UNLOADING LIQUID LOGGED GAS WELLS WITH LOW PRESSURE COMPRESSION

Harry D. Frasher
Compressco Field Services, Inc.

As a well declines as shown in Figure 1 the velocity through the production string continues to decrease. Liquid fall-back begins to occur when velocity gets below a point known as critical velocity. This liquid fall-back causes the well flow decline to further accelerate. Liquid fall-back is illustrated in Figure 2.

Charts can be derived for various tubing sizes similar to that shown in Figure 3. The tubing size we are using in our illustration is for 2-3/8".

From our decline curve in Figure 1 and the minimum volume required in Figure 3 for tubing pressure equal to 200 psig you can see that between Year 2 and Year 3 is when liquid fall-back will start to occur in our case. (i.e., once the volume goes below 498 mscfd from Figure 3 liquid fall-back will start to occur.)

The fall-back will occur until it reaches perhaps a level like that shown in Figure 4. If this well had the potential of producing 500 mscfd at 250 psig flowing bottom hole pressure it would now only be producing 200 mscfd because of the 300 foot of fluid exerting 150 psig of pressure on the formation that wasn't there before liquid loading started to occur.

At this point the operator must decide if he wants to live with the accelerated decline in flow or perhaps wants to reduce the flowing tubing pressure so that the velocity is once again above that required to carry the fluid to the surface.

If the operator elects to reduce the flowing tubing pressure by installing a compressor, we can see from the decline curve that he is going to need to move as much as 400 mscfd in the near future plus a little more by the additional draw-down effect that he would gain if he pulled the well down as explained in Figure 4. If we extrapolate the production on down to Year 4 and Year 5 on the decline curve we see production close to 320 mscfd at the beginning of Year 4 and 250 mscfd at the beginning of Year 5, if we could keep the well unloaded.

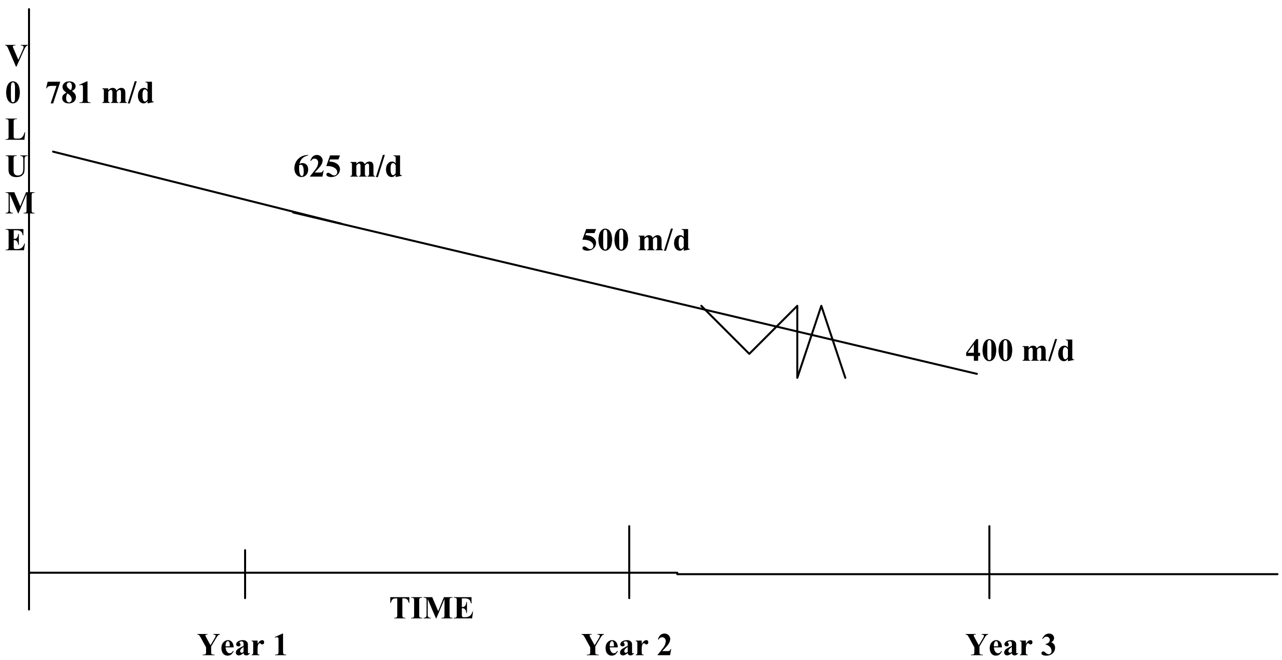
The operator can compare his 'Decline Curves' and 'The Minimum Volume Required Sheets to Prevent Loading' to 'Compressor Performance Curves' like those shown in Figure 5 and Figure 6. For a long term effect he may want to plot the amount of volume required to have sufficient velocity against the performance of the compressor such as that shown in Figure 7 in order to determine that the compressor capacity is moving enough gas to be above the critical velocity.

