MANAGE YOUR LOW PRESSURE GAS WELLS MORE EFFECTIVELY WITH THE "GAS WELL SPREADSHEET"

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Abstract

As our industry places an increasing emphasis on natural gas, it is imperative that it's production be maximized. As reservoir pressures fall, many gas wells experience difficulty producing to their fullest potential. This paper discusses a diagnostic "tool", which was developed to help detect gas wells with the opportunity to increase production.

This paper will familiarize the reader with a Lotus spreadsheet, which was developed to evaluate several gas wells in South East New Mexico. Easy to obtain data from each well is entered into the spreadsheet. The spreadsheet then calculates several parameters that are used to evaluate the performance of each well. Using this spreadsheet "tool", the Engineer as well as the Lease Operator can identify wells that have the potential to increase production.

Low pressure gas well production is often hampered by pressure restrictions and liquid loading problems. As the reservoir pressures continue to decline, eliminating these restrictions are even more critical. The "Gas Well Spreadsheet" is one way to help combat these operational concerns.

Introduction

In the past three years there has been an increased focus on the development of the low pressure Eumont and Jalmat gas pools in Southeast New Mexico. The activity has been centered around the drilling and recompletion work to access these reserves. Operators have focused on the areas where wells have encountered pockets of higher reservoir pressures with typical IP's above 1,000 MCFPD. However, there are also wells that have been producing for several years, and are in their last years of economic production. Reservoir conditions throughout this area, along with the time requirements of the recent development program, have made it difficult to manage these wells effectively to ensure that they were all producing to their fullest potential.

We learned early on that these new and old wells could not be treated the same. Due to the differences in the producing life cycle of these wells, we experienced many different problems that prohibited these gas wells from performing to the best of their ability.

In the newer completions, we found that flow was restricted by not having large enough tubing in the well. These wells were typically completed with 2 3/8" tubing and in most cases would IP over 1,000 MCFPD. In essence we were creating a downhole choke due to friction pressure caused by the high gas velocities. Granted, we did not experience any liquid loading problems in these wells, but the smaller tubing did not allow us to sufficiently lower the flowing bottomhole pressure to increase the pressure drawdown between the reservoir and the wellbore.

It is imperative in a low pressure reservoir that all restrictions be eliminated in order for the well to produce to it's potential. This requires the Operator and Engineer to take a close look at the surface piping and production equipment. Not only did we have problems with restrictive tubing in our newer completions, but we also experienced several problems with restrictive surface equipment. The surface equipment and piping design can and will cause problems with pressure bottlenecks in the system, which create backpressure on the well.

Gas wells with liquid production have loading problems when the velocity of the gas becomes insufficient to lift the associated liquids. This problem is magnified in a low pressure or low perm gas well. The smaller the cross sectional area of the flow path, the smaller the rate needed to lift liquids. We experienced many loading problems with wells that were producing later in the life cycle with the original 2 3/8" tubing. Ideally, we needed tubing that would shrink in diameter as the deliverability of the well decreased over a period of time.

There are many proven ways to combat these problems in gas well operation to increase production and optimize the wells performance capability. An SPE paper entitled "Tubing Flowrate Controller: Maximize Gas Well Production from Start to Finish[4]", written by William G. Elmer, Conoco Inc, addresses the issue of restrictive tubing early in the gas well life cycle. Two papers, "Gas Well Operation with Liquid Production[2]", by J.F. Lea Jr. and R.E. Tighe, and "A Practical Approach to Removing Gas Well Liquids[3]" by Edward J. Hutlas and William R. Granberry discusses the many methods used to solve gas well loading problems.

With the solution to our problems in mind, the question became how can we easily identify, react, and prioritize the work needed to solve our problems and revitalize our gas production in this area. Thus the "Gas Well Spreadsheet" was born. This paper does not attempt to discuss the solutions to these common operation problems, however, it discusses a diagnostic tool, which was developed to help manage these problems and their solutions.

