Designing a Closed Rotative Gas Lift System

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ABSTRACT

The purpose of this paper is to outline the procedure for designing an efficient closed rotative gas lift system. The system discussed includes both continuous-flow and intermittent gas lift wells. The importance of considering future as well as present gas requirements is noted. Adequate capacities of the high-pressure injection and the low-pressure gas systems are emphasized. Intermitting gas lift characteristics are reviewed to emphasize further the necessity for adequate volumes in both the low- and the high-pressure systems. Equations for calculating the gas volumes and the pressure losses in these systems are offered. Information required for properly sizing the compressor by the manufacturer is outlined. A flow diagram of a rotative gas lift system complete with regulators is presented. The purpose and the location of each regulator are given. Considerations and operational practices for efficient overall operation are noted. The paper is concluded with example calculations of a closed rotative gas lift installation for an eight-well system.

INTRODUCTION

A closed rotative gas lift system permits the artificial lifting of many wells with a central power supply. The system is referred to as "closed" because the injection gas is recycled. The high-pressure gas from the compressor is injected into the wells to lift the fluids. The injection gas and the produced fluids pass to the separator where the liquid phase is removed. The gas returns to the compressor where it is re-compressed, thus completing the cycle.

By properly designing the low- and the high-pressure systems, no make-up gas from an outside source is needed for most installations after the system is in operation. The fuel required to drive the prime movers for the compressors is obtained from the produced formation gas.

The closed rotative system offers maximum flexibility with minimum per-well cost. The economic advantage increases with the number of wells and the increased depth of lift. Higher gas costs and stricter conservation measures are making it more attractive. Rotative gas lift systems can be designed to sell high-pressure gas at a premium when excess formation gas is being produced.

The suggested procedure for designing a closed rotative gas lift system is outlined in the following sequence:

1. Gas Requirements and Injection Pressures
2. Gas Lift by Continuous Flow
3. Intermittent Gas Lift Operation
4. High-Pressure Injection Gas System
5. Low-Pressure Gas-Gathering System
6. Compressor Selection
7. Flow Diagram and Gas Regulation of a Closed Rotative Gas Lift System
8. Considerations for Efficient Operation
9. Example Calculations for a Closed Rotative System

GAS REQUIREMENTS AND INJECTION PRESSURES

First considerations by the engineer designing the system are the gas requirements to lift the wells and the injection pressure for these requirements. Generally, the gas requirements can be divided into those at present and those at abandonment. The injection pressure selected should be adequate to gas lift the wells to depletion efficiently. The initial compressor sizes can be based on the present gas requirements provided that the wells' producing characteristics are not rapidly changing.

The producing characteristics at present and at depletion for all the wells to be included in the gas lift system should be tabulated. This initial tabulation should include the present gross daily fluid production and water cut, the depth of the producing zones, the productivity indices, the static bottom-hole pressures, and the same data at depletion. These data will generally permit the operator to group all of the wells as two or three representative wells. The initial and ultimate gas requirements can be calculated for the representative wells and can be multiplied by the number of wells in each catagory.

For intermittent wells with little known data, gas requirements can be based on 300 to 400 cubic feet per barrel per 1,000 feet of lift (1). If the well will flow by heads or if an efficient chamber installation has been installed, less gas will be required; but wells with emulsion problems, high back pressure, or low injection pressure relative to the depth of the lift will require more gas. The injection pressure should be approximately 100 psi for each 1000 feet of lift for efficient intermittent operation (1). Intermittent lift is discussed at greater length later in this paper.

