A New Deep Gas Well Design Which Permits Use of the Most Advanced Completion Techniques

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INTRODUCTION

Deep gas well completions are a large part of the drilling development programs of many oil companies and the number of wells in this category (15,000 ft and deeper) is rapidly increasing. Few projects compare with deep gas wells in terms of investment (average cost of a 20,000-ft well is near one million dollars), thus much work has been done on completion design and procedure.

The type of completion used on deep gas wells varies widely throughout the oil industry and can make a significant difference in a well's performance. Shell's past practices have used the approach of setting combination tubing strings (usually 2⅞ in. x 3½ in.) at 2000 ft to 3000 ft off bottom. This design offers the advantages of producing through a string which can be easily replaced if damaged and being able to kill the well with little trouble. However, it does not provide the capability for perforating the well with a casing gun in an underbalanced condition or for treating the well at high pumping rates. These latter advantages can greatly increase a well's productivity and should be considered in all deep gas prospects.

DISCUSSION

The most important criteria in the design of completion equipment for deep gas wells are profit and minimum investment risk. Maximizing profit can be accomplished by increasing income, decreasing expense, or by doing both. Increasing a well's deliverability will increase income in many cases, if the well is not rate-restricted by law or for other reasons not related to the well's capability. It has been shown that pumping rate, during stimulation of deep gas reservoirs, increases the effectiveness of the treatment.[1] The effect is that of increasing the distance that the treating fluid penetrates into the formation. Deeper penetration of live acid increases the effective wellbore radius which in turn increases well productivity. The equipment design discussed in the following pages provides the capability of high rate treating and, as such, makes possible increased profit.

Equipment Costs

Since there are many possible configurations in deep gas well tubular design, it is necessary to establish criteria which reduce the number to only the most profitable possibilities. The drilling program currently used by Shell on deep Delaware Basin gas wells is optimum for 4½ in. or 5-in. production liners. The maximum liner size which could be used in the present design is 5½ in. An attempt to run tubulars larger than 5½ in. would result in expensive drilling design modifications. Running 6⅝ in. tubulars instead of 5½ in. would require additional expenditures of $100,000. Costs of various tubular combinations are shown in Table 1. Data available on deep well stimulation show that treatment effectiveness, as related to pumping rates, reaches diminishing returns as pumping rate is increased indiscriminately.[1] Thus, although the 6⅝ in. design would make possible extremely high pumping rates, it is doubtful that the increased cost of the installation would be justified. Therefore, the 6⅝ in. case has been eliminated from further consideration.

Examination of Fig. 1, keeping in mind the costs shown in Table 1, makes it possible to narrow the choices further. The curves of Fig. 1 reflect pressure drops versus treating rate for various pipe sizes using fresh water treating fluid. These rates can be increased significantly through the use of suitable friction-reducing agents.[2] Elimination of the 5½ in.

equipment for reason of cost is warranted since the treating capabilities far exceed that required in most stimulation procedures. Additionally, the risk of a poor cement job from using 5½ in. casing in a 6½ in. hole is high. The three remaining configurations require further investigation before a final selection can be made.

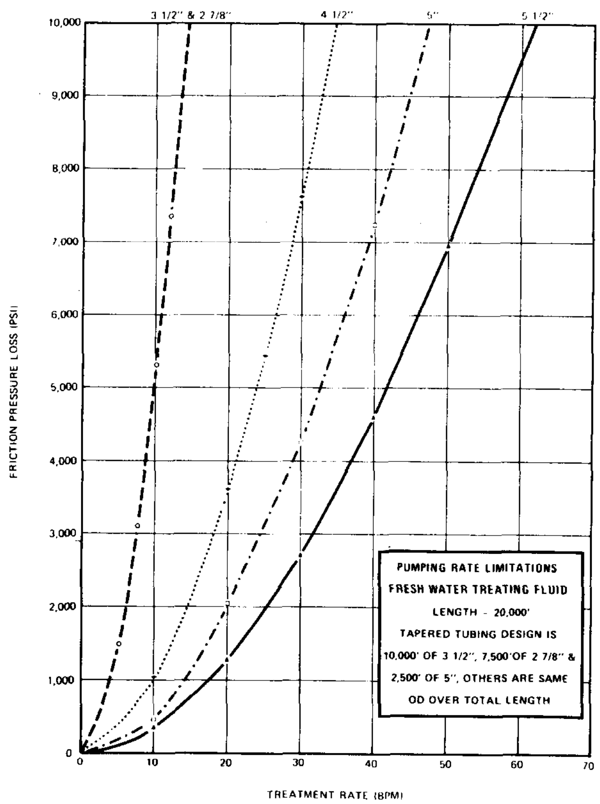


FIGURE 1

Flow Performance

Figure 2 is a plot of well performance versus time for the 4½ in., 5-in. and 3½ in. x 2⅞ in. configurations. The prediction is based on the method developed by D. G. Russell, et al.[3] As would be expected, the larger tubulars permit either a higher initial rate or a sustained rate for a longer time period than does the tapered tubing design. Larger tubulars,however, will generally cause the well to "log off" with fluid and die sooner than if smaller ID tubulars were used. This is the case here as indicated in Fig. 2. Parameters used to develop the curves of Fig. 2 were based on the performance history of a typical well in the Lockridge Field, Ward County, Texas, which was completed with 3½ in. and 2⅞ in. tubing. This field is a 20,000-ft Ellenburger gas field. The only parameter changed to run the 4½ in. and 5-in. cases was "skin factor" which was reduced from +1 to -4 (a result of the high rate treatment). An economic analysis of the three cases, using the performance predictions of Fig. 2, clearly indicates that the 4½ in. design is preferred.

Design Considerations

Tubing design considerations, although not discussed earlier, play an important part in the selection of the final configuration. Primarily, three items are considered when designing tubing or casing for a well; burst, collapse, and tension. Burst and collapse conditions should be handled in tubing design as they are in casing design. Tension, however, merits a different approach. Casing is normally designed in tension with a safety factor of 1.6 where tensile strength is mainly required only during running. Tubing should be designed with consideration given to pulling it at a later date, which leads to designing by the constant overpull method. This method allows for an amount of pull, over the weight of the tubing, up to the yield strength of the pipe body at the top of each section of a given weight and diameter pipe. Thus, if the tubing becomes stuck for any reason, attempts can be made to free it without jeopardizing the pipe. A typical tubing design chart is shown in Fig. 3. The original design used was 4½ in., 15.5 lb/ft tubing in conjunction with 4½ in., 15.1 lb/ft liner; however, considering the effect of tension on burst resistance of the pipe would permit use of a lighter-weight pipe for the design parameters used here (Fig. 4).