The Spreadsheet

The "Gas Well Spreadsheet" was developed to assist Conoco Personnel in surveillance of the Conoco operated low pressure gas wells in Southeast New Mexico. The spreadsheet serves as a data base that allows the Engineer and Field Supervisor to more effectively manage his or her gas wells. The spreadsheet will calculate different variables that are significant in regards to gas well performance. The combination of these output variables serves as a diagnostic tool to detect the wells with the opportunity for production increases. These different variables, such as loading rates, absolute open flow potential, etc., are calculated from easily obtained welldata. The data required is listed in the first 8 columns of the spreadsheet, and is used as the basis for the calculations in the next several columns. Listed below is the data which is needed for the calculations. This information will enable the user to fully characterize the wells performance in relation to it's flowing potential.

1. Well Name: The gas well name for which the data is being collected.

2. Static Meter Reading (PSIA): The pressure reading taken from the gas purchaser's sales meter or chart. (This pressure reading is usually given in absolute pressure in Southeast New Mexico.

3. Separator Pressure (PSIG): The separator pressure located on the gas well if it has one.

4. Flowing Tubing Pressure (PSIG): The wellhead tubing pressure while the well is flowing.

5. Flowrate (MSCFPD): The gas wells flowrate in Thousand standard cubic feet per day. This information can be taken from the sales meter.

6. Flowing Casing Pressure (PSIG): If the well is completed with a packer, a 1 to 2 minute shut-in tubing pressure reading will suffice, provided the well is not loaded up.

7. Shut-in Pressure (PSIG): This pressure reading is a pressure reading after the well has been shut-in for a stabilization period (48 to 72 hours normally). This information is usually available in office reports, from the Lease Operator, or through the Reservoir Engineer.

8. Tubing I.D. (inches): The inner diameter of the tubing string located in the well.

The above data serves as the basis for the following calculations. These calculations, which are located in the next 10 columns of the spreadsheet accurately characterize the wells flowing performance.

1. Turner Loading Rate[1] (MMSCFPD): This calculation is based on the Turner equation[1]. This is the rate at which the well will no longer be able to lift liquids at the present flowing conditions. Rates below this value will create loading problems.

$$= \frac{(3.06)\,(\text{Flow Area})\,(\text{Flowing Tubing Pressure})\,(\text{Gas Velocity, ft/sec})}{(\text{Temperature, }^\circ\text{R})\,(\text{Compressibility Factor})}$$

where (Gas Velocity, ft/sec) $= \dfrac{4.03[(P_L - 0.00279\,(\text{Flowing Tubing Pressure})]^{1/4}}{[(0.00279)\,(\text{Flowing Tubing Pressure})]^{1/2}}$

2. Present/Turner Ratio: This is the ratio between the current flowing rate and the Turner loading rate. Values less than one indicate possible loading problems. The larger the number indicates more potential for excess pressure drop due to friction in the tubing.

$$= \frac{\text{Current Flowrate (MCFPD)}}{\text{Turner Loading Rate (MCFPD)}}$$

3. Calc. AOF (MCFPD): The calculated absolute open flow potential assuming current conditions and a slope of (N) of 1. This is based on gas well deliverability equations. Using surface pressures contributes negligible error.

$$= \text{Current Flowrate}\,[(\text{Shut-in PSI}^2) / (\text{Shut-in PSI}^2 - \text{Flowing Casing PSI}^2)]^{\text{slope}}$$

4. Present/AOF Ratio: The percentage of the calculated absolute open flow based on current flowrates.

$$= \frac{\text{Current Flowrate (MCFPD)}}{\text{Calc. AOF (MCFPD)}}$$

5. Target % AOF: This value in percent is a reasonable number to estimate the amount of gas you can expect to produce in relation to the absolute open flow potential. This calculation is based on a 30 pound pressure drop between the reservoir pressure and the sales meter.

$$= [(\text{Shut-in PSI}^2) - (\text{Static Meter PSI} - 13.2 + 30)^2) / (\text{Shut-in PSI}^2)]^{\text{slope}}$$

