	m
Fall time thru gas,min	5.04	min	5.04	min
Fall time through gassy liquid, min	21.61	min	21.61	min
Total fall time, min	26.64	min	26.64	min
Total Fall Time x F Factor	29.31	min	29.31	min
Csg P to lift at 750 fpm	175.75	psig	1211.64	kpa
& Corresponding Tubing P, psi	100.90	psig	695.62	kpa
Min Plunger Arrival Time (>1000 Ft/	5.90	min	5.90	min
Max Plunger Arrival Time (<500 Ft/	11.80	min	11.80	min
Desired Liquid Production, Rate	12.00	bpd	1.908	m^3/day
Plunger Liquid Removal Effcy(per c	0.95	dimless	0.95	dimless
# Cycles/Day to Remove Desired Li	12.63	cy/day	12.63	cy/day
Max # Cycles/Day - Using Cycle Ti	35.03	cy/day	35.03	cy/day
Max Possible Liquid Production, Ra	33.28	bpd	5.291	m^3/day
Minutes per Cycle	114.00	min	114.00	min
Maximum Unloading Time, Min	11.80	min	11.80	min
Maximum Afterflow Time, Min	72.89	min	72.89	min
Minimum Required Gas Rate	28.32	MscfD	801.9	m^3/day
Desired Plunger Rise Velocity	750	Ft/min	228.6	m/min
Produced Gas (Formation or Daily F	800	Mscf/d	22653.4	m^3/day
Gas Leaks Past Plunger	150	Mscf/d	4247.5	m^3/day
Csg P @ Input Rise Velocity	176.14	psig	1214.30	kpa

Conventional Plunger Lift Analyzer Spread Sheet

(((ECHOMETER))) PLTECH Rules-of-Thumb Calculator

Manually input bbls in tubing, other	0.00	m^3	0.00	bbls
Input SI and Calculate SI Results	INPUT SI		US Inputs	
Tbg ID, cm	5.0673	cm	1.995	inch
Casing ID, cm	12.74	cm	5.016	inch
Average Well Temp, C	54.44	C	129.99	F
Pcsg, kpa	3333.00	kpa	483.46	psi
Ptbg, kpa	2068.00	kpa	299.97	psi
Pp, psi to lift Plunger wt, kg	34.47	kpa	5.00	psi
Line Pressure, kpa	344.70	kpa	50.00	psi
Liquid SG	1.00	dimless	1.00	dimless
Gas gravity	0.65	dimless	0.65	dimless
Plgr Fall Vel in Gas, m/s	76.20	m/min	250.00	ft/min
Plgr Fall Vel in Liq , m/s	12.19	m/min	40.00	ft/min
Depth to Spring, m	3333.00	m	10935.04	ft
Fraction of gas in Slug (~0.8)	0.80	Fraction	0.80	Fraction
Fudge Factor: Adjust Shut-in Time (	1.10	F. Facto	1.10	F Factor
RESULTS	SI Results		Oilfield Results	
m^3 in Tubing	0.260	m^3	1.638	bbls
Height of Gassy Liq, m	645.84	m	2118.90	ft
Fall time thru gas, min	35.26	min	35.26	min
Fall time through gassy liquid, min	52.97	min	52.97	min
Total fall time, min	88.24	min	88.24	min
Total Fall Time x F Factor	97.06	min	97.06	min
Csg P to lift at 750 fpm	1211.64	kpa	175.75	psig
& Corresponding Tubing P, psi	-53.39	kpa	-7.74	psig
Min Plunger Arrival Time (>1000 Ft/	10.93	min	10.93	min
Max Plunger Arrival Time (<500 Ft/	21.86	min	21.86	min
Expected Liquid Production, Rate	1.749	m^3/day	11.00	bpd
Plunger Liquid Removal Effcy(per c	0.90	dimless	0.90	dimless
# of Cycles per Day to Remove Liqu	7.46	cy/day	7.46	cy/day
Max # Cycles/Day - Using Cycle Ti	12.11	cy/day	12.11	cy/day
Max Possible Liquid Prodiction, Ra	2.837	m^3/day	17.64	bpd
Minutes per Cycle	192.94	min	192.94	min
Maximum Unloading Time, Min	21.86	min	21.86	min
Maximum Afterflow Time, Min	74.01	min	74.01	min
Minimum Required Gas Rate	1362.4	m^3/day	48.11	MscfD
Desired Plunger Rise Velocity	228.6	m/min	750	Ft/min
Produced Gas (Formation or Daily F	0.0	m^3/day	0.0	Mscf/d
Gas Leaks Past Plunger	0.0	m^3/day	0.0	Mscf/d
Csg P @ Input Rise Velocity	1214.30	kpa	176.14	psig

