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Gas Lift Design and Production Optimisation Offshore Trinidad

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ABSTRACT

By means of a variety of field examples, this paper describes how increased production rates were obtained from gas lift wells. These results were achieved through a wide range of activities including, special training for production operators, optimising gas injection rates, modifying surface piping systems, identifying and replacing defective wireline-retrievable gas lift valves, and improving gas lift design techniques.

A major modification of a standard gas lift design technique is discussed in detail. The modification optimises the depth of gas injection throughout the life of a well. An empirically derived chart, which relates valve spacing to the productivity index of a well, is also presented.

INTRODUCTION

Amoco Trinidad Oil Company (ATOC) produces oil and gas from four fields off the east coast of Trinidad. The three oil fields, Teak, Samaan and Poui, lie between 12 and 25 miles (20 and 40 km) offshore, as shown in Figure 1. Ten drilling platforms and three central field production platforms have been set in a water depth of 180 ft (55 m) to develop these fields. The producing formations are mainly Pliocene age sandstones. Measured depths of wells range from 4,000 to 12,000 feet (1,200 to 3,660 m) and average hole angle sometimes exceeds 50°. Sand production is a problem and the majority of wells are gravel packed. Oil production began from Teak and Samaan in 1972 and from Poui in 1974.

References and illustrations at end of paper

By December 1984, 85% of the 111 producing oil wells were on gas lift and production from these wells represented 78% of ATOC's total daily oil and condensate production of approximately 100,000 bbl/D [15,900 m^3/d]. A total of 165 x 10^6 scf/D (4.7 x 10^6 standard m^3/d) of gas lift gas was needed to maintain this level of oil production. 75% of the gas came directly from high pressure gas wells while the remainder was supplied by semi-closed rotative compressor systems. The available gas injection pressure was 1,150 psi(7,930 kPa) in Samaan: 800 psi (5,520 kPa) in Teak; and 850 psi (5,860 kPa) in Poui.

During 1984, special attention was paid to optimising production from gas lifted oil wells. As shown in Figure 2, this made a significant contribution to the reversal of a declining production trend. Comparing individual well tests done in January and December 1984, a total of over 6,000 bbl/D (950 m^3/d) of increased production due to gas lift optimisation was seen. Although less readily quantified, it is believed that, as a result of the introduction of improved gas lift design techniques, the production from new wells and workovers was also greater than might otherwise have been seen.

GAS LIFT PRODUCTION OPTIMISATION

Optimum production from gas lifted wells was achieved through a comprehensive approach to the problem, which included:-

Education: An experienced consultant was engaged to present a school on gas lift operations. An important aspect of this school was that it was held 'on site' at Galeota Point, so that both engineers and field production personnel could attend and discuss local field examples.

Well Performance Analysis: An extensive programme of flowing pressure and temperature gradient surveys was carried out in order to identify potential for increased production. Following analysis of these survey results, oil production increases (of over 10% for some wells) were quickly achieved, simply by correctly adjusting the gas injection rate.

Valve Replacement: Performance analysis also indicated the need for wireline work. The flowing pressure gradient survey of Samaan C-7 in April 1984, for example, showed that gas was being injected through the second valve at 3,400 ft (1,035 m) TVD, yet there was adequate injection pressure to unload below the third valve at 4,700 ft (1,430 m) TVD, as shown in Figure 3. The valves were wireline retrievable, 1½ in. (38.1 mm) OD, set in 3½ in. (88.9 mm) nominal OD sidepocket mandrels. It was decided that the second and third valves should be replaced and the test rack opening pressure, P_{tro}, at 60°F (15.5°C) of the new second valve set 10 psi (68.9 kPa) higher to encourage it to close. Numerous wireline trips into the well, several improvised tool modifications and three working days were required to carry out the work on this five year old, deviated hole, completion. As a result, however, oil production increased by more than 650 bbl/D (100 m^3/d) and gas lift gas consumption fell by more than 500 x 10^6 scf/D (14.6 x 10^3 standard m^3/d). Had the original design incorporated an additional mandrel at 5,500 ft (1,676 m), production could have been even higher.

More mandrels do not necessarily mean a better design, as Figure 4, the flowing pressure gradient survey of a seven year old completion in Samaan B-1, reveals. One more mandrel at 5,200 ft (1,585 m) TVD would have done much more for the well than the eight below 6,000 ft (1,830 m) TVD. It is the correct anticipation of the approximate depth of continuous injection that is important.

The flowing pressure gradient survey in Samaan B5, Figure 5, revealed another common problem. All valves had 3/16 in. (4.8 mm) ports. A single valve could not pass the 1,700 x 10^3 scf/D (48.1 x 10^3 standard m^3/d) of gas lift gas required by the well, so the result was inefficient multi-point injection over the large depth interval covered by the top three valves. The third valve was replaced with a valve having a 7/16 in. (11.1 mm) port. Production subsequently increased by over 300 bbl/D (48 m^2/d) of oil and the injection gas requirement was reduced by 500 x 10^3 scf/D (14.16 x 10^3 standard m^3/d).

Gas Lift Gas Distribution and Measurement: Inaccurate measurement and control of the gas flowrate to each well was an obvious handicap to production optimisation. The gas flowrate to an individual well could not be measured in some existing distribution systems, except by shutting off the supply to the well and recording the drop in total flowrate to the platform. More recently installed distribution manifolds incorporated a loop line with an orifice meter through which the flow to any individual well could be directed, while gas to other wells flowed, unmetered, directly to the wellheads.

