Simplified Charts for the Design of Intermittent Gas Lift Installations

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INTRODUCTION

Most of the gas-lift research conducted in the past decade has been directed toward continuous flow. The development of correlations to predict the pressure traverse of a continuous moving mixture of gas and liquids has received considerable attention. The use of working curves prepared from these correlations has greatly simplified the design of continuous flow gas lift installations.

Intermittent gas lift presents an entirely different picture. Although there have been a few significant publications presented, and the mathematical solution to the problem seems to be solved, a suitable liquid fallback correlation for all pipe sizes is not yet available.

However, the design of good intermittent installations is now possible, making use of the research completed in this area and utilizing the information gained from numerous field applications of intermittent gas lift.

The purpose of this paper is to present the design of intermittent gas lift installations in a simplified form making use of a series of charts which eliminate many tedious calculations.

TYPES OF INTERMITTENT GAS LIFT INSTALLATIONS

There are several types of intermittent gas lift installations that can be installed and they are listed as follows:

(1) Open (Fig. 1): This installation represents a straight tubing installation with no packer. It is not recommended for an intermittent installation, but may have to be run because of necessity when it is forbidden to run a packer because of well conditions such as corrosion, sand, etc. This will result in a very inefficient installation when the gas is likely to blow around the bottom of the tubing string.

(2) Semi-closed (Fig. 2): This represents a straight tubing installation utilizing a packer but no standing valve. It is recommended for wells having a high bottomhole pressure and a low productivity index. It is recommended that a standing valve be left out when well conditions such as sand, corrosion, etc. prohibit. This installation is suitable for high bottomhole pressure, low PI wells.

(3) Closed (Fig. 3): This represents a straight tubing installation incorporating both a packer and a standing value. It is recommended for all intermittent installations except those where a chamber installation is applicable. It is suitable for high bottomhole pressure, low PI; low BHP; high PI: low BHP: low PI, and other well conditions.

(4) Chamber Installation (Figs. 4 and 5): A chamber installation is ideal for those wells having a low bottomhole pressure and a high PI. However, it may also be used successfully for high BHP low PI wells. A chamber installation represents a good method for producing maximum production from depths below 6000-10,000 ft. They have been known to produce in excess of 400 BPD from below 10,000 ft.

In general, there are three types of intermittent gas lift well conditions that we are concerned with: (1) A straight tubing installation that will lift from the bottom of the well. (2) A straight tubing installation that will lift from an unknown depth. (3) A chamber installation.

Where possible, a packer and standing valve should always be installed with an intermittent gas lift installation.

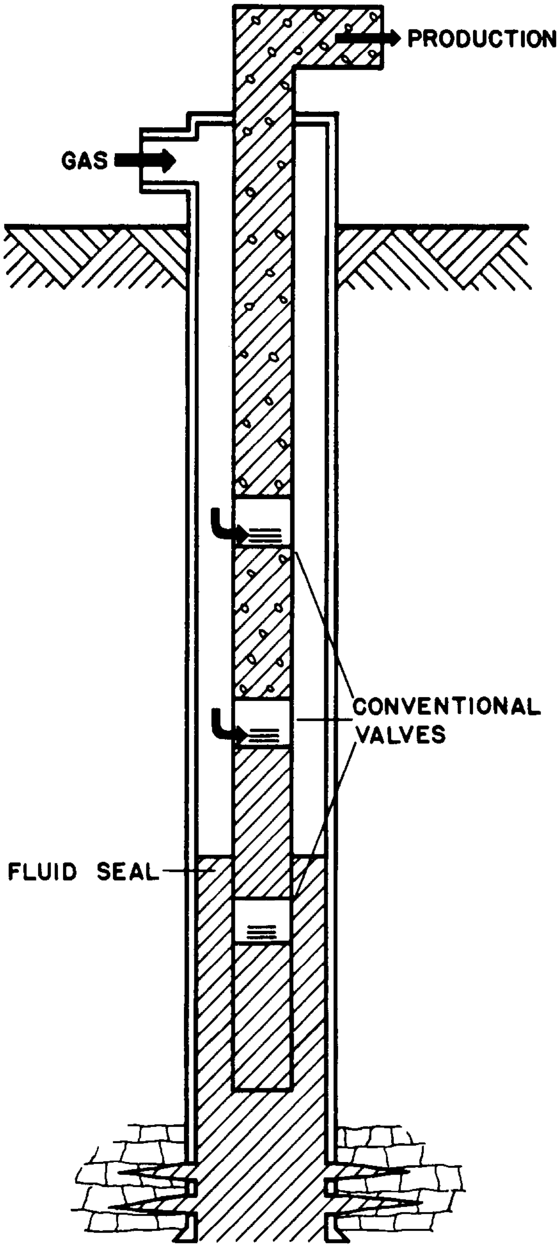


FIG. 1 STANDARD VALVE OPEN INSTALLATION

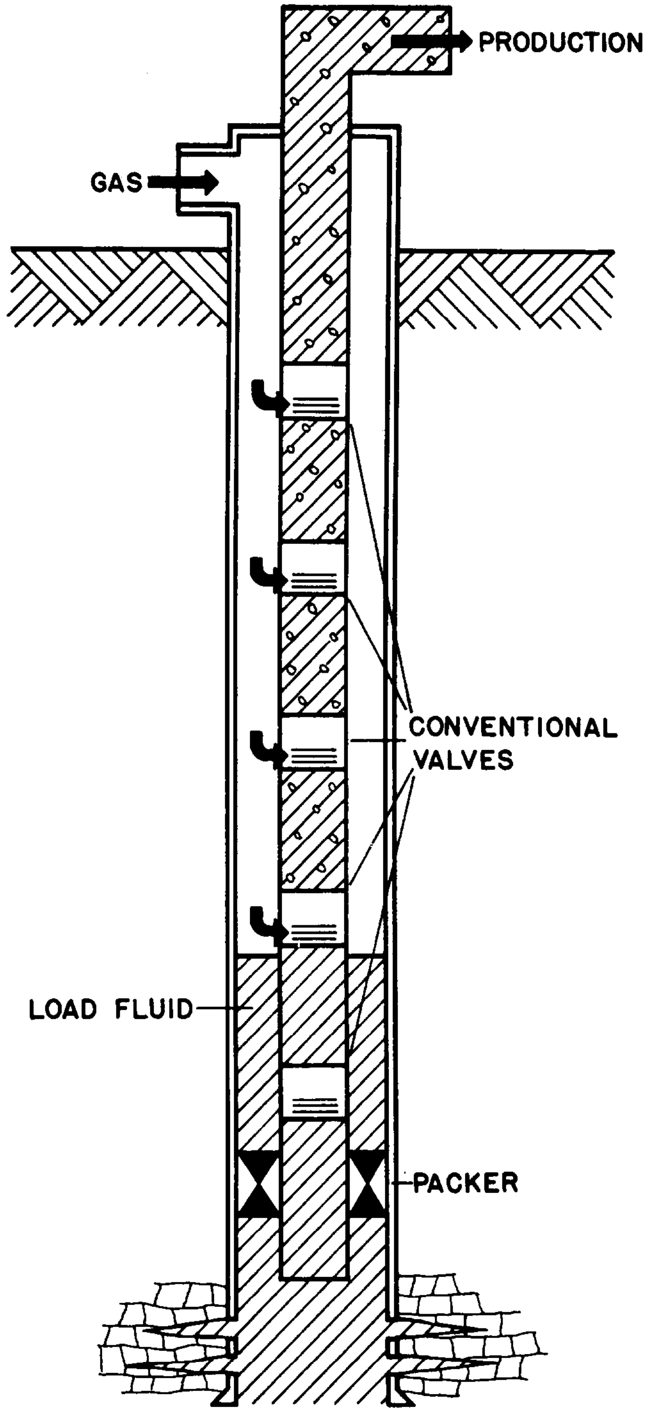


FIG. 2 STANDARD VALVE SEMI-CLOSED INSTALLATION

TYPES OF GAS LIFT VALVES FOR INTERMITTENT INSTALLATIONS

There are numerous types of gas lift valves that may be used in an intermittent installation. A brief description of each of these is given in the following discussion.

BALANCED VALVE (FIG. 6)

This particular valve has the same opening and closing pressure, hence the name balanced.

UNBALANCED PRESSURE-OPERATED VALVE (FIGS. 7a AND 7b)

This valve has a constant closing (dome

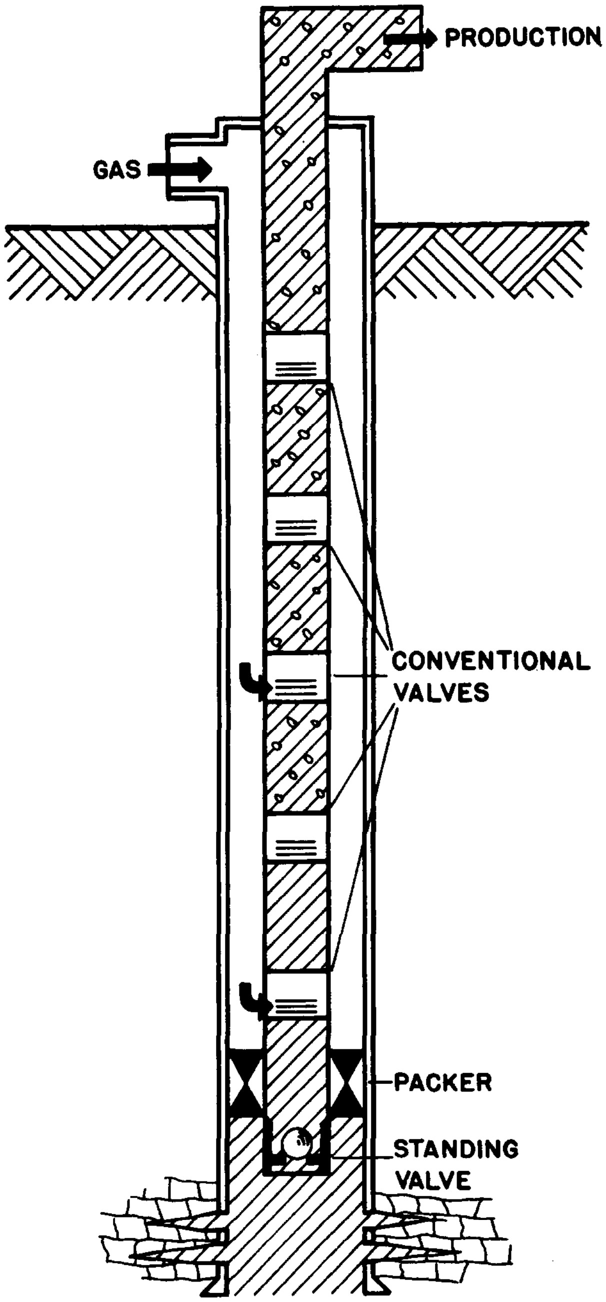


FIG. 3 STANDARD VALVE CLOSED INSTALLATION

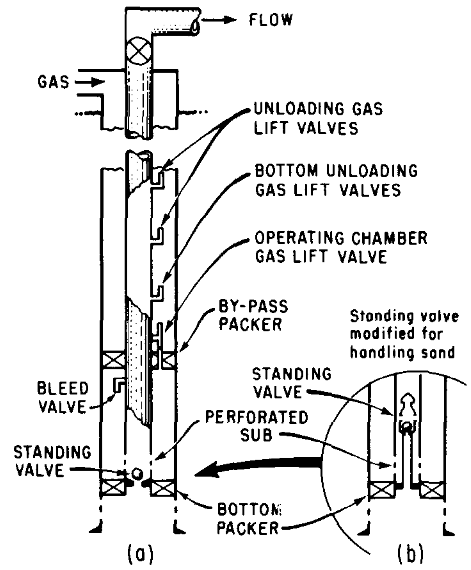


FIG. 4 TWO-PACKER CHAMBER INSTALLATIONS.

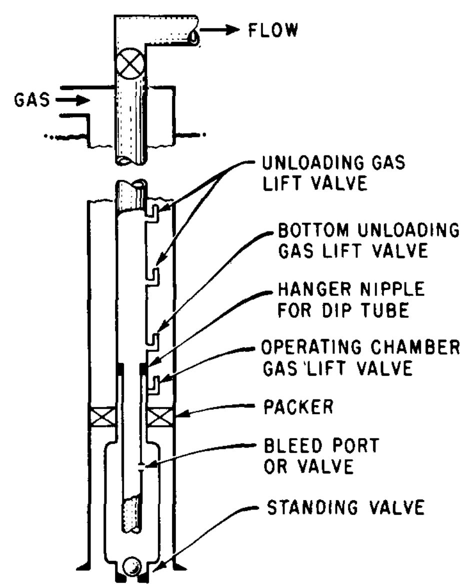


FIG. 5. INSERT CHAMBER INSTALLATION.

pressure) pressure and a variable opening pressure depending upon the tubing pressure. This difference between opening and closing pressure is known as the spread of the valve. The spread on this valve is varied by changing the port size and/or the bellows size. However, a 1-1/2 in. O.D. valve normally uses a 0.77-in.^{2} bellows and a 1-in. O.D. valve uses a 0.29-in.^{2} bellows. Once the bellows size and tubing pressure are fixed, the spread can only be varied by changing the seat size.