A continuous-flow gas lift installation requires a detailed analysis for accurate determination of the optimum injection pressure, of the point of gas injection, and of the gas requirements for minimum compressor horsepower. As previously noted, these calculations should be based on the maximum fluid production and on the minimum bottom-hole pressure expected during the productive life of the wells for the selection of the injection pressure. The complete analysis is beyond the scope of this paper but is thoroughly explained in the gas lift manual entitled "The Power of Gas" by Professor C. V. Kirkpatrick (2). Briefly the analysis consists of: (1) determining the flowing pressure traverses for various injection gas-fluid ratios and tubing back pressures; (2) plotting the required injection pressures versus the injection gas-fluid ratios for the different back pressures assumed in step (1); and (3) calculating and plotting the theoretical, adiabatic horsepower requirements versus the injection pressures for each tubing back pressure considered. Selection of injection pressure for minimum horsepower requirements represents the optimum design condition. If a detailed study cannot be justified because of limited well data, gas estimates for continuous flow can be based on 200 cubic feet per barrel per 1000 feet of lift for nominal tubing back pressures (1). For injection gas-fluid ratios less than 200 cubic feet per barrel per 1000 feet of lift, an injected pressure in psig should be equal to, or greater than, the required depth of gas injection divided by 5. This point of gas injection should not be confused with the total depth of the well, but it represents the point at which the injected gas must enter the fluid column to provide sufficient aeration to obtain the flowing bottom-hole pressure for a desired rate of production. For a point of gas injection at 3000 feet, the injection pressure should be approximately 600 psig for wellhead tubing pressures of 30 to 60 psig. The injection pressure should be greater for higher tubing back pressures.

The injection gas requirements as outlined above represent the cubic feet of gas needed per day to lift the wells. If all of the wells in the system can be produced to depletion by continuous flow, the compressor sizing is no problem. Injection gas is supplied to the wells at a constant rate. Intermitting wells which can be produced most efficiently with a time-cycle surface controller create a fluctuating demand for injection gas. Large volumes of injection gas are required over short intervals of time, and between injections no gas is required.

GAS LIFT BY CONTINUOUS FLOW

The design of the high-pressure gas injection and the low-pressure gathering systems represents no problem if all wells are being continuously flowed. Gas is injected and produced at a relatively constant rate; therefore, compressor sizing can be based on daily gas requirements without considering storage. The injection gas volume can be controlled by a choke, a pressure regulator, or a metering valve. In some areas, freezing may occur. If dehydration equipment is not effective or if injection of small quantities of alcohol does not prevent freezing, a full-open or closed-type diaphragm valves can be used on the injection gas line. The diaphragm valve is operated by a snap-acting pressure or a time-cycle pilot which results in interrupted gas injection to prevent solid hydrates from forming. The injection lines should be checked for pressure loss which will normally be negligible for average continuous-flow gas requirements in 2-in. or larger lines. The continuous-flow wells are in the minority of gas lift installations and represent little difficulty in the design of the closed rotative system.

INTERMITTING GAS LIFT OPERATION

Before the discussion of the design of the injection gas and the gas-gathering systems, the characteristics of intermitting gas lift operation will be noted. The high-pressure gas should be injected into the tubing through the valve at a rate which will insure no pressure drop under the liquid slug until this slug has surfaced. Field tests indicate that the liquid slug should have an average velocity of at least 800 to 1000 feet per minute for minimum fall-back and maximum recovery per cycle. Figure 1 is a 24-hour rotation two-pen pressure recording chart of the tubing and the casing pressures of an actual 5200-ft.-depth well in which the operating intermitting valve is located at 5000 ft. A 24-minute chart of the tubing and the casing pressures is shown in Figure 2. This well is being efficiently intermitted. The injection pressure represents approximately 100 psi per 1000 feet of depth. An adequate volume of gas is being introduced under the liquid slug to provide an average velocity of over 900 feet per minute. Figures 3 and 4 are 24-minute rotation two-pen tubing-and casing-pressure recording charts of an intermitting well with the operating gas lift valve at 4500 feet. The duration of gas injection was increased from 35 seconds in Figure 3 to 55 seconds in Figure 4, and the average slug velocity increased from 400 to 800 feet per minute. The production increased from 1.3 barrels to 2 barrels per cycle. The bottom-hole-pressure recording obtained simultaneously with Figures 3 and 4 shows that the starting fluid heads were about the same. The greater recovery and the increased drawdown result from less fall-back with a slug velocity of 800 feet per minute.