In both cases, the valves isolating the individual flowlines from the main distribution header or from the loop line eventually developed leaks due to wear and tear through regular use. To overcome this problem, all wells are now being provided with their own orifice flange meter tube, located between the distribution manifold and the wellhead.

Surface Flowing Tubing Pressure: Various efforts were made to reduce surface flowing tubing pressures. On some wells, which were known to have a scale problem, reduced bore choke bodies and reverse flow check valves were removed from the well flowline. Flowing tubing pressure typically dropped 5-10 psi (35-70 kPa) but any resultant change in production rates fell within the range of normal fluctuations in well test results and was therefore difficult to establish.

The most successful solution, where practical, was to 'twin' the 4 in. (101.6 mm) well flowline from the wellhead area to the production header, a distance which varied from 15-50 ft (4.6 - 15.2 m) depending on the slot occupied by the well. As shown in Figure 6, Teak C-2RD yielded over 500 bbl/D (80 m^3/d) of additional oil production after flowing tubing pressure dropped from 215 psi (1,480 kPa) to 195 psi (1,345 kPa) as a result of 'twinning'. Other high flowrate wells saw pressure drops of up to 40 psi (275 kPa) but production response varied, of course, with the productivity index of the well.

Attention was also given to the impact of individual wells on the total gathering system. On the Teak B satellite drilling platform, three oil wells produced into a 1.6 mile (2.56 km), 8 in. (203.2 mm) pipeline to the Teak A production platform. Well B-3A exhibited declining oil production and increasing water cut. The well was shut in to gauge its influence on pipeline pressure. Table 1 shows the results of the well tests carried out within a few days of the shut-in. With a lower pipeline pressure, production from the other two wells picked up and the net result was a loss of only 45 bbl/D (7m^3/d) of oil and a saving of 1.5 x 10^6 scf/D (42.5 x 10^3 standard m^3/d) of gas lift gas.

Downhole Design: Once a set of mandrels and valves are run into a well, they will stay there for several years and their spacing and pressure setting will be one of the main controlling influences on the wells' production level. With drilling and workover rigs active in the field, development of an improved design procedure was given immediate attention.

GAS LIFT DESIGN AS AN INTEGRAL PART OF PRODUCTION OPTIMISATION

Systems Analysis: Kanu[1] and Brown et al[2] have shown how systems analysis can help optimise production from gas lift wells. Given the casing pressure at surface, when lifting from the operating valve, and the operating differential pressure between the casing and the tubing at the point of injection, systems analysis techniques can also be used to determine the depth of the operating valve and the optimum injection gas liquid ratio (IGLR). Those two parameters can then be used together with the flowing tubing pressure gradient curve, which systems analysis also generates, as the basis for a graphical gas lift design technique. The choice of casing pressure and operating differential pressure requires some forethought, however. This is particularly so when unbalanced, bellows charged, injection pressure operated, continuous flow gas lift valves, and a design technique which involves a drop in surface operating pressure between successively deeper valves, are being used.

The casing pressure to use is the valve operating injection pressure, P_{ivo}, at surface, of the operating valve. This pressure is unknown at the outset and must be estimated. The pressure which is known is the surface pressure which corresponds to the valve operating pressure of the first valve, P_{ivo1}, ie the pressure available at surface for unloading to the depth of the first valve. If an injection pressure drop between each valve, ΔP_v, is to be taken when moving deeper, to ensure upper valves will not re-open under normal conditions, then:

$$P_{ivon} = P_{ivo1} - \sum_{j=1}^{n-1} \Delta P_{vj} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (1)$$

where n is the number of the operating valve and all pressures are assumed to be surface equivalents. It is, therefore, n and $\sum_{j=1}^{n-1} \Delta P_{vj}$ which must be estimated. This becomes easier with experience as it depends on a knowledge of the load fluid gradient, a familiarity with the characteristics of the valves to be used and on anticipating, approximately, the flowing tubing pressure gradient which systems analysis will generate. Without this experience, an iterative approach will be required, keeping in mind, however, that neither systems analysis nor gas lift design are intended to be precise sciences. In fact, at this stage, the estimate of n need not be correct. If $\sum \Delta P_v$ alone is of the right order, then acceptable systems analysis results will be obtained and the design procedure can continue. In the design example presented here (refer to Tables 2 & 3 and Figures 7 & 8), the pressure available at surface for unloading is 875 psi (6,035 kPa), n is estimated to be 5 and $\sum_{j=1}^{4} \Delta P_{vj}$ is estimated to be 75 psi (520 kP a). Using equation (1), P_{ivon} is therefore estimated to be 800 psi (5,520 kPa).

