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Gas-Lift Design and Performance Analysis in the North West Hutton Field

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Summary. Experience at the North West Hutton field has emphasized the importance of properly understanding gas-lift valve behavior. In conjunction with regular downhole pressure and temperature surveys, this has helped maximize production from gas-lifted wells. This paper emphasizes the importance of the downhole temperature survey and of simultaneous well testing with downhole survey work. The paper shows how this kind of performance analysis can reveal such classic problems as leaking valves and such fundamental problems as mandrel spacing that does not match well performance. These analysis techniques also can predict the consequences of increasing available surface injection pressure and have led naturally to the development of more flexible design procedures that optimize production from wells whose performance may be either unpredictable or unlikely to permit a deep point of injection. Field application of these design procedures also is discussed.

Introduction

The North West Hutton field is located in the East Shetland basin, in License Block 211/27 of the U.K. North Sea, approximately 300 miles northeast of Aberdeen. The reservoir lies at 12,000 ft subsea in the Middle Jurassic Brent group sandstones. It is characterized by a series of tilted fault blocks and extreme vertical and horizontal heterogeneity in its five major sand units.

Field production began in April 1983 following the installation of a 40-slot, twin-rig, fixed steel platform in 475 ft of water and the tieback of seven predrilled wells. By June 1983, the average daily oil production was almost 70,000 B/D. Reservoir pressure and production initially declined rapidly. To arrest this decline, water injection was started in Feb. 1984. Significant water production began in Sept. 1984, and the first well was placed on gas lift, using recirculated sales gas, in Oct. 1984. By Dec. 1985, all producing wells were being continuously gas-lifted (**Fig. 1**).

Wells typically are completed with either 5½- or 4½-in. production tubing and a deep-set 9⅝-in. production packer located just above the top of the 7-in. liner that penetrates the reservoir. Gas-lift gas circulates down the casing/tubing annulus and enters the tubing through a wireline-retrievable, 1½-in. gas-lift valve set inside a sidepocket mandrel in the tubing string. Wellbore deviation is in some cases as high as 70° and measured depth can be as deep as 19,000 ft.

With both increasing water cut in several key wells and a general repressurizing of the reservoir occurring as a result of water injection, we found that the original sales-gas discharge pressure of 1,600 psig was not adequate for injecting gas-lift gas as deep as desired into the production tubing. Consequently, in Sept. 1985, a backpressure-control valve was installed on the sales-gas line to boost the pressure of gas circulating for gas lift to 2,000 psig (**Fig. 2**).

With all producing wells on gas lift and with water production rates increasing as oil and associated gas production declined, a need soon arose for increased gas-lift gas rates. This increase was achieved in Feb. 1987 when the platform gas-compression packages were modified to boost their capacity from the original 40 MMscf/D to more than 70 MMscf/D. By Dec. 1988 this capacity was being fully utilized, continuously lifting 20 producing wells.

Well 211/27-A01—A Case Study

Gas-lift design and performance analysis in the North West Hutton field is best discussed in the context of a case study of one particularly important and interesting well, Well 211/27-A01, which is referred to here as Well A01.

Well A01 was the first well in the North West Hutton field to be brought on production (April 1983). Initially, it flowed naturally and tested oil at more than 26,000 B/D, with 0% water cut. By Feb. 1985, liquid production had fallen to less than 8,000 B/D and a 21% water cut had developed following injection-water breakthrough in Dec. 1984. It was predicted that the well would cease to flow once water cut reached 30%, and so the well was worked over and a gas-lift completion string was run. The valves were designed to unload and lift a well producing 6,000 BLPD with a 70% water cut. Initial gas-lifted liquid production was, in fact, more than 12,000 B/D with a 40% water cut. This result emphasized the need for more flexible gas-lift designs, particularly where production performance may change rapidly.

Increased Casing Pressure Requires Replacement Valves. The increase in available gas-lift gas casing pressure in Sept. 1985 was immediately put to use in newly completed wells. All gas-lift designs from that point onward were based on a surface casing pressure of 1,850 psig rather than the 1,500 psig previously available. This meant that deeper points of injection could be achieved, resulting in either increased production or reduced gas-lift gas-injection rates being required to reach the same production rate. These benefits, however, do not automatically carry over to wells where existing valves have been designed for a lower available casing pressure.

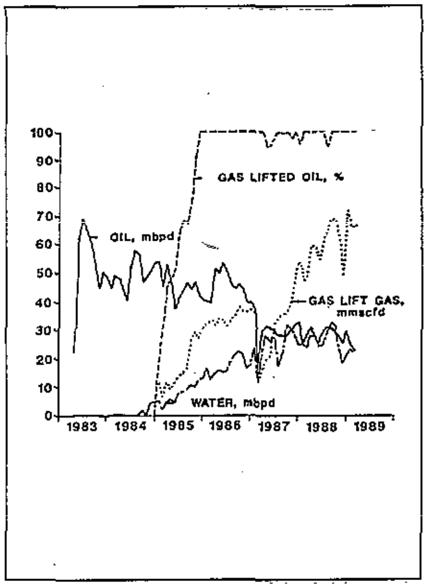

Fig. 1—North West Hutton production.

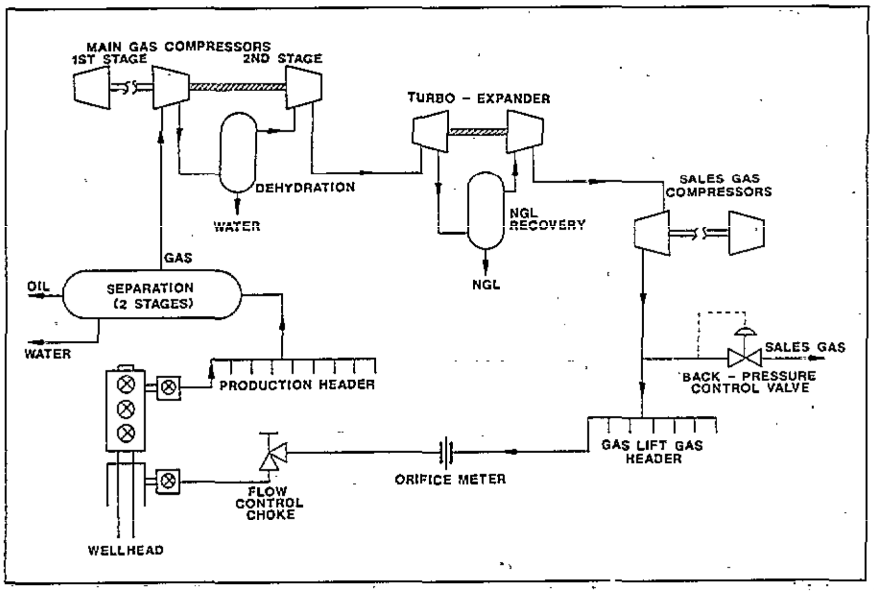

Fig. 2—North West Hutton platform gas-lift gas circulation system. (NGL = natural gas liquids.)

In Oct. 1985 a routine downhole pressure and temperature survey using Amerada™ gauges run on wireline was carried out in Well A01. The results (Fig. 3) suggested that inefficient multipoint injection was taking place through the top three valves. Casing pressure at the time was higher than the design casing pressure and two shallow valves had reopened.

Running temperature gauges with downhole pressure surveys is important because a drop in temperature over a valve depth clearly indicates a point of injection. This phenomenon is particularly useful in detecting a leaking valve at a shallow depth where the larger volumes of gas present in the production tubing can obscure the influence of gas injection on the pressure gradient. Equally important, but less frequently appreciated, is the fact that temperature measurements at depth enable us to analyze valve performance and also provide vital information for the design of replacement valves. Drawing a straight-line relationship between flowline temperature at surface and bottomhole temperature is a dangerous oversimplification in deepwater offshore production where significant cooling of the produced fluids occurs between the seabed and the wellhead. A valve that experiences a much higher temperature than it was designed for is likely to be found closed when it should be open and vice versa.