The injection plus produced gas returns to the system at a rate much lower than that at which the injection gas is introduced into the well. A 2-hour rotation chart for injection and produced gas is shown in Figure 5. This total gas-out chart is from the same well as that used for Figures 1 and 2. There are approximately 2500 ft. of 2-in. flow line between the well and the tank battery. The chart shows the gas entering the low-pressure system at a maximum rate of 420 cubic feet per minute for less than a minute with an average rate of over 260 cubic feet per minute for approximately four minutes. The remaining gas enters the system before and after the main head at a rate of less than 60 or 70 cubic feet per minute. If the compressor station was capable of compressing 420 cubic feet per minute, no gas would be vented regardless of the capacity of the low-pressure system. If two or more wells should intermit about the same time, gas would be vented unless adequate storage had been designed in the gas-gathering system to hold the excess gas until the compressor could handle it. Normally, for each cycle, the bulk of injection and produced gas takes over four minutes to enter the system for typical operating conditions as illustrated in Figures 1, 2, and 5. The volume of the low-pressure system should be based on the peak rate of total gas-out per cycle. This rate can be estimated by dividing the total gas-out in cubic feet per cycle by a factor of at least 4. Long and/or small flow lines, large casing annulus volumes, increased depth of lift, and high injection pressures result in a larger factor. For example, in Figure 5 the total gas-out is 2600 cubic feet per cycle, and the peak rate is 420 cubic feet per minute, representing a factor of 6.2.

HIGH-PRESSURE INJECTION GAS SYSTEM

Adequate volume in the high-pressure injection gas system is necessary to decrease the compressor requirements for leases with intermitting gas lift wells using time-cycle surface controllers. This high-pressure storage provides the difference in gas volume between the compressor output and the instantaneous intermitting gas requirements to lift the wells efficiently. Ample volume of high-pressure gas stored in this system permits the selection of a compressor size that delivers the gas lift requirements over a 24-hour period rather than on a per-minute basis. When several wells in the same system must be intermitted and maximum cycle rates are required to obtain the production, the volume of gas in the high-pressure system must be adequate to permit more than one well to inject gas at the same time. The number of wells which could intermit at one time must be estimated for each closed rotative system. The greater the number of injection cycles per day, the greater would be the number of wells which could intermit at the same time. Staggering the wells can be assured only if one central timer is used to actuate the individual surface controllers at the various wells.

For example, we shall assume that a well requires 1000 cubic feet per minute for efficient lifting, but the compressor delivers only 500 cubic feet per minute. The storage must supply the additional 500 cubic feet per minute. If no storage existed, the compressor would have to be capable of delivering 1000 cubic feet per minute (3). Since storage can be obtained for less cost than that of the additional compressor horsepower, adequate storage should be incorporated in rotative gas lift systems. The smaller the system, the more critical this volume becomes.

The gas volume available for injection in the high-pressure system is primarily a function of the actual pipe capacity of the system and the difference in pressure between the operating injection pressure at the well and the pressure maintained in the system by the compressors. If the pressure in the system and operating injection pressure were the same, the per-minute gas requirements available to the wells would be only the output of the compressor. The actual cubic feet of gas stored in the high-pressure system can be calculated with the following equation:

$$V_s = \left[\frac{P_h}{Z_h} - \frac{P_i}{Z_i}\right] \frac{V_h \; T_s}{P_s \; T_h} \qquad \text{Equation (1)}$$

Where:

- P_h - pressure in the high-pressure system, psia
- P_i - Injection pressure at the wellhead, psia
- P_s - Standard pressure base, psia
- T_h - Temperature of the gas in the high-pressure system, R
- T_s - Standard absolute temperature base, R
- V_h - Capacity of high pressure system, cu ft
- V_s - Volume of gas stored in system at standard conditions, cu ft
- Z_h - Compressibility factor at P_h and T_h
- Z_i - Compressibility factor at P_i and T_h