PILOT VALVE (FIG. 8)

The purpose of a pilot valve is to give a variable spread without changing the main port size. Good intermittent lift installations require a large port size. However, for a valve similar to Fig. 7, the spread may be excessive. There-

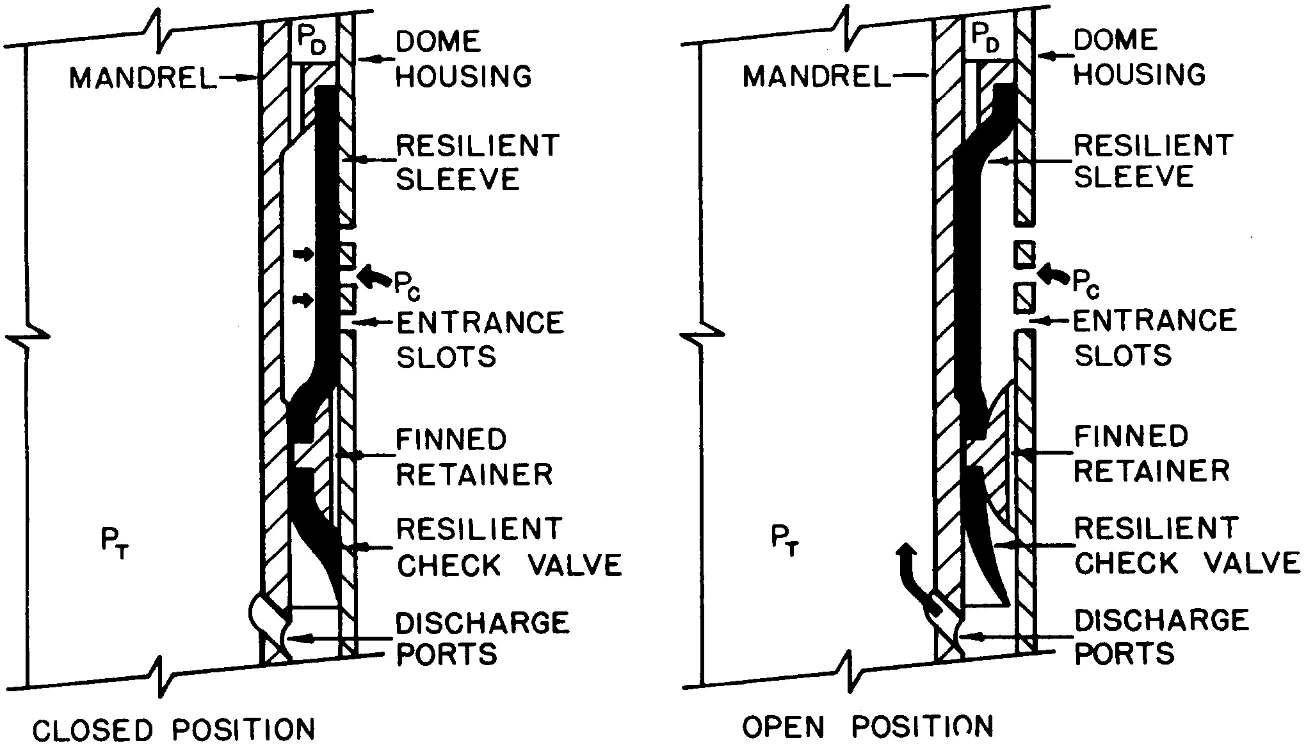


FIGURE **NO. 6**
OTIS BALANCED GAS LIFT VALVE

fore, a pilot valve is needed whereby the pilot control valve size can be changed to vary the spread and the main port size left alone. There are numerous versions of this valve but all accomplish the same purpose.

FLUID OPERATED VALVE (FIG. 9)

This is a valve that is opened by a liquid building-up in the tubing. Again, numerous versions of this valve are available and it may be balanced or unbalanced. Figure 9 shows a schematic of a fluid-operated valve. This valve has been used extensively in dual installations. Obviously, it cannot be used to deplete a low bottomhole pressure well.

Combination Tubing Pressure Opened and Casing Pressure Closed Valve (Fig. 10)

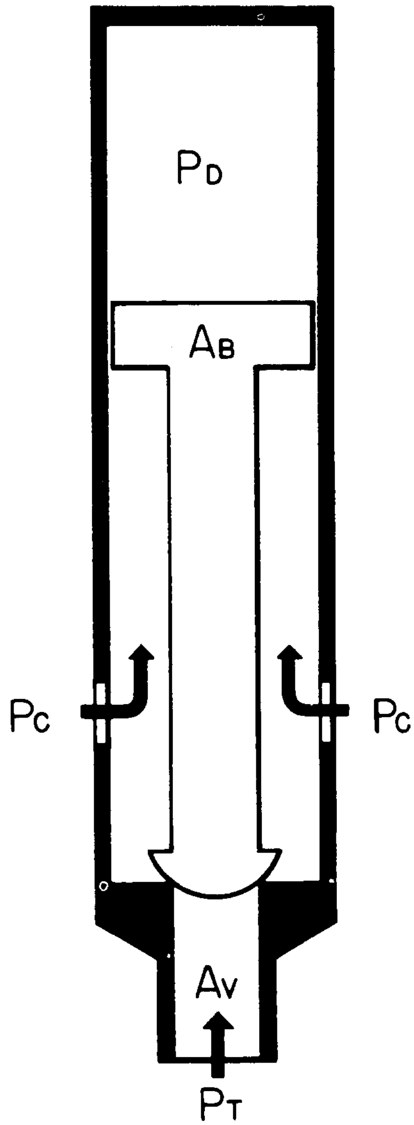
Again, there are numerous combinations of this valve, but most of them accomplish the same purpose. This is a valve that requires a set casing pressure to open the bellows section of the valve and yet will not pass gas until a tubing pressure build-up has opened the fluid pilot section. Also, a casing pressure overbuild (pressure over and above the bellows section opening pressure) can be tolerated without opening the fluid pilot section. It essentially offers the safety feature of two valves in one, that is, a differential valve and a pressure-operated valve.

TYPES OF SURFACE CONTROL

There are several types of surface controls that may be used for injecting gas into an intermittent lift installation. The type of surface control will vary depending upon the type of gas lift valves installed in the well. However, the type of gas lift valve does not always limit the installation to one type of surface control.

100 Per Cent Surface Intermitter Control (Fig. 11)

The most widely used method of surface control is making use of an intermitter to inject gas into the casing-tubing annular space. This means that the surface gas injection system must store the necessary volume of gas to supply the well when the intermitter opens. This type of control is a necessity for installations using unbalanced valves. It offers the flexibility of easily



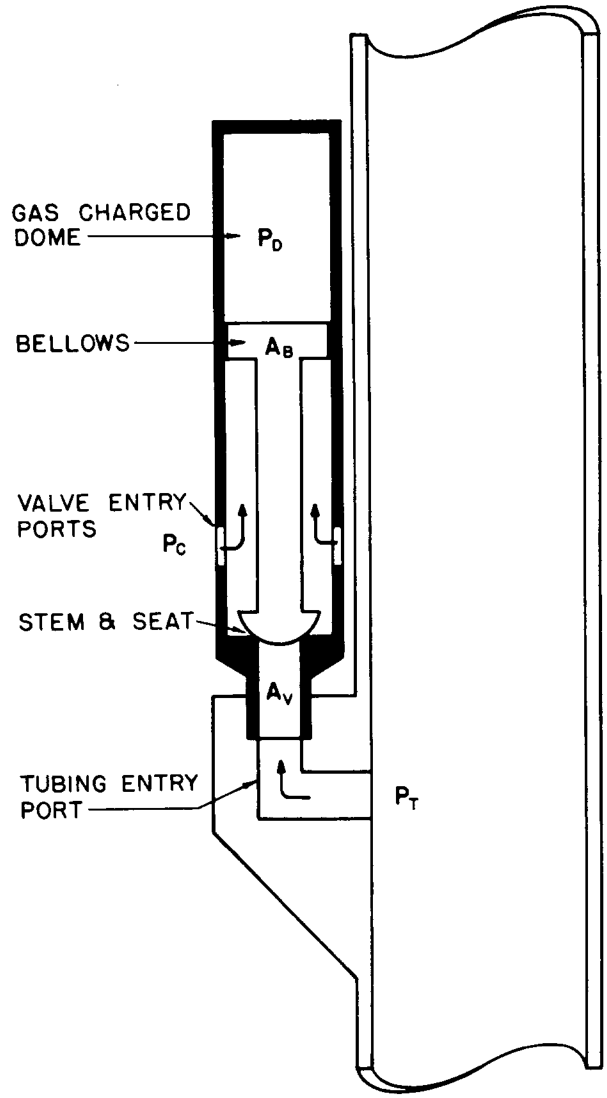


FIGURE 7-b BELLOWS VALVE SCHEMATIC

FIG. 7-a BELLOWS VALVE SCHEMATIC

changed cycle times and the amount of injected gas per cycle.

100 Per Cent Choke Control (Fig. 12)

This type of control is one whereby all the gas is injected through a choke at the surface. This type of control is suitable for multiple lift installations and for single string completions where gas is available in a limited volume. This requires a valve that is at least partially controlled by a fluid feed-in into the tubing string. In most cases it is used for a valve that incorporates the correct amount of spread in order to inject a volume of gas into the tubing which will lift the tubing load. It is necessary to design the installation such that the valve opens and closes with enough difference in pressures to supply the needed gas. For example, a valve might open at 800 psi and close at 700 psi in a 1-1/2 in. x 2-in. annulus and allow 5000 scf of gas to enter the tubing because of this drop in pressure.

A modification of this type of control is to utilize a regulator in conjunction with a choke. (Fig. 13) This eliminates the very tedious job of having to select the exact choke size. For ex-

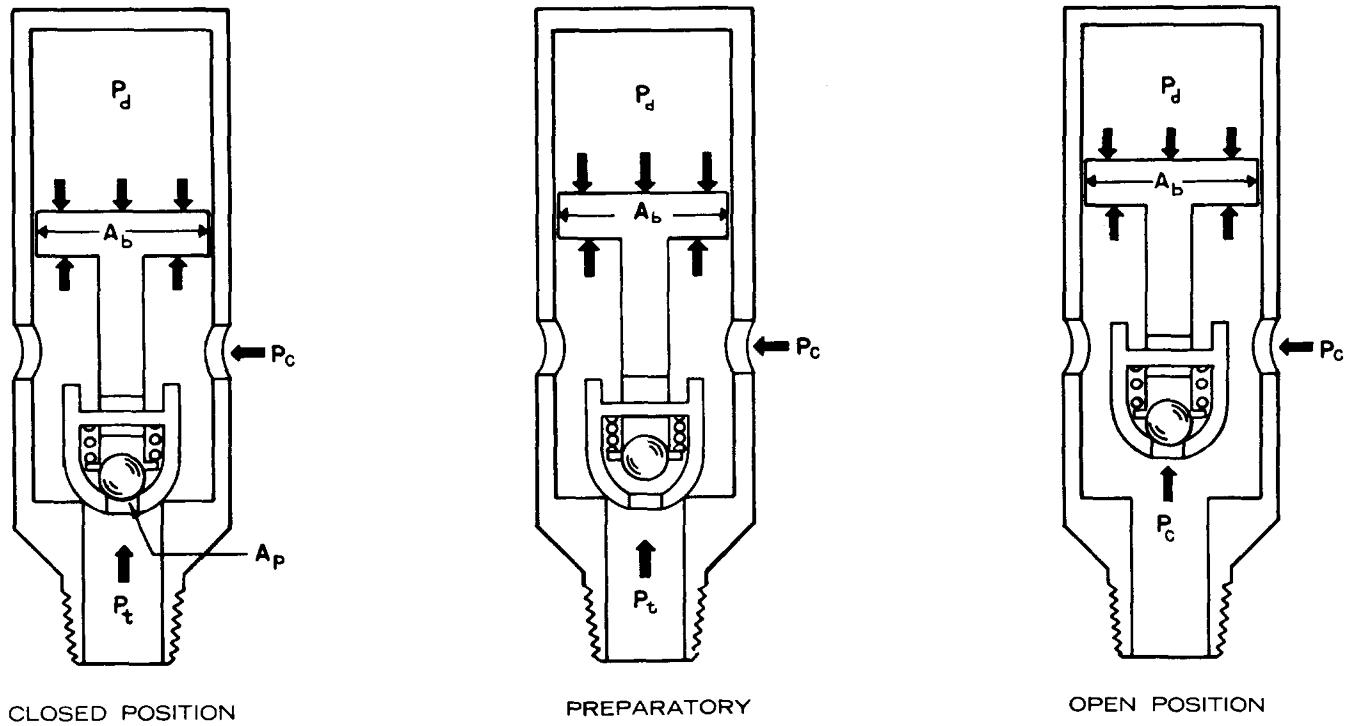


FIG. 8 PILOT VALVE

ample, let us assume we have a valve opening at 800 psi and closing at 700 psi and a well that should be cycled every 40 minutes. The selection of a choke size to give us 100 psi build-up in exactly 40 minutes generally requires a trial and error procedure. A regulator can be placed in the line such that the gas is shut off when the casing pressure reaches 800 psi. This may occur in 15-30 minutes but need not occur at exactly 40 min. A precaution here is that the choke should not be too large. The casing pressure then remains at 800 psi until the gas lift valve opens.

COMBINATION SURFACE CHOKE AND SURFACE INTERMITTER CONTROL

This type of control may be used where the surface injection storage system is not capable of supplying all the needed gas instantaneously For example, we may need to have the casing to build to 800 psi and drop to 700 psi to supply the needed gas. However, we may not want to incorporate all this spread into the gas lift valve, which may actually be unwise if we do not know the exact well conditions. For example, we may design the gas lift valve to open at 750 psi and close at 700 psi. We can then allow a choke to feed gas into the casing until the pressure reaches 745 psi (just before opening the valve). The intermitter then opens on a by-pass arrangement and allows the additional build-up to 800 psi.

This type of control is most commonly used on dual installations where the choke is continually feeding a continuous flow string and the intermitter opens to supply gas to an intermittent string.

FACTORS NECESSARY FOR THE DESIGN OF AN INTERMITTENT GAS LIFT INSTALLATION

The following factors should be considered in the design of an intermittent gas lift installation:

(1) Type of installation
(2) Type of gas lift valve
(3) Type of surface control
(4) Location of top valve depth
(5) Pressure available
(6) Gas volume required
(7) Unloading gradients
(8) Difference between valve opening pressure and tubing load

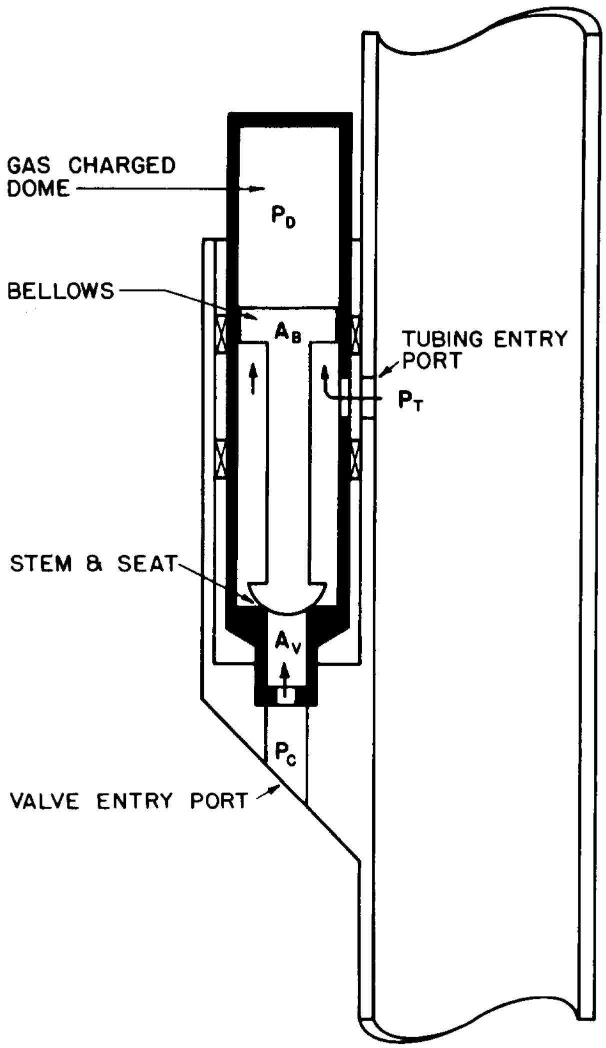


FIGURE 9 FLUID OPERATED VALVE

(9) Port size on gas lift valve
(10) Cycle frequency and pressure stabilization time

CHARTS PREPARED TO SIMPLIFY THE DESIGN OF INTERMITTENT GAS LIFT INSTALLATIONS

In order to simplify the design of intermittent gas lift installations, the following charts, patterned after Brown and Thrash.[1] have been prepared and are given in their order of use in design.