The operating differential pressure, ΔP_{op}, is discussed in detail by Mach et al[3]. This also must be estimated. Mach et al[3] show ΔP_{op} to be equal to the valve spacing, S, times the static load fluid gradient, g_{ws}. For the design technique being used here, this relationship is more complex, as illustrated by Figure 9. Here, for ΔP_{opn} expressed in psi,

$$\Delta P_{opn} = \Delta P_s + A + B$$

where,

$$A = \Delta P_{vn-1} - C$$

$$B = 50 - \Delta P_{vn-1}$$

$$C = S \times g_g$$

therefore,

$$\Delta P_{opn} = \Delta P_s + [\Delta P_{vn-1} - (S \times g_g)] + [50 - \Delta P_{vn-1}]$$

which simplifies to,

$$\Delta P_{opn} = \Delta P_s - (S \times g_g) + 50 \quad \ldots\ldots\ldots \quad (2a)$$

or, for ΔP_{opn} expressed kpa,

$$\Delta P_{opn} = \Delta P_s - (S \times g_g) + 345 \quad \ldots\ldots\ldots \quad (2b)$$

The 50 psi (345 kPa) constant in equation (2a) ((2b)) is a factor which ensures that a differential pressure, sufficient to cause gas to enter the tubing, exists at a valve before the valve above closes during transfer down to that valve of the point of injection. (It can also be seen as a spacing safety factor which brings valves closer together.)

It is the 'spacing' differential pressure, ΔP_s, that, in this case, is equal to S times g_{ws}. Therefore, for a known g_{ws}, the choice of S automatically defines ΔP_s and vice-versa. Mach et al[3] show how the choice of operating differential (which is closely related to the spacing differential) should be influenced by the productivity index, J, of the well. For practical purposes, a valve spacing chart, Figure 10, which defines S and ΔP_s for a given well productivity index, was developed from operational experience for ATOC's offshore fields. The chart is a graphical representation of the following equation:

$$S = 500 - 250 \log J_o \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (3a)$$

where S is expressed in ft, or

$$S = 152.4 - 76.2 \log J_o \quad \ldots\ldots\ldots\ldots \quad (3b)$$

where S is expressed in m. Alternatively, based on pressures,

$$\Delta P_s = (500 - 250 \log J_o)\, g_{ws} \quad \ldots\ldots\ldots\ldots \quad (4a)$$

where ΔP_s is expressed in psi, and

$$\Delta P_s = (152.4 - 76.2 \log J_o) g_{ws} \qquad (4b)$$

where ΔP_s is expressed in kPa. The general form of the equation,

$$S = \alpha - \beta \log J_o \qquad (4c)$$

is such that the constant terms α, which controls the absolute value of S, and β, which controls the sensitivity of S to J_o, can readily be altered in response to any technical or economic factor which might influence the number of valves to be run. In this example, with J_o equal to 1.6 bbl/(psi-D) (0.037 m^3/(kPa-d)) and using Figure 10, S was found to be 450 ft and, for a g_{ws} of 0.465 psi/ft (10.52 kPa/m), ΔP_s was found to be 210 psi (1,450 kPa). Returning to equation (2a), with a g_g of 0.018 psi/ft (0.41 kPa/m), we then have:

$$\Delta P_{opn} = 210-(450 \times 0.018) + 50 = 252 \text{ psi } (1{,}737 \text{ kPa})$$

which is rounded off to 250 psi (1,725 kPa).

Basic Design Technique: The basis for the spacing and pressure setting of the valves is a design technique discussed in detail by Winkler and Smith[4]. This technique was familiar to ATOC engineers and a design procedure which was generally based on it had been used successfully at Galeota Point for several years. A particular strength of this technique is its use of a variable, ΔP_v, known also as the Additional Production Pressure Effect, APPE. This compensates for any difference in tubing pressure sensitivity between valves and minimises the risk of valve interference through unwelcome re-opening of valves above the point of injection.

Operating Bracket: Mach et al[3] and Kanu et al[5] discuss the need for this feature in a design. Present and future uncertainties in the data used for systems analysis, particularly the Inflow Performance Relationship for the well, mean that it is unrealistic to claim that systems analysis will provide the definitive depth of injection. It is, in fact, only an indication of the general area of operation to be expected early in the life of the well. The close spacing of valves around this 'provisional' operating valve depth ensures that reductions in P_{wf}, which result from downward transfer of the point of injection between valves, are smaller and more frequent during the life of the well, thereby tending to produce a state of continuous production optimisation. The higher valves in the bracket allow for a rising point of injection, perhaps as a result of waterflooding or other pressure maintenance activities in the reservoir.

The bracketed interval is constructed as described by Mach et al[3]. In this example, the top of the bracket was defined as the depth of injection which would result from pressure at the wellhead and in the tubing at the provisional design operating valve depth being 5% higher than predicted with the same ΔP_{op} as previously specified. The bottom of the bracket was found by assuming pressures 15% less than predicted.

Unloading Valves: The spacing of unloading valves follows, in general, the standard procedure. The first valve was not taken down to the theoretical fluid level, as it is normal practice to spot a viscous gel pill over the perforations during a workover, thus enabling a full column of fluid to be supported, while on some new completions, gas lift is used to unload the tubing prior to performing underbalanced, through tubing, perforating.

Unloading valves, spaced above the point at which the reservoir starts to feed in fluids to the tubing, are all given a 3/16 inch (4.75 mm) port. Unloading valves below this point were given port sizes capable of passing the volume of gas calculated by multiplying the feed in rate by the design IGLR. The feed in rate was determined by extending a load fluid gradient line down, from P_{tfmin} at valve depth, to the perforation depth. The pressure at that depth was then used to determine a corresponding flowrate from the IPR curve generated during systems analysis (Figure 8).

The pressure in the bellows of the unloading valves is based on an expected temperature at valve depth. This is found at the point at which a line drawn from static surface temperature to the flowing temperature at the point of feed-in intersects the valve depth.