Note that a production test was carried out simultaneously with the survey. Thus, the survey data become immensely more valuable because correlations of multiphase-flow pressure vs. depth can be used to match the data and then can be manipulated to simulate altered circumstances like a new depth of injection or new injection-gas/liquid ratio. Having been tied to real data, the results predicted by the simulations can be used with some confidence.

Had the temperature profile in Well A01 been known earlier, it would have been possible, given the production test data and the casing pressure at surface, to predict that the top three valves were open and passing gas. **Table 1** compares the calculated tubing pressure required to open the valve given the measured temperature at depth and the calculated casing pressure at depth, p_{to}, with the actual measured tubing pressure at depth, p_t. (A more complete discussion of p_{to} is provided in the Appendix.) Table 1 shows that Valve 1 is calculated to be on the point of opening, while all lower valves are clearly open. Tubing pressure measured at Valve 4 is actually higher than the calculated casing pressure, so gas cannot pass from the casing into the tubing at Valve 4 or at any deeper

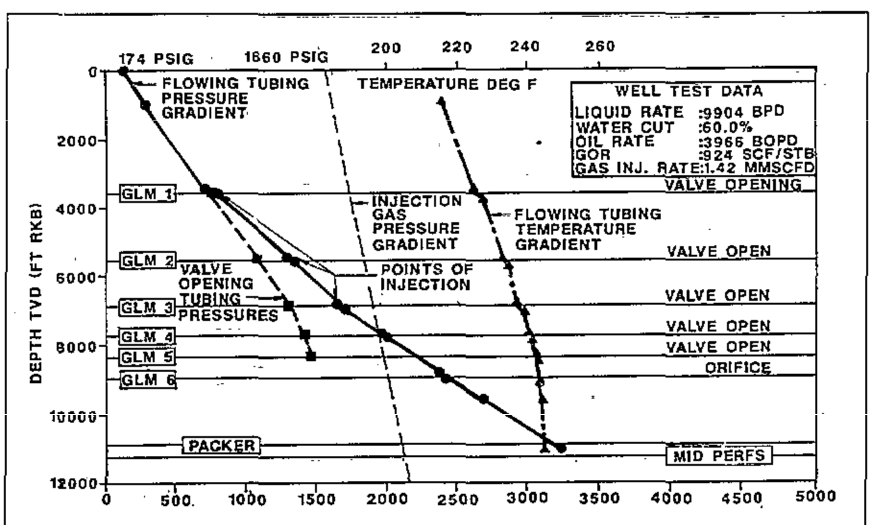

Fig. 3—Well A01 tubing pressure and temperature gradient survey, Oct. 10, 1985. (RKB = rotary Kelly bushing; GLM = gas-lift mandrel.)

"Performance analysis is a valuable aid in the development of a flexible design procedure. Where appropriate, application of a flexible design procedure can yield higher production rates than are possible with more conventional design procedures."

TABLE 1—WELL A01 VALVE-OPENING TUBING PRESSURES, OCT. 10, 1985

Valve	D_{tv} (ft)	T_{dv} (°F)	p_{vo} (psig)	p_v (psig)	F_e	p_{cf} (psig)	p_{to} (psig)	p_t (psig)	Valve Position
	Surface					1,660			
1	3,612	230	870	1,335	0.46	1,806	782	782	Opening
2	5,529	235	975	1,501	0.46	1,883	1,053	1,304	Open
3	6,893	239	1060	1,637	0.46	1,938	1,284	1,714	Open
4	7,744	240	1095	1,691	0.46	1,972	1,361	1,995	Open
5	8,296	242	1110	1,720	0.46	1,994	1,398	2,213	Open
6	8,845	243	*	*	*	2,016	*	2,340	*

*Orifice valve.

TABLE 3—WELL A01 NEW MANDREL DEPTHS

	Proposed (ft)		Installed (ft)	
Mandrel	D_{tv}	D_m	D_{tv}	D_m
1	3,210	3,260	3,210	3,260
2	5,650	6,460	5,405	6,135
3	7,750	9,270	7,015	8,290
4	9,550	11,415	8,095	9,695
5	10,415	12,455	8,895	10,650
6	—	—	9,690	11,585
7	—	—	10,415	12,455
Packer	10,535	12,595	10,535	12,595

TABLE 2—WELL A01 WELL-TEST RESULTS

Date	Total Liquid (STB/D)	Oil (STB/D)	Water Cut (%)	GOR (scf/STB)	p_t (psig)	Gas Injected (MMscf/D)	p_{cfs} (psig)
Oct. 19, 1985	10,808	3,024	72	928	279	3.02	1,705
Nov. 4, 1985	13,013	3,554	72	887	294	2.95	1,882
Increase	2,205	530					

valve. Most gas, therefore, is entering through Valves 2 and 3.

Valves 1 through 4 were pulled on Oct. 29, 1985. Valve inspection confirmed the analysis. Valve 1 was found to have a p_{vc} slightly lower than originally set. Thus, Valve 1 had a greater tendency to open than the calculations revealed. Valves 2 and 3 were found to have heavy scale deposits (mainly calcium sulfate) below the valve seat. In a high-water-cut well, scale deposits are good indicators that gas has been continuously injected through these valves. These deposits also partly explain why Valves 2 and 3 were incapable of passing as much gas as should have been possible for the given casing and tubing pressures and the valve pressure, p_v, trim, and temperature.

Table 2 gives the results of two well tests, one before and one after the valve replacement work. An increase of more than 500 BOPD was seen. It was apparent, however, that the recently increased gas-lift casing pressure still was not adequate to lift the well effectively enough to sustain a reasonably low flowing bottomhole pressure (BHP) in the face of the increasing volumes of injection water now being produced. A more radical solution was to isolate the main water-producing layers with straddle packers. This required a workover and thus provided the opportunity to install a more appropriate gas-lift design.

A More Flexible Design. Mach *et al.*[1] discuss the concept of an "error envelope" or "bracketed interval" of equally spaced mandrels around an anticipated depth of injection. This concept is particularly helpful in wells, like those in the North West Hutton field, where inflow performance relationships are either difficult to define (owing to complex multilayer production) or changing rapidly. Some success has been reported[2] in applying this technique to offshore fields in Trinidad.

The objective of a gas-lift design is to specify a series of valves and mandrel depths that will successfully unload a well and will then behave consistently when production performance deviates from design assumptions. Unfortunately, conventional design techniques are limited to unloading the well to a particular depth, which, in turn, is limited by the intersection of the casing pressure gradient and the anticipated flowing tubing pressure gradient. The bottom mandrel is located at this depth and an orifice is installed as the continuous injection valve. Mandrel spacing above the point of injection is governed more by the load fluid gradient than by considerations of future well performance. Thus, if a well is expected to be a prolific producer but is not, the bottom mandrel may be stranded well above packer depth and the drawdown of flowing BHP achievable with gas lift may be restricted.

The bottom mandrel in the original gas-lift design for Well A01 is located almost 1,700 ft true vertical depth (TVD) above the packer. This could have been a serious handicap had a successful water-shutoff workover been carried out through the tubing. Conversely, if the original design had been used and injection-water breakthrough increased, the point of injection would have jumped from Valve 3 to Valve 2, representing a TVD change of more than 1,350 ft. The consequent large step change in flowing BHP would not indicate a truly optimized gas-lift design.

The engineer planning the workover estimated that, following successful water shutoff, the well would produce between 5,750 and 8,250 B/D of water-free oil with a flowing BHP around 2,000 psig. For this production rate, assuming an 11-lbm/gal workover fluid to control reservoir layers receiving strong waterflood support and a maximum available surface casing pressure of 1,850 psig, a conventional design with only five mandrels was prepared (**Table 3**).