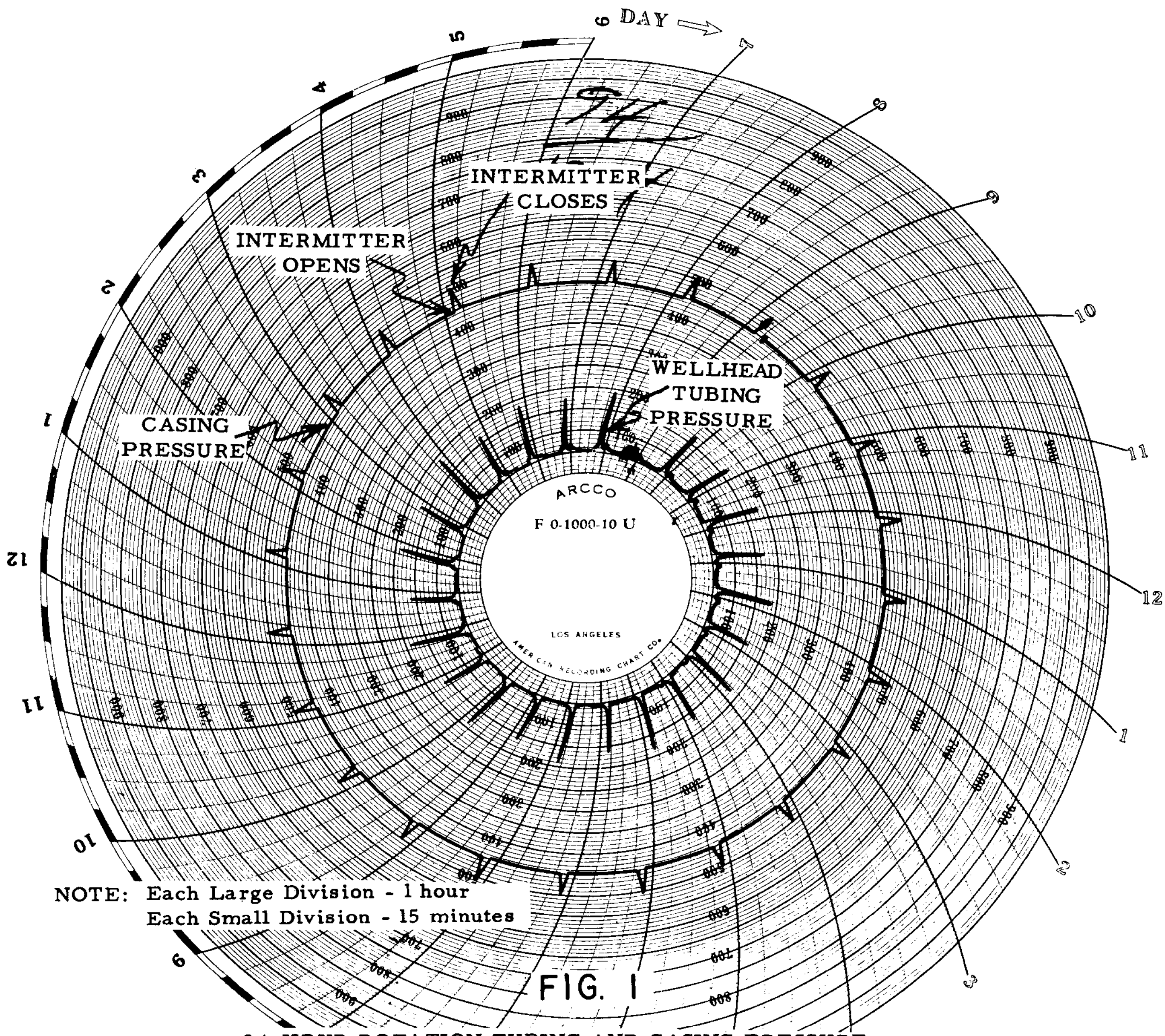
