Effect of Back Pressure on Intermittent Gas Lift

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INTRODUCTION

The Jameson (Strawn Reef) Field, located in the northwest corner of Coke County, Texas contains 140 Sun Oil Company owned wells and produces from an average total depth of 6400 ft. Although gas lift has been utilized in the field since 1951, The importance of an effective and efficient lift system has markedly increased since initiation of a large scale waterflood program in July 1963. Since that time water production has increased steadily, gas-oil ratios have declined sharply, and many former flowing wells have been placed on gas lift. Currently, 42 wells on intermittent gas lift produce 1800 BOPD and 6300 BWPD, which represents 60 per cent of the field's oil production and 85 per cent of the water production. Wells on lift vary in producing rates from 25 to 800 bbls fluid/day and PI's range from .01 to more than 2.

PROBLEM AREAS

About two years ago a program was begun to determine means of up-grading the Jameson gas lift system. At that time some of the problem areas in the system were:

(1) All wells had 2 in. flowlines. Many were excessively long (up to 7500 ft), and there were numerous flowline swings or expansion joints.

(2) All wells were equipped with flowing-type christmas trees which included flow tees, wing valves, chokes and a number of tees and ells between the wellheads and flowlines.

(3) Gas lift valves were small-ported (generally 5/16 in. diameter) and were spaced according to out-dated design methods.

Instrumental in pointing out the need for correcting some of the foregoing undesirable practices was an excellent technical report by Brown and Jessen, published in 1962, which presented detailed comparisons of the effects of surface chokes and port sizes.[1]

BACK PRESSURE REDUCTION MEASURES

Initial efforts to improve lift performance in this field were directed at the removal of surface chokes. To further reduce back pressure, the top portion of the christmas trees was subsequently replaced with streamlined sections of 2 in. piping between the master valves and flowing lines. Fig. 1 illustrates this "goose-neck" piping, which is being utilized on all installations equipped with plastic-coated tubing (about 80 per cent of the total). On wells having bare tubing, a slightly different version is used, which incorporates a 45 degree flow tee and wing valve, to permit running BHP bombs or other tools into the well. At the same time the streamlined piping was installed, flowline swings were removed where practical, with particular emphasis on those near the wells. As expected, streamlining wellheads and removal of flowline swings resulted in increased production rates and overall efficiency, primarily because of reduced back pressure on the producing formation, less fluid fallback and the resultant increase in bottom hole pressure draw down.

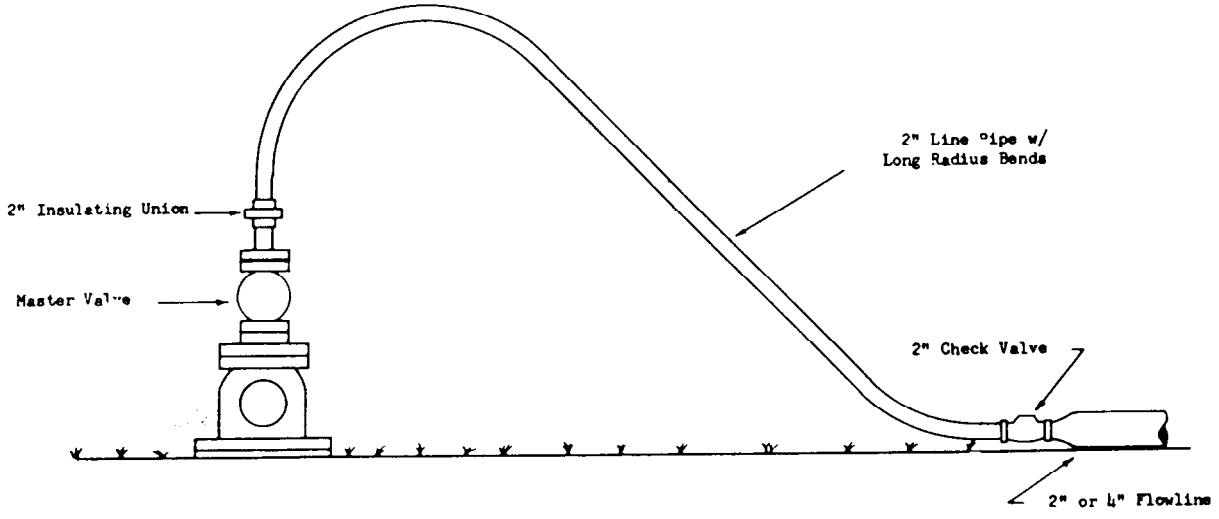
The first opportunity to observe the effect of a larger flowline, coupled with an up-to-date valve string occurred late in 1963. A well equipped with 2 in. tubing, 5/16 in. ported intermittent valves and a 2 in. flowline, 3300 ft in length was producing a maximum of 2 BOPD and 200 BWPD. Bottom hole pressure data indicated the well was not being drawn down sufficiently to achieve capacity production. In an effort to increase fluid production and oil yield, 2-1/2 in. tubing was run with .580 in. ported intermittent valves, and the 2 in. flowline was replaced with a 4 in. line. Subsequently, this well has sustained a production rate of about 45 BOPD and 720 BWPD. Significant results of this test installation were:

(1) Oil production increased more than 22-fold by increasing total fluid production 3.8 times.
(2) By taking advantage of an adequate flowline, together with modern subsurface equipment and design techniques, an uncommercial well became a profitable producer.

The favorable results of this test provided the impetus to further expand the program of gas lift modernization. Today, practically all gas lift wells are equipped with large-ported valve strings (.500 in. or larger), designed according to the greatly improved techniques which have evolved during the past two years. In many instances, it has been determined that improved production and efficiency justify pulling wells solely to update valve strings.