Output Figure for Routine 9: Calculate Downhole SRP Pump Clearance vs P and T

CALCULATE CHANGE IN PUMP CLEARANCE AT BOTTOM HOLE CONDITION: THD AND BHD

Inputs in yellow				
INPUT TEMP'S AND THERMAL C				
Input Ttop	70			
Input Tbot	100			
Input C	0.0000094			
(Dt*C+1)	1.000282			
INPUT PRESSURES , MODULUS				
Input Pd	1200			
Input Pip	200			
Input E	30000000			
Input Poissons	0.27			
		THD BBL		
Poissons Ratio	0.27	Poissons=	0.27	
Input Do	1.76	Ro=	0.88	
Input Di	1.503	Ri=	0.7515	
Pd	1200	Po=	200	
Pip	200	Pi=	1200	
E	30000000	E=	30000000	With Temp
		Radius Char	0.0001631	0.0001632
		Bot Dia	1.5033262	1.5037502
		THD PLGR		
Poissons Ratio	0.27	Poissons=	0.27	
Input Do	1.5	Ro=	0.75	
Input Di	0.875	Ri=	0.4375	
Pd	1200	Po=	700	
Pip	200	Pi=	1200	
E	30000000	E=	30000000	With temp effects below
		Radius Char	1.197E-07	1.198E-07
		Bot Dia	1.5000002	1.5004232

$$\delta r=\left(\frac{1-\nu}{E}\right)\left(\frac{a^2p_i-b^2p_o}{b^2-a^2}\right)r+\left(\frac{1+\nu}{E}\right)\left(\frac{a^2b^2\left(p_i-p_o\right)}{b^2-a^2}\right)\frac{1}{r}$$

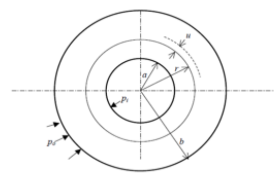
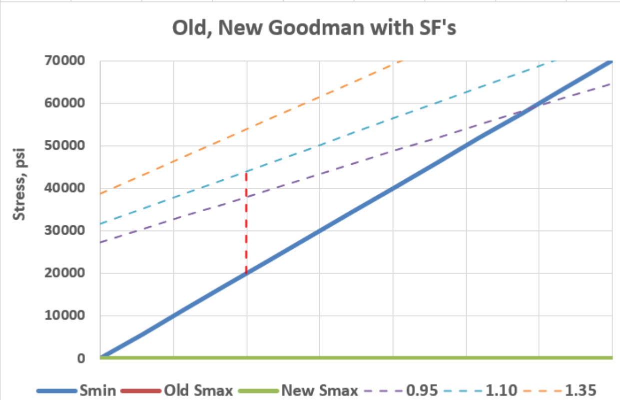


Figure 2. Deformation of the cylindrical pressure vessel.
At radius, *r* the vessel has a displacement, *u* (in the radial direction) when loaded.

TOP HOLD DOWN RESULTS		
Ainitial=	0.00707206	% Change
Afinal=	0.00784582	10.94
Initial Clearan	0.003	
Bottom Cleara	0.00332599	

Output Figure for Routine 10: Current and Proposed Fatigue SR Analysis

INPUTS IN YELLOW		
INPUT CASE TO ANAYLZE		
Input Rod diameter, in	**0.875**	**Inch**
Input Max Load, lbs	**27000**	**lbs**
Input Min Load, lbs	**12000**	**lbs**
input Tensile,T	**115000**	**psi**
Input SF	**;kj,mb,**	**dim'less**
• Smin actual =	**19966**	**psi**
• Smax actual=	**44924**	**psi**
% allowable stress range, old	**125**	**dim'less**
% allowable stress range, new	**87**	**dim'less**
•Smax allowable, old = (T/4 +.5625 Smin)SF		**psi**
•Smax, allowable, new= (T/2.8 +.375 Smin)SF		**psi**
Smax, allowable, old	**39980.99**	**psi**
Smax, allowable, old	**48568.74**	**psi**
Input SF one WRT to old Goodman		**0.95**
Input SF two WRT to old Goodman		**1.10**
Input SF three WRT to old Goodman		**1.35**



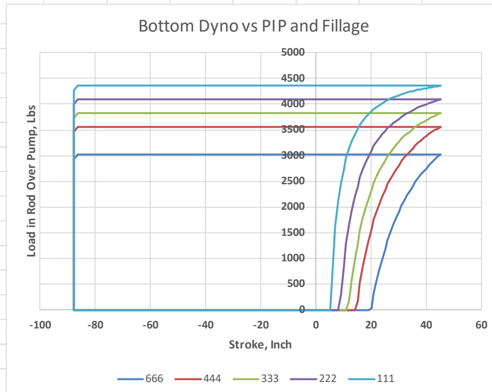
Output Figure for Routine 11: Dev Visualize Bottom Dyno Card Load Release P