Another important condition which must be investigated in detail is tubing movement. A well can experience numerous different combinations of pressure and temperature throughout its life and each condition produces forces which affect the tubing in a unique way. The four basic forces resulting in tubing length changes are: piston forces, ballooning and reverse ballooning forces, helical buckling forces, and forces caused by temperature changes. The equations depicting these length changes are described in Fig. 5 (along with equations describing stresses induced in the string as a result of these changes). Symbols

TABLE 1

EQUIPMENT COSTS FOR
VARIOUS COMPLETION TYPES

EQUIPMENT ITEM	COMPLETION TYPES TUBING & LINER 6-5/8"	5-1/2"	5"	4-1/2"	3-1/2" x 2-7/8" (5" liner)
LINER	$ 65,700	$ 50,100	$ 38,200	$ 32,500	$ 38,200
PACKER & RELATED EQUIPMENT	7,500	5,800	5,300	4,800	4,000
TUBING	57,000	38,300	33,200	35,000	33,500
PRESSURE TEST TUBULARS	4,000	2,500	2,500	2,000	3,000
WELLHEAD	60,000	47,800	42,000	33,900	27,500
DRILLING MODIFICATIONS	50,000	---	---	---	---
TOTAL COST	$244,200	$144,500	$121,200	$108,200	$106,200

NOTE: Liner costs are for 10,000' of pipe suitable for H_2S service.

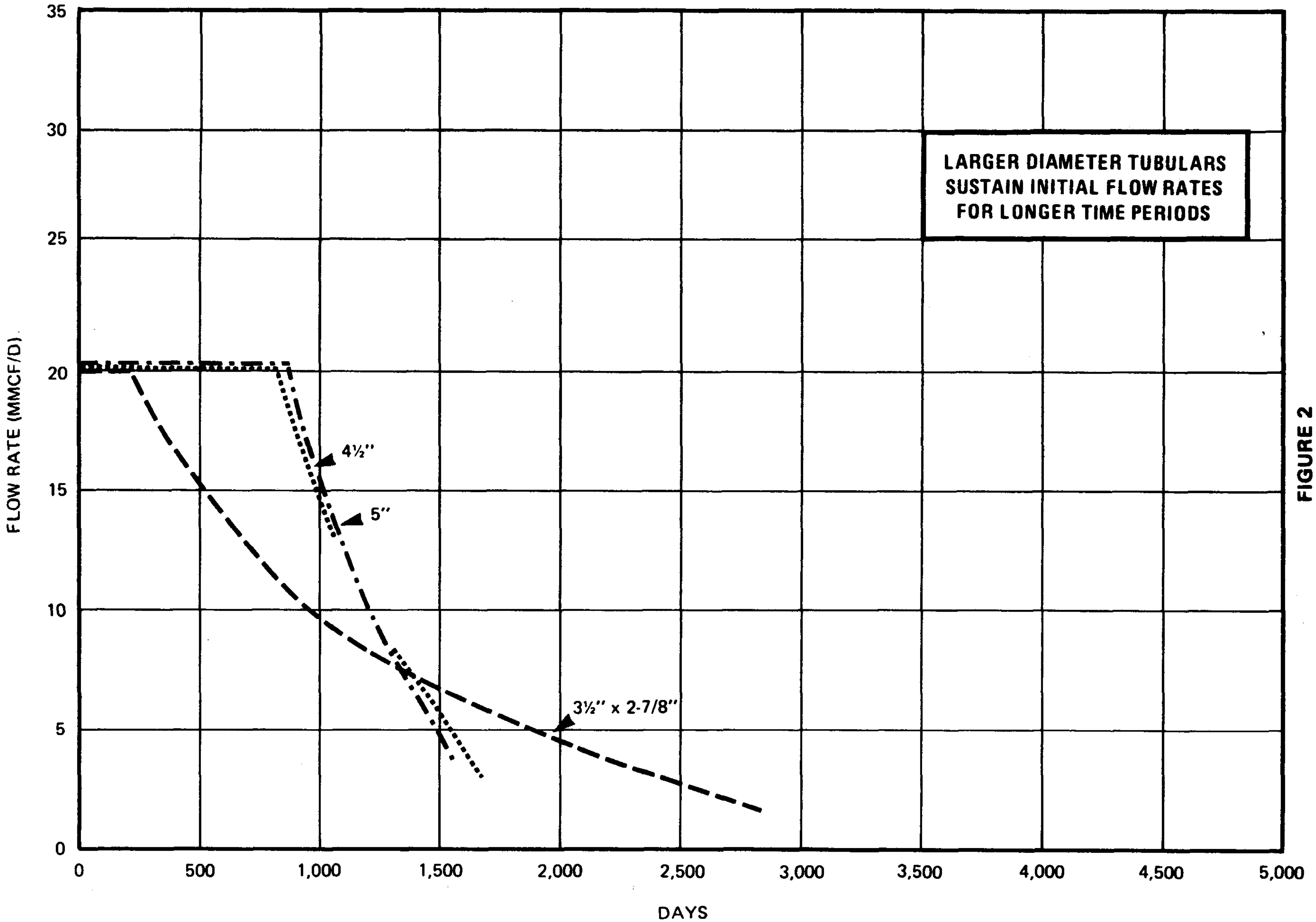
Tubing costs are for 10,000' of pipe suitable for H_2S service except for the tapered design which is 10,000' of 3-1/2" tubing and 7500' of 2-7/8" tubing.

Wellhead costs are for stainless steel trees which are full opening to the tubing and liner except for the tapered design where the tree is full opening to the 3-1/2" tubing.

Drilling modifications include any changes required to run liner larger than 5-1/2" OD.

used are those of Lubinski.[4] If the tubing is permitted to move freely during daily operations, this movement can be described by a graph as shown in Fig. 6. Such movement can lead to serious problems if measures are not taken to offset it. Two approaches are used to handle tubing movement: (1) provide enough seals and/or sealing surface and permit the tubing to move, (2) slack-off enough weight at the packer to prevent any movement. Permitting free tubing movement can lead to seal wear and eventual failure, while preventing motion by slacking-off weight is not possible during certain well operations. For these reasons the best approach is a combination of these methods; slack-off enough weight to prevent tubing movement during daily operations and provide adequate seal length for use during periods of large motion such as is encountered during treatment. The type of seal arrangement most suitable to this application is the polished bore receptacle shown schematically in Fig. 7. The major advantage provided by this arrangement is the full opening area through the seal assembly. This permits use of a large OD perforating tool which can be used for underbalance perforating if desired. A conventional packer with an extended seal bore could be used, but it would be necessary to set it inside large ID casing to make it full opening to the tubing and would probably mean exposing a liner top to well fluids. A schematic of the downhole equipment is included as Fig. 8. The wellhead used with the 4½ in. equipment is a single block tree with 4⅛ in. bore valves and is rated 10,000 psi working pressure.