Operating Bracket Valves: The depth of the first valve within the bracket is determined in the standard way, unless it is found to lie deeper than the top of the bracket by an amount greater than the pre-determined interval spacing within the bracket. In this case, it would be moved up to a depth equal to the top of the bracket, plus the intervalve spacing. The P_{tfmin} of the valve immediately above would then be found by extending a load fluid gradient line upwards from a point at the depth of the lower valve which is equal to the operating pressure of the valve at the depth of the lower valve, less the 50 psi (345 kPa) spacing safety factor (See Fig. 7 insert).

The depth of the remaining valves within the bracket are assigned by use of the predetermined spacing interval, S. The values of P_{tfmin} are found as described above.

Since all valves within the bracket are considered possible design operating valves they are given the same port size. This is the size of port which will pass the volume of gas determined by the design production rate and optimum IGLR given by systems analysis. In this case the production rate is 3,150 bb/D (500 m^3/d) and the IGLR is 1,000 scf/bbl (180 standard m^3/m^3), so the gas injection rate is 3.15 x 10^6 scf/D (89.2 x 10^3 standard m^3/d) and the port size necessary is 7/16 inch (11.1 mm).

If it is found that the P_{ivo} at surface of the two valves which straddle the provisional design operating valve depth are both significantly different from the P_{ivo} used in systems analysis, then the design may need to be restarted, with a better estimate of P_{ivo} at surface for the operating valve being used in systems analysis. In this case the difference was considered acceptable.

Valves Below the Operating Bracket: Some wells may need valves installed below the operating bracket in order to handle temporary or unexpected poor inflow performance, or eventual depletion. In most cases, especially deep wells where the operating bracket is well above the packer, there is no need nor economic justification for spacing valves as closely as they are within the bracket. Valves can therefore be spaced, for example, 1.5 or 2 times as far apart as they are within the bracket. In fact the spacing may be determined freely, within reason, to suit the situation. In the case of the example well it was decided to place two valves, on 800 ft (244 m) spacing intervals, between the last bracketed valve and the packer.

Increasing the spacing by a factor of two, increases the operating differential by a factor of two also and if pressure drops continue to be taken between the design operating pressures of successively deeper valves, the values of both P_{tfmin} and P_{ivo} become too low. Valves below the bracket are therefore designed to have the same value of P_{ivo} at surface as that of the last valve within the bracket. Since well production rates below the bracket are expected to be lower, the port size is reduced to a size with a port area which is equal to, or just greater than, half the port area of the bracket valves. In this case the size is 5/16 inch (7.9 mm).

Multipoint Injection: Multipoint injection lowers the productive potential of a well when it occurs over a large interval at shallow depth and prevents transfer down to a deeper valve. Over a smaller area, such as a portion of the operating bracket, the effect is not as damaging. The risk of this is minimised, however, by the drop in operating pressure taken between valves in the operating bracket. This problem has not been exhibited by the field examples discussed later.

Below the operating bracket, it is accepted that multipoint operation will be normal, although some higher valves may still close as the fluid gradient becomes lighter and tubing pressure at depth falls. It is assumed, however, that the productivity index of the well is no longer what it once was and that the inefficiency of multipoint operation is not as significant.

Port Sizing: Port sizing was done using charts based on the 'Thornhill-Craver' choke equation. It is obvious, however, from reading the report by Cook and Dotterweich[6] in which the equation is developed, that the equation cannot accurately represent the rate of gas flow through a gas lift valve. This problem will only be overcome when valve manufacturers publish comprehensive sets of gas passage performance charts for their valves, similar to those discussed by DeMoss and Tiemann[7].

FIELD RESULTS

The change from old to new design procedure was made in stages. The first step was the introduction of an operating bracket of closely spaced valves around the expected point of injection. Teak E16, completed in April 1984, was the first well to benefit from this. The flowing tubing pressure gradient curve used in this early design followed the old procedure and was a 100% water curve taken from a book of curves. The original, old style, design proposed for the well (see Table 4) would probably not have permitted gas injection below 3250 ft (991 m) TVD. The new design, while still based on a partially developed and imperfect procedure, was a big improvement. Analysis of the design in conjunction with well test and casing pressure data suggests that gas is entering the tubing within the operating bracket and possibly as deep as valve no. 6 at 3800 ft (1,158 m). This valve was designed to pass 2.0 x 10^6 scf/D (56 x 10^3 standard m^3/d), which is what the well has, on average, taken. The original design proposal, however, would not have been capable of passing this volume of gas through a single valve and inefficient multipoint injection, high in the well, would probably have resulted. Altogether, the original design proposal would have produced significantly less oil from the well.

Teak E10XX, completed in May 1984, was the second well where progress was made. This time a 50 psi (345 kPa) drop in injection pressure, which had been taken between the first and second valves to account for a 'theoretical' change from 'kick-off' to 'operating' pressure, was eliminated. 'Kick-off' pressure was found in reality to be a safe maximum continuously available operating pressure. Teak E10XX has been steadily producing over 3000 bbl/D (477 m^3/d) of oil since completion. Again, analysis of available information would suggest that gas is being injected through a valve in the heart of the bracketed interval.