Weight of Gas Column (Chart No. 1)

This chart gives an easy means for determining the pressure exerted by a column of gas if the surface pressure is known. Also, the surface pressure may be determined from any pressure at depth. For normal wells it has been found that the increase in temperature down the well offsets the increase in density due to pressure and therefore an average gradient in psi/1000 ft work very well. For example, if the surface pressure is 800 psi, $\gamma_g = 0.65$ and depth $= 8000$ ft; then the gas pressure at $8000 + \frac{19(8000)}{1000} = 800 + 152 = 952$ psig (See Chart No. 1). Since this chart is based on an average temperature of 100°F at the surface and 70°F + 1.6° F/100 ft at depth, it should be corrected for abnormal temperatures such as the cool conditions that exist in West Texas.

For example, if we have 75°F at the surface and 120°F at 8000 ft, we have an average of 97.5°F. The average temperature upon which the chart was based is

$$\frac{100 + \left[70 + 1.6\left(\frac{8000}{1000}\right)\right]}{2} = 149°F$$

The correction is then

$$(152)\left(\frac{149 + 460}{97.5 + 460}\right) = (152)\left(\frac{609}{557.5}\right)$$

$$= 166 \text{ psig.}$$

The pressure at 8000 ft is then 800 + 166 = 966 psig instead of 952 psig.

Intermittent Gas Volume Requirements (Chart 2)

After the operating pressure at depth has been determined (966 psig from Chart No. 1) the gas volume required can be obtained from Chart 2. This value is found to be 6600 SCF cycle for 2-in. tubing and 50 psig separator pressure. These charts were prepared under the following assumptions and average conditions: The gas volume requirements were determined by calculating the number of SCF of gas necessary to fill the tubing string less the remaining slug length in the tubing as it reaches the surface at the average pressure and temperature underneath the liquid slug from bottom to top.

The following constants were utilized:

(1) Surface temperature — 80°F
(2) Temperature gradient — 1.6°F 100 ft
(3) Gas specific gravity — 0.65
(4) Gas deviation was accounted for

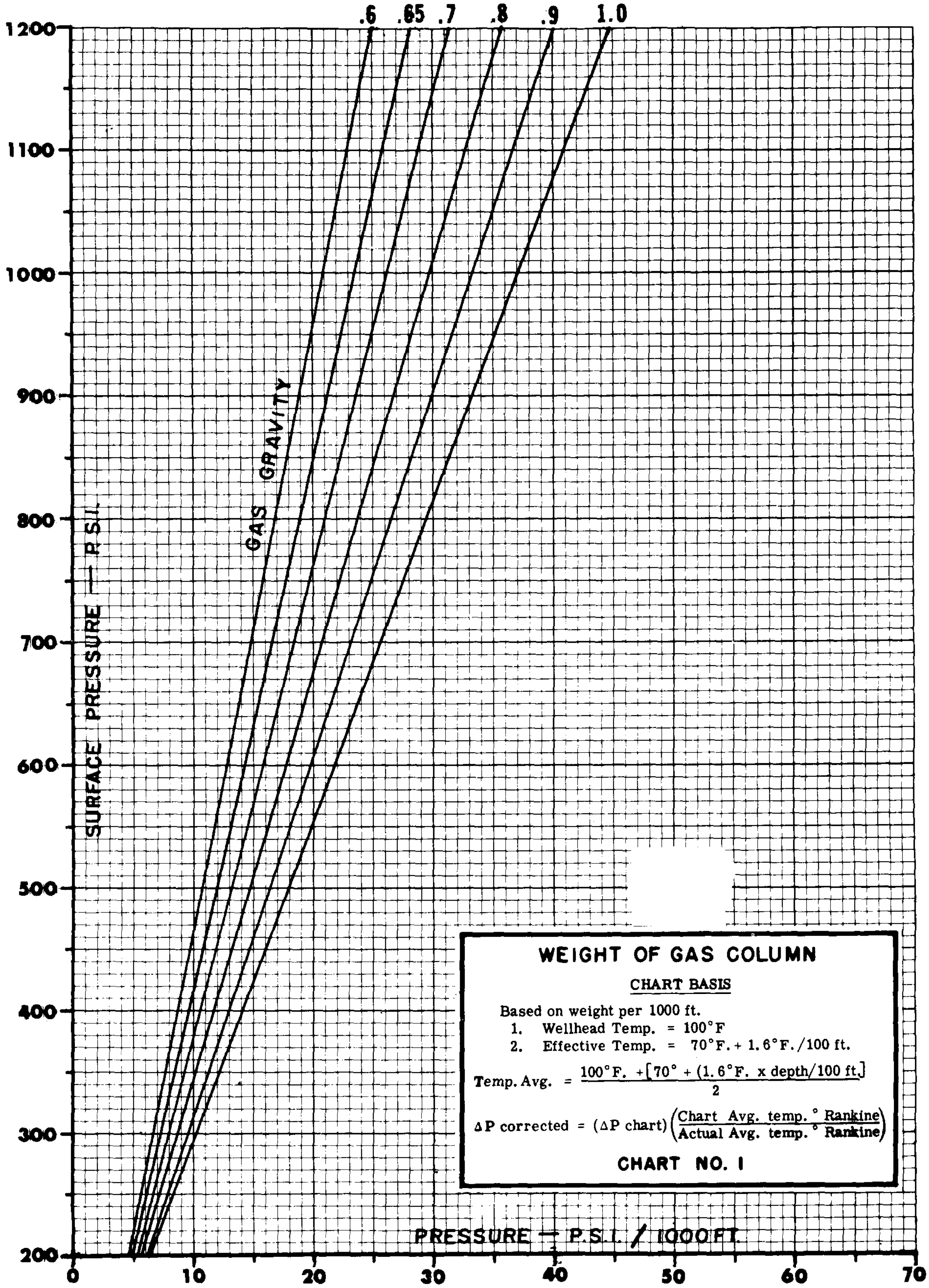
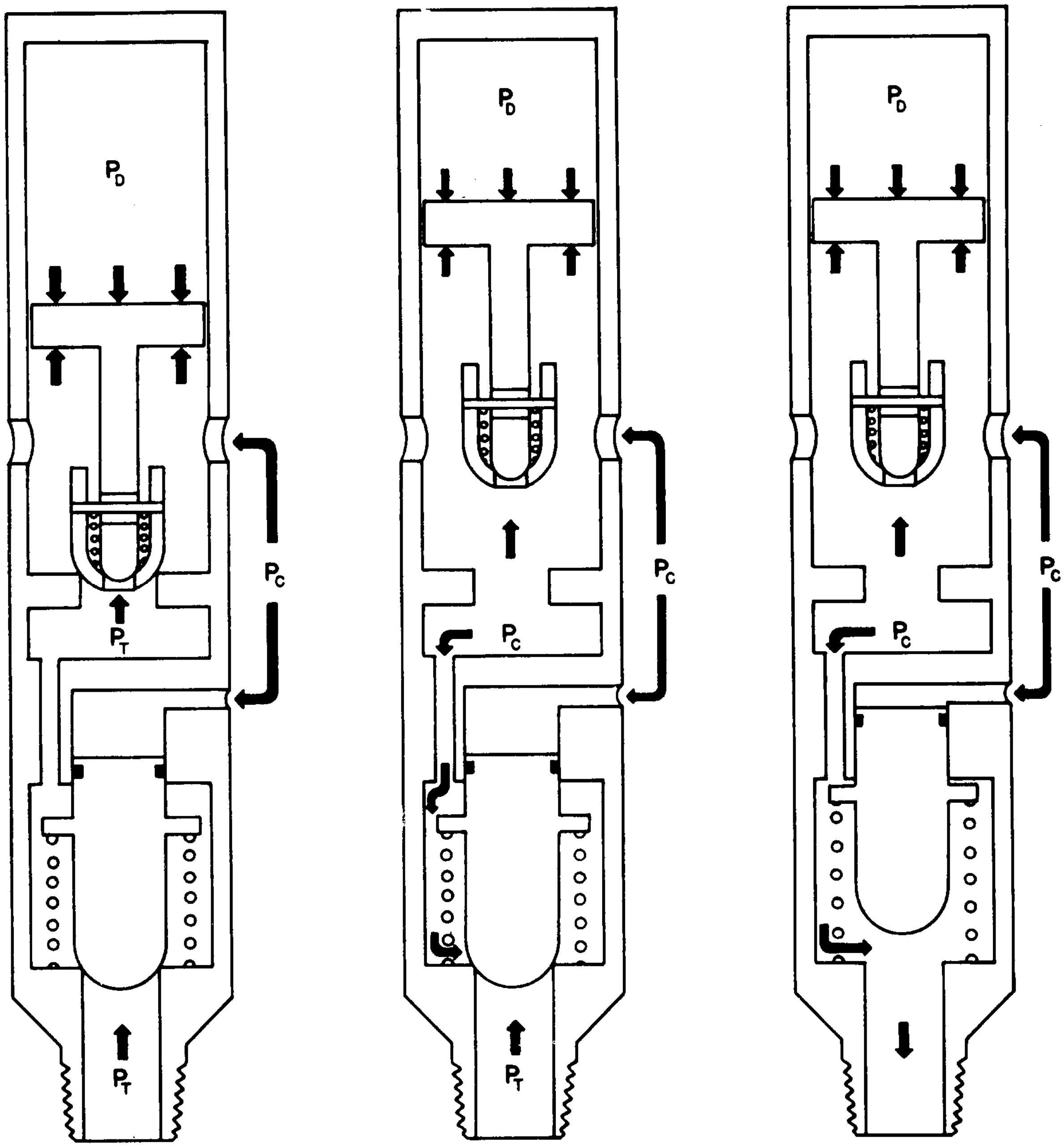

.6
.65
.7
.8
.9
1.0
GAS GRAVITY
SURFACE PRESSURE — P.S.I.
PRESSURE — P.S.I. / 1000 FT.
1200
1100
1000
900
800
700
600
500
400
300
200
0
10
20
30
40
50
60
70
WEIGHT OF GAS COLUMN
CHART BASIS
Based on weight per 1000 ft.
1. Wellhead Temp. = 100°F
2. Effective Temp. = 70°F. + 1.6°F./100 ft.
Temp. Avg. = $\frac{100°F. + [70° + (1.6°F. \times depth/100 ft.]}{2}$
ΔP corrected = (ΔP chart) $\left(\frac{\text{Chart Avg. temp. ° Rankine}}{\text{Actual Avg. temp. ° Rankine}}\right)$
CHART NO. 1

FIGURE 10
FLUID OPERATED GAS LIFT VALVE



CLOSED POSITION BELLOWS VALVE AND PILOT VALVE CLOSED.

PREPARATORY POSITION BELLOWS VALVE OPEN & PILOT VALVE CLOSED.

OPEN POSITION BELLOWS VALVE AND PILOT VALVE OPEN.

(5) A 35° API oil was lifted

(6) The gas pressure placed underneath the slug at the operating valve is the opening pressure of the valve.

(7) The gas pressure in the tubing as the slug is being produced at the surface is

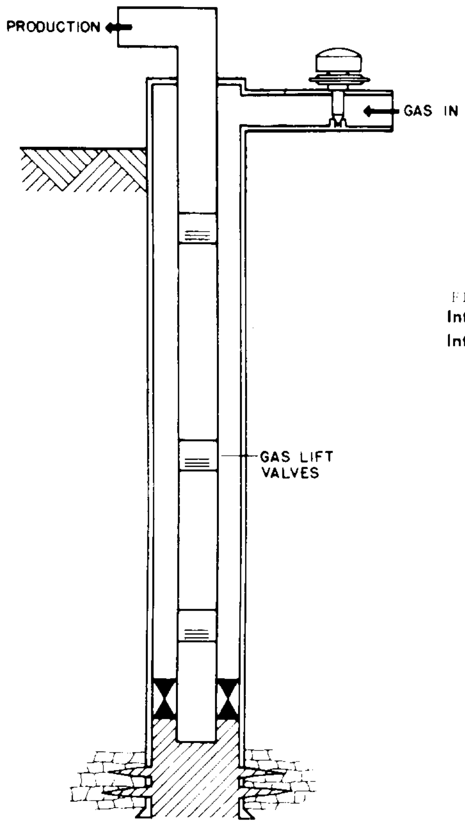


FIGURE 11
Intermitter Control For Intermitting Lift

the tubing back pressure plus the hydrostatic head pressure of the remaining slug.

(8) The difference between the tubing load to be lifted and operating lift pressure is 200 psi.

(9) The fall-back is assumed to be 7 per cent per 1000 ft

(10) The volume that the liquid fall-back in the tubing string occupies is neglected and assumed to be occupied by gas.

(11) The gas column weight in the tubing string was accounted for in order to determine the initial length of the liquid slug.

Annular Pressure Reduction (Chart 3)

Depending upon the type of valve being used, the next chart to use would be one giving the necessary casing pressure drop to allow the injection of 6600 SCF. As noted (Chart 3), the abscissa (horizontal) is plotted in SCF/1000 ft.