PLTech LLC

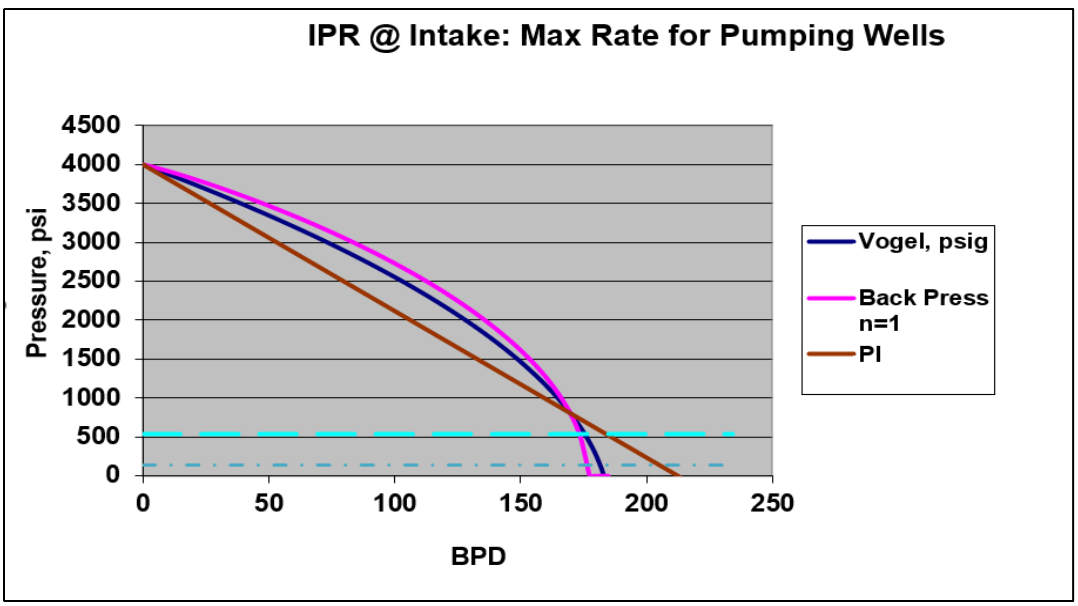
Note: Gas starts at zero (X) for all intake pressures

INPUT

Gross Stroke	133
Net Stroke (>17% of Gross)	88
Gross minus Net Stroke	45
k, ratio sp ht	1.3
Pump Discharge P	1923.3
Pump Dia	1.75
Area Pmp	2.40
Input PIP One	666
Input PIP two	444
Input PIP three	333
Input PIP four	222
Input PIP five	111
Input Depth	4675
Input Tubing Gradient, psi/ft	0.39
Input WHP	100
Bottom rod diameter	0.75
Correction if below 1 or 2	0
Input 1 for Effective Force, 2 for Tru	1
Pd=	1923.25



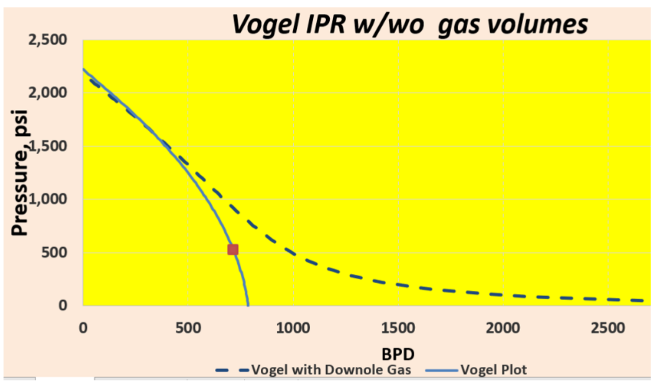
Output Figure for Routine 12: Max Rate from Pumping using IPRs



Output Figure for Routine 13: SRP Pump Spacing

		INPUT			Spacing	Load Change, lbs
Rod Size D, in	Arod sq in	L of each size	Pump D	Fld Ht Change	Stretch, in	5472
0.625	0.307	0	1.75	Iinitial to Pumping	0.00	OT,in
0.750	0.442	2000	API	6000	9.91	13.79
0.875	0.601	2000	30	(Estimate)	7.28	Thermal Effects,in
1.000	0.785	2000	SL, surface	Initial avg rod	5.58	2.06
1.125	0.994	0	144	temp in Well, F	0.00	Pmp'd off
1.250	1.227	0	SPM	120	0.00	F
1.375	1.484	0	11	Avg Well Temp, F	0.00	1.25
1.500	1.766	0		169.1	0.00	Spacing Min, in
					22.78	15.85