Knowing the well's past performance, however, and being aware of the possibility that the straddle packer arrangement might fail, we decided to make the design flexible. Because the anticipated point of injection was immediately above the packer, a bracketed interval of four equally spaced mandrels was established in the bottom 2,300 ft of the tubing string. The number of extra mandrels used was limited because this was the first installation of its kind in the North West Hutton field.

The workover successfully increased oil production to more than 8,000 B/D, but more than 4,000 B/D of water continued to be produced. A downhole pressure and temperature survey in April 1986 confirmed the success of the revised gas-lift design in coping with production rates significantly different from those that were anticipated. Injection was found to be taking place at Valve 5 at 8,895 ft (TVD) (**Fig. 4**), 1,100 ft deeper than would have been possible in the conventional five-mandrel design, which, consequently, would have produced at least 300 B/D less oil.

Because of the low injection-gas/liquid ratio at the time of the survey (gas injection had been cut back for operational reasons at that time), the change in pressure gradient at the point of injection is relatively subtle. Unfortunately, the temperature survey, although useful for future valve redesign work, is not very good. In this situation the calculation of valve-opening tubing pressure provides useful confirmation of what should be happening in the absence of any obvious signs to the contrary. **Table 4** reveals that only Valve 5 is both open and in a position where casing pressure is higher than tubing pressure, and so it is confirmed to be the single point of gas injection.

On June 14, 1986, after it had been shut in temporarily to facilitate a wireline drift run, the well would not take gas-lift gas. The well was now flowing naturally but at a rate of 8,000 BLPD with a 63% water cut.

Analysis indicated that Valves 1 through 3 should be closed, as designed, and that casing pressure was insufficient to allow injection at Valves 6 and below. Valves 4 and 5, however, should have been open and passing gas. Inspection of those two valves after pulling revealed that both were heavily coated with scale. The passage beneath the valve seat in Valve 4 was virtually blocked,

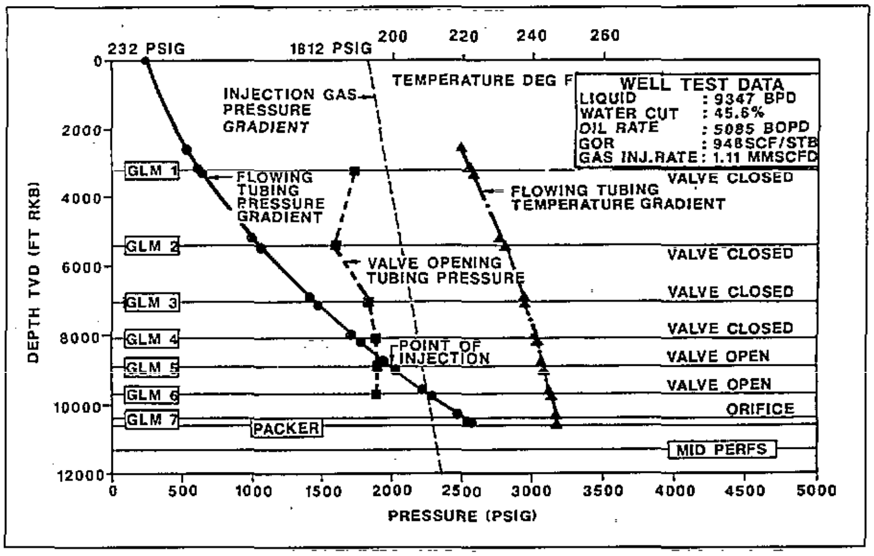

Fig. 4—Well A01 tubing pressure and temperature gradient survey, April 9, 1986.

while the nose cone of Valve 5, which proved hard to pull and which had been the point of injection in April, was the area of heaviest scaling. That gas passage could be totally blocked by scale buildup, and particularly, that this could occur around the bottom of the mandrel sidepocket so that the valve itself did not appear blocked (as with Valve 5) help explain why Valve 3, in the Oct. 1985 survey, did not appear to be passing a significant volume of gas with a more-than-adequate differential pressure available. (Now, a combined scale/corrosion inhibitor is injected into the gas-lift gas at surface and the problem appears to be under control.)

We decided to replace Valves 4 through 6. All three replacement valves were given larger port sizes than the originals to permit higher gas injection rates, and the test rack pressures were modified accordingly to retain consistency with the existing design.

A second downhole pressure and temperature survey was run in this completion on June 24, 1986. Compared with its natural flow potential, gas lift had boosted liquid production to more than 11,000 B/D with a 70% water cut. Compared with the April survey, the point of injection had been forced upward by rising tubing pressure at depth to Valve 4 at the top of the bracketed interval of equally spaced mandrels (Fig. 5). The same phenomenon would have been experienced by the conventional five-mandrel design under these circumstances, with Valve 2 being the new point of injection at a shallower depth (2,500 ft) than was attained by the more flexible design approach.

With a relatively low injection-gas/liquid ratio, the change in tubing pressure gradient at the point of injection is subtle, and again, the temperature survey is relatively poor. Valve-opening tubing-pressure calculations are therefore helpful in confirming that single-point injection should occur even though the casing pressure at surface is 65 psi higher than the design maximum value.

Table 5 presents results of these calculations.

Note that increased casing pressures will reduce p_{to} values. Comparison of Tables 4 and 5 reveals that the effect in this case is minimal, partly because the valves have relatively large port sizes, which make them less sensitive to casing pressure, and partly because of the offsetting influence of increased temperatures. For a small ported valve, a small rise in casing pressure can cause a dramatic drop in the tubing pressure required for the valve to open.

Gas-Passage Performance. One major problem with the gas-lift design for Well A01 was the gas-passage capacity of the valves. As designed, Valve 4 has a maximum capacity of almost 4 MMscf/D (corrected for temperature and a gas specific gravity of 0.71). Actual tubing pressure, however, was too close to the casing pressure and the valve could not deliver the volume desired (Fig. 6).

Had this situation been foreseen, we could have replaced Valve 4 with two mandrels sized to give, in combination, the desired flow rate. We also could have replaced the valve with an orifice, which is capable of a much higher flow capacity. The decision to perform a wireline valve replacement must account for the risk factor related to wireline work in deep, deviated, scale-prone wells. Wireline work in the North West Hutton field has generally been very successful, but problems have occurred, causing considerable deferred production, and in the worst cases, the need for full-scale workovers. Another factor in a well with rapidly changing performance is the potential need to replace the orifice within a short time with another valve or a dummy. As pointed out by Winkler,[3] gas-passage performance is an area requiring further work.

Well 211/27-A31—Flexible Design Taken a Stage Further

As water production increased in Well A01, another water-shutoff workover was required. This time an attempt was made to shut off the bottomwater producing layer with through-tubing bridge plugs and cement, both placed by coiled tubing. The work was partially successful but created a legacy of mechanical problems that eventually led to the well being plugged and sidetracked as Well 211/27-A31 (referred to here as Well A31) in Aug. 1987.

TABLE 4—WELL A01 VALVE-OPENING TUBING PRESSURES, APRIL 9, 1986

Valve	D_{tv} (ft)	T_{dv} (°F)	p_{vc} (psig)	p_v (psig)	F_e	p_{cf} (psig)	p_{to} (psig)	p_t (psig)	Valve Position
	Surface					1,812			
1	3,210	222	1,250	1,883	0.34	1,960	1,734	623	Closed
2	5,405	233	1,180	1,847	0.46	2,060	1,597	1,046	Closed
3	7,015	238	1,258	1,986	0.46	2,120	1,829	1,441	Closed
4	8,095	242	1,278	2,046	0.46	2,180	1,889	1,743	Closed
5	8,895	244	1,289	2,068	0.46	2,210	1,901	1,987	Open
6	9,690	246	1,296	2,084	0.46	2,250	1,889	2,263	Open
7	10,414	247	*	*	*	2,275	*	2,516	*

*Orifice valve.