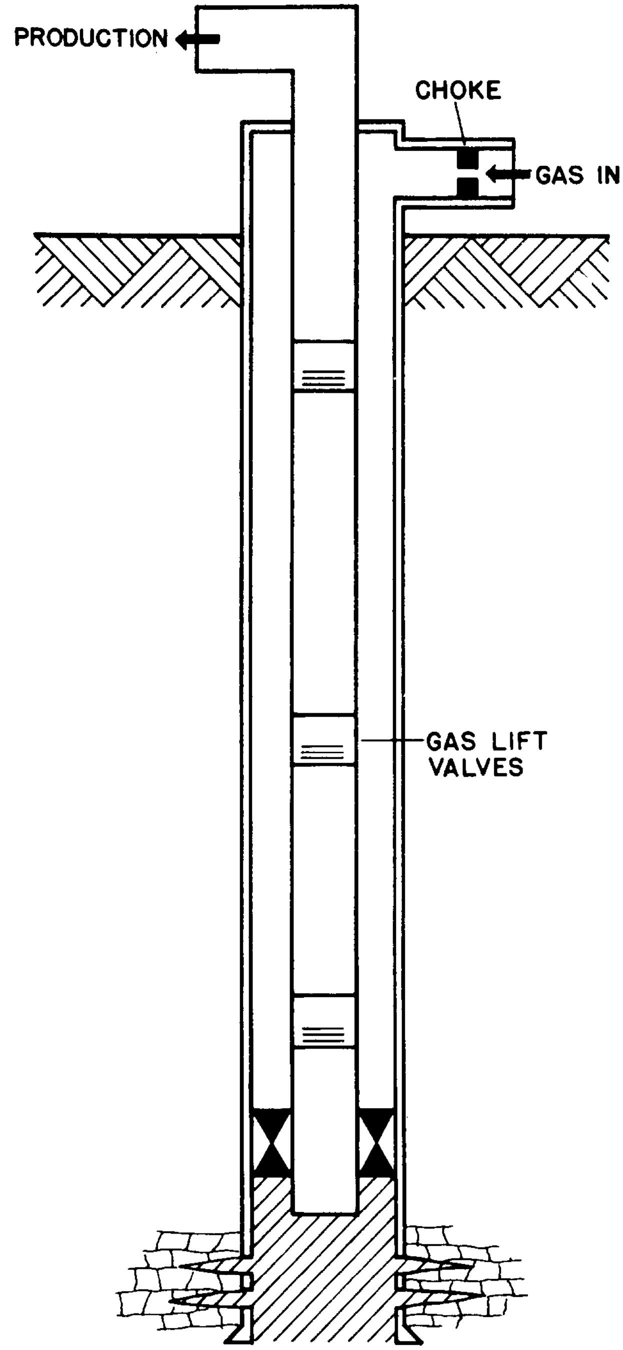
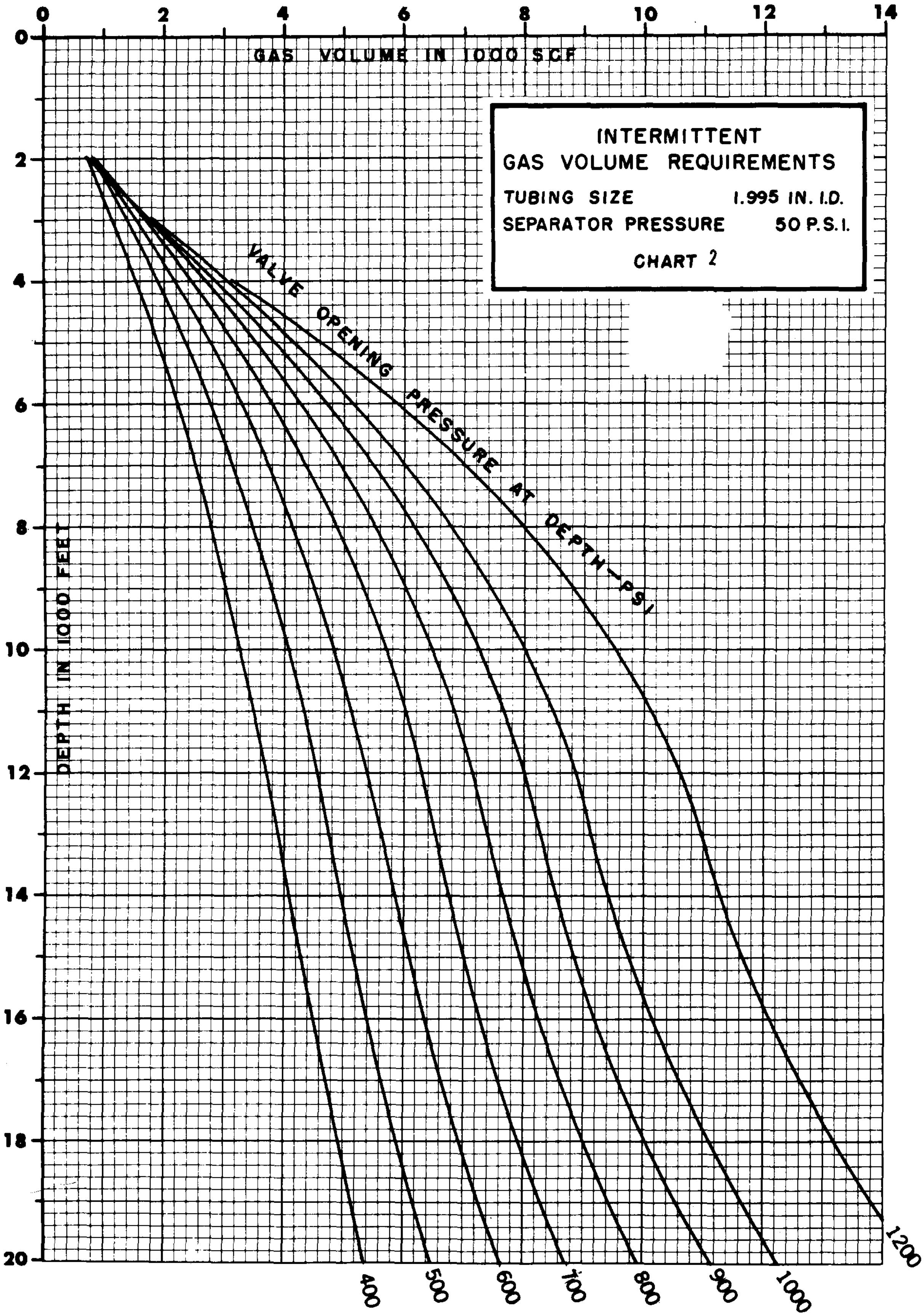


FIG. 12 CHOKE CONTROL OF INJECTION GAS

Therefore, we must divide 6600 SCF total by 8000/1000 or $\frac{6600}{8} = 825$ SCF/1000 ft. We now refer to Chart 3 and note that an annular pressure reduction of 120 psi is required to deliver



GAS VOLUME IN 1000 SCF
0
2
4
6
8
10
12
14
INTERMITTENT
GAS VOLUME REQUIREMENTS
TUBING SIZE 1.995 IN. I.D.
SEPARATOR PRESSURE 50 P.S.I.
CHART 2
VALVE OPENING PRESSURE AT DEPTH-PSI
DEPTH IN 1000 FEET
16
18
20
400
500
600
700
800
900
1000
1200

6600 SCF for 2-in. tubing and 5-1/2 in. casing. Although this chart is normally used with 100 per cent choke control at the surface, it is also very useful for 100 per cent intermitter control. For 100 per cent choke control it tells us that the operating valve must have a spread of 120 psi under load conditions; that is, with the tubing load to be lifted.

However, for 100 per cent intermitter control, it also tells us how to set the surface closing pressure on the operating valve. For this example the surface line pressure (operating pressure) should be 120 psi greater than the surface closing pressure on the operating valve. If this is not true, then ample gas volume must be necessary to supply the gas.

For 800 psi at the surface and 966 psi at 8000 ft, the closing pressure on the valve would be 966 – 120 = 846 psi.

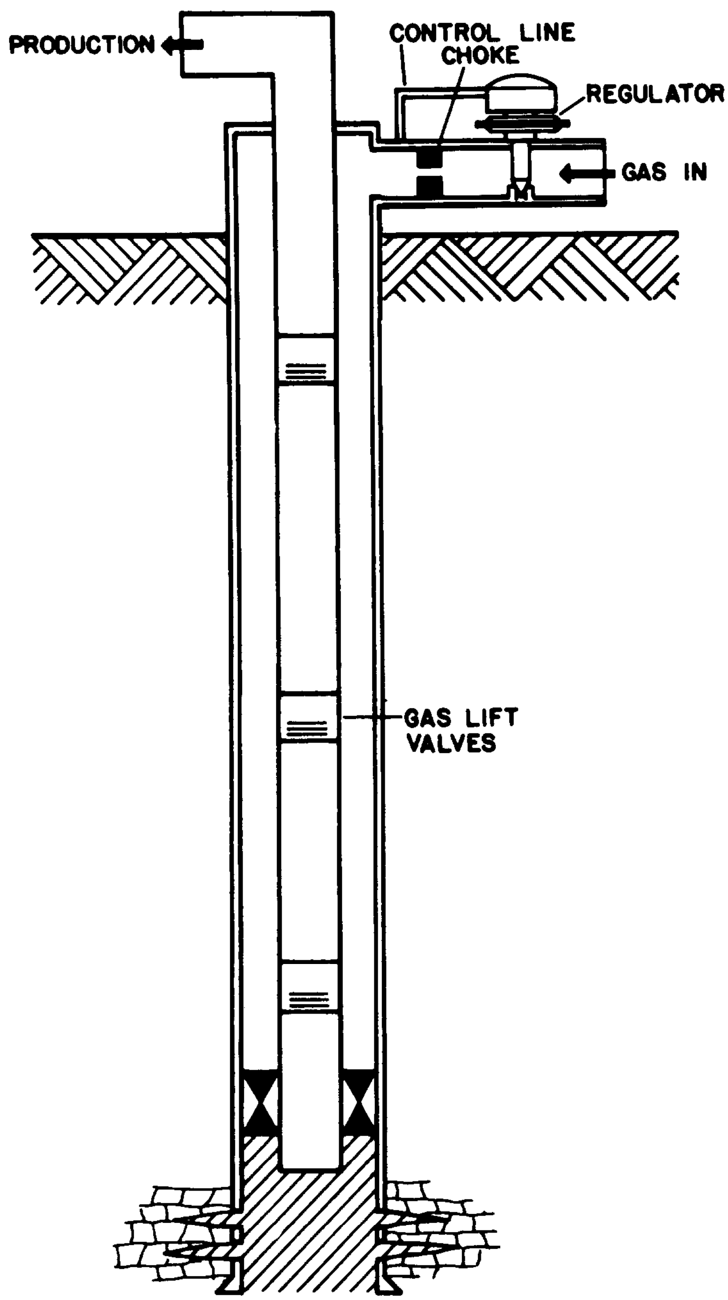


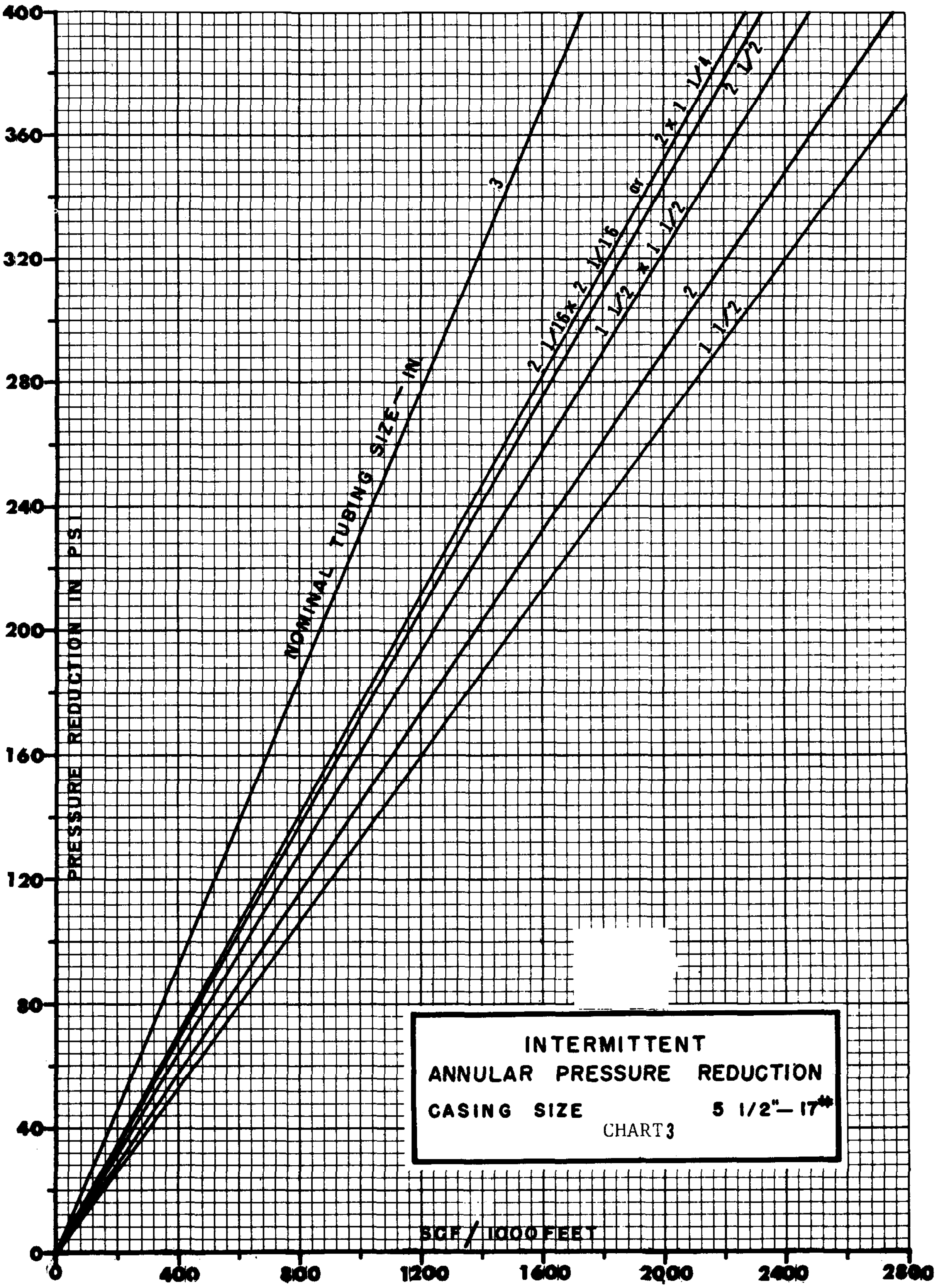
FIGURE 13 REGULATOR IN SERIES WITH CHOKE

Value Selection Chart (Chart 4)