Pressure losses in flowlines have been reduced where necessary by replacing 2 in. lines with 4 in., by looping 2 in. lines with additional 2 in. lines, and by shortening lines as a result of installation of separation stations at central locations. One such station, serving nine lift wells, achieved an increase from the prior production of 300 BOPD and 1500 BWPD to 550 BOPD and 2350 BWPD. The out-of-pocket cost of the station, including extensive flowline modifications paid out in less than a month.

Table 1 shows a comparison of before and after production tests from 11 intermittent lift wells which have undergone flowline modifications to



Typical Surface Hook-up Of Gas Lift
Installation With Plastic Coated Tubing

Fig. 1

Well No.	Before Production Test				After Production Test				Increase BFPD	Percent Increase		Length of Flowline, Ft	Description of Change
	Cycles Per Day	BOPD	BWPD	Total Fluid	Cycles Per Day	BOPD	BWPD	Total Fluid		Oil	Fluid		
1-W	120	17	140	157	120	35	158	193	36	106	23	3400	Looped existing 2" FL with addl 2" line
1-P	120	21	180	201	120	34	216	250	49	62	24	2000	Looped existing 2" FL with addl 2" line
3-P	120	43	157	200	192	64	266	330	130	49	65	2100	Looped existing 2" FL with addl 2" line
11-D	180	121	251	372	180	168	296	464	92	39	25	2000	Looped existing 2" FL with addl 2" line
18-D	60	29	173	202	60	45	211	256	54	55	27	2300	Looped existing 2" FL with addl 2" line
40-K	192	80	240	260	120	29	366	395	135	45	52	3300	Looped existing 2" FL with addl 2" line
18-K	120	10	302	312	240	47	591	638	326	370	104	6200/2000	Replaced 2" FL with shorter 4" line
16-K	192	4	183	187	240	69	516	585	398	1625	213	5500/2200	Replaced 2" FL with shorter 4" line
17-K	192	24	244	268	240	82	410	492	224	242	84	3700/900	Replaced 2" FL with shorter 4" line
2-B	80	91	120	211	80	116	169	285	74	27	35	4000/1400	Replaced 2" FL with shorter 4" line
4-B	120	148	104	252	120	124	128	252	None	None	None	4200/2500	Shortened 4" FL

Effect of Back Pressure Reduction On Performance of Intermittent Gas Lift Wells

Table 1

minimize back pressure. The first six examples deal with looping existing 2 in. lines with additional 2 in. lines. In this category the least gain achieved in total fluid production was 23 per cent and the largest was 65 per cent.

The next four examples illustrate the results of replacing 2 in. flowlines with shorter 4 in. lines. In this category, generally higher volume wells than the previous group, the gains in total fluid were somewhat greater, ranging from 35 to 213 per cent. In both groups, it may be noted that oil production generally increased at a higher rate than did total fluid. For example, well 16-K experienced a 17-fold gain in oil rate by doubling total fluid. Results to date indicate the gains in total fluid achieved in this field by reducing back pressure are not short lived, but have been sustained for periods of up to two years. In most cases, however, oil rates have gradually declined after an initial large improvement.

In more than half the examples included in Table 1, the production gains were attained without increasing cycle frequency. This, in effect, means the injection gas-fluid ratios were automatically reduced by an amount corresponding to the increases in total fluid, ranging as high as 92 per cent.

In the last example, notice the production rate remained unchanged although the 4 in. flowline was reduced in length from 4200 to 2500 ft. This indicates that once adequate line capacity is provided, reducing the length (or increasing the size) will not have a pronounced effect on production.

It is emphasized that the magnitude of production gains shown in Table 1 were achieved, except in the last example, by moderate to drastic reductions of flowline back pressure and are not necessarily indictive of results which can be expected in less severe circumstances.

FLOWLINE REQUIREMENTS

Experience derived from intermittent lift operations in the Jameson Field has led to broad classification of flowline requirements for various producing rates and lengths of lines, as shown in Table 2. Although wholly empirical, this data has proven valid and useful as a guide in the determination of flowline requirements. Its main utility stems from the fact that it is much less complicated than most of the rigorous mathematical approaches found in the literature.

Production BFPD	Length of Flowline Miles	Nominal Line Size Inches
0 - 150	Up to 1	2
150 - 250	Less than 1/2	2
150 - 250	More than 1/2	3
250 - 450	Less than 1/2	3
250 - 450	More than 1/2	4
450 & up	All lengths	4

Recommended Flowline Sizes For Intermittent Gas Lift Wells

Table 2

To check the adequacy of an existing flowline, one criterion which may be applied is to note if tubing pressure drops to separator pressure between cycles when the well is being produced at the desired rate.

The 2-pen pressure recorder is a valuable tool to employ in determining the adequacy of a flowline as well as to effectively monitor the overall gas lift operation. An appreciable delay in tubing pressure decline following the surfacing of a fluid slug indicates a back pressure problem, which can limit both the well's ability to produce and the efficiency of the installation.

SUMMARY

In order to achieve maximum production and efficiency from intermittent gas lift installations, the following factors should be considered:

(1) Every reasonable effort should be made to minimize the effects of back pressure. Basic considerations include a flowline of adequate capacity, the absence of tubing chokes or other restrictions near the well, and the lowest trap pressures practical.

(2) To reduce pressure drop across gas lift valves, the largest port sizes compatible with conditions should be utilized.

(3) Full use should be made of the recently published intermittent gas lift design techniques.

REFERENCE

1. Brown, Kermit E. and Jessen, Frank W. "Experimental Gas Lift Project The Vertical Flow of Liquid Slugs By Intermittent Gas Lift", Technical Report To The Ohio Oil Co., Sun Oil Co., Otis Engineering Corp., May 1, 1962.