Teak E4X, completed in June 1984, benefitted from the full system analysis approach in the estimation of an expected depth of injection related to a realistic flowing tubing pressure gradient curve. Ironically, this complex, high angle, multizone, gravel packed completion was not a success. The systems analysis work and the gas lift design were based on information that suggested the well could make up to 4000 bbl/D(636 m^3/d) of oil but it only produced 800 bbl/D(127 m^3/d), 95% water. This was not a problem, however, for the gas lift design and analysis of available information indicate that gas was injected into the tubing at the bottom valve, just over 300 ft (91 m) above the packer. The old procedure would have forced the lowest valve to be located much higher in the string following the constraint imposed by the convergence of the flowing tubing pressure and casing pressure gradient lines.

Due to an extensive development drilling and workover programme on the Teak E platform it has not yet been possible to run downhole pressure and temperature surveys in these wells, but surface data has been encouraging, showing that flowing tubing and casing pressures have remained stable since unloading was completed.

CONCLUSION

This paper demonstrates that significant incremental production can be achieved by a comprehensive approach to the problem of gas lift production optimisation. A review of operating practices in the light of basic principles can be valuable, no matter how well the operation appears to be running. The downhole gas lift design is of paramount importance. This design can be enhanced with the aid of systems analysis and by the incorporation of constant, productivity index related, valve spacing over an interval around the anticipated depth of injection, together with a drop in operating injection pressure between valves. This technique has successfully been applied with unbalanced, bellows charged, injection pressure operated, continuous flow gas lift valves in high rate offshore wells.

NOMENCLATURE

AP/AB	=	ratio of port area to effective bellows area.
APPE	=	additional production pressure effect, the pressure drop taken in operating pressure between valves, psi (kPa).
D_{TV}	=	true vertical depth, ft (m).
g_g	=	gas gradient, psi/ft (kPa/m).
g_{ws}	=	static load fluid gradient, psi/ft. (kPa/m).
J_o	=	productivity index for oil, bbl/(psi-D) (m^3/(kPa.d)).
P_{bt}	=	bellows pressure at downhole temperature, psi(kPa).
P_{ivo}	=	injection pressure at which valve operates, psi (kPa).
P_{tf}	=	flowing tubing pressure, psi (kPa).
P_{tro}	=	test rack pressure at which valve operates, psi (kPa).
P_{wf}	=	bottomhole flowing pressure, psi (kPa).
ΔP_{op}	=	operating pressure differential between casing and tubing, psi (kPa).
ΔP_s	=	differential pressure used in spacing valves within bracket, psi (kPa) .
ΔP_v	=	APPE (see above), psi (kPa).
q_{gi}	=	rate of gas injection scf/D (standard m^3/d).
q_L	=	rate of liquid production bbl/D (m^3/d).
S	=	constant spacing interval between valves within operating bracket, ft (m).
TVD	=	D_{TV} (see above)

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SI METRIC CONVERSION FACTOR

141.5/(131.5 + °API)	=	g/cm^3
bbl/D x 1.589 873 E-01	=	m^3/d
bbl/(psi-D) x 2.305 916 E-02	=	$m^3/(kPa.d)$
(°F-32)/1.8	=	°C
ft. x 3.048* E-01	=	m
ft^3/D x 2.831 685 E-02	=	m^3/d
in x 2.54* E + 01	=	mm
mile x 1.609 344* E + 00	=	km
psi x 6.894 757 E + 00	=	kPa
psi/ft x 2.262 059 E + 01	=	kPa/m
scf/bbl x 1.801 175 E - 01	=	'standard' m^3/m^3

* Conversion Factor is exact

Table 1

Impact Of One Well On A Gathering System - Teak B Platform.

Well No.	Tubing Pressure psi (kPa)	PRODUCTION RATES Oil bbl/D (m^3/d)	Water bbl/D (m^3/d)	Gas 10^3scf/D (10^3m^3/d)	TEAK B Gas Injection Rate 10^3scf/D (10^3m^3/d)	TEAK A Pipeline Pressure psi (kPa)	Separator Pressure psi (kPa)
B3A	185 (1275)	226 (35.9)	1166 (185.4)	722 (20.4)	762 (21.6)		
B7X	190 (1310)	1168 (185.7)	- (-)	155 (4.4)	3107 (88.0)		
B10	210 (1450)	515 (81.9)	901 (143.3)	120 (3.4)	819 (23.2)		
PLATFORM TOTAL BEFORE B3A SHUT-IN		1909 (303.5)	2067 (328.7)	997 (28.2)	4688 (132.8)	150 (1035)	27 (185)
B7X	160 (1105)	1227 (195.1)	- (-)	371 (10.5)	2119 (60.0)		
B10	180 (1240)	637 (101.3)	971 (154.4)	128 (3.6)	1026 (29.0)		
PLATFORM TOTAL AFTER B3A SHUT-IN		1864 (296.4)	971 (154.4)	499 (14.1)	3145 (89.0)	105 (725)	27 (185)
DIFFERENCE IN TOTALS		45 (7.1)	1096 (174.3)	498 (14.1)	1543 (43.8)	50 (310)	-

Table 2

Well Data For Gas Lift Design Example.