It should be pointed out that the Performance Curves are derived from compressor calculations that take into consideration the capabilities and limitations of the compressor. Those capabilities and limitations being: horsepower, displacement (cfm), maximum compressor ratios, maximum rod load, maximum discharge temperature, minimum volumetric efficiency, and maximum working pressure of vessels.

Figure 8 is a Case History of a well that is past the slug stage but before the gas bubbling through the liquid stage in Figure 2. After the well was unloaded, charts such as those found in Figure 10 & 11 can be used to examine the casing pressure to determine if a well is continuing to stay unloaded. An explanation to using these charts is found in Figure 9. An Illustration of this well is shown in Figure 12. Since the tubing string could not possibly hold the 50 Bbls that was produced over night, most of it had to be lying out in the formation as illustrated.

In concluding, balance between the potential flow of the well and set-up of the compressor to achieve the optimum flow of the well so that liquid loading does not become a factor is the key point of this paper. By the compressor representative identifying with factors of the well such as: draw-down pressure analysis, casing pressures that indicate liquid loading, volumes required to be above critical velocity, he can better assist the well operator in maximizing his production. By the well operator having a grasp of the limitations of the compressor such as: maximum horsepower, maximum rod load, minimum volumetric efficiency, maximum discharge temperature, maximum working pressure of the vessels, maximum compressor ratios, contaminations in the process gas, he can help prevent failures, pre-mature wear, and excessive down-time. Hence, by each being aware of the other's factors balance between the well performance and compressor performance is achieved for maximum economical recovery when compression is employed.

Well Decline



1. **Well decline could be in the 5% to 20% per year range. We are using 20% in our case above.**

2. **The well we will be discussing is at the beginning of Year 2.**

3. **We know that the decline is not really a straight line but more jac'd because of fluctuating line pressures and possible liquid loading effects.**