One important aspect which should be considered in the equipment design for high-pressure gas wells is a means for performing safe workover operations (eg. repairing a tubing leak) on the well without killing it with fluid. Many wells have suffered impairment from fluid used to hold the formation during workover operations. The full opening feature of



LARGER DIAMETER TUBULARS SUSTAIN INITIAL FLOW RATES FOR LONGER TIME PERIODS
FLOW RATE (MMCF/D)
35
30
25
20
15
10
5
0
4½"
5"
3½" x 2-7/8"
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
DAYS

FIGURE 2

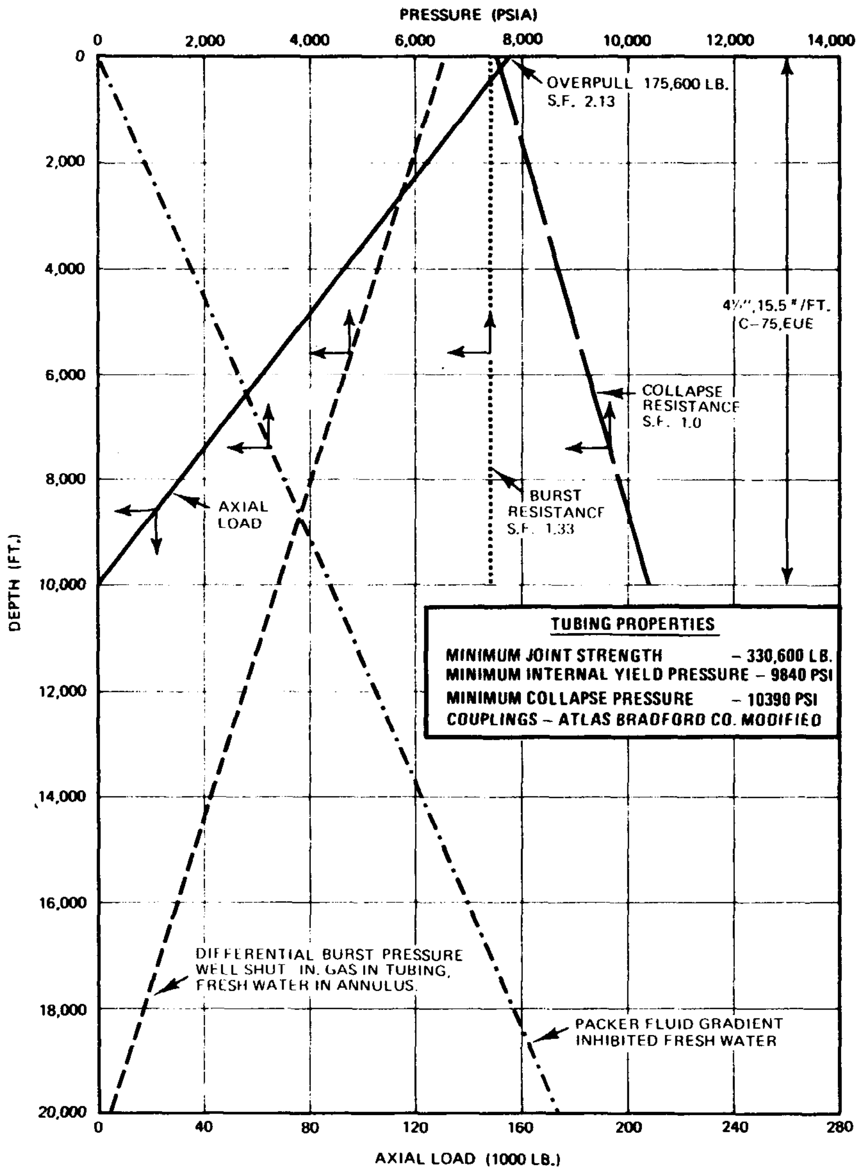


FIGURE 3

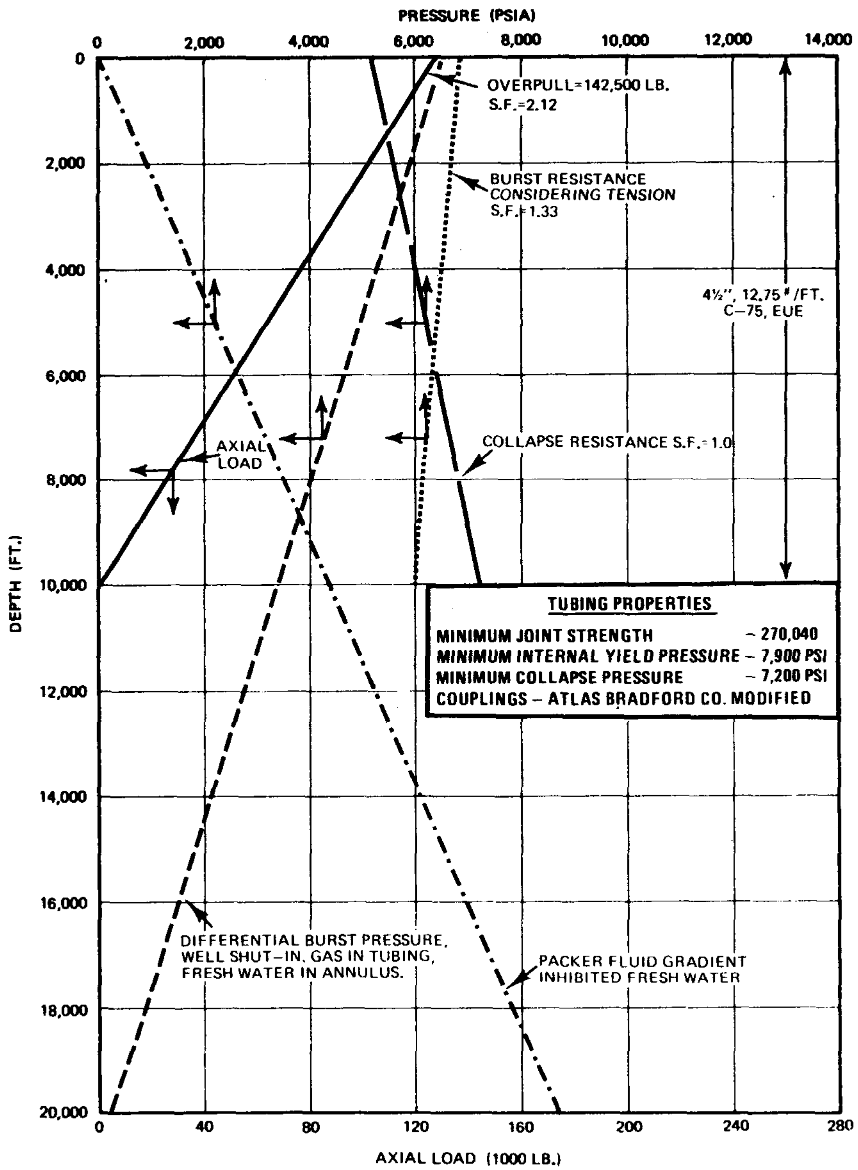
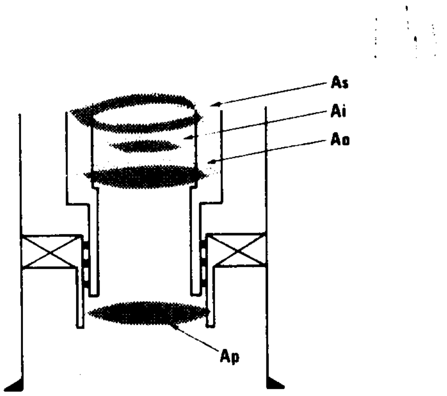


