SYSTEM IMPROVEMENTS INCREASE PROFITABILITY IN A MAJOR GAS-LIFTED FIELD

Gabor Takacs, Zoltan Turzo

Petroleum Engineering Department
University of Miskolc, Hungary

Abstract

The majority of wells in the biggest Hungarian oil field is placed on continuous flow gas lift. The gas lift system, designed in the late 1960s, has many very unique features dictated by the economic and technological constraints of those times. Proper operation was maintained till recently but changes in reservoir parameters due to the depletion of the field have brought about many unfavorable conditions leading to increased lift gas requirements and rising production costs.

The paper investigates the effects of the crucial system parameters like tubing size, wellhead and gas lift pressures, and their role in the field's profitability. Using field data and computer calculations, optimum values for tubing size and injection pressure are found. The widespread use of wellhead chokes for controlling well production rates is shown to have a detrimental effect. With assumed optimum conditions, total required gas lift volumes are calculated and compared to present values. The system modifications proposed by the authors are shown to have a great potential in significantly improving the economy of production operations in Algyö.

Introduction

The Algyö field

The largest oil and gas accumulation in Hungary is the Algyö field, situated in the Southern part of the country near the city of Szeged. The field was discovered in 1965, its original oil in place volume is 629 million bbl with a large gas reserve of $4x10^6$ MMscf. Main productive horizons (a total of 76 layers) are heavily layered sandstone formations having large gas caps and thin oil edges. The reservoirs are highly heterogeneous, delta type sediments. Produced crude oils are light, sometimes volatile.

Up to now more than 1000 wells had been drilled with depths between 5,900 ft and 6,900 ft. Algyö is a mature field past its peak production period of around 21,600 bpd of crude. Reservoir management involves water injection at the gas-oil and the water-oil contacts. The gas caps and the oil bodies are produced simultaneously. A continuous but slow drop in reservoir pressure and a more rapid increase in water cut is experienced.

Main features of the gas lift system

To-day, about 65% of the field's total liquid production comes from gas lifted wells placed on continuous lift. Total number of gas lifted wells is about 226, from which about 20% are dual installations.

The basic design parameters of the gas lift system were determined in the late 1960s. The technical and economic situation of those times in the country necessitated the use of several special solutions, of which the following must be mentioned.

- An extremely high injection pressure of 1,740 psi is used. The aim of this design was to reduce the number of gas lift valves required.
- For unloading, a separate pressure of 2,320 psi is utilized. Thus a dual-pressure surface injection gas distribution system was built.
- Almost exclusively, instead of gas lift valves, simple orifice valves are run in the gas lift mandrels.
- Gas injection occurs through existing, pre-installed valve mandrels with no optimum injection point being sought.
- To control liquid production rates, wellhead chokes are installed on most wells.

Although some of the above solutions, for special cases, are also used in other parts of the world, the Algyö gas lift system is far from being a conventional case. In spite of its special features the system could meet the technical and economic requirements at the time of its design. With the progressive depletion of the field, however, field conditions underwent many significant changes like a continuous drop in formation pressure and a rapid increase in water cuts. Because of those changes, production costs had risen steadily in recent years. The operator of the field, **MOL Plc.**, initiated a general survey of production practices and contracted the **Petroleum Engineering Department** to help their efforts in improving the economy of gas lift operations. This paper discusses in detail the most important findings of our studies. [1, 2]

Analysis methodology

In general, lift gas requirements of continuous flow gas lifting are basically determined by three operating parameters: injection pressure, wellhead pressure, and the size of tubing used. In the following, the effects of these parameters on the efficiency of gas lifting will be investigated. An analysis of the inefficiencies caused by chokes, installed on wellheads to limit liquid flow rates, will also be done.

Measured and calculated data

Field-wide production performance data were collected as of July 1994. All relevant well parameters for a total number of 185 wells were processed. Since our studies were not aimed at establishing optimum conditions for each individual well but rather at the general evaluation of field practices, key wells, representing the conditions of the various formations were set up. The use of these key wells and computer programs allowed us to reliably simulate the operational parameters of the Algyö gas lifted wells.

Computer predictions served for the comparison of current field practices to optimum conditions. The computer program **CONTLIFT** [3] was used to calculate the lift gas requirements of continuous flow gas lifting. This program finds, based on the surface injection pressure, the required injection depth, i.e. the running depth of the operating gas lift valve as well as the injection gas volume. Wellhead pressure is usually assumed to be equal to the minimum pressure needed to transfer the wellstream to the separator. These assumptions are crucial for the optimum design of a gas lift installation, but considerable deviate from the actual conditions prevailing in Algyö. In the field, gas is not injected at the ideal depth, but at the depth of an existing valve mandrel. Further, to enable the control of liquid rates, wellhead chokes are installed. Because of all these, calculated and measured gas requirements will considerably differ.