Figure 1

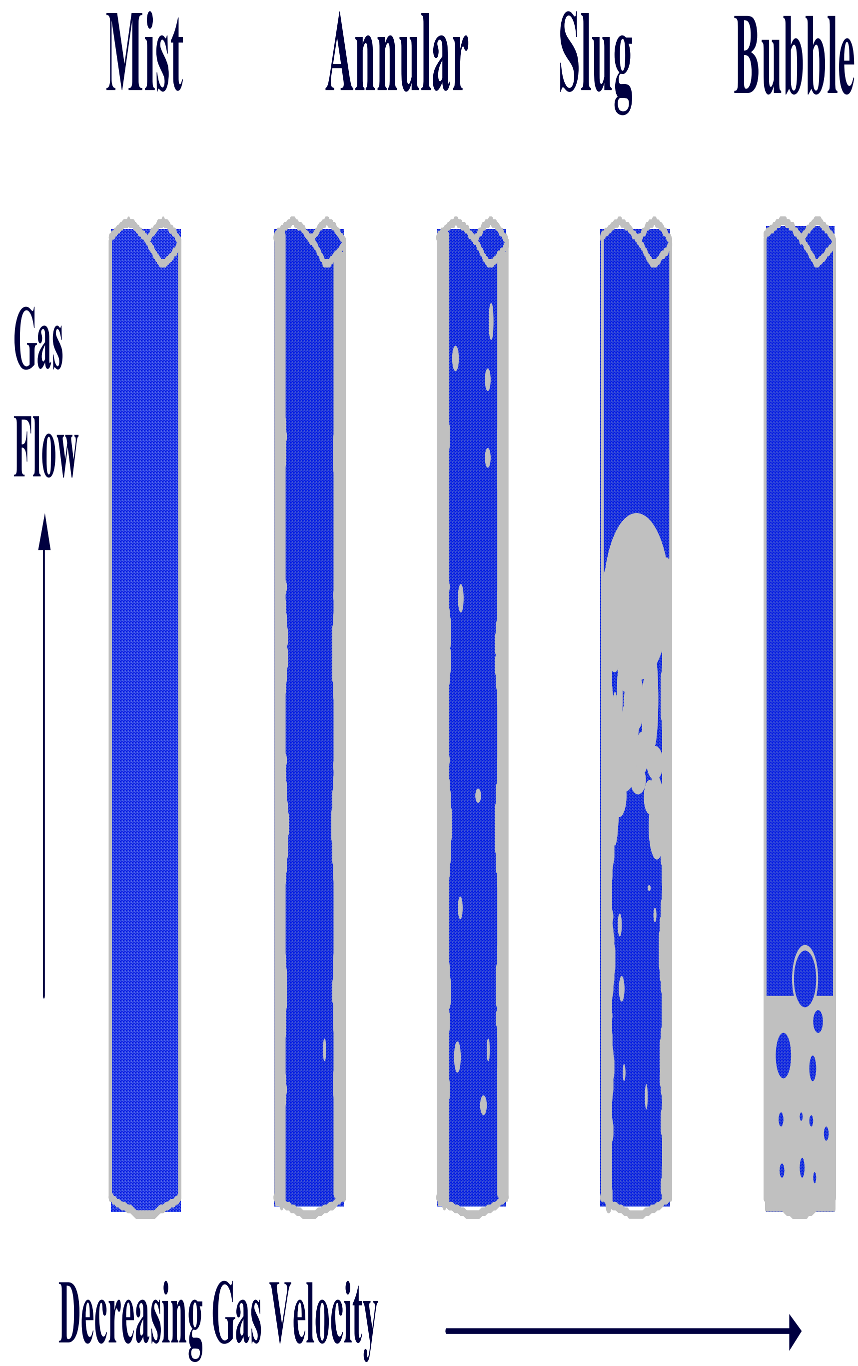


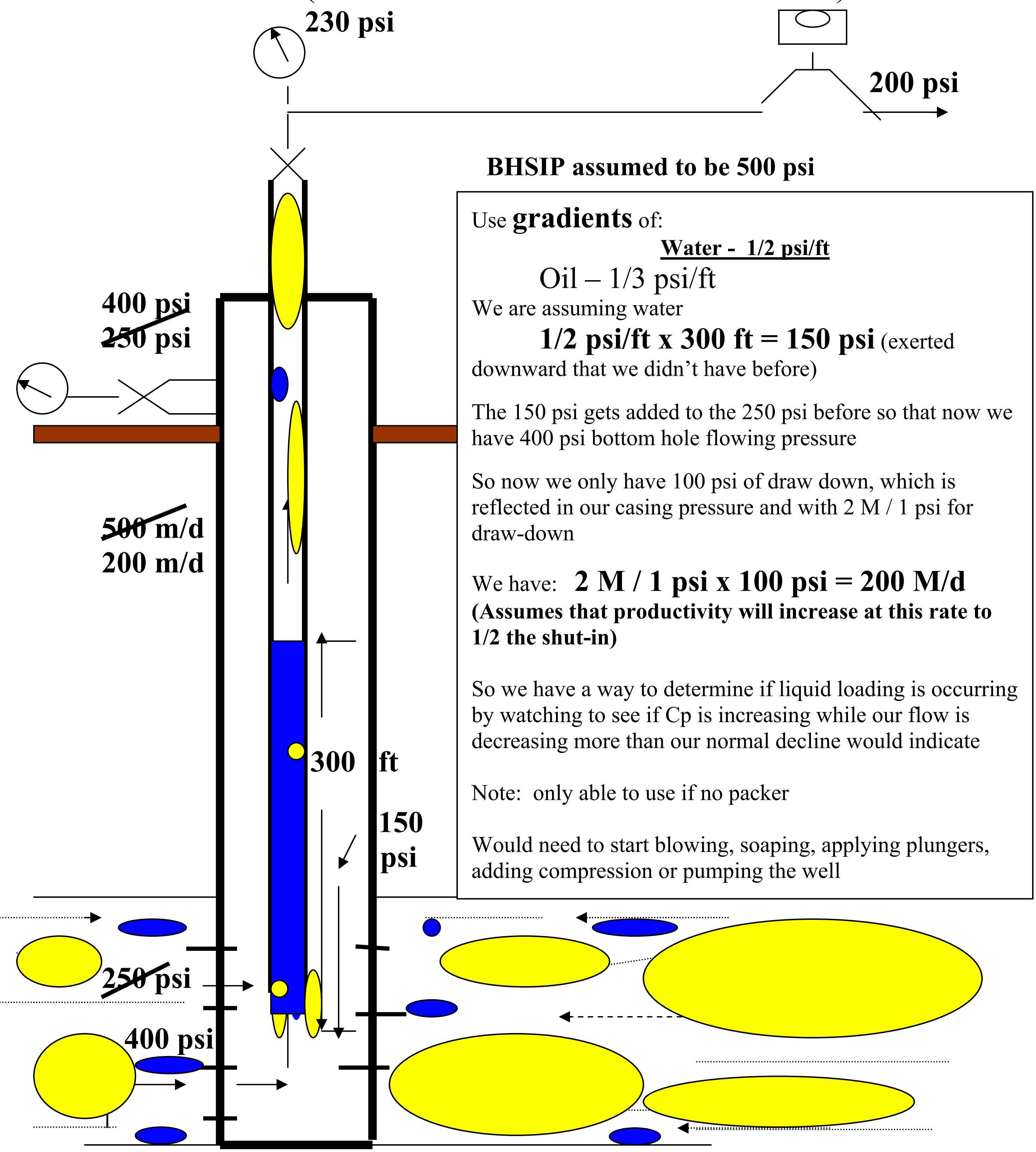
Figure 2

Estimated Minimum Volumes Required to Prevent Liquid Loading

Tubing Pressure (Psig)		Flow Area - Ft^2	Temp ^{o} F	Mscfd (Water) *	Mscfd (Condensate)*
0		0.022	60	86	55
5		0.022	60	115.9	75
10		0.022	60	139.9	91
15		0.022	60	157.9	102.2
20		0.022	60	169.9	110
25		0.022	60	176	113.9
50		0.022	60	249.1	161.5
75	2-3/8	0.022	60	305.2	197.2
100		0.022	60	351.9	227.8
150		0.022	60	431	278.8
200		0.022	60	498.1	322.2
250		0.022	60	555.9	359.6
300		0.022	60	608.6	393.6
350		0.022	60	657.1	425

* Use for maximum liquid-gas ratios up to 100-130 Bbls/MMscf
If as much as 10% water use the water column

<u>BASIC WELL</u> – Fall Back Occurring
(New Flow with – 300 ft of Fluid Head)



BHSIP assumed to be 500 psi

Use **gradients** of:

<u>Water - 1/2 psi/ft</u>

Oil – 1/3 psi/ft

We are assuming water

1/2 psi/ft x 300 ft = 150 psi (exerted downward that we didn't have before)

The 150 psi gets added to the 250 psi before so that now we have 400 psi bottom hole flowing pressure

So now we only have 100 psi of draw down, which is reflected in our casing pressure and with 2 M / 1 psi for draw-down