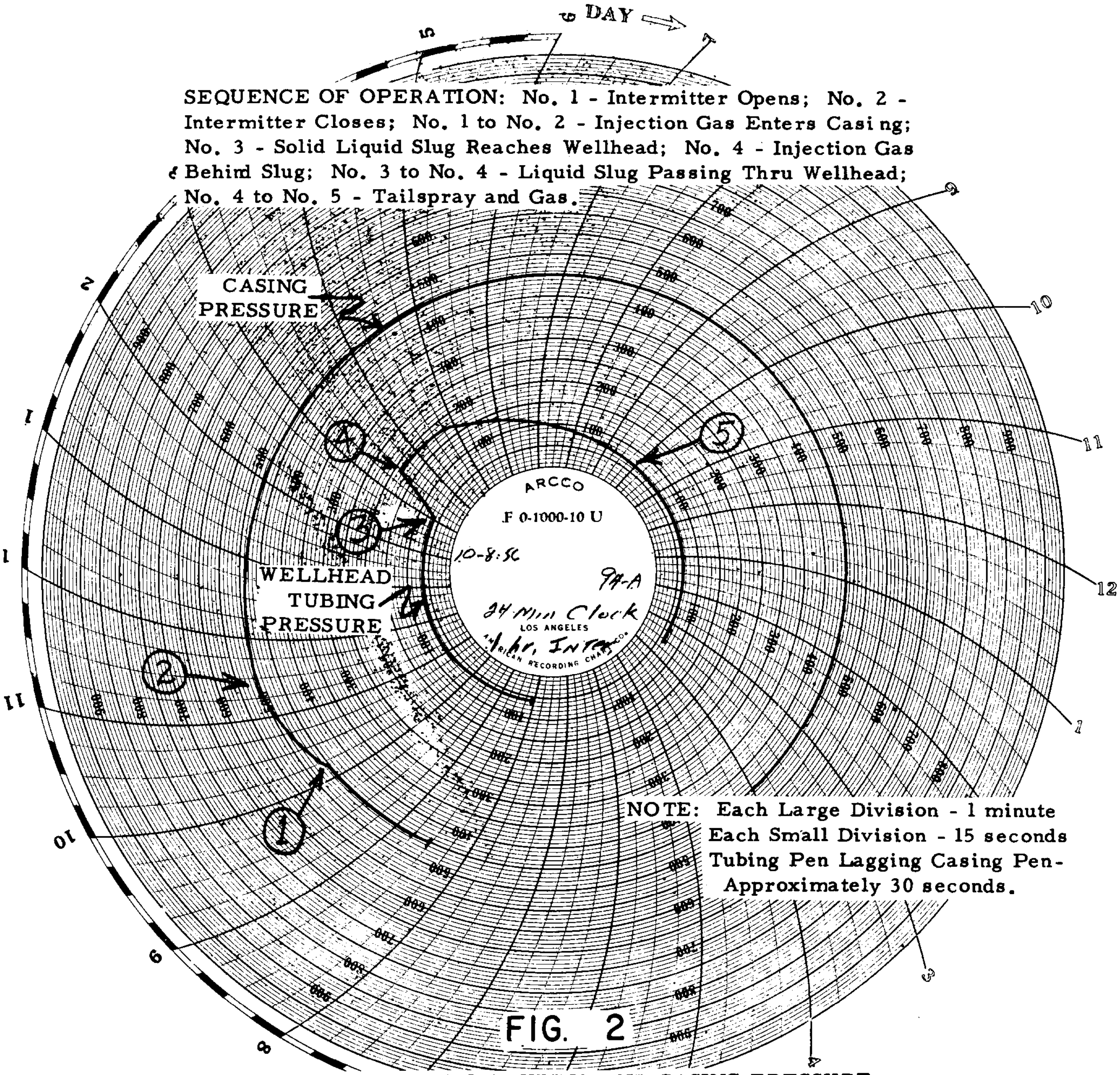