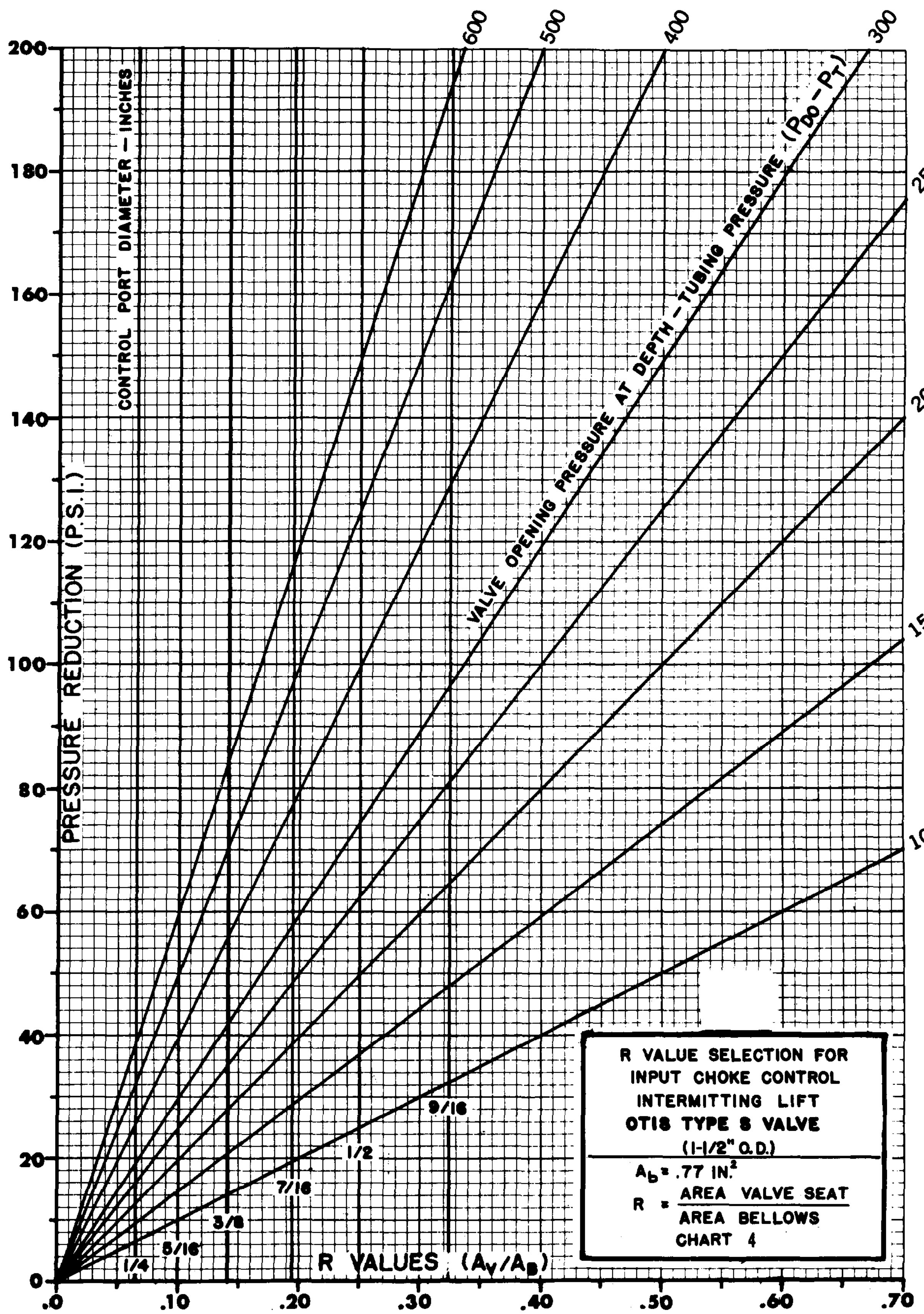
Once the total gas volume and annular pressure reduction have been determined, a valve control seat and/or main seat size must be selected that will give the required pressure reduction under operating conditions. Depending upon the type of valve and the type of surface control, the valve may give 100 per cent of the reduction, or a portion thereof. From Chart 4 a 1-1/2 in. main valve size and a difference of 300 psi between opening pressure at depth and tubing load we note that a control port with .40 in.^{2} of area is needed to give just exactly 120 psi reduction. Proceeding back to the left to the first standard port size we encounter a 11/16-in. and then a 9/16-in. control port size. Since a 11/16-in. is normally not a standard stock size we would select a 9/16-in. port if we are using 100 per cent surface choke control. In making this selection always select a port size that is smaller than the needed indicated size from Chart 4. The reason for this is that the surface choke is continually passing gas during that period when the gas lift valve is open. For example, in an 8000 ft well the gas lift valve will remain open approximately eight minutes (time for slug to travel to the surface). Gas will be entering the casing annular space during this eight minutes and will be injected into the tubing string, thereby using more gas than the casing pressure drop alone would indicate.

Temperature Correction (Charts 5A and 5B)

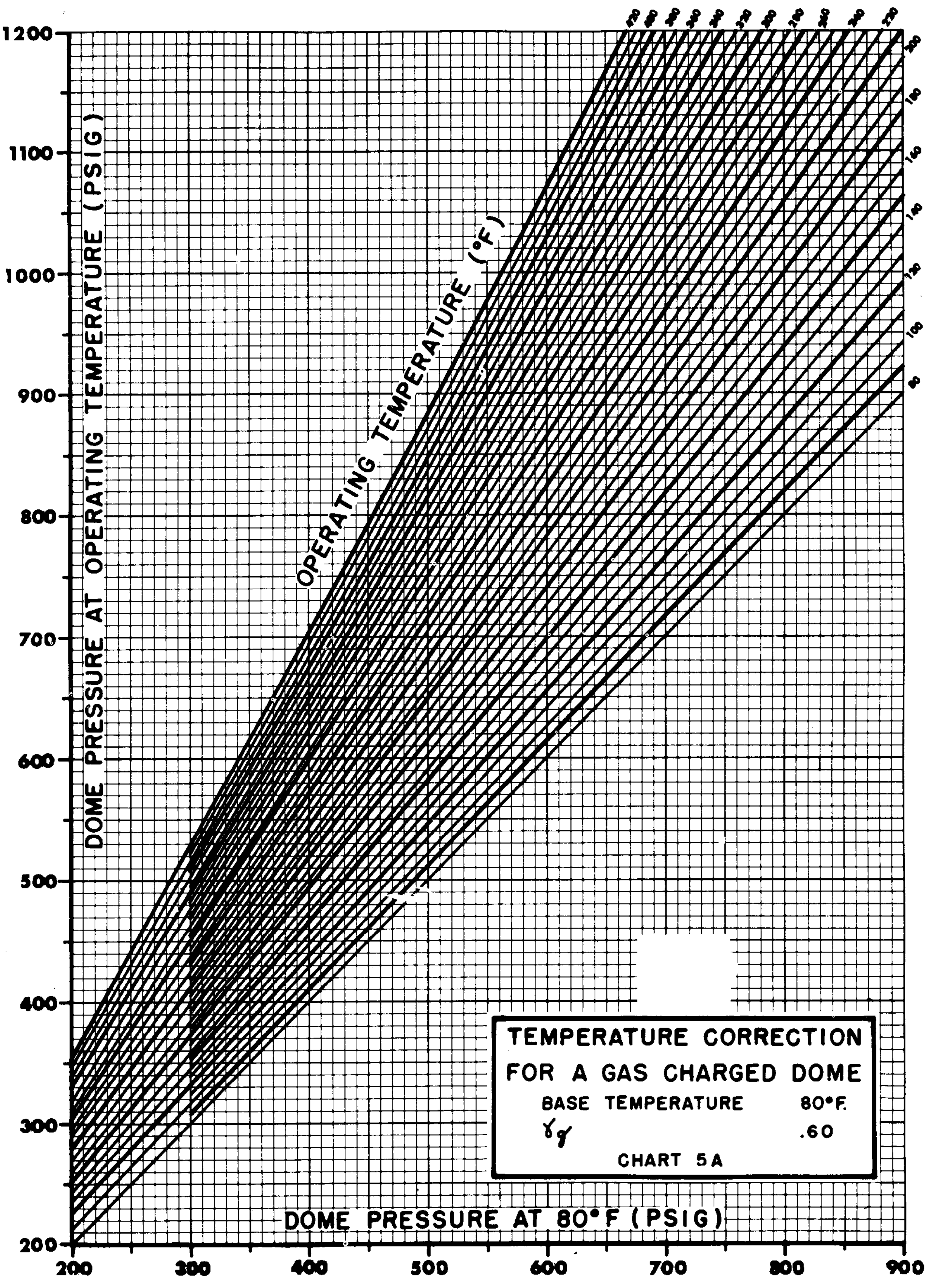
Charts 5A and 5B give a ready means of converting dome pressures at any temperature to dome pressures at standard shop settings of 80°F or 60°F, and as charged with natural gas or nitrogen.

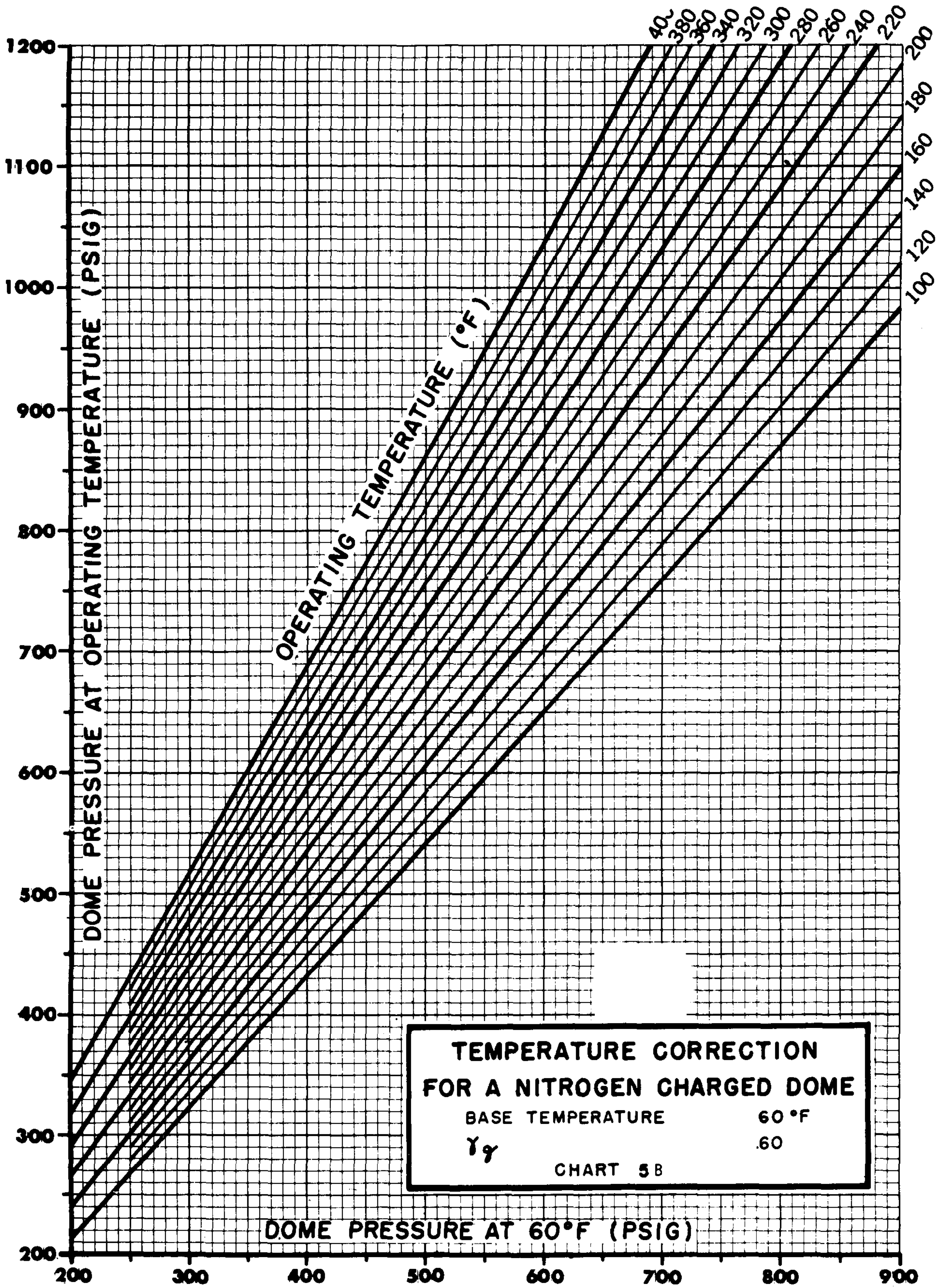


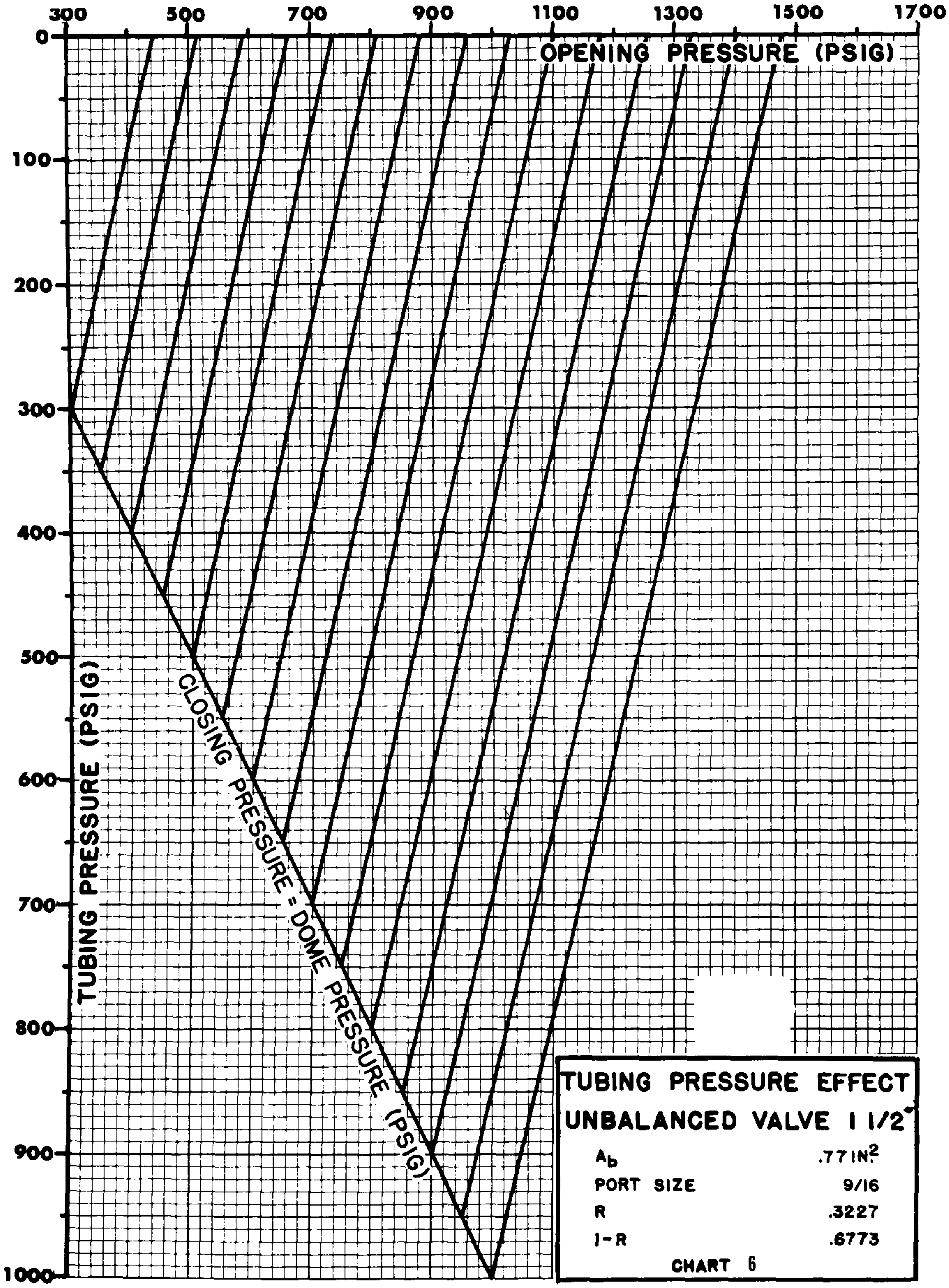
INTERMITTENT
ANNULAR PRESSURE REDUCTION
CASING SIZE 5 1/2"— 17#
CHART 3
PRESSURE REDUCTION IN PSI
SCF / 1000 FEET
NOMINAL TUBING SIZE — IN
3
2 1/16 x 2 1/16 or 2 x 1 1/4
2 1/2
1 1/2 x 1 1/2
2
1 1/2
0
40
80
120
160
200
240
280
320
360
400
400
800
1200
1600
2000
2400
2800