TABLE 5—WELL A01 VALVE-OPENING TUBING PRESSURES, JUNE 24, 1986

Valve	D_{tv} (ft)	T_{dv} (°F)	p_{vc} (psig)	p_v (psig)	F_e	p_{cf} (psig)	p_{to} (psig)	p_t (psig)	Valve Position
	Surface					1,915			
1	3,210	238	1,250	1,844	0.34	2,065	1,711	740	Closed
2	5,405	245	1,180	1,895	0.46	2,165	1,576	1,302	Closed
3	7,015	249	1,258	2,045	0.46	2,240	1,813	1,789	Closed
4	8,095	252	1,250	2,025	0.60	2,290	1,847	2,140	Open
5	8,895	253	1,260	2,047	0.60	2,330	1,859	2,443	Open
6	9,690	254	1,265	2,058	0.60	2,365	1,853	2,748	Open
7	10,414	255	*	*	*	2,400	*	3,028	*

*Orifice valve.

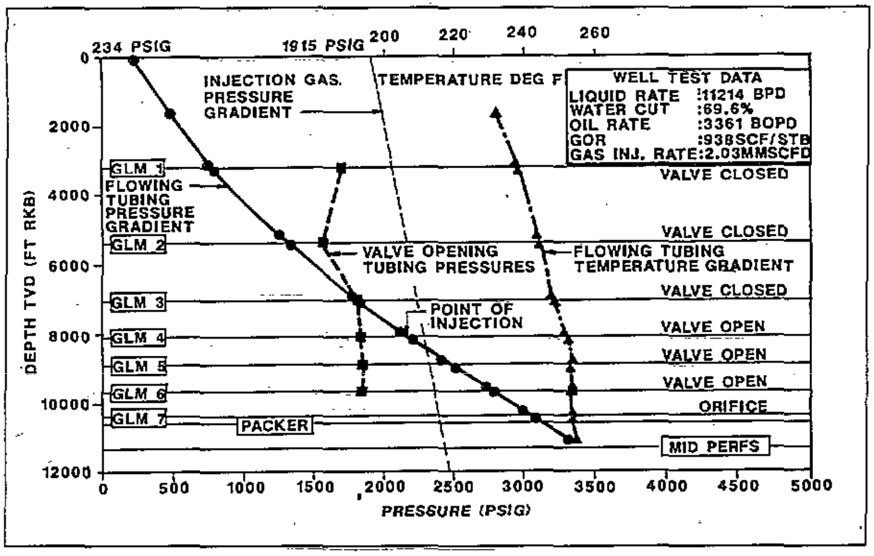

Fig. 5—Well A01 tubing pressure and temperature gradient survey, June 24, 1986.

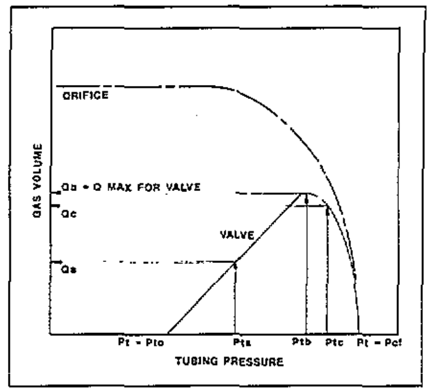

Fig. 6—Valve gas-passage performance.

The official oil-production prediction was that Well A31 would at first produce 3,000 B/D with 0% water cut and then fall to 1,300 B/D with 35% water cut after the first year. Knowledge of Well A01's history, however, led to a more cautious approach to gas-lift design.

Design Technique. *Given the extremely* wide range of possible production performance from Well A31, a more radical deviation from conventional design philosophy was taken. Instead of spacing mandrels on the basis of an assumed objective tubing-pressure-gradient curve, a preset spacing pattern was selected (see **Table 6 and Fig. 7**). This pattern increased the total number of mandrels installed to nine, thus providing more flexibility with respect to depth of injection while retaining a bias in favor of closer spacing deeper in the well around the anticipated depth of injection.

The standard design technique, which was successfully used by the gas-lift equipment vendor on more predictable, less prolific North West Hutton wells, is based on the use of a constant surface casing pressure. Design casing pressure, like the objective gradient curve, is an assumption; in reality, its value depends on many other variables. It is helpful to view the curve simply as a logical means of establishing consistency in the relationship between valves during the design procedure. The same is true for design techniques where casing pressure is dropped by either fixed or variable amounts between valves.

A technique based on taking a 50-psi drop in casing pressure between valves on the way down was considered best suited to the design objectives for Well A31. In theory the pressure drop helps ensure that upper valves will close and stay closed once operation has moved to a lower valve and thus promote stable gas-lift production.

The tubing opening pressure, p_{to}, for each valve was chosen by taking a fluid gradient from the casing pressure at depth for the valve below up to the depth of the valve of interest. The fluid gradient was varied from kill fluid weight near surface to formation water weight above the packer. This ensured that the well would unload under the most adverse conditions, while minimizing the risk of unstable multipoint injection.

Given the uncertainty that surrounded the gas-lift demand of the well, we decided to size the gas-lift valve trim by common sense rather than detailed design (i.e., smaller trim for unloading valves and larger trim for potential operating valves). Likewise, we decided not to double up the mandrels containing 1-in. valves (in use because of mandrel OD restrictions inside the high-set 7-in. liner) and to accept that, in the event of a high gas demand being experienced at that depth, multipoint injection over a limited interval could develop to overcome the gas-throughput limitations of the smaller valves.

Performance Analysis of the New Design. An equipment failure during the 7-in. liner cementing job resulted in poor isolation of key reservoir layers. Consequently, when the well was perforated, its performance was dramatically different from prediction. Once the well settled down, the oil rate was remarkably close to predictions. The water cut, however, was quite different. Initial tests yielded more than 22,000 BLPD at 96% water cut, flowing naturally.

Gas lift was first applied to the well in mid-Sept. 1987 when the well was producing more than 16,000 BLPD at 87% water cut. Simulation combined with valve-opening tubing-pressure analysis suggests that the gas was being injected through Valve 2.

The first downhole pressure and temperature survey was conducted in Nov. 1987 when the well was producing just under 10,500 BLPD at 69% water cut. Injection occurred through Valve 5 (**Fig. 8**). A second survey was run in June 1988 when the well was producing 6,600 BLPD at 70% water cut (**Fig. 9**). Injection occurred through both Valves 8 and 9, the 1-in. orifice valve on bottom being unable to handle the gas demand on its own with the differential pressure available to it. Despite multipoint injection, the well was producing in a stable fashion.

Temperature drops across valve depths clearly indicated the point of injection in

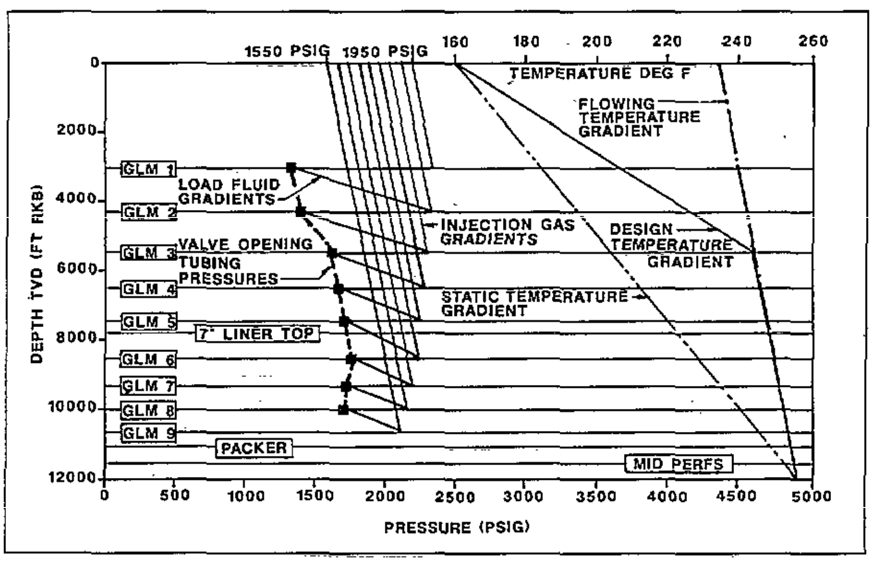

Fig. 7—Well A31 graphical design.

both surveys. Conversely, the absence of temperature drops at other valves offered reassurance that valves that previously acted as operating valves had successfully closed once the point of injection was transferred downhole.