Establishment of key wells

In order to exclude the effects of the variations in the main parameters of the formations investigated, calculations were conducted for each of the main productive formations of the Algyö field. To improve the reliability of statistical results, only the most significant data were included in the analysis by constructing key wells for each formation. The criteria used for setting up the key wells was the liquid rate. For each formation, the liquid rate ranges covering the individual rates of 95% of the wells were determined, as displayed in **Table 1**.

Using measured field data, key wells with average properties were created for each formation, the main parameters of which are shown in **Table 2** along with the number of wells they represent. As seen, a total of 185 gas lifted wells are included in the present study. Before actual calculations were conducted, it was checked how properly the key wells represented the conditions of each formation. Measured total liquid and lift gas volumes were compared to the values calculated using the key wells. The field-wide measured liquid rate of 53,900 bpd compares well to the calculated value of 51,500 bpd. Measured and calculated gas requirements were 26.5 MMscf/d and 26.7 MMscf/d, respectively. Since these numbers are in excellent agreement, it is proved that key wells effectively represent the average conditions of the formations investigated.

The effect of tubing size

Two tubing sizes, 2 3/8" and 2 7/8" are used in Algyö. To analyze the role of tubing size on lift gas requirements, measured injection gas volumes are evaluated first. Lift gas consumption for the different formations is shown in **Fig. 1**. As seen, except for the **Szeged-1** zone, gas requirement for the bigger tubing size is greater than for the smaller one. This phenomenon is attributed to the different wellhead pressures in the two cases.

Using the data of the key wells the program **CONTLIFT** was run to find the lift gas requirements when using the **Duns-Ros** [4] and the **Orkiszewski** [5] vertical multiphase flow correlations. Wellhead pressures were assumed to be equal to actual field values that, due to the effect of wellhead chokes, were considerably higher than optimum. Calculation results are summarized in **Table 3** where average field data along with calculated injection depths and injection gas volumes are shown. As seen, calculated and measured GLRs differ considerably. The main cause of discrepancies is that the computer program uses optimum depths for gas injection whereas actual injection depths are different. It is also obvious that, according to calculation results received from both vertical flow correlations, the use of a smaller tubing size (2 3/8") results in decreased injection gas requirements, as compared to the larger tubing size.

In order to further investigate the effect of tubing size on gas lifting, an additional study was conducted. It involves calculation of lift gas volumes for a wellhead pressure of (290 psi), the pressure needed to transfer the wellstreams to the separators. Calculation results using the **Orkiszewski** correlation (previously found to properly simulate Algyö conditions) are compared to field data in **Fig. 2**. The figure proves that gas lifting under optimum conditions would result in considerable savings of injection gas volumes for each formation.

The effect of wellhead pressure

In the following, the positive effects of decreasing the wellhead pressure on lift gas requirement is investigated. Calculations will be performed with the following basic assumptions:

- Optimum conditions are assumed, i.e.:
  - gas is injected at the deepest possible depth, and
  - no wellhead choke is installed.
- Injection gas requirement is found by using the **Orkiszewski** correlation.
- The technical feasibility of reducing the separator pressure is not investigated.

Specific and daily lift gas volumes were calculated for wellhead pressures of 145, 218, and 290 psi. Condensed results are shown in **Fig. 3** that also contains the GLR values measured in the field. As seen, actual field values are extremely high as compared to all assumed cases, the main reason being the presence of wellhead chokes. The figure also shows that present lift gas volumes could substantially be reduced were the wellhead pressure reduced to the easily attainable level of 290 psi. This case is of special importance since a wellhead pressure of 290 psi is sufficient to transfer the wellstreams to the separators at 260 psi.

Decreasing the wellhead pressure below 290 psi does not incur such drastic changes in gas volumes as from the present value to 290 psi. Based on this fact, we can conclude that, even without any changes to the field's present-day surface gathering system, the optimization of Algyö gas lifted wells can bring about substantial savings. To estimate injection gas volume savings, **Table 4** is presented where lift gas requirements for the wellhead pressures investigated are shown. If compared to present conditions, decreasing the wellhead pressure to 290 psi and injecting gas at ideal depths results, for the 185 wells studied, in a total daily saving of over 21 MMscf of lift gas. It should be noted that, due to the inaccuracies of the vertical multiphase flow correlation used, these numbers can contain some errors, since accuracies of 10 to 20% are common. But the savings, if corrected to account for such factors, are still very substantial.