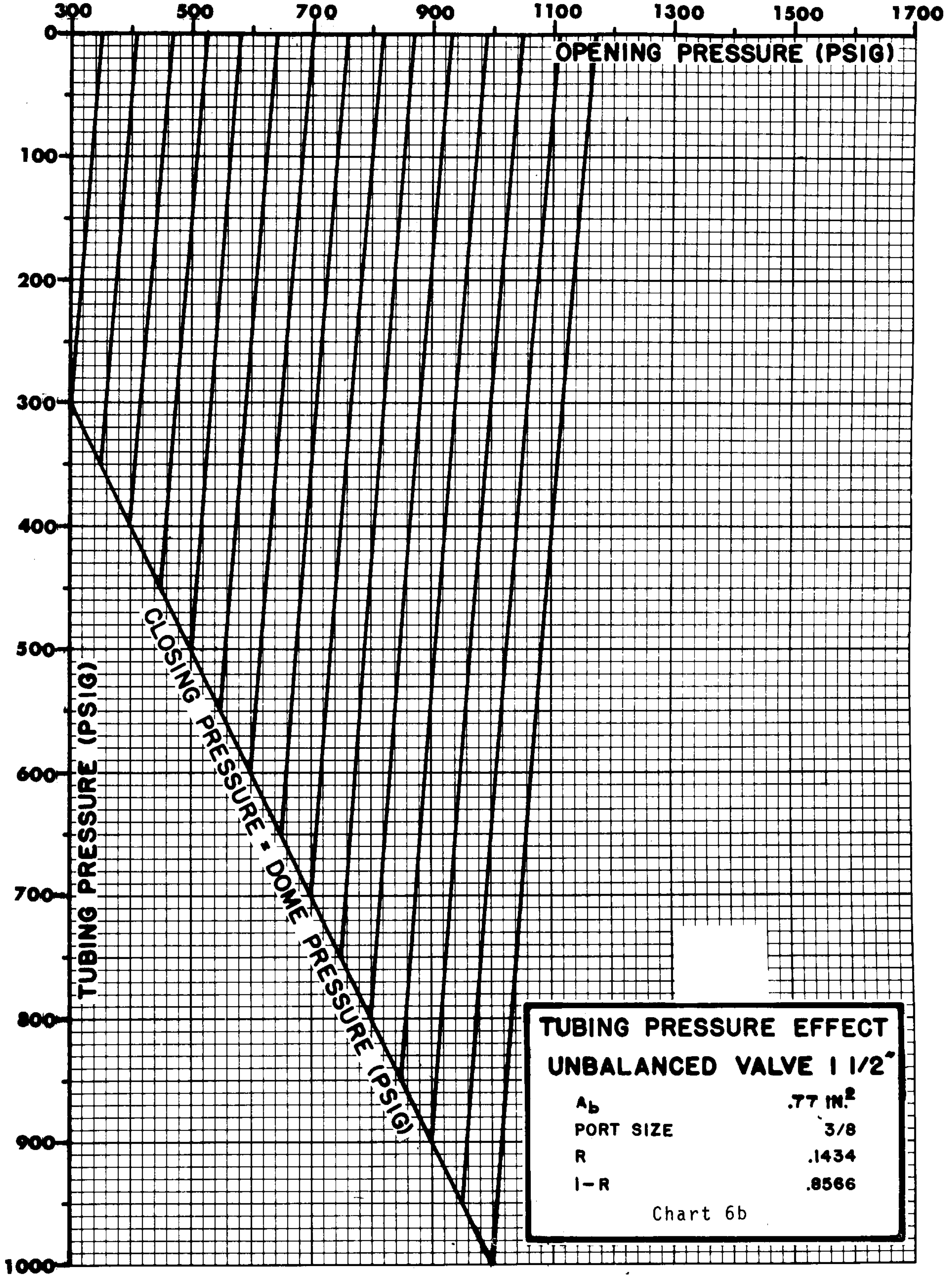


R VALUE SELECTION FOR
INPUT CHOKE CONTROL
INTERMITTING LIFT
OTIS TYPE S VALVE
(1-1/2" O.D.)
A_b = .77 IN.^{2}
R = AREA VALVE SEAT / AREA BELLOWS
CHART 4
PRESSURE REDUCTION (P.S.I.)
R VALUES (A_V/A_B)
CONTROL PORT DIAMETER – INCHES
VALVE OPENING PRESSURE AT DEPTH – TUBING PRESSURE ($P_{DO}-P_T$)
600
500
400
300
250
200
150
100
1/4
5/16
3/8
7/16
1/2
9/16
0
20
40
60
80
100
120
140
160
180
200
.0
.10
.20
.30
.40
.50
.60
.70

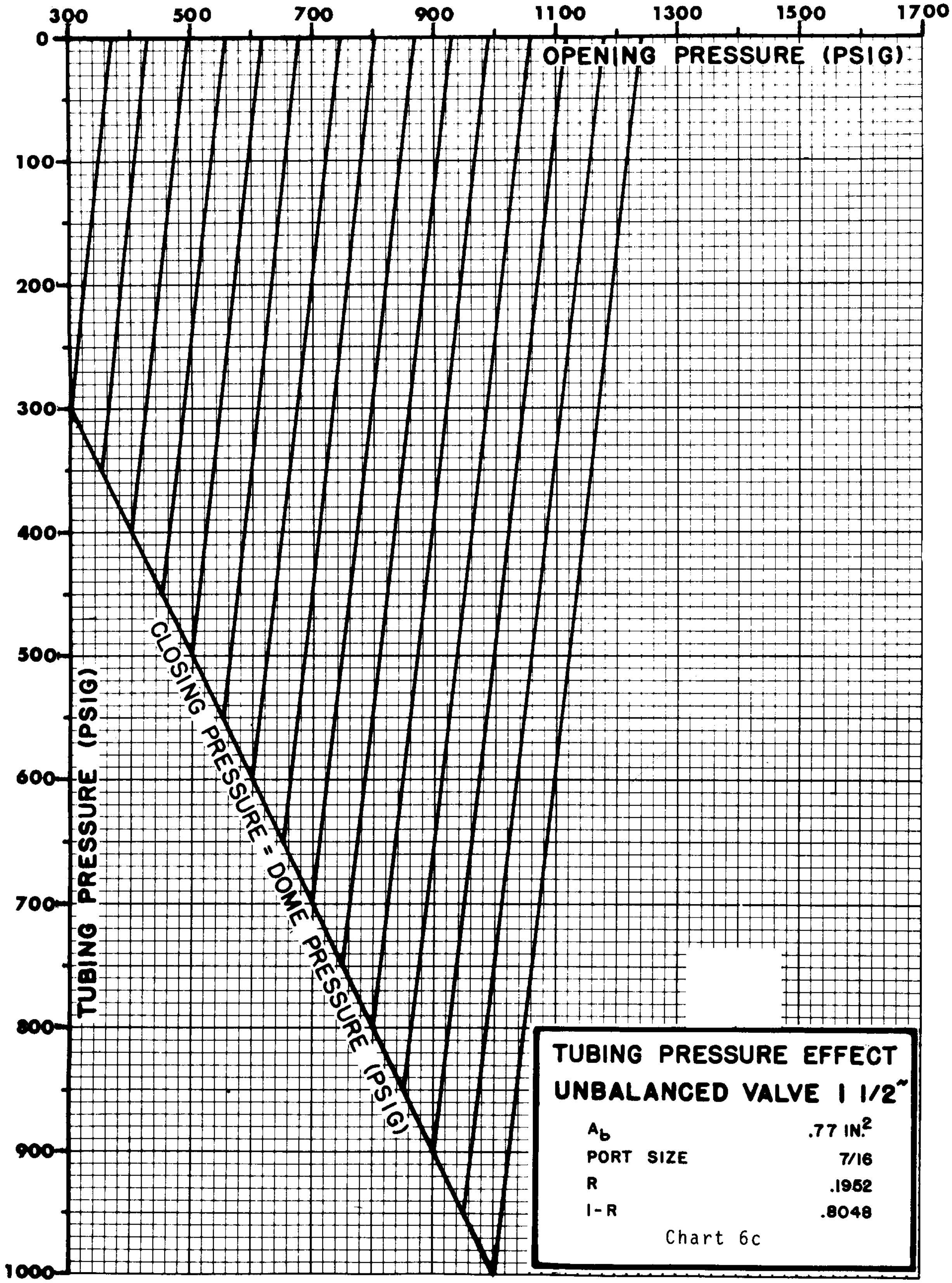

TEMPERATURE CORRECTION
FOR A GAS CHARGED DOME
BASE TEMPERATURE 80°F.
γ_g .60
CHART 5A
DOME PRESSURE AT OPERATING TEMPERATURE (PSIG)
DOME PRESSURE AT 80°F (PSIG)
OPERATING TEMPERATURE (°F)
1200
1100
1000
900
800
700
600
500
400
300
200
200
300
400
500
600
700
800
900


TEMPERATURE CORRECTION
FOR A NITROGEN CHARGED DOME
BASE TEMPERATURE 60 °F
γ_g .60
CHART 5B
DOME PRESSURE AT OPERATING TEMPERATURE (PSIG)
DOME PRESSURE AT 60°F (PSIG)
OPERATING TEMPERATURE (°F)
200
300
400
500
600
700
800
900
1000
1100
1200
100
120
140
160
180
220
240
260
280
320
340
360
380
400

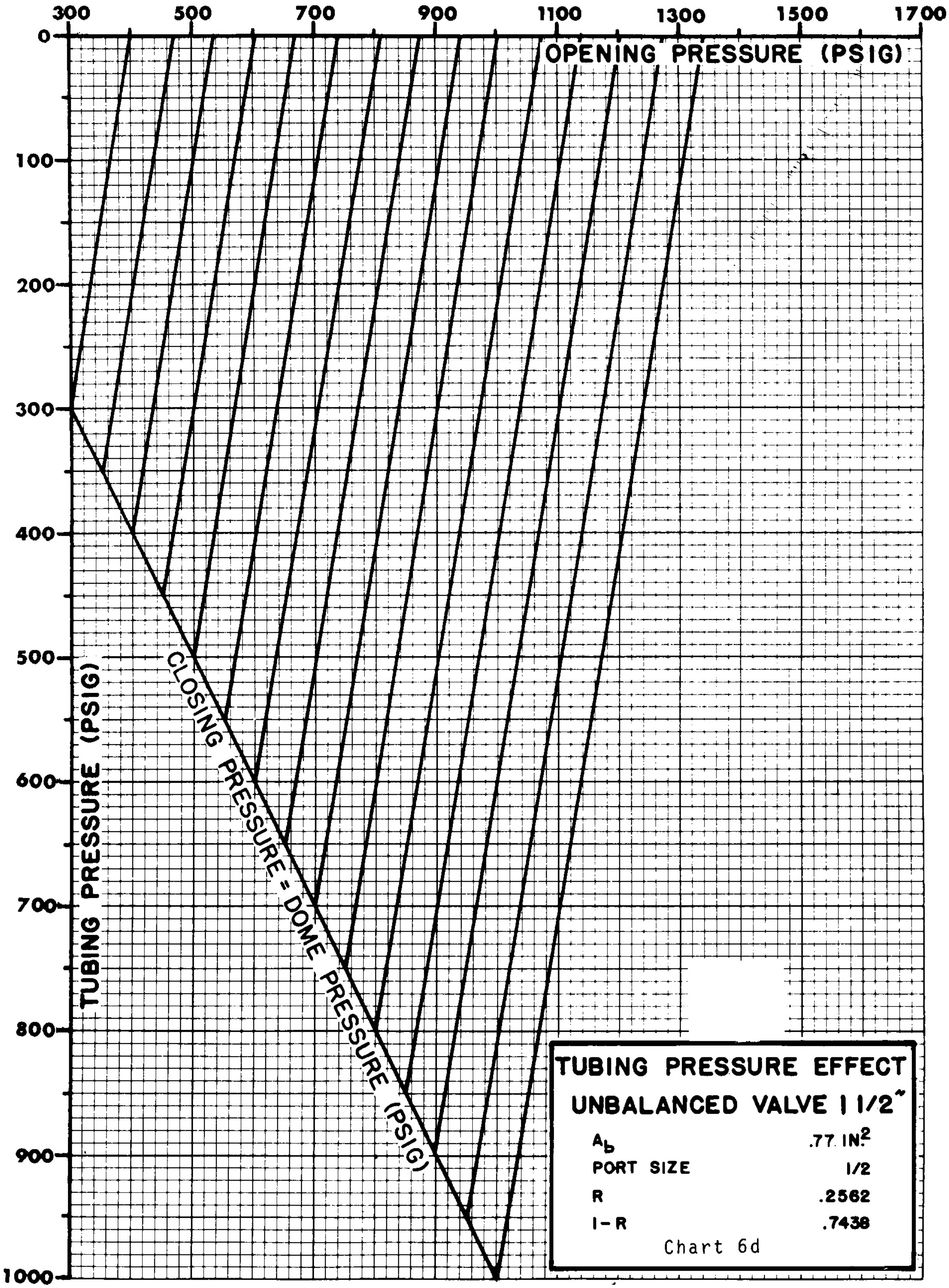

300
500
700
900
1100
1300
1500
1700
OPENING PRESSURE (PSIG)
0
100
200
300
400
500
600
700
800
900
1000
TUBING PRESSURE (PSIG)
CLOSING PRESSURE = DOME PRESSURE (PSIG)
TUBING PRESSURE EFFECT
UNBALANCED VALVE 1 1/2"
A_b .77 IN.^{2}
PORT SIZE 9/16
R .3227
1-R .6773
CHART 6