6. Max. Increase (MCFPD): This value is the difference between the current flowrate and the target percentage of AOF. This calculation is a reasonable estimate of the increase in production that can be expected if any unnecessary restrictions are eliminated.

$$= (\text{Target \% of AOF})\ (\text{Calc. AOF}) - \text{Current Flowrate}$$

7. Friction/Pressure Drop Data: This information is listed in three parts, the tubing friction loss, the pressure losses due to piping between the wellhead and separator, and the pressure losses between the separator and the sales meter. These columns are calculated by subtracting the tubing pressure from the casing pressure, the separator pressure from the tubing pressure, and the meter pressure from the separator pressure.

8. Tubing Friction Indicator: This column is an attempt to identify the wells which show larger than expected pressure drop up the tubing. The higher the number, the more excessive the pressure drop. This calculation will identify wells which indicate plugging problems (paraffin and/or salt) restricting the flow area up the tubing.

$$\frac{\dfrac{1}{[\text{Current Flowrate}]}}{(\text{Tubing ID})^{2.667}\ (\text{Casing PSI} + 13.2)^2 - (\text{Flowing Tubing PSI} + 13.2)^2}$$

   This equation was developed for wells of similar depth using industry available algorithms. The result is qualitative indication of friction to be used when comparing to other similar depth wells.

Once the data has been collected and the information calculated, this spreadsheet becomes an excellent tool to help identify problems that may be occurring in any low pressure gas well. The spreadsheet supplies all the information needed to make intelligent decisions concerning the flowing performance of any well and allows the user to prioritize the work accordingly.

The spreadsheet has served as an excellent tool that allows the Engineer and field personnel to better manage their low pressure gas wells in Southeast New Mexico. The following information includes several case histories using the spreadsheet to identify wells that were flowing below their potential. As you will see from these case histories, the improved production performance is dramatic.

Application

Conoco field personnel in Southeast New Mexico collected the necessary data on 26 of Conoco's low pressure gas wells in the Eumont & Jalmat gas pools. These 26 wells resulted in estimated production increases of 9,417 MCFPD. This number was generated by the Max. Increase column in the spreadsheet. The predicted flowrate increase assumes a 30 PSI difference between the reservoir and sales meter. These numbers are heavily dependent upon the accuracy of the Shut-in pressure data and the flowing bottomhole pressure information. Small changes in these numbers can result in large flowrate changes. Of the 26 wells surveyed, 7 of the wells represented 7,800 MCFPD of the estimated 9,400 MCFPD in flowrate improvements. These 7 wells were looked at for flowrate improvements based on the spreadsheet information. The following recommendations were made and the work was completed on these 7 wells. Please refer to Table #1 for a printout of the spreadsheet.

Case History #1: Data generated from this well indicated that we were losing 77 PSI up the tubing due to friction pressure. At this pressure drop we were only able to draw the bottomhole pressure down to 13 psi below the reservoir pressure. The small tubing was causing a flow restriction which was causing a high pressure drop. Therefore we had to expend most of the reservoir energy to lift the gas up the tubing. Also, we noticed from the spreadsheet information that we lost 18 psi in the piping alone from the well to the separator. The recommendation was to pull the packer and flow this well up the tubing - casing annulus. Also, the surface piping was enlarged from 2" to 4". The results of this work improved the flowrate from 753 MCFPD to an average rate of 1,167 MCFPD over a 3 month period. At this new rate we felt we might be loading up the casing because of the larger flow area so we placed a casing flowrate limiter on the well (similar to the tubing flowrate controller[4]). We operated this way for almost a year before we placed a pumping unit on the well to handle the 30 BWPD. Please see figure #1 for a decline curve.