Depth to perforation mid-point	:	9238 ft (2815 m) M.D.
Hole Angle	:	30°
Tubing Inner Diameter	:	3.96 in. (100 mm)
Flowing Temperature at Surface	:	110°F (43°C)
Flowing Temperature at Bottom	:	175°F (79°C)
Flowing Pressure at Surface	:	100 psi (689.5 kPa)
Flowing Pressure at Bottom from Test	:	2250 psi (15515 kPa)
Shut-in Pressure at Bottom from Test	:	2750 psi (18961 kPa)
Liquid Rate from Test	:	1250 bbl/D (198.75 m^3/d)
Water Cut	:	33%
Formation Gas Oil Ratio	:	700 scf/bbl (126 standard m^3/m^3)
Oil Gravity (Density)	:	27° API (0.89 gm/cm^3)
Water S.G. (Relative Density)	:	1.02
Gas S.G. (Relative Density)	:	0.6
Design Casing Operating Pressure	:	800 psi (5516 kPa)
Design Injection Gas Liquid Ratio	:	1000 scf/bbl (180 standard m^3/m^3)
Design Difference in pressure between tubing and Casing at Operating Gas Lift Valve	:	250 psi (1690 kPa)

Table 3

Gas Lift Design Example Results.

Valve No.	D_{tv} ft	P_{tf} Min psi	P_{tf} Max psi	P_{ivo} psi	P_{ivo} @ Surface psi	P_{ivo} for Dn-1 @ Dn psi	Pbt psi	P_{tro} @ 60°F psi	T @ Depth °F	q_L bbl/D	q_{gi} 10^3ft/D	Port Size	AP/AB	APPE	Σ APPE
1	1650	270	535	900	875	-	876	800	110	-	-	3/16	0.038	10	10
2	2950	410	685	915	865	925	896	805	133	-	-	3/16	0.038	10	20
3	3950	520	750	920	855	930	893	815	142	892	892	1/4	0.067	15	35
4	4750	670	810	920	840	935	870	915	149	3150	3150	7/16	0.201	35	70
5	5200	645	795	895	805	930	845	885	152	3150	3150	7/16	0.201	40	110
6	5650	610	770	865	765	905	814	845	156	3150	3150	7/16	0.201	40	150
7	6100	470	-	835	725	875	761	785	159	3150	3150	7/16	0.201	-	-
8	6900	485	-	850	725	-	812	738	166	-	-	5/16	0.104	-	-
9	7700		-	-	-	-	(333)	300*	172	-	-	5/16	0.104	-	-

* Predetermined Low Value
( ) Derived from *

Table 4

Well Teak E-16 Gas Lift Design Comparison.

Well Completion Equipment: 4½ inch production tubing and 1½ inch gas lift valves above 5100 ft TVD, 3½ inch tubing and 1 inch gas lift valves below 5100 ft TVD (inside 7 inch liner). Packer at 6600 ft TVD. Hole angle, 34°.

	Original Proposal	Actual Design Installed
Objective:	To get valves as close as possible to bottom using the standard design technique.	To optimise production from the well using sound design principles.
Minimum Fluid Gradient Curve:	500 BLPD, 90% Water	4000 BLPD, 100% Water

Valve No.	D_{TV} (ft)	P_{tf} (psi)	P_{ivo} (psi)	P_{ivo} @S (psi)	Port Size	D_{TV} (ft)	P_{tf} (psi)	P_{ivo} (psi)	P_{ivo} @S (psi)	Port Size
1	1398	190	677	650	3/16	1450	295	775	750*	5/16
2	2380	257	687	641	1/4	2390	440	769	729*	5/16
3	3250	322	685	623	1/4	2900	520	712	664	3/8
4	3950	383	682	607	5/16	3200	510	699	649	7/16
5	4500	430	670	585	5/16	3500	495	683	625	7/16
6	4930	470	661	567	5/16	3800	480	661	601	7/16
7	5250	500	652	553	1/4	4100	450	643	577	7/16
8	5500	520	641	536	1/4	4400	432	622	551	7/16
9	5800	540	634	524	1/4	4700	275	601	524	7/16
10						5300	225	551	467	3/8
11						5900	95	425	331	3/8
12						6500	-	285	225	3/8

* 50 psi higher kick-off pressure used for top two valves

Well Test Results

Date YY/MM	Tubing Pressure psi(kPa)	Production Rate Oil bbl/D(m^3/d)	Water bbl/D(m^3/d)	Gas 10^3ft^3/D(10^3m^3/d)	Casing Pressure psi(kPa)	Gas Injection Rate 10^3ft^3/D(10^3m^3/d)
84/07	385 (2655)	5569 (885.4)	293 (46.6)	3021 (85.5)	0.0	0.0
85/04	140 (965)	2450 (389.5)	1501 (238.7)	1551 (43.9)	615 (4240)	1685 (47.7)
86/05	110 (758)	1365 (217.0)	1554 (247.1)	713 (20.2)	615 (4240)	2591 (73.4)

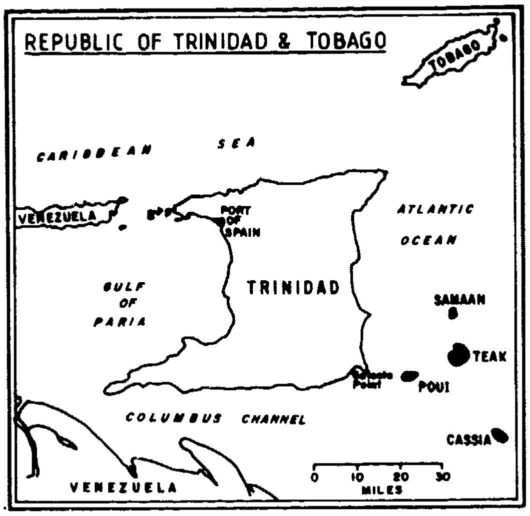


Fig. 1—Field location map.