Well A31 provides an excellent example of the inherent flexibility of gas lift as an artificial-lift method and demonstrates how production can be optimized over the life of a well by application of an appropriate design technique.

Conclusions

This paper demonstrates the benefits to be gained from performance analysis of gas-lifted wells. Pressure and temperature surveys incorporating simultaneous production tests provide the basic information required.

Calculation of the tubing pressure required to open a valve, given a measurement of the temperature at depth and an estimate of the casing pressure at depth, provides further valuable performance information. These calculations can be used with curves of simulated tubing pressure vs. depth to predict gas-lift design performance under varying conditions.

Performance analysis is a valuable aid in the development of a flexible design procedure. Where appropriate, application of a flexible design procedure can yield higher production rates than are possible with more conventional design procedures.

Nomenclature

- D_m = measured depth, ft
- D_{tv} = TVD, ft
- F_{dc} = dome pressure correction factor
- F_e = dynamic tubing sensitivity factor
- F_{pvt} = bellows protection liquid-correction factor
- F_t = temperature correction factor
- G_F = fluid gradient in tubing above valve, lbm/gal
- p_{cf} = flowing casing pressure, psig
- p_{cfs} = flowing casing pressure at surface, psig
- p_s = pressure effect of spring, psi
- p_t = tubing pressure
- p_{to} = tubing pressure at which valve opens, psig
- p_v = valve adjustment pressure, psig
- p_{vc} = valve adjustment pressure in test rack at 60°F, psig
- Q = gas flow rate, scf/D
- $\overline{T}$ = average temperature, °R
- T_{dv} = temperature at valve depth, °F
- $\overline{z}$ = average gas compressibility factor
- γ = gas specific gravity, air=1.0

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TABLE 6—WELL A31 GAS-LIFT DESIGN

Valve**	D_{tv} (ft)	p_{cfs} (psig)	p_{cf} (psig)	G_F (lbm/U.S. gal)	p_{to} (psig)	F_e	p_v (psig)	T_{dv} (°F)	p_{vc} (psig)
1	3,000	1,950	2,090	12.0	1,310	0.34	1,825	200	1,300
2	4,250	1,900	2,100	11.0	1,385	0.46	1,770	216	1,215
3	5,500	1,850	2,110	10.0	1,590	0.46	1,870	233	1,195
4	6,500	1,800	2,105	9.0	1,640	0.60	1,825	246	1,175
5	7,500	1,750	2,100	8.5	1,660	0.60	1,835	248	1,175
6	8,500	1,700	2,100	8.5	1,770	0.545	1,920	250	1,315
7	9,250	1,650	2,085	8.5	1,755	0.545	1,905	251	1,305
8	10,000	1,600	2,070	8.5	1,740	0.545	1,890	252	1,290
9	10,750	1,550	2,055	8.5	*	*	*	253	*
Packer	11,100								

*Orifice valve.

**Valves 1 through 5 are 1½-in. OD, Valves 6 through 9 are 1-in. OD owing to dimensional restrictions on mandrels inside 7-in. liner.

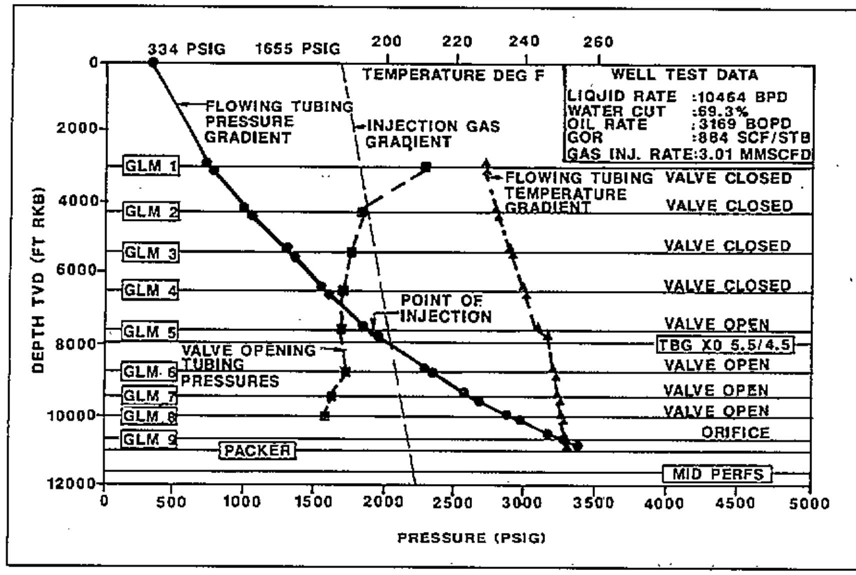

Fig. 8—Well A31 tubing pressure and temperature gradient survey, Nov. 15, 1987.

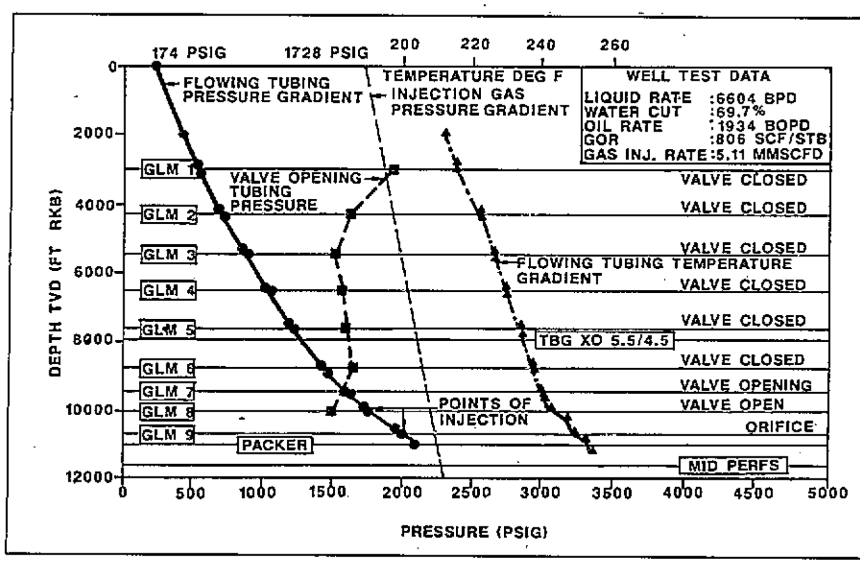

Fig. 9—Well A31 tubing pressure and temperature gradient survey, June 17, 1988.

Author

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this paper. Thanks also to Proverbs 3:5–6 for some special wisdom.

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Appendix—Valve-Opening Tubing-Pressure Analysis

Calculating the tubing pressure at which a valve will open is effectively doing design calculations in reverse. Instead of starting with p_{to} and calculating trim size and p_{vc}, p_{vc} and trim size are known and p_{to} must be calculated. Essentially, this is done by rearranging the design equations in vendor-supplied gas-lift manuals.[4] The key variables involved in this calculation are temperature and casing pressure at depth.

Temperature at depth can be measured with a wireline gauge, while casing pressure at depth must be estimated from surface flowing casing pressure using Eq. A-1 (from Ref. 5) and assuming no friction loss in the casing/tubing annulus.

$$p_{cf}=p_{cfs}e^{(\gamma D_{tv})/(53.34\bar{T}\bar{z})}. \quad \text{(A-1)}$$

Eq. A-1 is an iterative equation owing to the dependence of the $\bar{z}$ factor on average temperature and pressure but, with experience and good $\bar{z}$-factor charts for gas-lift gas, adequate first-run results can be produced.