FIGURE 4



Tubing Movement Due to :

Piston Forces – $\Delta L = -\frac{L}{EAs}\left[(Ap-Ai)\,\Delta Pi - (Ap-Ao)\,\Delta Po\right]$

Ballooning – $\Delta L = -\frac{\nu}{E}\,\frac{\Delta \rho i - R^2 \Delta \rho o}{R^2-1}\,L^2 - \frac{2\nu}{E}\,\frac{\Delta pi - R^2 \Delta po}{R^2-1}\,L$

Helical Buckling – $\Delta L = -\frac{r^2 Ap^2 (\Delta Pi - \Delta Po)^2}{8EI\,(Ws + Wi - Wo)}$

Temperature Changes – $\Delta L = L\beta\Delta T$

Tubing Stresses Due To :

Pressuring Operations – $So = \sqrt{3\left[\frac{Pi-Po}{R^2-1}\right]^2 + \left[-\frac{(Pi-R^2 Po)}{R^2-1} + \sigma a \pm \sigma b\right]^2}$

$$Si = \sqrt{3\left[\frac{R^2(Pi-Po)}{R^2-1}\right]^2 + \left[-\frac{(Pi-R^2 Po)}{R^2-1} + \sigma a \pm \frac{\sigma b}{R}\right]^2}$$

Slack - off But Before Pressuring Operations – $So = \left|\frac{F}{As} + \frac{DrF}{4I}\right|$

FIGURE 5

TUBING MOVEMENT – STRESS EQUATIONS

the 4½ in. design makes it possible to lubricate a packer into the well with a blanking plug in place. After setting the packer and loading the hole, workover operations may be performed safely. It is then a simple operation to retrieve the plug and place the well in operation.

Dual Gas Well Design

The same considerations which were enumerated for the equipment design of single-zone deep gas wells apply equally to the design of dual-zone equipment. Evaluation of the three configurations shown in Fig. 9 should be based on three objectives; (1) perforating both zones in an underbalanced condition, (2) giving each zone a high rate treatment and (3) not killing either zone if possible. Final selection depends on the flow characteristics of each configuration as exhibited in Figs. 10 through 13 (a performance prediction like that of Fig. 2 is preferred if attainable). The curves of Figs. 10 through 13 were generated using a flowing tubing pressure of 1200 psi.

A completion technique used to perforate the upper zone underbalanced in a concentric-type dual would be restricted in most instances to that case where the upper pay zone is relatively thin. The technique used would be that of raising the tubing with wellhead attached and perforating with a through-tubing gun. Control of the well would be provided by the wellhead and the high pressure wrap-around seal through which one joint of tubing can be stripped.

Table 2 is a summary of the dual configurations showing cost and performance. Information related to dual completions is more selective than that of singles. The curves and summary shown here are intended to suggest an approach which would yield that configuration most suited to a particular well and cannot be generalized to include all wells. Plans were made to complete a dual well with a concentric design using 3½ in. and 2⅞ in. tubing inside 7-in. and 4½ in. liner but the gas zones were abandoned as the well was running low to other producers in the field.

Included as Table 3 is a recommended equipment-running procedure for deep gas wells using the 4½ in. design. One item worthy of mention is the method used to lower the fluid level in the tubing to prepare for underbalanced perforating. Swabbing inside casing carries the risk of leaving tools in the hole