The detrimental effects of wellhead chokes

Because of the specific features of the Algyö gas lift system (an extremely high injection pressure, the use of simple orifices instead of gas lift valves) wellhead chokes have to be used to control well flow rates. Surface chokes, however, substantially reduce the economy of continuous flow gas lifting because the pressure drop occurring across them greatly increases the energy losses in the system. Some of the undesirable consequences of the presence of wellhead chokes were shown earlier in the paper when the effect of wellhead pressure on lift gas volumes was investigated. The next section presents a further investigation of this problem by utilizing **Systems (Nodal) Analysis** methods.

Calculations were performed using an example Algyö well with the data shown in **Table 5**. For Nodal Analysis, the solution node was placed at the wellhead, upstream of the choke. The production system of the well was thus divided into the subsystems comprising the productive formation and the tubing string, and that of the surface choke, the flowline, and the separator. Two cases were investigated: with and without a wellhead choke; calculated performance curves are displayed in **Fig. 4**. It is easy to see that removal of the wellhead choke would greatly increase the well's liquid production rate for the current injection GLR. Since the increased liquid rate is greater than the allowable, the target production could more efficiently be attained by injecting less gas into the tubing. A decreased injection GLR of 111 scf/bbl and use of a greater surface choke (0.35 in), as indicated by a modified performance curve **4** , would result in a flow rate very close to the current value. Therefore, flow rate control of the wells can much more economically be achieved by increasing the surface choke size and by injecting less gas into the well than it is allowed by the current practice of extensive choking.

Proposed modifications

Based on the investigations detailed earlier in the paper the authors developed a set of proposed improvements for Algyö conditions.

Present and proposed conditions of an example Algyö well are given in **Fig. 5**. At present, a high pressure differential of 466 psi occurs through the downhole choke used instead of the gas lift valve. Calculated gas injection volume through the installed choke with a diameter of 0.06 in is about 103 Mscf/d, that compares well to the measured injection GLR.

In order to improve the economic parameters of gas lifting in Algyö, the following improvements and modifications are proposed:

- Decreasing the surface injection pressure,
- removal of wellhead chokes, and
- use of gas lift valves for gas injection.

It is well known that the ideal injection gas pressure at injection depth equals the tubing pressure valid at the same depth plus the pressure drop in the gas lift valve. In the example, the surface injection pressure corresponding to this value is 1,378 psi, compared to 1,740 psi used in the field. Since the wellhead choke is removed, wellhead pressure equals the input pressure required to transfer the wellstream to the separator, i.e. 290 psi. After calculating the injection gas volume required for continuous flow gas lifting for the proposed case, it was found that an injection volume corresponding to a GLR of 56 scf/bbl was sufficient to lift the given liquid rate. Gas usage, as compared to the current value of 232 scf/bbl, decreased to one-fourth of its original level.

A comparison of current and proposed conditions for the entire Algyö field showed [1] that the proposed modifications would greatly improve the economy of production operations. The improvements mean that, while maintaining the same liquid production from the wells, less lift gas volumes are needed at a lower injection pressure. Therefore, the saving of substantial gas compression, consequently production costs can be achieved for each well and the whole field alike.

Under proposed conditions, control of the wells' liquid production becomes easier, too, because downhole gas injection occurs through a gas lift valve ensuring the controlled injection. In the field today, with the injection pressure of 1,740 psi, the well's liquid rate is primarily determined by downhole choke's gas throughput capacity. Well flow rates in Algyö being relatively low, the choke sizes needed are, in most cases, very small, or even impractically small. This is the reason why one must inevitably install surface wellhead chokes to control well rates The disadvantages of this practice, as it was shown earlier in the paper, lead to very inefficient and costly gas lift operations.

Conclusions

The main objective of this paper was the investigation of possible improvements to gas lift operations in the Algyö field. A detailed elaboration of the proposals presented here is outside of the scope of the paper, but the information presented here should be sufficient to bring up some important topics. The most basic conclusions are given below:

- According to calculation results the use of 2 3/8" tubing, instead of the 2 7/8" size, is more favorable in all cases.
- Decreasing the wellhead pressure to 290 psi (easily achieved by removing the wellhead chokes) can ensure the saving of vast injection gas volumes, provided the wells operate under ideal conditions.
- Wellhead chokes are detrimental to gas lift operations and cause great energy losses, their use must be avoided.
- Decreasing of the surface injection pressure to the ideal level would not only improve the economy of gas lifting but would also substantially improve the production control of wells.