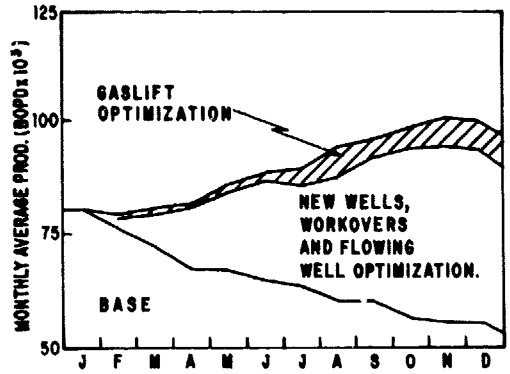
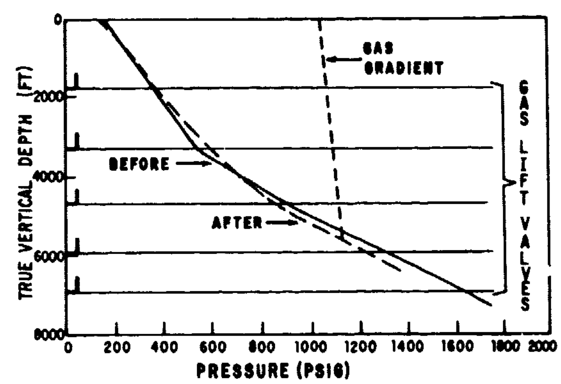


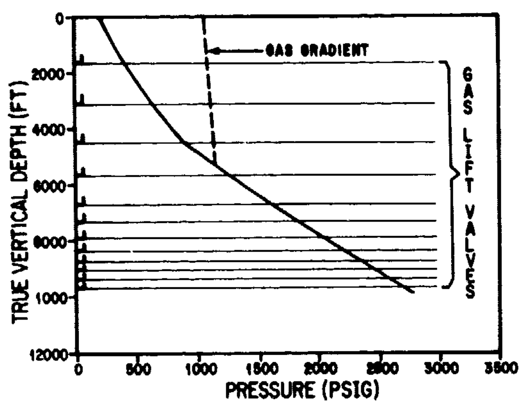
Fig. 2—A.T.O.C. oil production during 1984.



WELL TESTS

	TUBING PRESSURE psi (kPa)	PRODUCTION OIL bbl/d (m^3/d)	PRODUCTION WATER bbl/d (m^3/d)	RATE GAS $10^3 ft^3$/d $10^3 m^3$/d	CASING PRESSURE psi (kPa)	GAS INJECTION RATE $10^3 ft^3$/d $10^3 m^3$/d
BEFORE	160 (1103)	1002 (159)	788 (125)	501 (14.2)	1040 (7171)	1574 (44.6)
AFTER	155 (1069)	1669 (265)	1259 (200)	824 (23.3)	1060 (7309)	1052 (29.8)

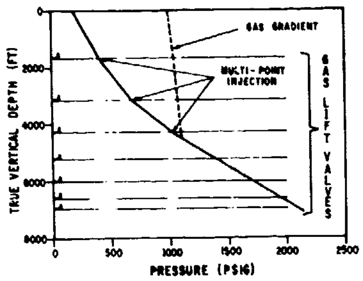
Fig. 3—Samaan C-7 flowing pressure gradient survcys before and after valve replacement.



WELL TEST

TUBING PRESSURE Psi (kPa)	PRODUCTION OIL bbl/d (m^3/d)	PRODUCTION WATER bbl/d (m^3/d)	RATE GAS $10^3 ft^3$/d ($10^3 m^3$/d)	CASING PRESSURE Psi (kPa)	GAS INJECTION RATE $10^3 ft^3$/d ($10^3 m^3$/d)
185 (1275)	475 (76)	4274 (680)	1370 (38.8)	1050 (7240)	1560 (44.2)

Fig. 4—Samaan B-1 flowing pressure gradient survey.



WELL TESTS

	TUBING PRESSURE psi (kPa)	PRODUCTION OIL bbl/d (m^3/d)	RATE WATER bbl/d (m^3/d)	GAS 10^3 ft^3/d 10^3 m^3/d	CASING PRESSURE psi (kPa)	GAS INJECTION RATE 10^3 ft^3/d 10^3 m^3/d
BEFORE	200 (1379)	198 (31)	1452 (231)	464 (13.1)	1020 (7033)	2257 (63.9)
AFTER	195 (1345)	512 (81)	4146 (659)	588 (16.6)	950 (6550)	1770 (50.1)

Fig. 5—Samaan B-5 flowing pressure gradient survey.

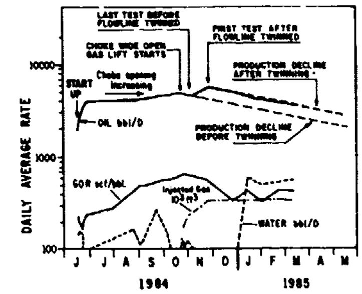


Fig. 6—Teak C-2RD historical production.