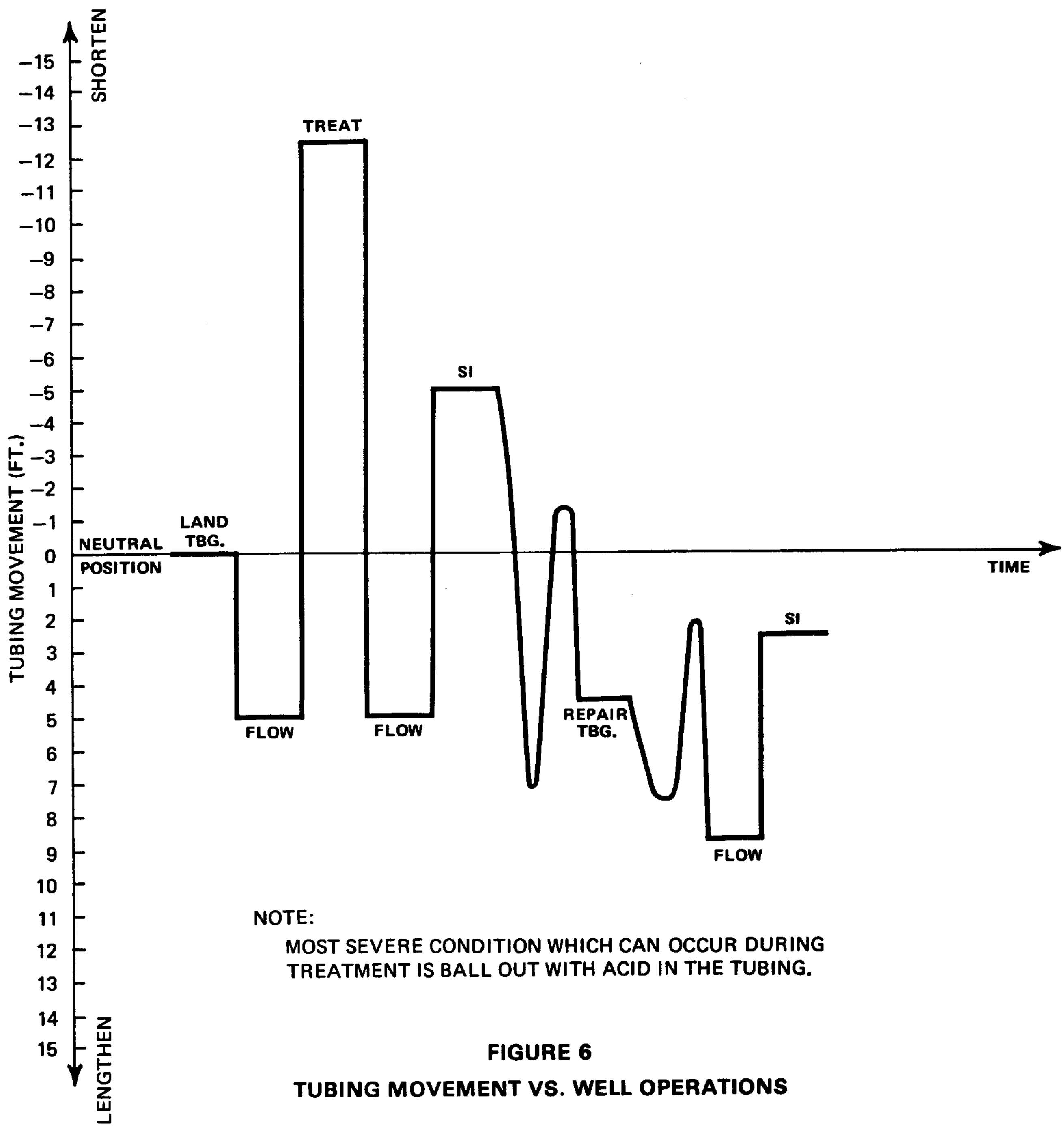


FIGURE 6

TUBING MOVEMENT VS. WELL OPERATIONS

which can be difficult to fish. A preferred method of lowering the fluid level is to use high-pressure nitrogen gas as a displacement fluid when displacing the packer fluid to the annulus. This method is considerably safer and the cost is not prohibitive.

CONCLUSION

A new concept in deep gas well completions permits better stimulation attempts which can result in significant increases in well productivity. Use of 4½ in. tubing and liner as a production string makes it possible to perforate a well with a large OD gun (offering larger holes and better penetration than a through-tubing gun) while maintaining a pressure differential into the wellbore (underbalanced condition). Perforating with the pressure differential into the formation (overbalanced condition) can result in perforations plugged with foreign material and, if the foreign material is insoluble in acid, productivity impairment can result. Perforating underbalanced is desirable in certain formations and improves the possibility that the perforations are open.

The 4½ in. tubulars make possible high rate treatments. By minimizing pressure loss due to friction in the tubulars, treatment rates approaching 50 BPM are attainable. It has been recognized that pumping rate is a significant factor in determining the distance live acid will penetrate down a vertical fracture.[1] Deeper penetration of live acid maximizes the effective wellbore radius which increases well productivity.

A well completion using the above design and techniques resulted in a productivity increase of 27 per cent over an offset well completed with 2⅞ in. and 3½ in. tubing as a production string. Treatment rate in the new type completion averaged 31 BPM at 8000 psi as compared to 12 BPM at 9000 psi in the other (total volume of acid used was the same in each case). Comparison of estimated reservoir properties for the two wells shows: new well has a porosity of 4 per cent, permeability of 0.4 md and net pay 80 ft; offset well has a porosity of 3.5 per cent, permeability of 1.1 md and net pay 100 ft.

REFERENCES

1. Whitsitt, N. F., et al: A New Approach to Deep Well Acid Stimulation Design, The Western Company, June 1970.
2. Friction Loss Data on Dowell Oil and Gas Well Treating Fluids in Oilfield Tubular Goods, Dowell Division of The Dow Chemical Company, January 1965.
3. Russell, D. G., et al: Methods for Predicting Gas Well Performance, *Jour. Petr. Tech.*, January 1966.
4. Lubinski, Arthur, et al: Helical Buckling of Tubing Sealed in Packers, *Jour. Petr. Tech.*, pp. 655-670, June 1962.