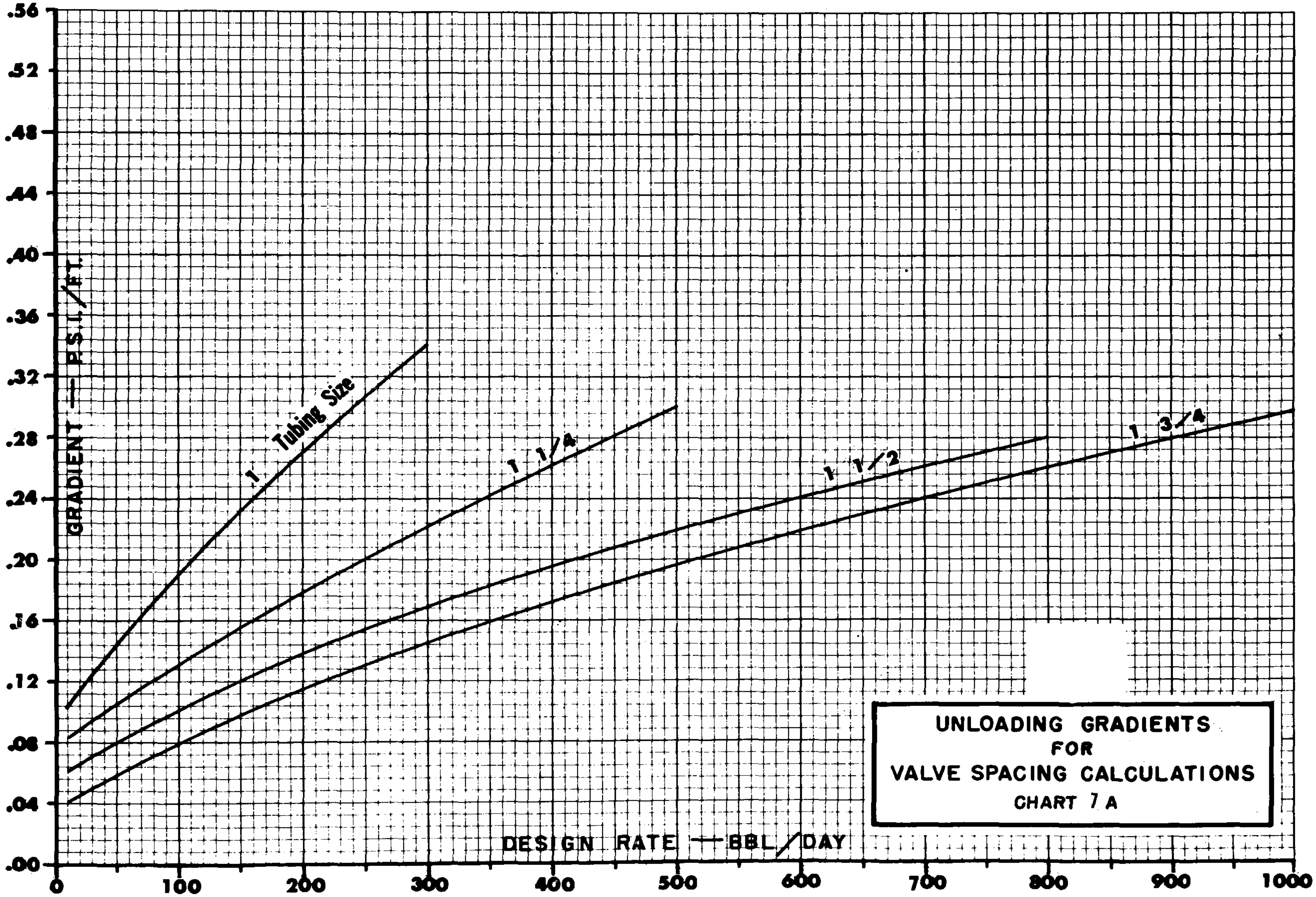


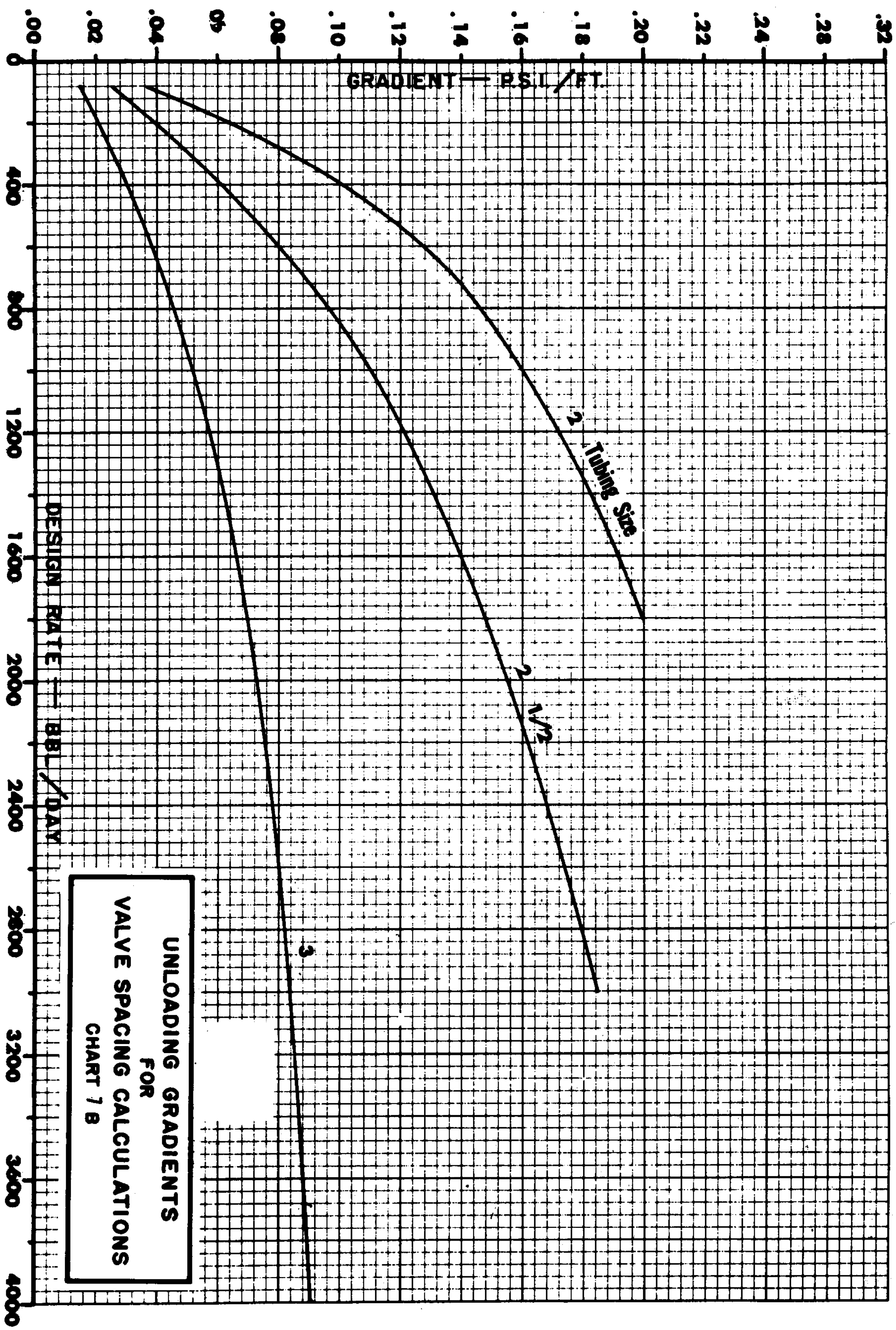
OPENING PRESSURE (PSIG)
300
500
700
900
1100
1300
1500
1700
TUBING PRESSURE (PSIG)
0
100
200
300
400
500
600
700
800
900
1000
CLOSING PRESSURE = DOME PRESSURE (PSIG)
TUBING PRESSURE EFFECT
UNBALANCED VALVE 1 1/2"
A_b .77 IN.²
PORT SIZE 3/8
R .1434
1−R .8566
Chart 6b



300
500
700
900
1100
1300
1500
1700
OPENING PRESSURE (PSIG)
0
100
200
300
400
500
600
700
800
900
1000
TUBING PRESSURE (PSIG)
CLOSING PRESSURE = DOME PRESSURE (PSIG)
TUBING PRESSURE EFFECT
UNBALANCED VALVE 1 1/2"
A_b .77 IN.^{2}
PORT SIZE 7/16
R .1952
1-R .8048
Chart 6c


300
500
700
900
1100
1300
1500
1700
OPENING PRESSURE (PSIG)
0
100
200
300
400
500
600
700
800
900
1000
TUBING PRESSURE (PSIG)
CLOSING PRESSURE = DOME PRESSURE (PSIG)
TUBING PRESSURE EFFECT
UNBALANCED VALVE 1 1/2"
Ab .77 IN.2
PORT SIZE 1/2
R .2562
1-R .7438
Chart 6d


UNLOADING GRADIENTS
FOR
VALVE SPACING CALCULATIONS
CHART 7 A
GRADIENT — P.S.I./FT.
DESIGN RATE — BBL/DAY
1 Tubing Size
1 1/4
1 1/2
1 3/4
.00
.04
.08
.12
.16
.20
.24
.28
.32
.36
.40
.44
.48
.52
.56
0
100
200
300
400
500
600
700
800
900
1000



GRADIENT — P.S.I./FT.
.00
.02
.04
.06
.08
.10
.12
.14
.16
.18
.20
.22
.24
.28
.32
DESIGN RATE — BBL/DAY
0
400
800
1200
1600
2000
2400
2800
3200
3600
4000
2 Tubing Size
2 1/2
3
UNLOADING GRADIENTS
FOR
VALVE SPACING CALCULATIONS
CHART 7 B

For example, if the valve opening pressure at 8000 psig and 120°F is 966 psig, and the closing pressure is 846 psig, we may go to Chart 5A and find the dome pressure at 80°F to be 770 psig, or, from Chart 5B, the dome pressure at 60°F (charged with nitrogen) is 750 psig.

As noted, these charts may be used for determining the dome pressure at any temperature provided the dome pressure is known at a known temperature. These charts may be used for temperature corrections of any closed container and therefore are not restricted to gas lift valves.

Tubing Pressure Effect (Charts 6, 6b, 6c, 6d)

Charts 6 and 6b-d give a means for determining the opening pressure of the gas lift valve under any tubing load. In addition, the valve opening pressure (stamped pressure on the valve at shop setting temperature) can be found at zero tubing pressure.

For example, the 9/16 ported valve (Fig. 5) was found to have a dome pressure of 766 psig at 80°F. This is also the closing pressure of the valve. The opening pressure of this valve at 80°F and zero tubing pressure is found to be 1135 psig, which is also the stamped pressure on the gas lift valve.

The opening pressure of this valve at depth can also be determined for varying tubing loads. For example, this valve was found to have a dome pressure (closing pressure) of 846 psig at 8000 ft and 120°F. From Chart 6 its opening pressure with a tubing load of 600 psig is found to be 960 psig, which gives it a spread of 960-846 = 114 psi.

Charts of this type are used to determine opening pressures under possible operating conditions. For example, a good design check is to make certain that the operating valve can be opened under a light tubing load. In checking this same valve for a 200 psig tubing load, we find that a casing pressure of 1155 psig at the valve is needed which in turn requires a surface opening pressure of 975 psig as determined from Chart No. 1.

Spacing Charts

Charts 7A and 7B are used for obtaining spacing gradients to determine the distance between gas lift valves in the design of an installation. These charts were prepared from the minimum gradient that is possible to obtain by continuous flow for the various flow rates. It is recommended that a minimum spacing gradient of .04 psi/ft be used for all tubing sizes. These charts are not to be confused with flowing gradient charts and should be used in spacing valves only.

By way of example, the spacing gradient for a 200 BPD rate and 2-in. tubing is .064 psi/ft. (See Chart 7B).

DESIGN EXAMPLES

One set of well conditions will be given and an intermittent installation utilizing different types of surface control will be designed.

Given:

Well depth 8000 ft.
Casing size — 5 1/2" — 17 lb/ft
Tubing size — 2-3/8" O.D. EUE
Separator Pressure — 50 psig
Kick-off pressure — 900 psig
Operating pressure — 800 psig
Gas Specific gravity — 0.65
Formation temperature — 120°F.
Surface temperature — 75°F.
Bottom-hole pressure — Low
Desired rate — 100 B/D — 35°API oil
Water production — zero
Productivity index — unknown
Well is to be loaded to the surface with deal oil (35°API) for purpose of pulling tubing.

This example uses the same values as found under the previous explanation of Charts 1, 2, 3, 4, 5, 6, and 7.

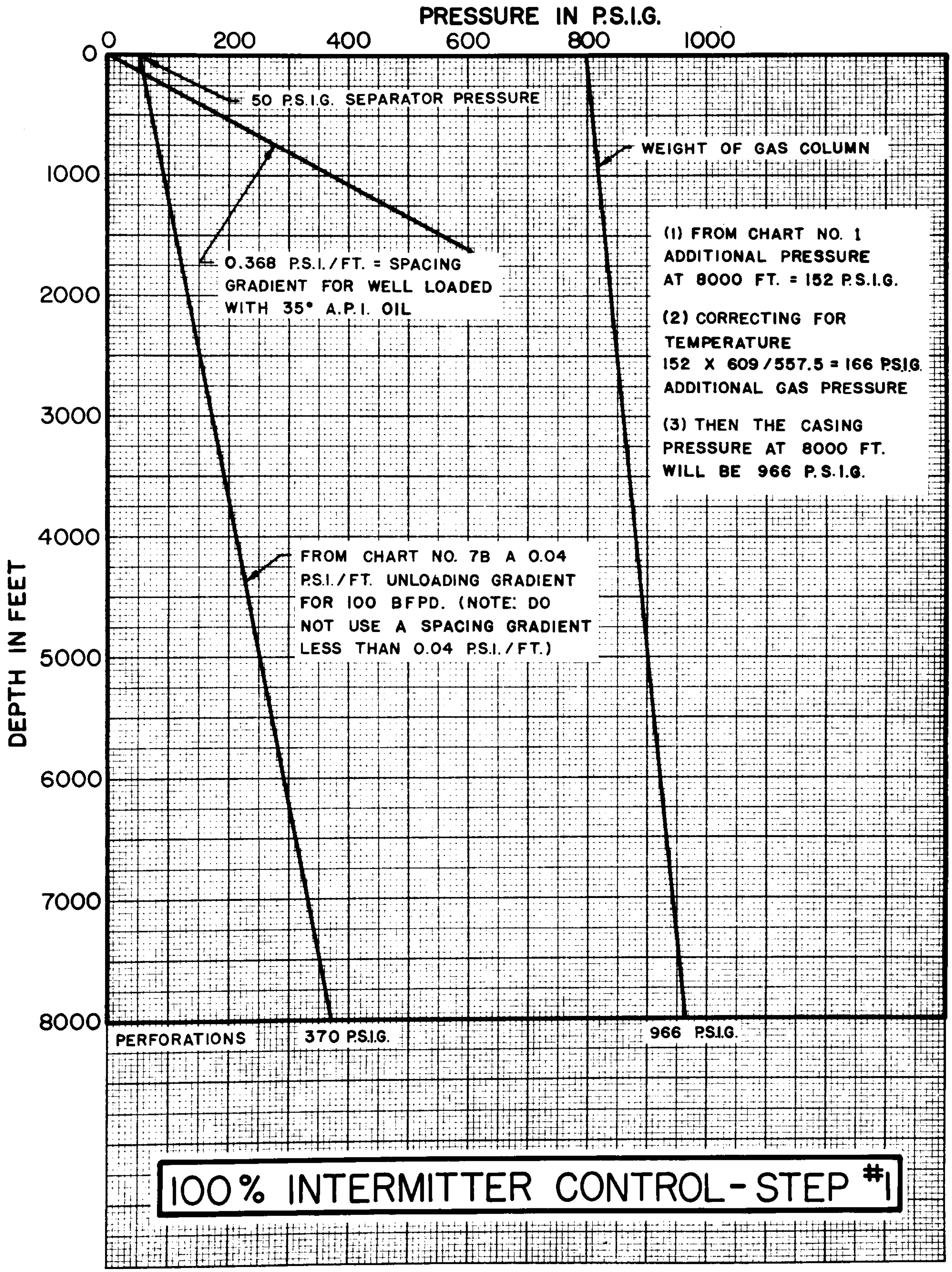
For simplification, a series of steps such as spacing procedures, etc. will be eliminated in this design procedure. For example, steps 1, 2, and 3 are presented graphically as noted on the figures, entitled step 1, step 2, and step 3. Detailed explanations are on the charts themselves.