Case History #2: Spreadsheet information indicated that this well was being drawn down by only 22 psi at the 562 MCFPD rate up 2 3/8" tubing. Tubing friction was causing an 83 psi drop up the tubing alone. Again it was recommended to pull the packer and instigate flow up the casing. Surface piping was also enlarged due to the expected bottleneck at the higher rates. The results of this work increased production from 562 MCFPD to a daily rate of 1,152 MCFPD. Eventually, we installed a tubing flowrate controller[4] on the well to optimize production without loading up the casing. The tubing flowrate controller ensures that flowrates up the tubing are sufficient to lift all liquids up the tubing and the remaining excess gas will then flow up the annulus. This prevents paraffin from plugging up the annulus and the well from having loading problems. Please see figure #2 for a decline curve.

Case History #3: Spreadsheet information indicated that the well was only being drawn down by 18 psi from the estimated reservoir pressure of 118 psi. The calculations indicated that we were only producing 28% of the AOF. The tubing was determined restrictive since we were loosing about half of the reservoir energy trying to fight friction. Again it was recommended to pull the packer and start to flow up the annulus to eliminate the small flow area. Surface piping was enlarged and redesigned to eliminate the excessive 17 psi drop on the surface. The work increased production,and eventually a tubing flowrate controller[4] was installed. With the tubing flowrate controller, a sustained increase in production of about 150 MCFPD has been obtained. Please see figure #3 for a decline curve.

Case History #4: The spreadsheet information indicated that the tubing and surface equipment was causing a significant restriction to it's flowing potential. We were loosing 68 psi up the 2 3/8" tubing while only drawing the well down by 60 psi. Also, a total of 55 psi of backpressure was being exerted due to surface piping and equipment design. Work was therefore recommended to reduce these bottlenecks as a result of identification by the spreadsheet. The packer was removed and flow was instigated up the tubing-casing annulus. Also, the surface piping was enlarged and modified to reduce the pressure bottlenecks. As a result production increased from 1,182 MCFPD to 1,830 MCFPD in the month of December. The production rates at this time have been sufficient to keep this well unloaded up the annulus. Please see figure #4 for a decline curve.

Case History #5: The spreadsheet indicated that this well was only being drawn down by 24 psi as a result of flowing up 2 3/8" tubing. Also, it was noticed that the surface piping was causing a restriction, especially at the higher anticipated rates. Since there was no packer in the well, flow was diverted up the annulus and surface piping was redesigned. The production increased from 612 MCFPD to 1,928 MCFPD in a matter of days, which was an increase of 1,316 MCFPD. Please see figure #5 for a decline curve.

Case History #6: Again the spreadsheet indicated that the tubing was restricting production performance. Since the well calculated to be marginally capable of flowing up the annulus, a tubing flowrate controller[4] was recommended. Surface line loses were minimal and therefore no work was done to the piping or equipment. A tubing flowrate controller was installed and production increased by about 200 MCFPD. Please see figure #6 for a decline curve.

Case History #7: This well appeared to be under performing based on the spreadsheet data and calculations. Again, the under performance could be contributed to restrictive tubing and surface piping. In addition, the pressure losses appeared to be higher than expected, possibly due to paraffin deposits in the tubing and flowline. Based on the recommendation the packer was removed and flow was instigated up the annulus. Performance improved slightly, but the well appeared to load up on the casing. A flow controller[4] was installed in March of 1995 and production increased by about 100 MCFPD. A pumping unit was recently installed and the well has responded by producing 1,052 MCFPD or an overall increase of about 400 MCFPD. Please see figure #7 for a decline curve.

As a result of the initial success with the spreadsheet in mid to late 1994, the spreadsheet data was collected for all of Conoco's wells in the Eumont and Jalmat area. This type of work continued through 1995 using the spreadsheet as guidance for the Engineer's and field personnel. Although the results were not as dramatic in most cases, it was more of a function of hitting the highest potential wells first. In 1995 the team has continued to eliminate bottlenecks and tubing restrictions. Also, we have begun to place pumping units on the wells where the data indicates that the wells have loaded up. To constantly look at our wells and better manage our reservoirs, we continue to collect the necessary data about once a quarter.