References

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Table 1
Liquid flow rate ranges of the wells selected.

Formation	Liquid Flow Rate Minimum bpd	Liquid Flow Rate Maximum bpd
Algyő-2	252	440
Szeged-1	252	660
Szeged-3	157	472
Szőreg-1	189	264
Csongrád-D-1	113	233

Table 2
Main assumed parameters of Algyö key wells.

Formation	Tub. size in	Well Depth ft	FBHP psi	Liquid Rate bpd	Water Cut %	Prod. GLR scf/bbl	Number of Wells
Algyő-2	2 3/8	6129	2235	323.4	91	108	42
	2 7/8	6129	2237	318.6	90	104	14
Szeged-1	2 3/8	6037	2218	332.3	88	107	29
	2 7/8	6037	2217	332.7	96	63	3
Szeged-3	2 3/8	5919	2207	284.9	83	159	28
	2 7/8	5919	2195	304.0	86	149	10
Szőreg-1	2 3/8	5782	2307	220.6	82	141	26
	2 7/8	5782	2296	239.5	74	182	12
Csongrád-1	2 3/8	5554	2268	159.6	86	164	17
	2 7/8	5554	2256	175.0	79	106	4
Total							185

Table 3
Measured and calculated values of average specific lift gas requirements and injection depths for current well-head pressures.

Formation	Current			Orkiszewski			Duns-Ros		
	Inj. Depth	Injection GLR scf/bbl		Inj. Depth	Injection GLR scf/bbl		Inj. Depth	Injection GLR scf/bbl	
	ft	d = 2 3/8 "	d = 2 7/8 "	ft	d = 2 3/8 "	d = 2 7/8 "	ft	d = 2 3/8 "	d = 2 7/8 "
Algyő-2	**4485**	**523**	**386**	**5105**	**233**	**439**	**5108**	**329**	**435**
Szeged-1	**4183**	**442**	**561**	**5074**	**305**	**688**	**5007**	**504**	**644**
Szeged-3	**4160**	**517**	**448**	**4944**	**396**	**661**	**4944**	**504**	**555**
Szőreg-1	**3937**	**633**	**569**	**4491**	**511**	**672**	**4491**	**541**	**511**
Csongrád-D-1	**4149**	**602**	**492**	**4385**	**572**	**1010**	**4383**	**540**	**714**

Table 4
Calculated specific and daily lift gas requirements for different wellhead pressures.

Formation	Number of Wells	Injection GLR scf/bbl				Lift Gas Requirement Mscf/d				Lift Gas Savings Mscf/d		
WHP (psi) —>		145	218	290	Current	145	218	290	Current	145	218	290
Algyő-2, d = 2 3/8"	42	0	32	81	523	0	435	1113	7185	7185	6751	6072
Algyő-2, d = 2 7/8"	14	41	100	173	386	183	451	781	1743	1560	1292	962
Szeged-1, d = 2 3/8"	29	0	32	81	442	0	314	785	4309	4309	3996	3525
Szeged-1, d = 2 7/8"	3	90	154	233	561	91	155	235	567	475	412	331
Szeged-3, d = 2 3/8"	28	0	0	24	517	0	0	193	4168	4168	4168	3975
Szeged-3, d = 2 7/8"	10	0	57	133	448	0	176	408	1377	1377	1201	969
Szőreg-1, d = 2 3/8"	26	0	0	24	633	0	0	138	3672	3672	3672	3534
Szőreg-1, d = 2 7/8"	12	0	0	23	569	0	0	68	1653	1653	1653	1585
Csongrád-D-1, d = 2 3/8"	17	0	0	18	602	0	0	49	1651	1651	1651	1602
Csongrád-D-1, d = 2 7/8"	4	0	51	119	492	0	36	85	348	348	313	264
Totals:	185					274	1566	3854	26675	26401	25109	22820

Table 5
Example well data for Nodal Analysis.