EXAMPLE 1

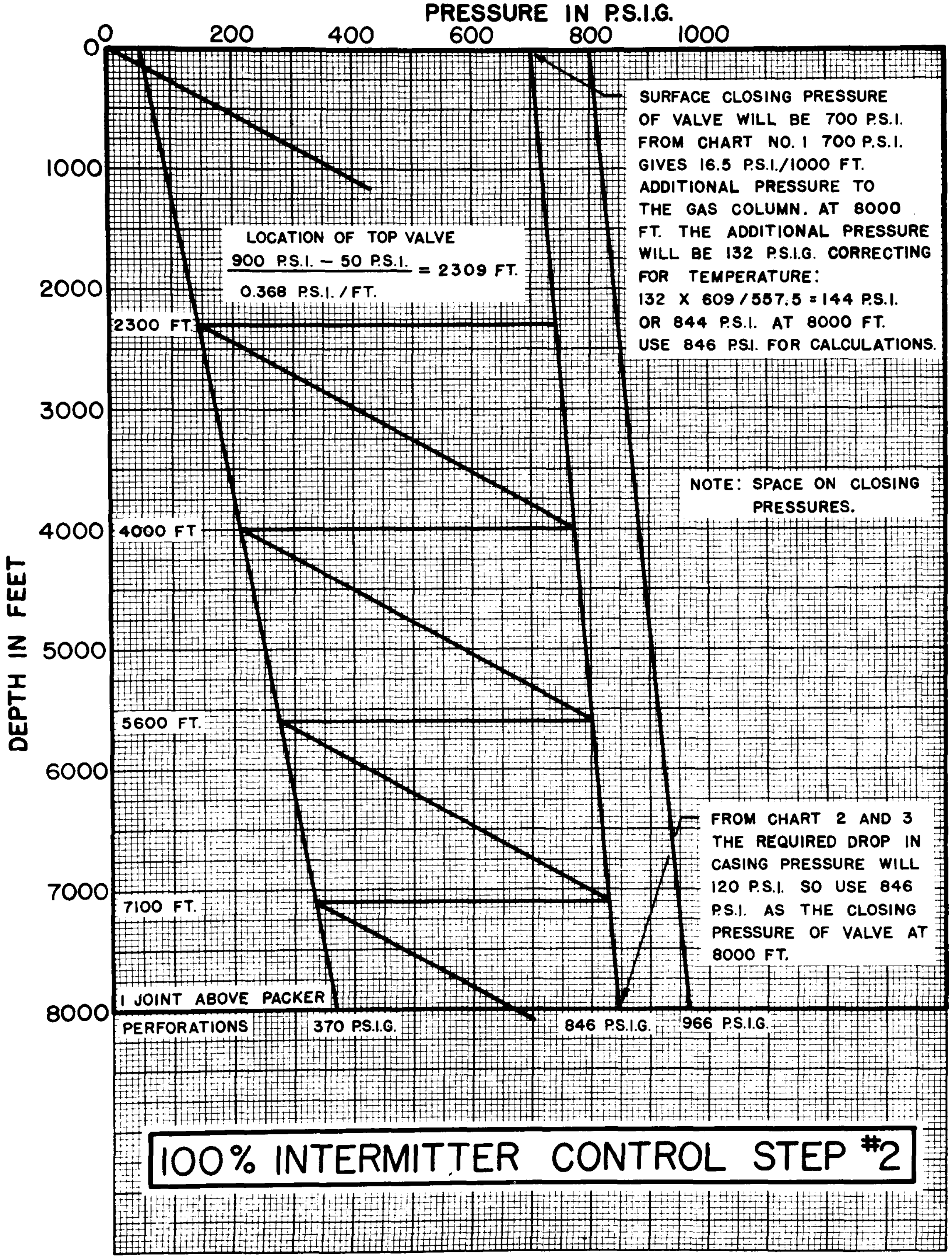
Design of Installation for
100 Per Cent Intermitter Control

Step 1 — See chart labeled Step 1
Step 2 — See chart labeled Step 2
Step 3 — See chart labeled Step 3
Step 4 — Selection of Control Port Size

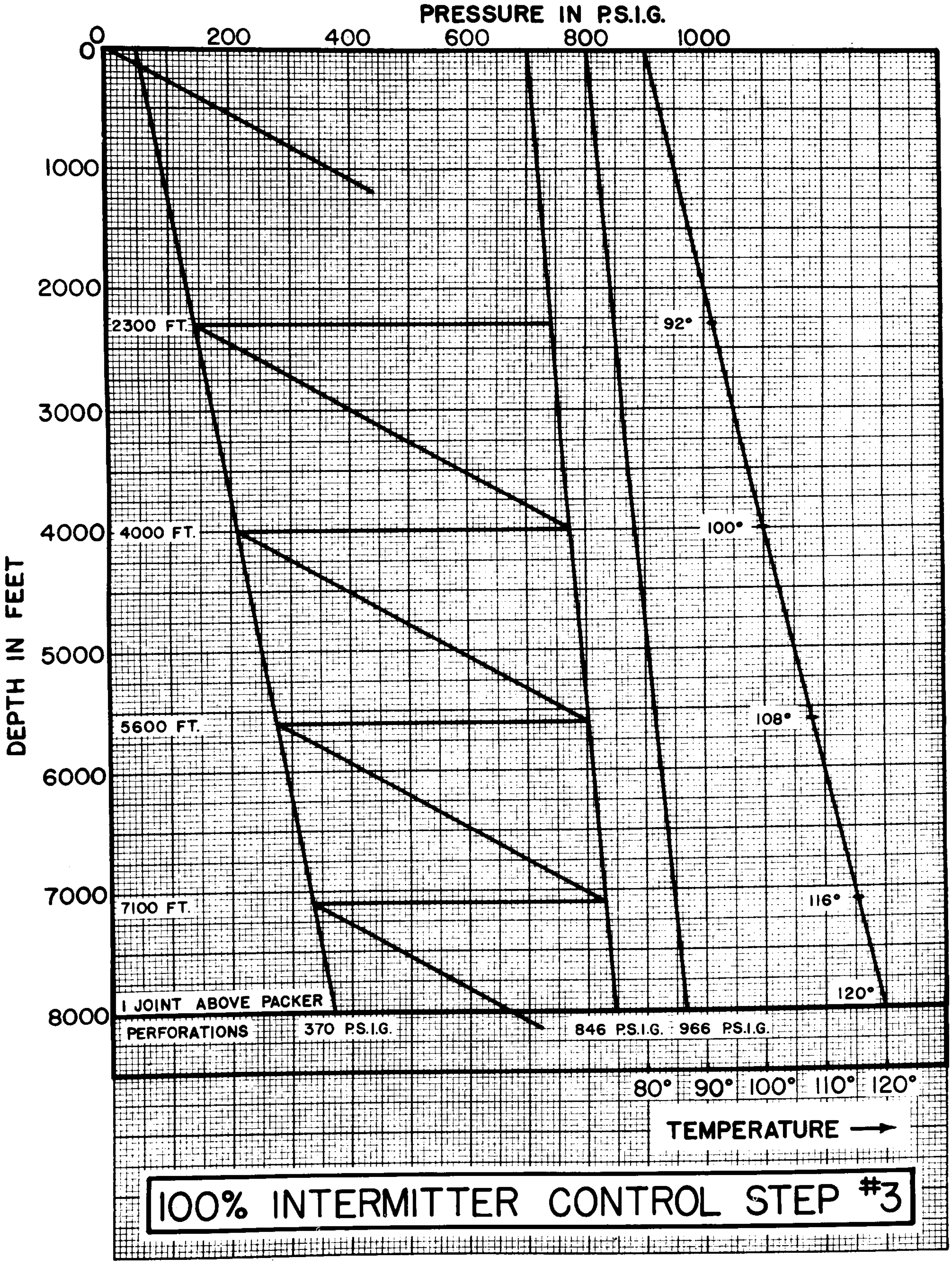
Since this is to be a 100 per cent intermitter control, select a control port with minimum spread characteristics. In this case, where a 1-1/2-in. O.D. bellows valve will be utilized, use a



PRESSURE IN P.S.I.G.
0
200
400
600
800
1000
0
1000
2000
3000
4000
5000
6000
7000
8000
DEPTH IN FEET
50 P.S.I.G. SEPARATOR PRESSURE
WEIGHT OF GAS COLUMN
0.368 P.S.I./FT. = SPACING GRADIENT FOR WELL LOADED WITH 35° A.P.I. OIL
(1) FROM CHART NO. 1 ADDITIONAL PRESSURE AT 8000 FT. = 152 P.S.I.G.
(2) CORRECTING FOR TEMPERATURE 152 X 609/557.5 = 166 P.S.I.G. ADDITIONAL GAS PRESSURE
(3) THEN THE CASING PRESSURE AT 8000 FT. WILL BE 966 P.S.I.G.
FROM CHART NO. 7B A 0.04 P.S.I./FT. UNLOADING GRADIENT FOR 100 BFPD. (NOTE: DO NOT USE A SPACING GRADIENT LESS THAN 0.04 P.S.I./FT.)
PERFORATIONS
370 P.S.I.G.
966 P.S.I.G.
100% INTERMITTER CONTROL - STEP #1



100% INTERMITTER CONTROL STEP #2



PRESSURE IN P.S.I.G.
0
200
400
600
800
1000
0
1000
2000
3000
4000
5000
6000
7000
8000
DEPTH IN FEET
2300 FT.
4000 FT.
5600 FT.
7100 FT.
1 JOINT ABOVE PACKER
PERFORATIONS
370 P.S.I.G.
846 P.S.I.G.
966 P.S.I.G.
92°
100°
108°
116°
120°
80°
90°
100°
110°
120°
TEMPERATURE →
100% INTERMITTER CONTROL STEP #3

3/8-in. control port where $\frac{A_V}{A_B} = 0.14$ and $1 - \frac{A_V}{A_B} = 0.86$.

Step 5 — Determining $P_{D\ 60°}$

From Step 2, we know that for a 700 psig surface closing pressure $P_{D\ 120°} = P_{Vc}$ at depth $= 846$ psig.

Using Chart 5b, we find that $P_{D\ 60°} = 750$ psi.

Step 6 — Determining P_{TRO}

Using Chart 6B, we find that P_{TRO} at 60° for the bottom valve (8000 ft) will be 870 psig.

Step 7 — Determine if the bottom valve can be opened with, say a 200 psig tubing load. Again, using Chart 6A, we find that this valve can be opened with a 200 psig tubing load and 950 psig casing pressure at 8000 ft.

Step 8 — Tabulation of valves

VALVE NO.	CONTROL PORT	LIFT PORT	DEPTH	$T°_F$	P_{sc}	$P_{vc}=P_D@T°_F$	$P_D@60°$	$P_{TRO}@60°$
1	3/8"	3/4"	2300 ft	92°	750	791	755	870
2	3/8"	3/4"	4000 ft	100°	740	810	745	870
3	3/8"	3/4"	5600 ft	108°	730	825	750	870
4	3/8"	3/4"	7100 ft	116°	720	840	750	870
5	3/8"	3/4"	8000 ft	120°	700	846	750	870

EXAMPLE 2

Design of Installation for 100 Per Cent Surface Choke Control

Utilizing information obtained from Steps 1, 2, and 3 of the 100 per cent intermitter control example, we can determine the correct control port and the test rack opening pressure of the valves at 60°F.

Step 4 — Determining the Control Port Size

From Chart 4, we find that to lift a load with a differential of 300 psi, a port with an A_v/A_b value of 0.40 should be used. Since gas is entering the casing at the surface during the time the valve is open, a control port with a smaller A_v/A_b value should be used. In this case, we would select a 9/16-in. control port which has an A_v/A_b value of 0.324 and with a 300 psi differential allows a spread of 97 psi.

Step 5 — Determine the P_D at 60°

Since the closing pressure of the valve at 8000 ft should be 846 psi, select from Chart 5b the dome pressure at 60°F.

Using this chart, we find that P_D at 60°F $= 750$ psig.

Step 6 — Determine the P_{TRO} at 60°F

Using Chart 6, we find that the test rack opening pressure will be 1100 psi.

VALVE NO.	CONTROL PORT	LIFT PORT	DEPTH, FT	$T°_F$	P_{sc}	$P_{uc}=P_D@T°_F$	$P_D@60°$	CALCULATED P_{TRO} @ 60°
1	9/16"	3/4"	2300	92	700	740	710	1060
2	9/16"	3/4"	4000	100	700	770	720	1070
3	9/16"	3/4"	5600	108	700	802	730	1080
4	9/16"	3/4"	7100	116	700	830	740	1090
5	9/16"	3/4"	8000	120	700	846	750	1100

EXAMPLE 3

Design for Installation for Combination Surface Choke and Surface Intermitter Control

From Steps 1, 2, and 3 of the 100 per cent surface intermitter control example, we know that a 120 psi drop in casing pressure is required.

Step 4 — Select a Control Port Size

Using Chart 4, we find that using a 300 psi differential, a 7/16-in. control port would give a spread of 58 psig and a 1/2-in. port a spread of 74 psig. Since the 7/16-in. port will supply approximately one-half of the required spread use this as you control port sizes.

Step 5 — Determine P_D @ 60°

With a closing pressure of 846 psi, using Chart 5b, we find the P_D @ 60° to be 750 psig.

Step 6 — Determine the P_{TRO} @ 60°

Utilizing Chart 6c, we find the test rack opening pressure to be 930 psig.

Step 7 — Tabulation of Values

VALVE NO.	CONTROL PORT	LIFT PORT	DEPTH	$T°_F$	P_{sc}	$P_{uc}=P_D@T°_F$	P_D@60°	P_{tro}@60°
1	7/16"	3/4"	2300ft	92°	700	740	710	890
2	7/16"	3/4"	4000	100°	700	770	720	900
3	7/16"	3/4"	5600	108°	700	802	730	910
4	7/16"	3/4"	7100	116°	700	830	740	920
5	7/16"	3/4"	8000	120°	700	840	750	930

REFERENCES

1. Brown, K. E., and Thrash, P. J., "Guidelines to Gas Lift Design and Control," Otis Engineering Corporation 1966, Dallas, Texas