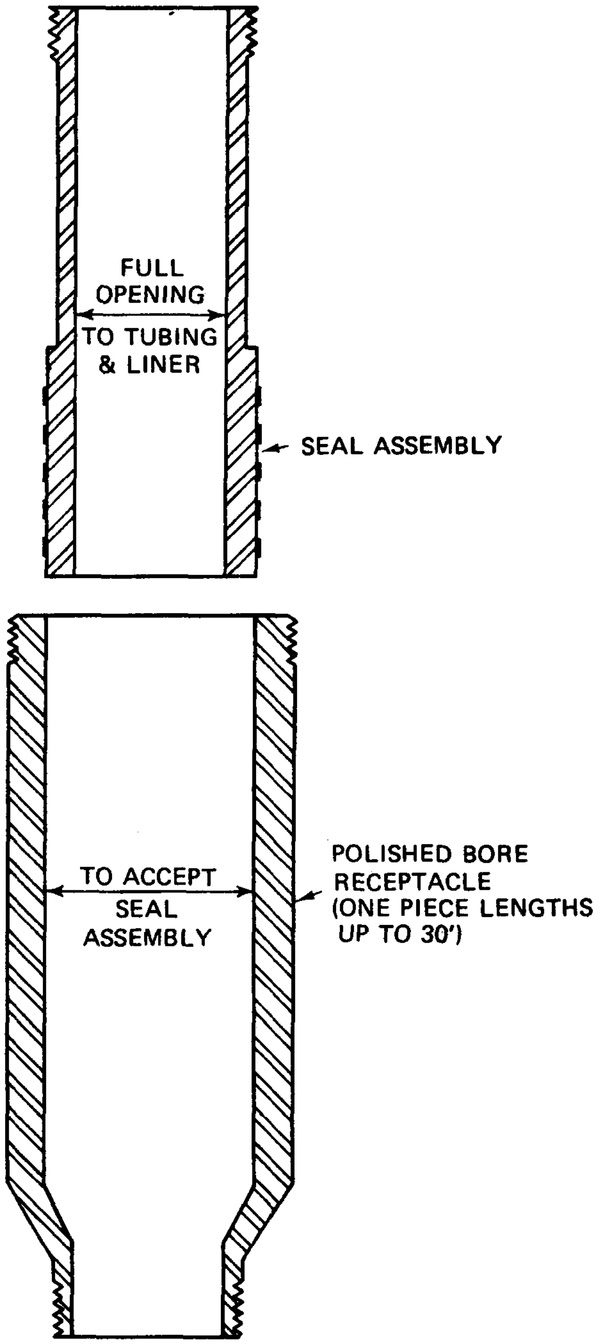
TABLE 2

COST AND PERFORMANCE SUMMARY
DUAL GAS WELL COMPLETIONS

COMPLETION DESIGN			COST	FLOW PERFORMANCE (MMcf/D)			
TYPE*	TUBING	CASING		UPPER ZONE	LOWER ZONE	SPREAD	MIN. RATE
CC	3-1/2" & 2-3/8"	7" & 4-1/2"	$180,400	27.0	19.0	8.0	19.0
CC	3-1/2" & 2-7/8"	7" & 4-1/2"	182,900	18.4	23.2	4.8	18.4
CC	4-1/2" & 2-3/8"	7" & 4-1/2"	191,500	24.5	19.6	4.9	19.6
CC	4-1/2" & 2-7/8"	7" & 4-1/2"	194,000	17.3	26.5	9.2	17.3
CC	3-1/2" & 2-3/8"	7" & 5"	195,100	33.3	19.0	14.3	19.0
CC	3-1/2" & 2-7/8"	7" & 5"	197,600	27.7	23.3	4.4	23.3
CC	4-1/2" & 2-3/8"	7" & 5"	206,200	28.5	19.7	8.8	19.7
CC	4-1/2" & 2-7/8"	7" & 5"	208,700	24.8	26.5	1.7	24.8
C	2 3/8"	4-1/2"	167,800	19.5	12.5	7.0	12.5
C	2 7/8"	4-1/2"	169,500	11.6	18.5	6.9	11.6
C	2 3/8"	5"	173,600	27.2	12.5	14.7	12.5
C	2 7/8"	5"	180,300	20.5	18.5	2.0	18.5
P	3-1/2" & 2-3/8"	4-1/2"	151,500	23.5	18.2	5.3	18.2
P	3-1/2" & 2-7/8"	4-1/2"	153,800	17.0	23.0	6.0	17.0
P	3-1/2" & 2-3/8"	5"	157,200	27.1	18.2	8.9	18.2
P	3-1/2" & 2-7/8"	5"	159,500	24.5	23.0	1.5	23.0

*CC — Combination Concentric
C — Concentric
P — Parallel

Note: All configurations listed permit accomplishment of the three stated objectives (perforating underbalanced, high rate treating and not killing either zone) except for the parallel combinations which require additional equipment valued at $56,000 for the 4-1/2" liner and $71,000 for the 5" liner. This additional equipment consists of wellhead and tubing required for safe operations. Cost includes the mechanical equipment used in completing the well. Drilling costs are not included.



MANUFACTURED BY:

BAKER OIL TOOLS
BROWN OIL TOOLS
OTIS ENGINEERING
TEXAS IRON WORKS

FIGURE 7
POLISHED BORE RECEPTACLE AND SEAL ASSEMBLY

TABLE 3
EQUIPMENT RUNNING PROCEDURE FOR DEEP GAS WELLS

1. Make-up each connection to manufacturer's recommended torque: 4½ in. EUE—3600 ft-lbs.
2. Test each connection above slips being sure that pipe is suspended from elevators during testing.
3. Stab seal assembly into receptacle:
   a) Attempt to rotate off any shoulder which will take weight.
   b) When reasonably sure that seals are in receptacle, pressure test internally.
   c) If pressure test successful, pull seals out of receptacle w/100 psi surface tubing pressure. Measure distance traveled from tubing in neutral to point where seals leave receptacle (pressure falls off). Check to make sure this distance is as required.
   d) Re-enter receptacle and space out for specified slack-off. Place any required tubing subs under one full joint at surface.
4. Land tubing.
5. Remove blow-out preventers.
6. Install wellhead. (If tubing cannot be raised with wellhead attached, perform steps 8-10 before installing wellhead.)
7. Pick tubing up and out of packer bore receptacle.
8. Displace annulus w/packer fluid.
9. Depress fluid level w/N_2 (if required) and close master valve.
10. Land tubing being sure that receptacle is entered properly by checking slack-off.
11. Flange up wellhead.
12. Test internally to specified pressure. Bleed off test pressure.
13. Caliper tubing and liner.
14. Prepare for perforating and treating.