Conclusions

After developing and utilizing the "gas well spreadsheet" for two years the following conclusions can be made.

1. The data required for input into the spreadsheet is easy to obtain and not too time consuming.

2. Flowing bottomhole pressures may be estimated by using the casing pressure or a 1 minute shut-in tubing pressure if the well is completed with a packer. This assumption is valid assuming the well is flowing enough to stay unloaded.

3. The spreadsheet is an excellent diagnostic tool to be used for the effective management of several gas wells in an area. Problems with each well can be easily identified and the recommended work effectively prioritized.

References

1. Turner, R.G. et al,: "Analysis and prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells", JPT (Nov. 1969) 1475

2. Lea, J.F. et al,: "Gas Well Operation with Liquid Production", paper SPE 11583 presented at the 1983 Production Operations Symposium, Oklahoma City, Feb. 27 - Mar. 1

3. Hutlas, E.J. et al,: "A Practical Approach to Removing Gas Well Liquids", JPT (Aug. 1972) 916

4. William G. Elmer: "Tubing Flowrate Controller: Maximize Gas Well Production From Start to Finish", paper SPE 30680 presented at the 1995 SPE Annual Technical Conference & Exhibition, Dallas, U.S.A., Oct. 22 - 25

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Table 1

Well Name	GPM Static Reading (PSIA)	Sep. Pres.	Flowing Tubing Pressure	Flowrate (MSCFPD)	1 Minute Tubing Pressure	7 Day Shut-in Pressure	Tubing I.D.	Turner Loading Rate	Present/ Turner Ratio	Calc. AOF MCFPD	Present/ AOF Ratio	Target % AOF	Max Incr MCFPD	FRICTION LOSS DATA: 1 minute - Tbg psi	FRICTION LOSS DATA: Tbg psi -Sep psi	FRICTION LOSS DATA: Sep psi -Line psi	Tubing Friction Indicator
Case History #1	40.3	32	50	753	127	140	1.995	242	3.11	4252	17.7%	83.4%	2792	77	18	4.9	1.04
Case History #2	40	30	35	562	118	140	1.995	211	2.66	1941	29.0%	83.5%	1059	83	5	3.2	1.36
Case History #3	41.2	33	50	617	100	118	1.995	242	2.55	2189	28.2%	75.8%	1043	50	17	5	0.96
Case History #4	29.7	48	72	1182	140	200	1.995	282	4.19	2318	51.0%	94.6%	1010	68	24	31.5	0.68
Case History #5	29.2	22	50	612	104	128	1.995	242	2.53	1801	34.0%	87.1%	956	54	28	6	1.01
Case History #6	43.7	32	33	762	100	140	1.995	207	3.69	1556	49.0%	81.3%	503	67	1	1.5	0.85
Case History #7	32.6	44	78	555	138	200	1.995	292	1.90	1059	52.4%	93.9%	440	60	34	24.6	1.37