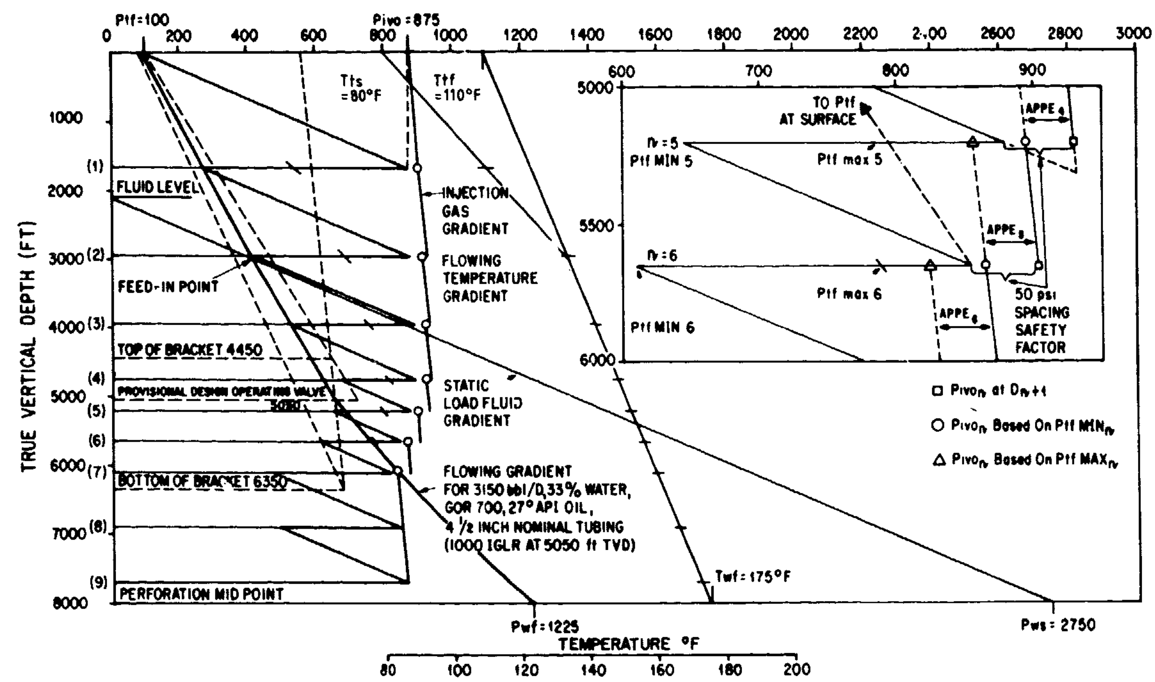


Fig. 7—Graphical design example.

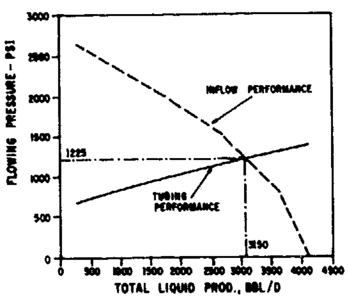


Fig. 8—Design example system performance graph.

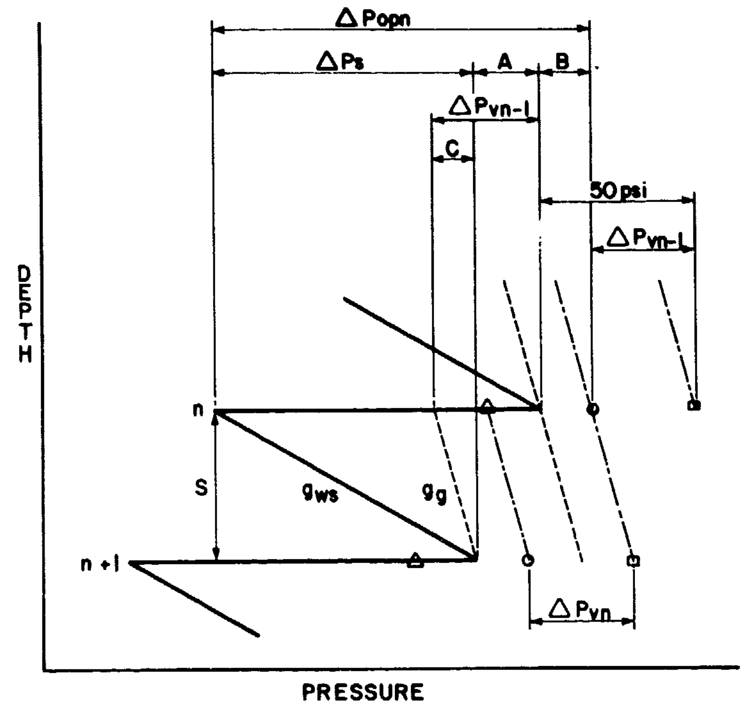


Fig. 9—Derivation of operating differential pressure.

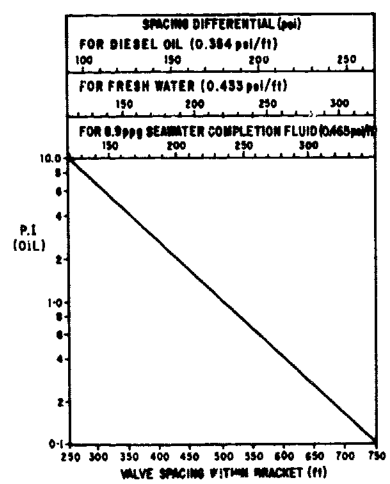


Fig. 10—Valve spacing chart.