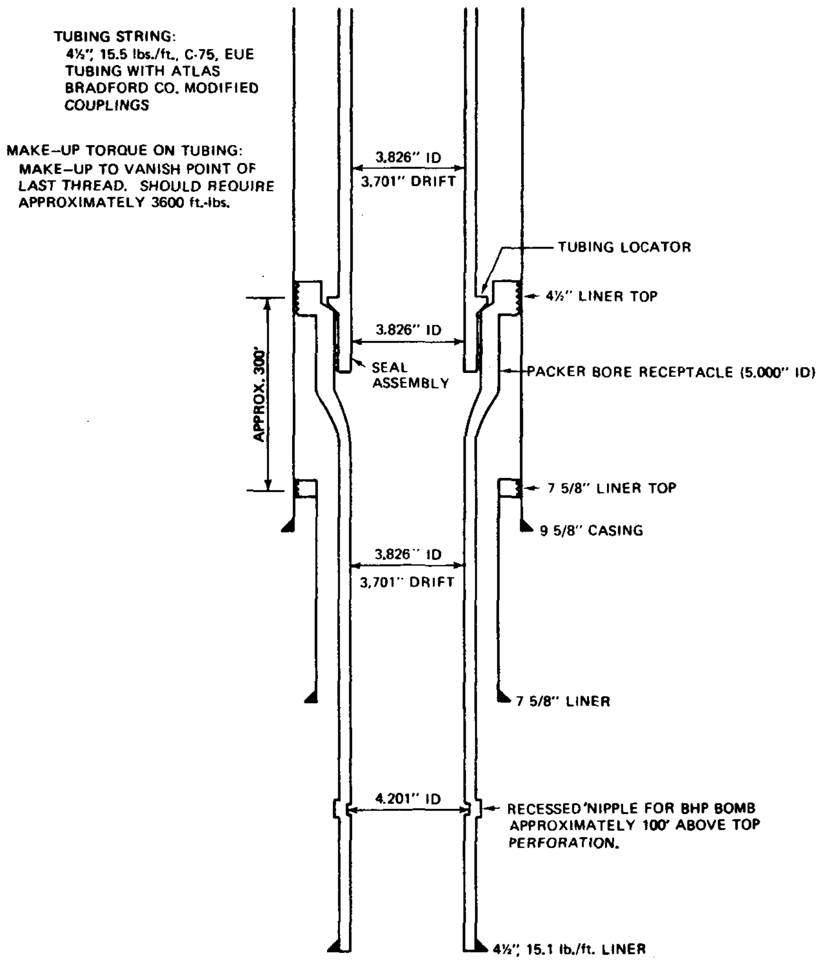


FIGURE 8
SUBSURFACE COMPLETION EQUIPMENT

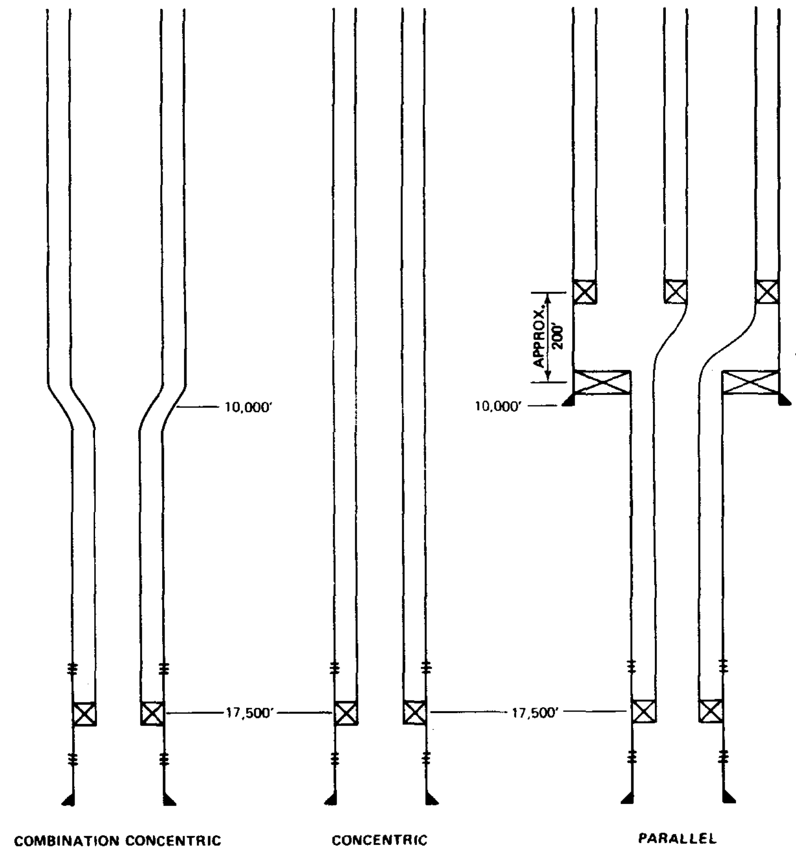


FIGURE 9
DUAL WELL CONFIGURATIONS

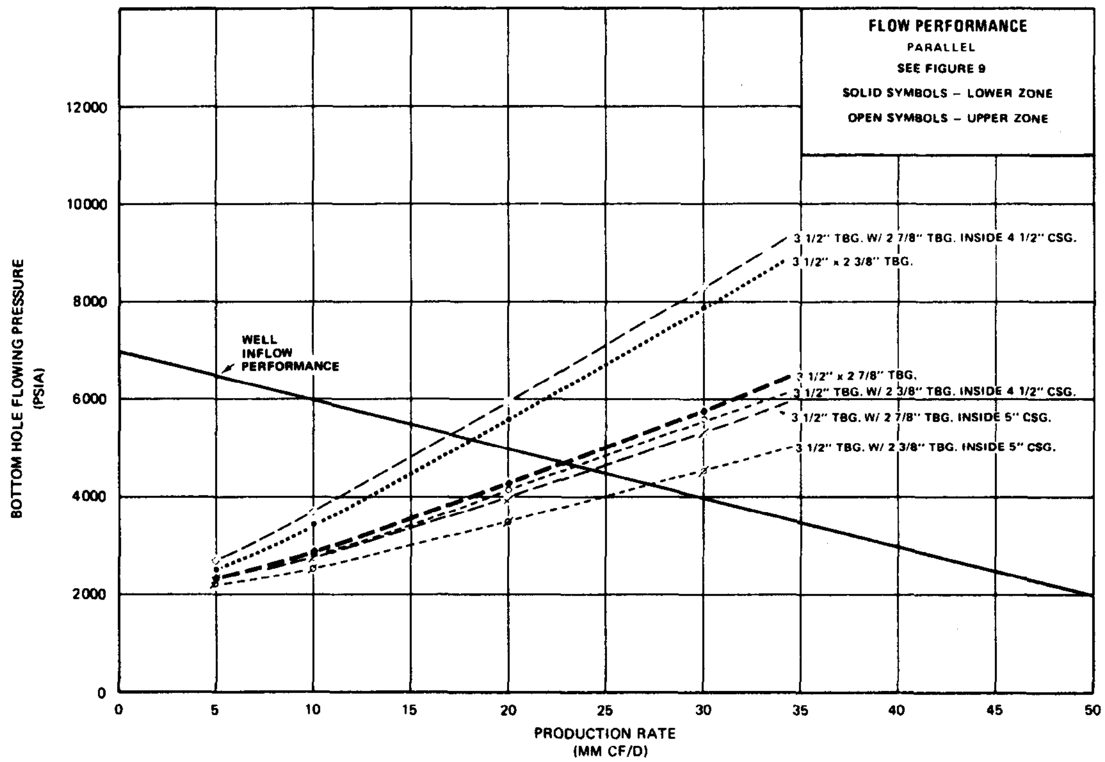