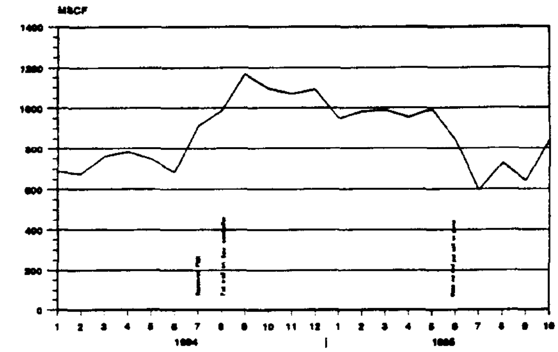


Figure 1 - Case History No. 1

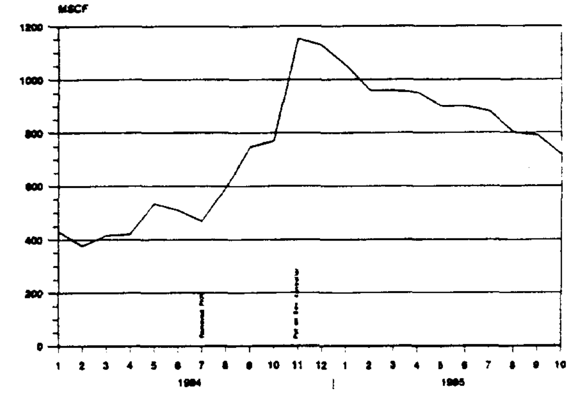
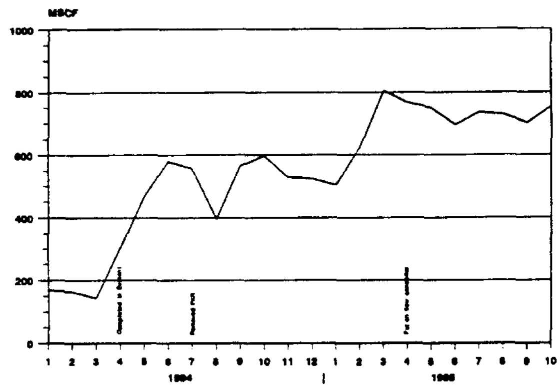


Figure 2 - Case History No. 2



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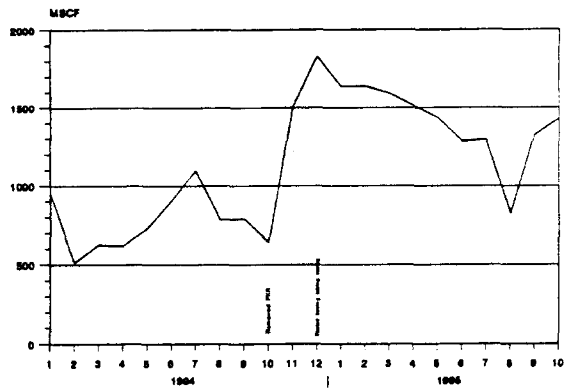

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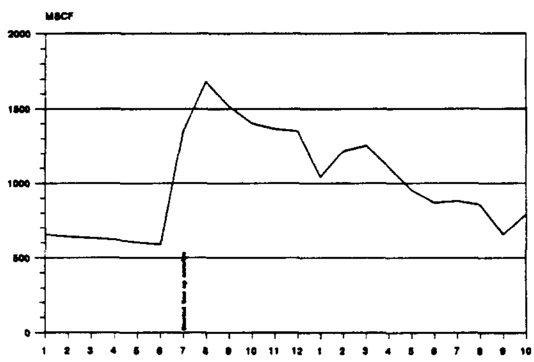

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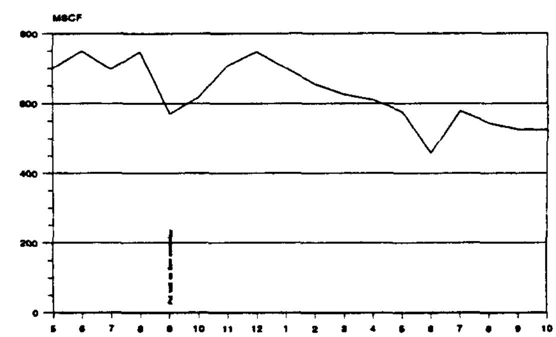

Figure 6 - Case History No. 6

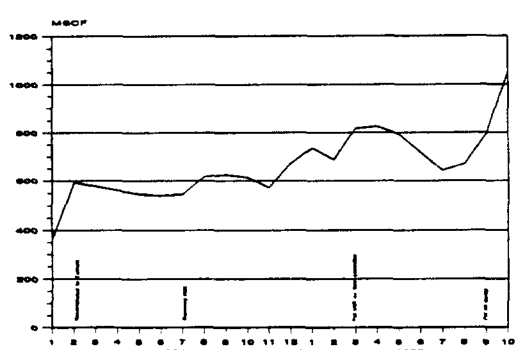

Figure 7 - Case History No. 7