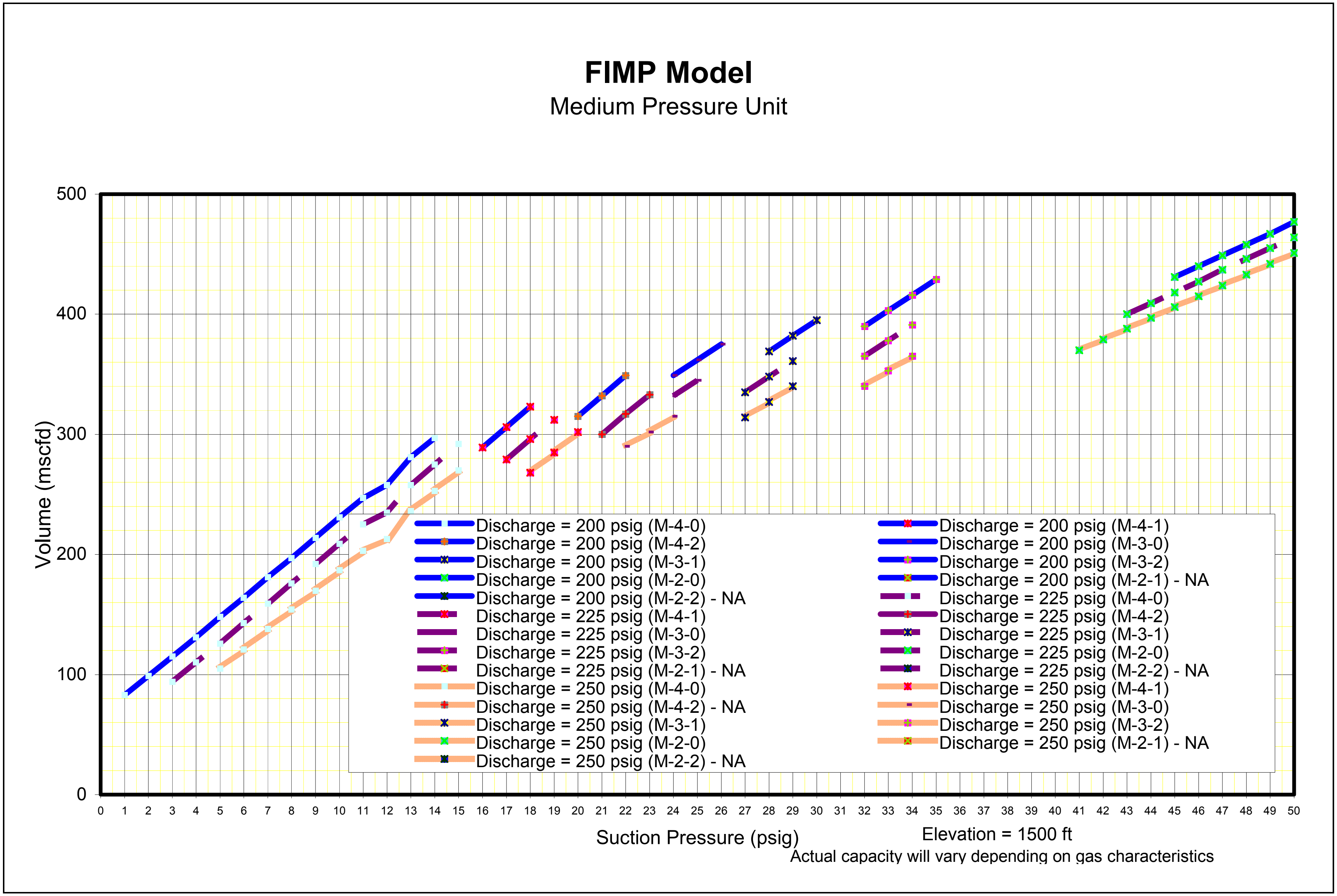
We have: **2 M / 1 psi x 100 psi = 200 M/d**

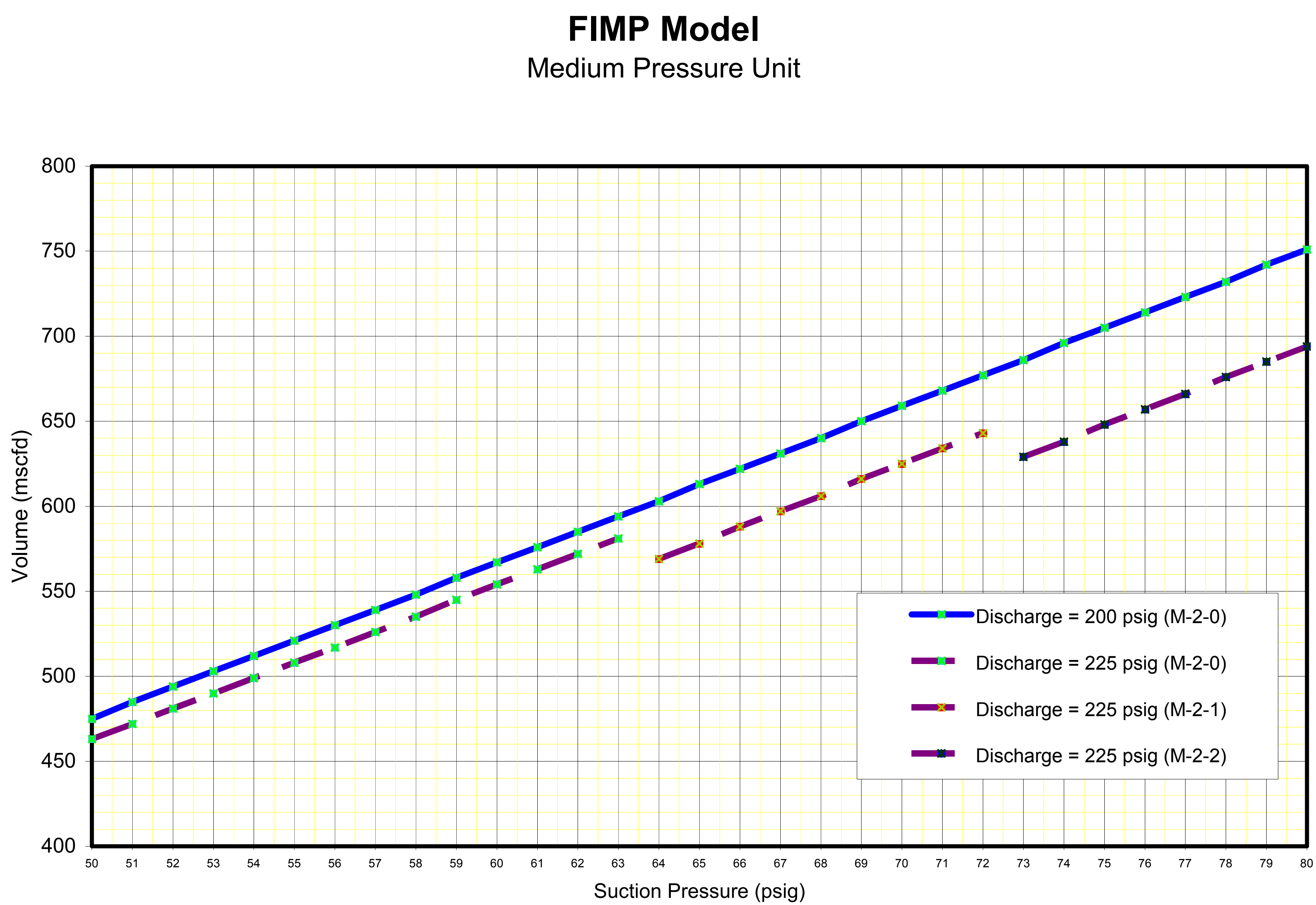
(Assumes that productivity will increase at this rate to 1/2 the shut-in)