Caution should be exercised, however, in deep wells where a wide range of pressures and temperatures are seen. In these cases, several calculations should be made, working down the well in stages.

If temperature at depth is different from design assumptions, p_v at depth must also be calculated.

$$p_v=[(p_{vc}+p_s)F_tF_{pvt}]-p_s. \quad \text{(A-2)}$$

For the 1½-in. Teledyne-Merla LN-20R™ valve used in the North West Hutton field,

$$F_{pvt}=1.0+(T_{dv}\,°\text{F}-72)2.741\times10^{-4}. \quad \text{(A-3)}$$

A standard equation for temperature correction (Ref. 6) was used, where

$$F_t=1.0+(T_{dv}\,°\text{F}-60)2.15\times10^{-3}. \quad \text{(A-4)}$$

Eq. A-4 was used in the work reported in this paper, but it loses accuracy above 1,000 psig, and the new equations recently presented by Winkler[7] will give more reliable results.

Eq. A-2 can be simplified by combining F_t and F_{pvt}:

$$F_{dc}=F_tF_{pvt} \quad \text{(A-5a)}$$

$$=[5.89\times10^{-7}(T_{dv}\,°\text{F})^2]+[2.35\times10^{-3}(T_{dv}\,°\text{F})]+0.854. \quad \text{(A-5b)}$$

Over the temperature range of most interest in the North West Hutton field (i.e., 50°F above and below a typical average well temperature of 230°F), the quadratic Eq. A-5b can be represented by a straight-line equation:

$$F_{dc}=2.62\times10^{-3}(T_{dv}\,°\text{F})+0.824. \quad \text{(A-5c)}$$

Once p_v has been determined, p_{to} is obtained from

$$p_{to}=[p_v-p_{cf}(1.0-F_e)]/F_e. \quad \text{(A-6)}$$

SI Metric Conversion Factors

bbl	× 1.589 873	E−01	=	m³
ft	× 3.048*	E−01	=	m
ft³	× 2.831 685	E−02	=	m³
°F	(°F−32)/1.8		=	°C
in.	× 2.54*	E+00	=	cm
lbm/U.S. gal	× 1.198 264	E+02	=	kg/m³
psi	× 6.894 757	E+00	=	kPa

*Conversion factor is exact.

Provenance

Original SPE manuscript, **Gas Lift Design and Performance Analysis in the North West Hutton Field,** received for review Sept. 5, 1989. Paper accepted for publication Sept. 27, 1990. Revised manuscript received Sept. 4, 1990. Paper (SPE 19280) first presented at the 1989 SPE Offshore Europe Conference held in Aberdeen, Sept. 5–8.

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TABLE 5 : WELL A01 VALVE OPENING TUBING PRESSURES, 24/06/86

Valve Number	TVD ft	Tdv °F	Pvc @ 60°F psig	Pvc psig	Fe	Pcf	Pto psig	Pt psig	Valve Position
	Surface					1915			
1	3210	238	1250	1844	0.34	2065	1711	740	Closed
2	5405	245	1180	1895	0.46	2165	1576	1302	Closed
3	7015	249	1258	2045	0.46	2240	1813	1789	Closed
4	8095	252	1250	2025	0.60	2290	1847	2140	Open
5	8895	253	1260	2047	0.60	2330	1859	2443	Open
6	9690	254	1265	2058	0.60	2365	1853	2748	Open
7	10414	255	*	*	*	2400	*	3028	*

* Orifice Valve

TABLE 6 : WELL A31 GAS LIFT DESIGN

Valve Number	TVD ft	Pcfs psig	Pcf psig	G_F lb/gal	Pto psig	Fe	Pvc psig	Tdv °F	Pvc @ 60°F psig
1	3000	1950	2090	12.0	1310	0.34	1825	200	1300
2	4250	1900	2100	11.0	1385	0.46	1770	216	1215
3	5500	1850	2110	10.0	1590	0.46	1870	233	1195
4	6500	1800	2105	9.0	1640	0.60	1825	246	1175
5	7500	1750	2100	8.5	1660	0.60	1835	248	1175
6	8500	1700	2100	8.5	1770	0.545	1920	250	1315
7	9250	1650	2085	8.5	1755	0.545	1905	251	1305
8	10000	1600	2070	8.5	1740	0.545	1890	252	1290
9	10750	1550	2055	8.5	*	*	*	253	*
Packer	11100								

* Orifice Valve

NOTES
1) G_F = Fluid gradient in tubing above value.
2) Valves 1-5 are 1½ inch O.D., valves 6-9 are 1 inch O.D. due to dimensional restrictions on mandrels inside 7" liner.