Reservoir Pressure, psi	2408
Productivity Index, bbl/psi/d	1.86
Liquid Rate, bpd	410
Water Cut, %	82
Well Depth, ft	6129
Injection Depth, ft	4085
Tubing Size, in	2 3/8
Production GLR, scf/bbl	111
Injected GLR, scf/bbl	232
Wellhead Choke Size, in	0.25
Length of Flowline, ft	1969
Diameter of Flowline, in	2.5
Separator Pressure, psi	261

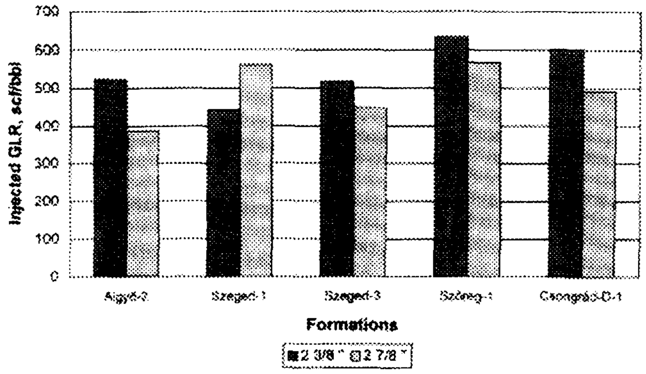

Figure 1 - Average measured specific lift gas requirements in function of tubing size.

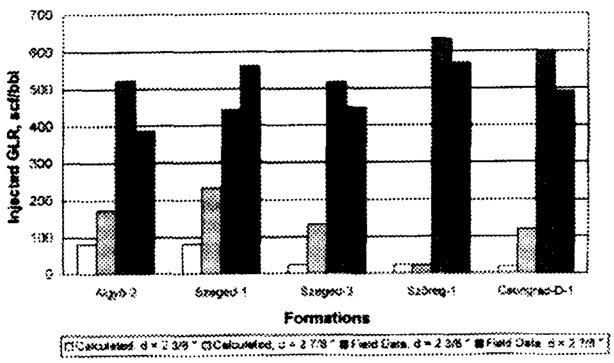

Figure 2 - Specific lift gas requirements under optimum (calculated by the Orkiszewski Correlation) conditions.

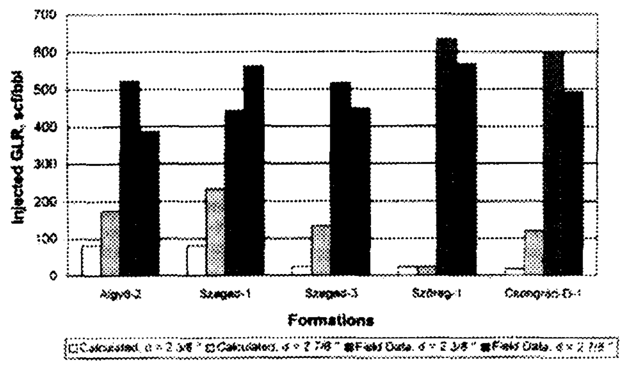

Figure 3 - Measured and calculated specific lift gas requirements for different wellhead pressure.

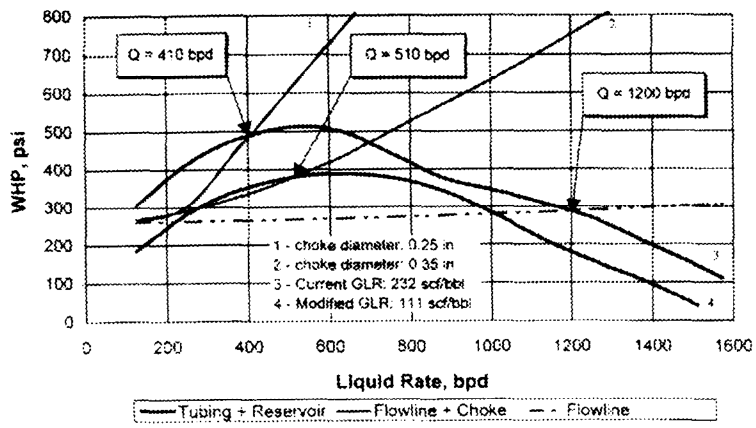

Figure 4 - Nodal Systems Analysis results for an example well showing the effects of wellhead chokes.

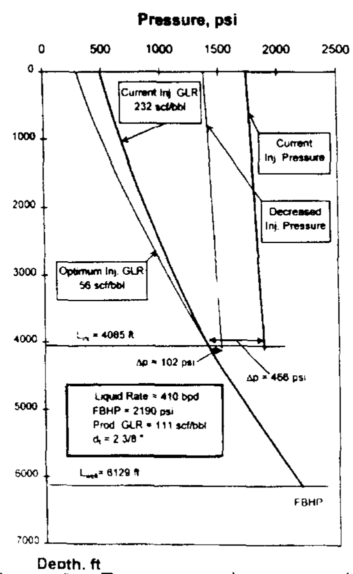

Figure 5 - Present and proposed downhole conditions in an example well.