So we have a way to determine if liquid loading is occurring by watching to see if Cp is increasing while our flow is decreasing more than our normal decline would indicate

Note: only able to use if no packer

Would need to start blowing, soaping, applying plungers, adding compression or pumping the well


FIMP Model
Medium Pressure Unit
Volume (mscfd)
Suction Pressure (psig)
Elevation = 1500 ft
Actual capacity will vary depending on gas characteristics
Discharge = 200 psig (M-4-0)
Discharge = 200 psig (M-4-1)
Discharge = 200 psig (M-4-2)
Discharge = 200 psig (M-3-0)
Discharge = 200 psig (M-3-1)
Discharge = 200 psig (M-3-2)
Discharge = 200 psig (M-2-0)
Discharge = 200 psig (M-2-1) - NA
Discharge = 200 psig (M-2-2) - NA
Discharge = 225 psig (M-4-0)
Discharge = 225 psig (M-4-1)
Discharge = 225 psig (M-4-2)
Discharge = 225 psig (M-3-0)
Discharge = 225 psig (M-3-1)
Discharge = 225 psig (M-3-2)
Discharge = 225 psig (M-2-0)
Discharge = 225 psig (M-2-1) - NA
Discharge = 225 psig (M-2-2) - NA
Discharge = 250 psig (M-4-0)
Discharge = 250 psig (M-4-1)
Discharge = 250 psig (M-4-2) - NA
Discharge = 250 psig (M-3-0)
Discharge = 250 psig (M-3-1)
Discharge = 250 psig (M-3-2)
Discharge = 250 psig (M-2-0)
Discharge = 250 psig (M-2-1) - NA
Discharge = 250 psig (M-2-2) - NA