FIGURE 10

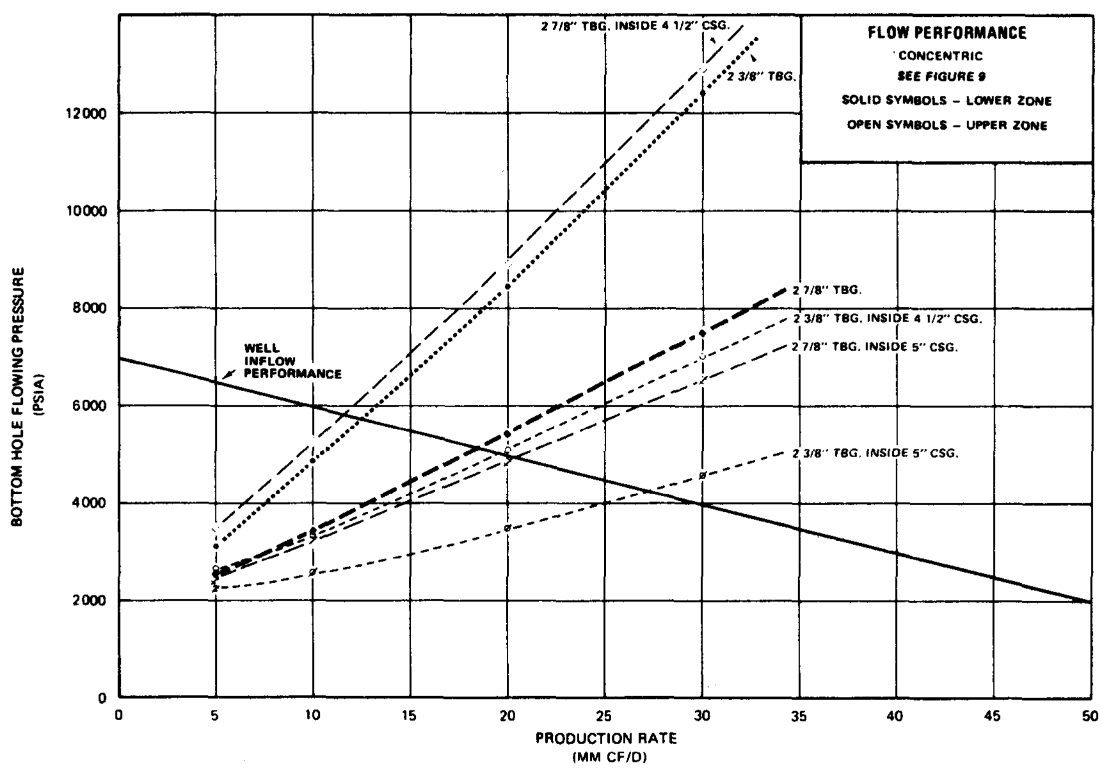


FIGURE 11

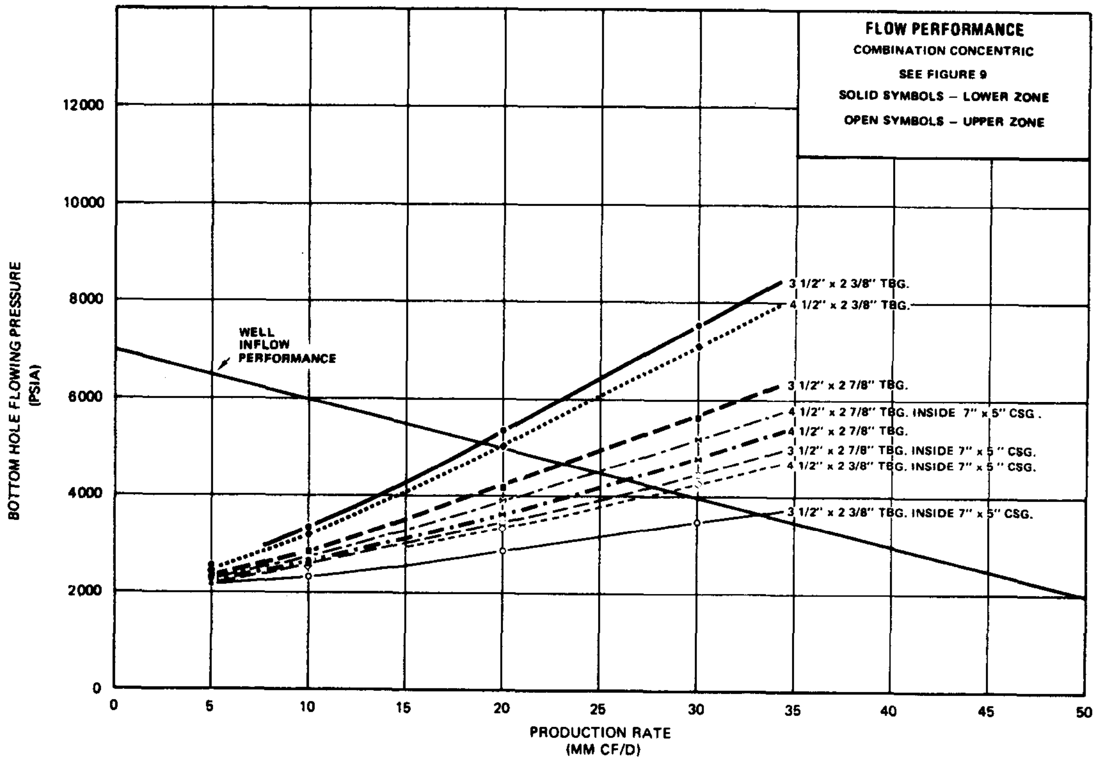


FIGURE 12

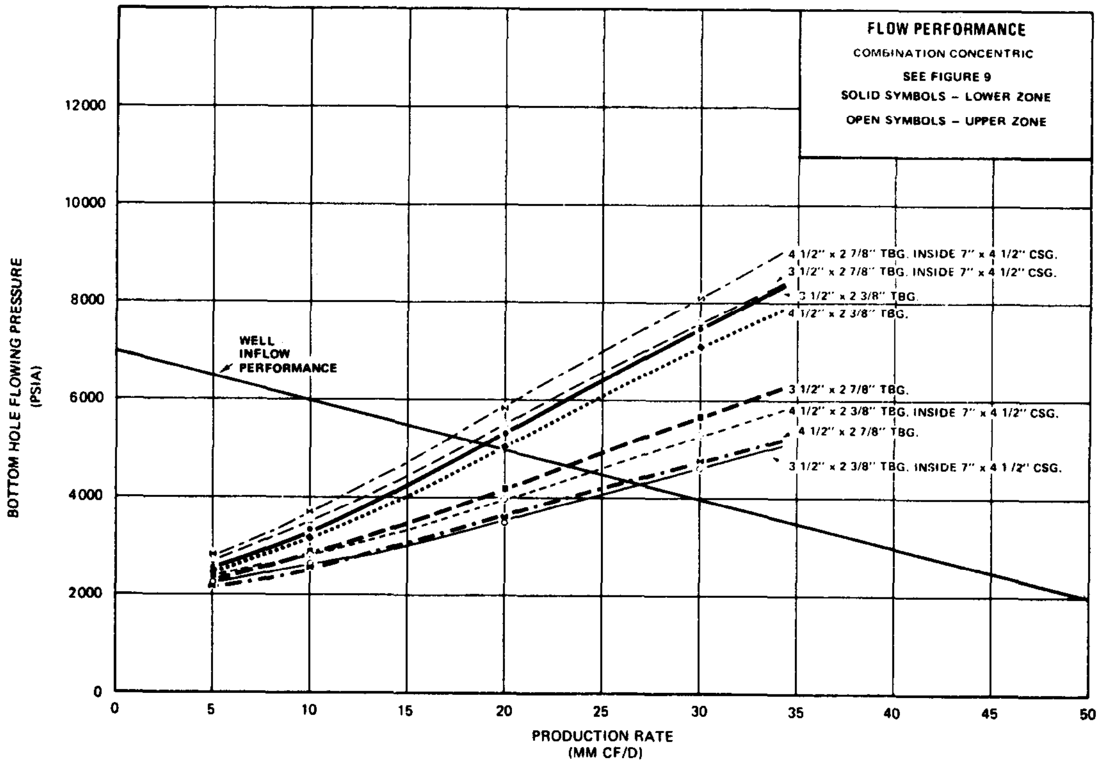


FIGURE 13