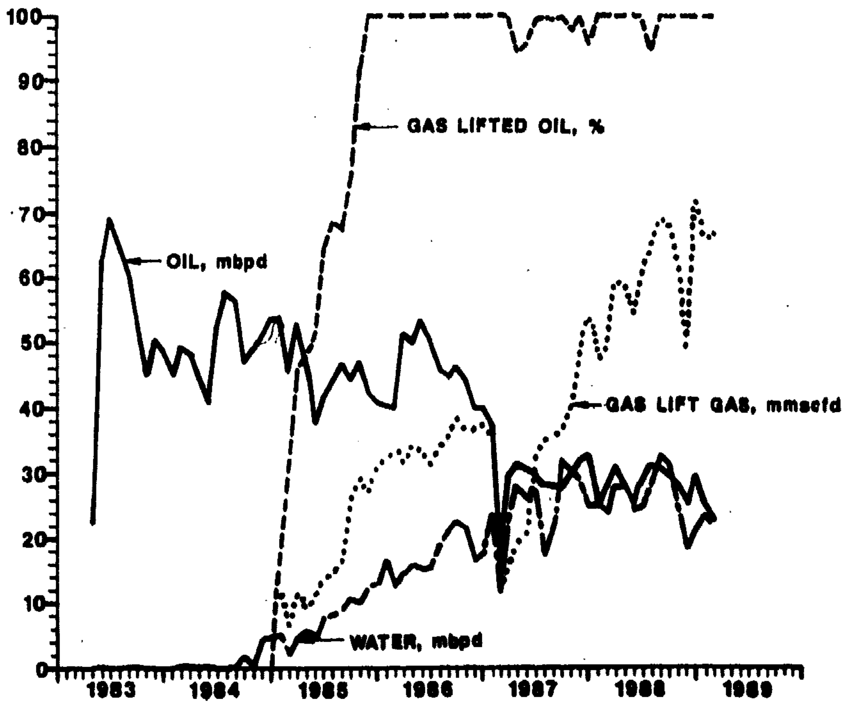

FIG. 1. NORTH WEST HUTTON PRODUCTION

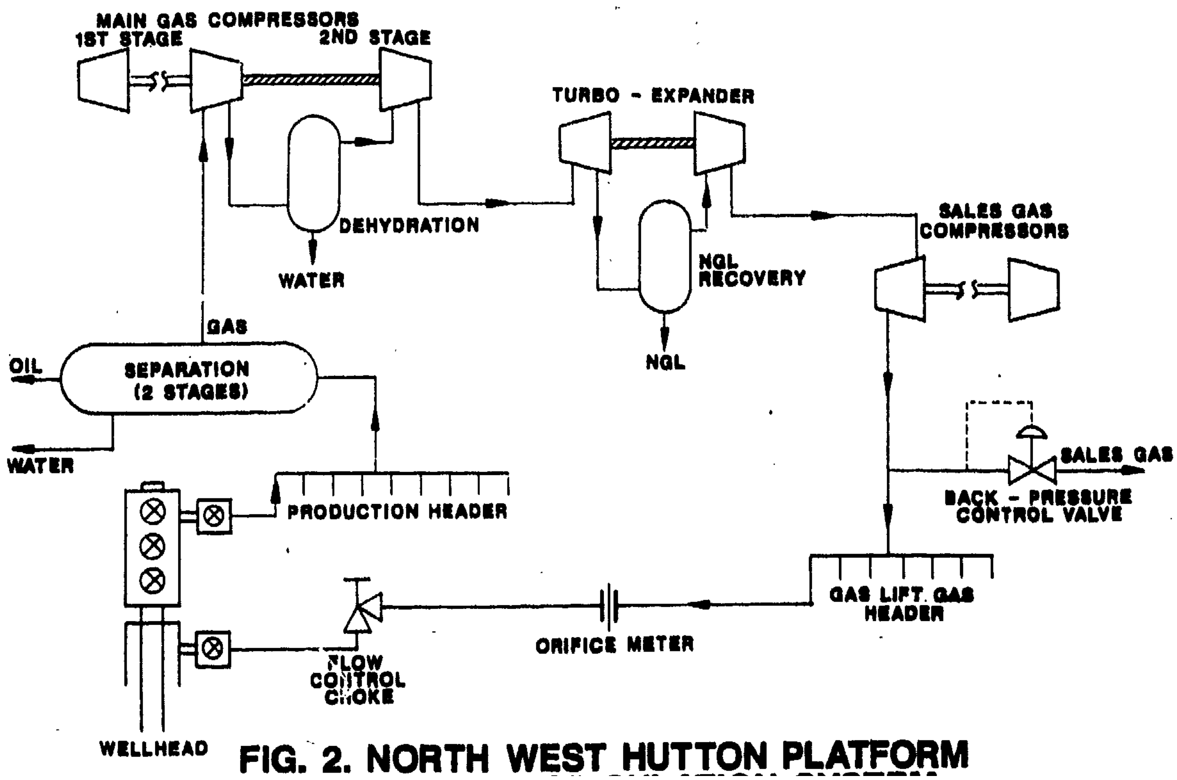

FIG. 2. NORTH WEST HUTTON PLATFORM

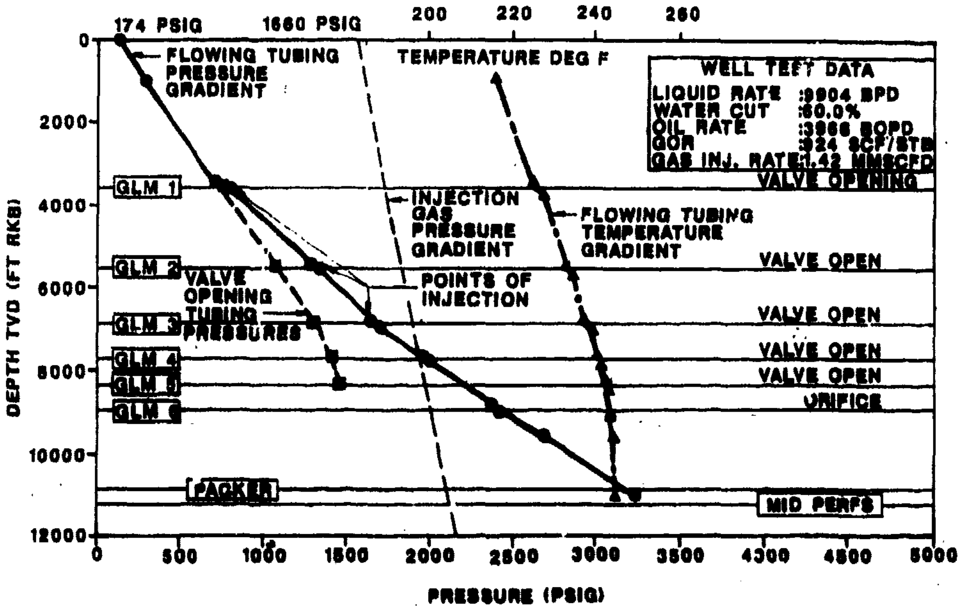

FIG 3 : WELL A1 TUBING PRESSURE AND TEMPERATURE GRADIENT SURVEY 10TH OCTOBER 1985

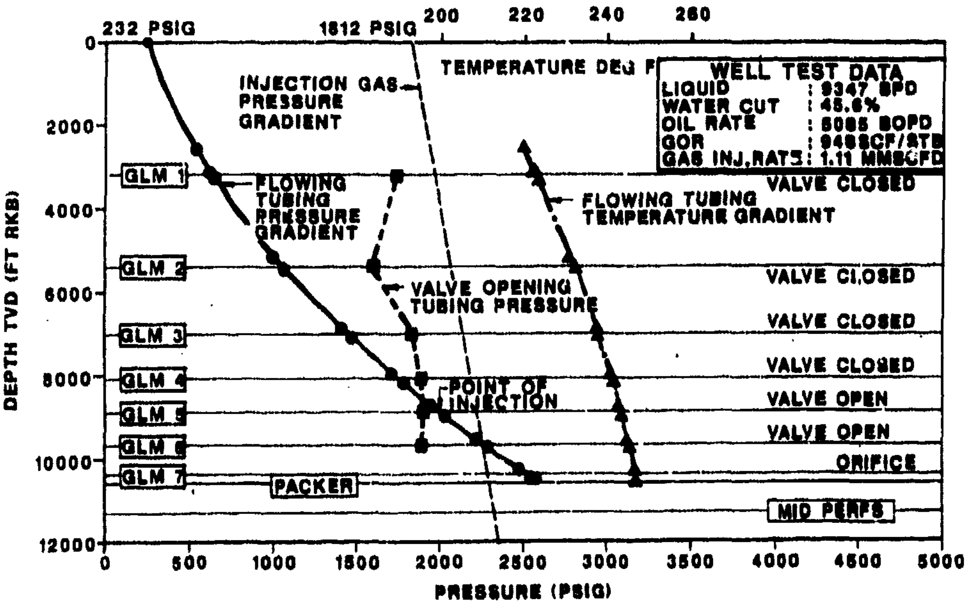

FIG 4 : WELL A1 TUBING PRESSURE AND TEMPERATURE GRADIENT SURVEY – 9 APRIL 1986

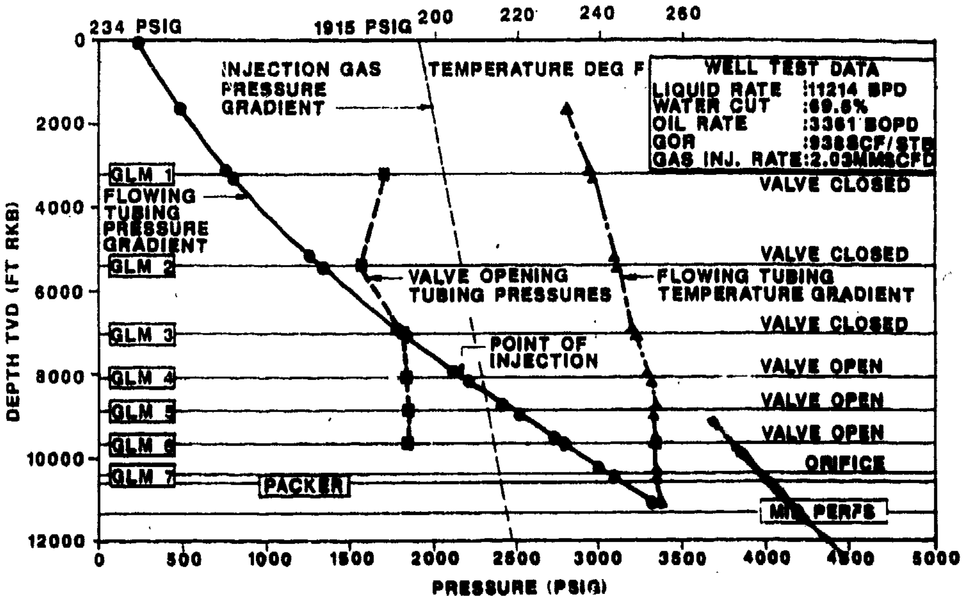