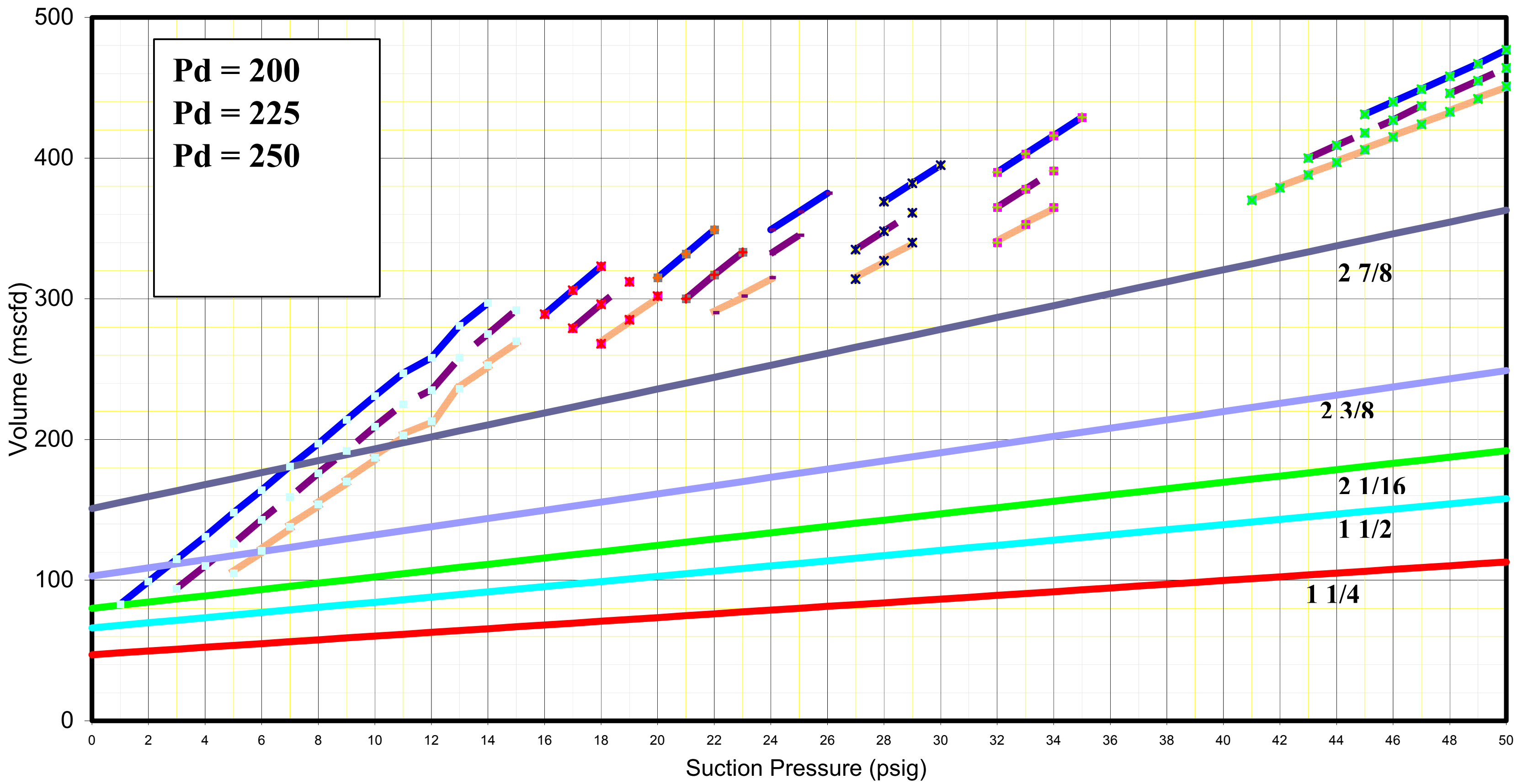
Actual capacity will vary depending on gas characteristics

(Figure 6)

Elevation @ 1500'

FIMP Model

Medium Pressure Unit Performance vs Volume Required in Tubing to be above Critical Velocity



Actual capacity will vary depending on gas characteristics

(Figure 7)

Elevation @ 1500 ft

CASE HISTORY

(Example of Heavy Liquid Loading)

Situation

- **Mesaverde well at ~ 5280' w/ 2-3/8" tubing**
- **Well had been making 500 m/d on a fairly low sales line pressure of 50 psi, but the line pressure fluctuated to 200 psi at times**
- **Well had dropped to a flowing volume of 130 m/d in a short period of time (i.e., not fitting the normal decline)**

What was done

- **Customer put a Gas Jack Compressor on and pulled the tubing pressure down to 5 psi --- Well made 130 m/d**
- **Customer even tried to flow up the casing (which would just cause the well to load up more because of larger flowing area**
- **Customer swabbed the well and the swabbing unit reported 10' of fluid – information was not accurate**
- **Customer had a well close by with 500 psi on it and decided to bring a line over and tie into the casing**
- **Overnight the well unloaded about 50 Bbls of fluid to the pit**

End results

He then put the Gas Jack Compressor back on and the well made 500 m/d with 7 BFD with Tp = 23 and Cp = 80

(See Figure 12 for this illustration. Illustration is to be exaggerated, because at 50 Bbls, the fluid had to be not only standing in the tubing but had to be strung out into the formation.)

After six (6) months of production well was still flowing ~ 400 m/d with the compressor and showing no signs of liquid loading.