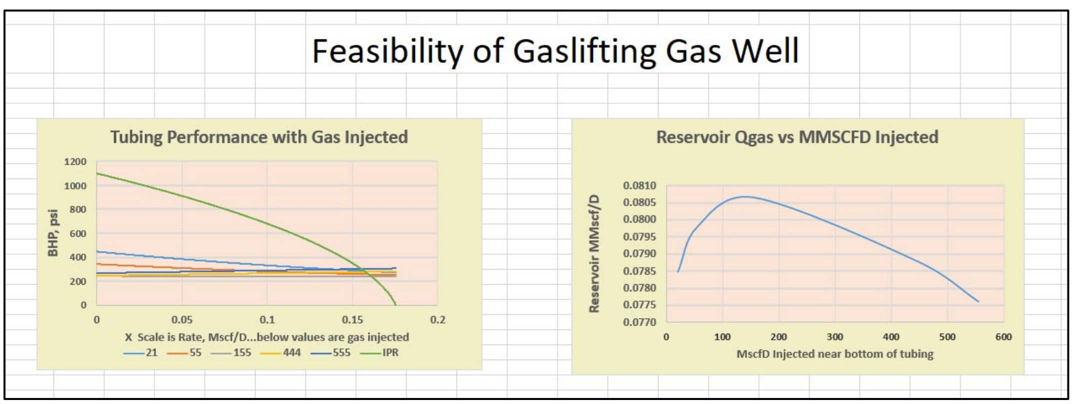
Output Figure for Routine 14. ESPs Performance with IPR and Gas



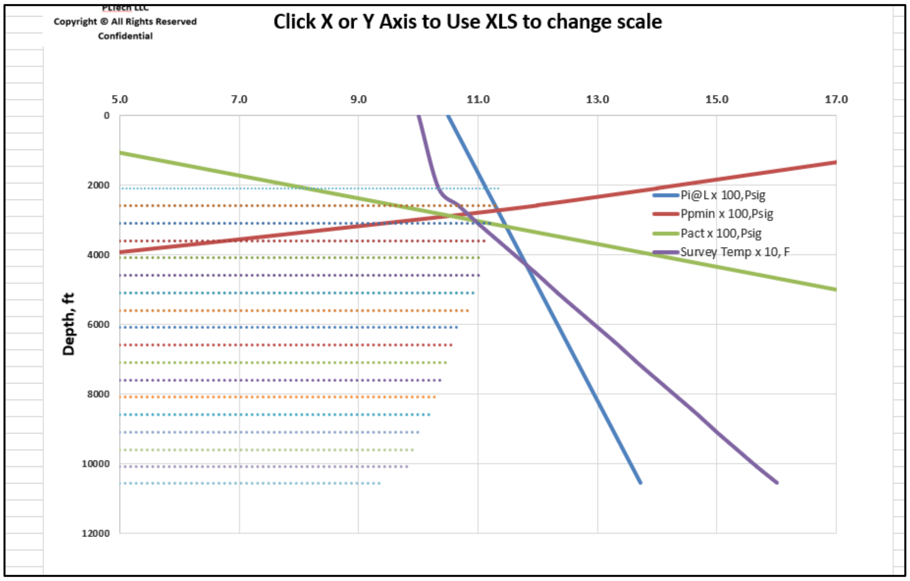
Vogel Number:
.2= Vogel , 1=PI , < than .2, < Q than Vogel , >.2 better than Vogel
Flow efficiency is assumed to be 1.

Test BOPD	300	Input
Test BWPD	400	Input
Vogel Number	0.2	Input
Ptest, psig	600	Input
SIBHP, psi	2222	Input
Gas Gravity	0.65	Input
BHT, F	160	Input
API	33	Input
GOR, scf/bopd	400	Input
Separation %	50	Input
% Oil	42.9	Calculated
Water Fraction	0.57	Calculated
Qtest,BFPD	700	Calculated
Qmax ,BFPD	787	Calculated
Pb, psi	2011	Calculated
PI, bpd/psi	0.592	Calculated
SpGr Oil	0.86	Calculated

Output Figure for Routine 15. Gas Well Gas lift



Output Figure for Routine 16: Gas lift Pressure Traverse Analyzer



Output Figure for Routine 17: Gas lift Pressure Traverse Analyzer