FIG 5 : WELL A1 TUBING PRESSURE AND TEMPERATURE GRADIENT SURVEY - 24TH JUNE 1986

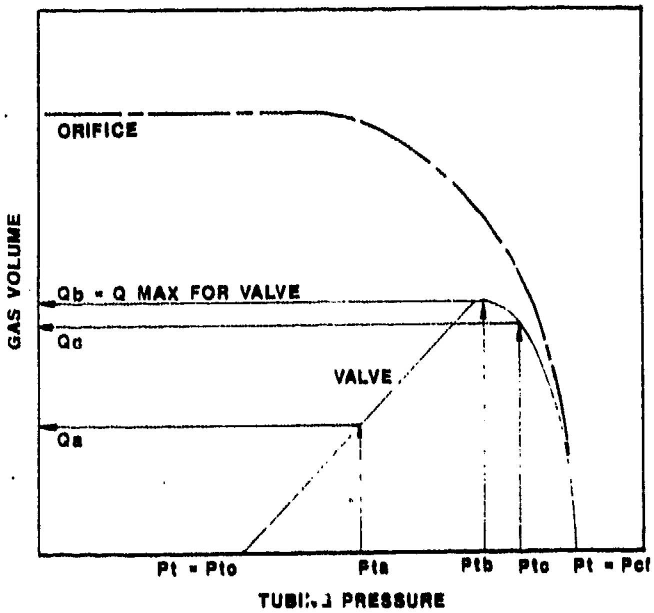

FIG. 6. VALVE GAS PASSAGE PERFORMANCE

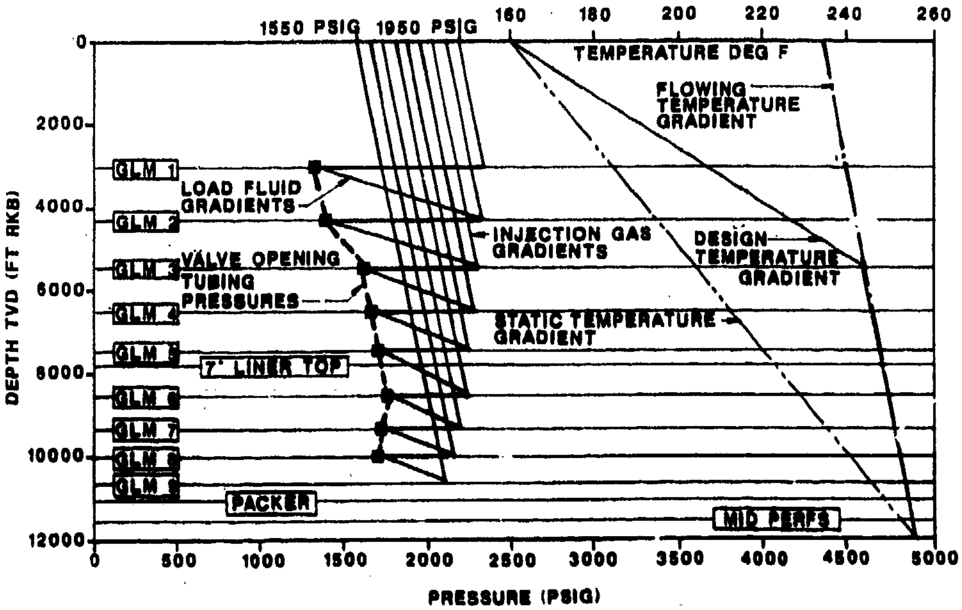

FIG. 7. WELL A-31 GRAPHICAL DESIGN

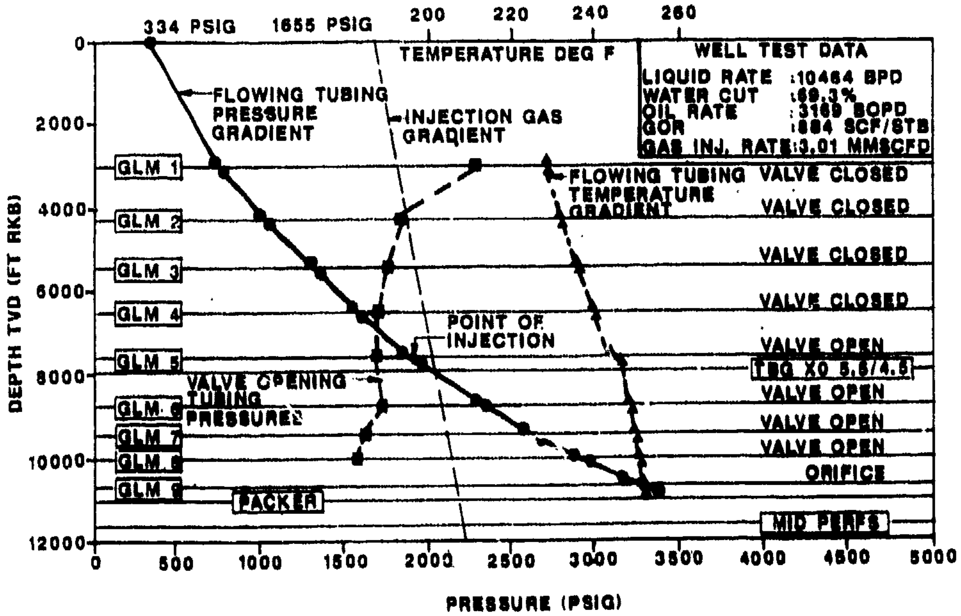

FIG 8 : WELL A31 TUBING PRESSURE AND TEMPERATURE GRADIENT SURVEY 15TH NOVEMBER 1987

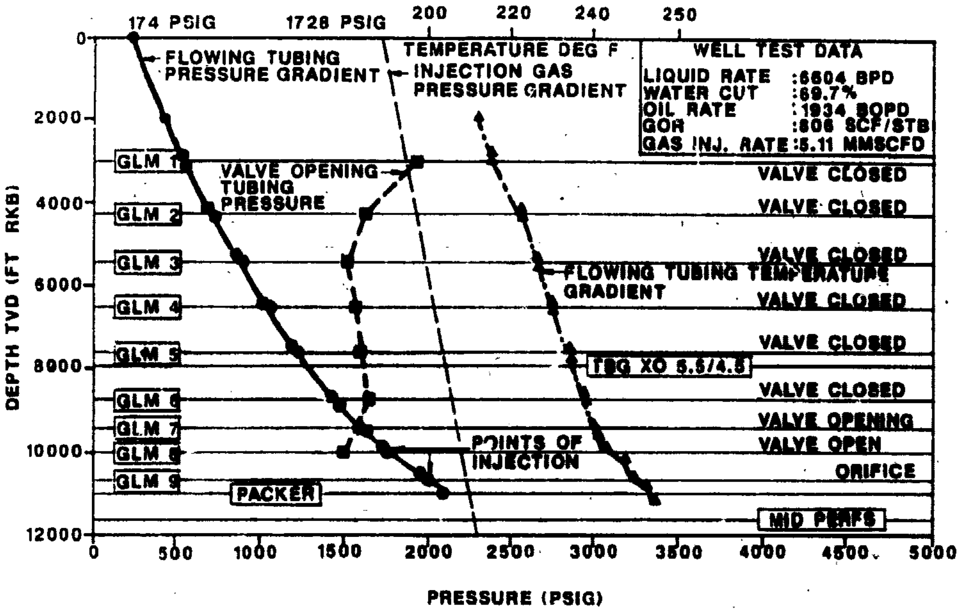

FIG 9 : WELL A31 TUBING PRESSURE AND TEMPERATURE GRADIENT SURVEY 17TH JUNE 1988