Figure 8

Explanation of Charts

(Complete charts available at presentation/booth)

Estimate Casing Pressure (Cp) for Various Flows (Mscfd) and Tubing Pressure (Tp) if Liquid Loading is not occurring (Figure 10)

- **Find 500 m/d and 5000' well with 2-3/8" tubing**
- **Look down the column and find Tp = 51 (This is hi-lited in blue) and then read across to the Cp column to find our estimated Cp, which is 100 psi in this case**
- **Actual conditions for this case were Tp = 23 and Cp = 80 --- so the chart was able to make a reasonable estimate**

(But this is only a single phase flow chart and we might want to add additional amounts for the liquid in the tubing string at any one time --- We get that number from the "Estimate Equivalent Head of Fluid")

Estimate Equivalent Head of Fluid Based on Liquid and Gas Production (Figure 11)

- Find 500 m/d at the top with Tp = 25 and Well Depth = 5000 and 7 Bbls/Day of fluid. Where this row and column intersect is 1.06 equivalent head of fluid at any one time
- **Implies, 1.06' x 1/2 psi/ft = 1/2 psi**
- Which implies, the liquid production effect added for this example is fairly negligible for adding to our already estimated casing pressure for Figure 10.

Figure 9

Estimated Casing Pressure (Cp) for Various Flows (Mscfd) and Tubing Pressures (Tp) If Liquid Loading is not Occurring

Use to help determine if liquid loading is likely occurring - Use with discretion

(Actual conditions will vary depending on specific gas characteristics, pipe characteristics, and liquid production)

	Tubing Size		Volume, Mscfd			
			250	350	450	500
Tubing Depth, ft.	Nominal	Cp, psig	Tp, psig	Tp, psig	Tp, psig	Tp, psig
5000	**2-3/8"**	350	**347**	**344**	**340**	**338**
		300	**296**	**293**	**288**	**286**
		250	**246**	**242**	**236**	**233**
		200	**195**	**190**	**183**	**178**
		150	**143**	**136**	**127**	**121**
		125	**117**	**109**	**97**	**89**
		100	**90**	**79**	**63**	**51**
		75	**62**	**46**	**15**	**#NUM!**
		50	**30**	**#NUM!**	**#NUM!**	**#NUM!**
		25	**#NUM!**	**#NUM!**	**#NUM!**	**#NUM!**
5500	**2-3/8"**	350	**347**	**343**	**339**	**336**
		300	**296**	**292**	**287**	**284**
		250	**245**	**241**	**235**	**231**
		200	**194**	**189**	**181**	**176**
		150	**142**	**135**	**124**	**117**
		125	**116**	**107**	**93**	**84**
		100	**89**	**77**	**58**	**44**
		75	**60**	**43**	**-1**	**#NUM!**
(Add equivalent head of liquid from Figure 11)		50	**27**	**#NUM!**	**#NUM!**	**#NUM!**
		25	**#NUM!**	**#NUM!**	**#NUM!**	**#NUM!**

Estimated Equivalent Head of Fluid
Based on Liquid and Gas Production

Bbls./ Day	Tubing Size Nominal	Area, ft.²		Well Depth, ft.	Mscfd 500 / Tubing Pressure, (Tp), psig 0	Mscfd 500 / Tubing Pressure, (Tp), psig 25	Mscfd 500 / Tubing Pressure, (Tp), psig 50
			Act Q, Mcfd		498299	184509	113215
			Velocity, ft/min		15947	5905	3623
1	2-3/8	0.02	Equiv. column of fluid - for	1,000	0.011	0.030	0.050
			Equiv. column of fluid - for	2,500	0.028	0.076	0.124
			Equiv. column of fluid - for	5,000	0.056	0.152	0.248
			Equiv. column of fluid - for	7,500	0.085	0.228	0.372
3	2-3/8	0.02	Equiv. column of fluid - for	1,000	0.034	0.091	0.149
			Equiv. column of fluid - for	2,500	0.085	0.228	0.372
			Equiv. column of fluid - for	5,000	0.169	0.456	0.744
			Equiv. column of fluid - for	7,500	0.254	0.685	1.116
5	2-3/8	0.02	Equiv. column of fluid - for	1,000	0.056	0.152	0.248
			Equiv. column of fluid - for	2,500	0.141	0.380	0.620
			Equiv. column of fluid - for	5,000	0.282	0.761	1.240
			Equiv. column of fluid - for	7,500	0.423	1.141	1.860
7	2-3/8	0.02	Equiv. column of fluid - for	1,000	0.079	0.213	0.347
			Equiv. column of fluid - for	2,500	0.197	0.533	0.868
			Equiv. column of fluid - for	5,000	0.394	1.065	1.736
			Equiv. column of fluid - for	7,500	0.592	1.598	2.604

CASE HISTORY
Liquid Loaded into Formation