FIG. 1

24-HOUR ROTATION TUBING AND CASING PRESSURE CHART OF EFFICIENTLY INTERMITTING WELL

Depth of Operating Valve - 5000' Valve Port Size - 5/16"
Tubing Size - 2" EUE Production Per Cycle - 1.2 BO
Time Cycle Surface Controller Open - 75 seconds every hour.
Time Intermitter Opened Until Slug Surfaced - 5 min. 20 sec.

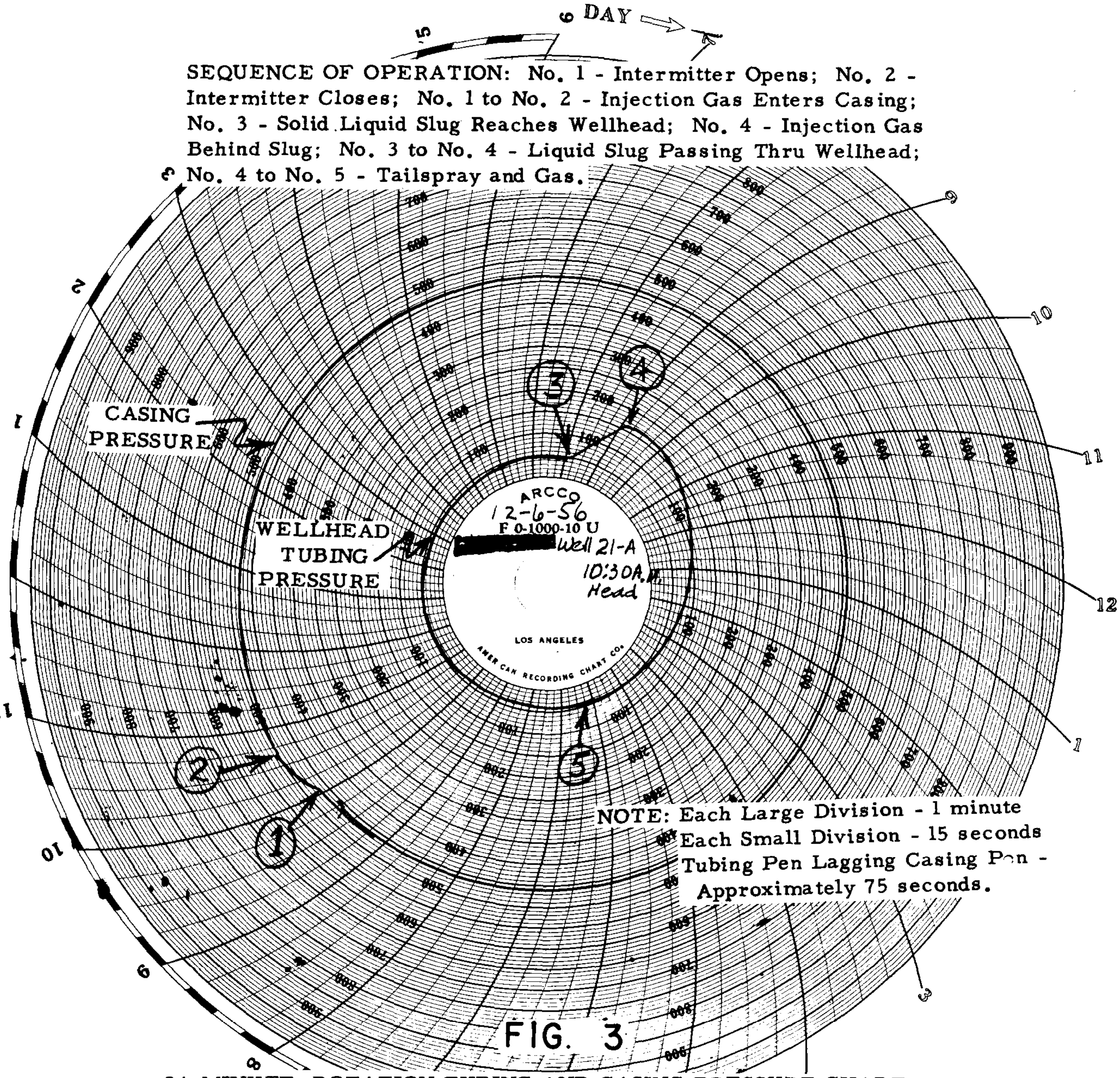
Figure 1. 24-Hour Rotation Tubing and Casing Pressure Chart of Efficiently Intermitting Well with 5/16-in. Port Valve at 5000 Feet.



24-MINUTE ROTATION TUBING AND CASING PRESSURE CHART OF EFFICIENTLY INTERMITTING WELL

Depth of Operating Valve - 5000' Valve Port Size - 5/16"
Size Tubing - 2" EUE Production Per Cycle - 1.2 BO
Time Cycle Surface Controller Open - 75 seconds every hour
Time Intermitter Opened Until Slug Surfaced - 5 mins. 20 sec.
Average Velocity of Slug - 938 ft. per minute

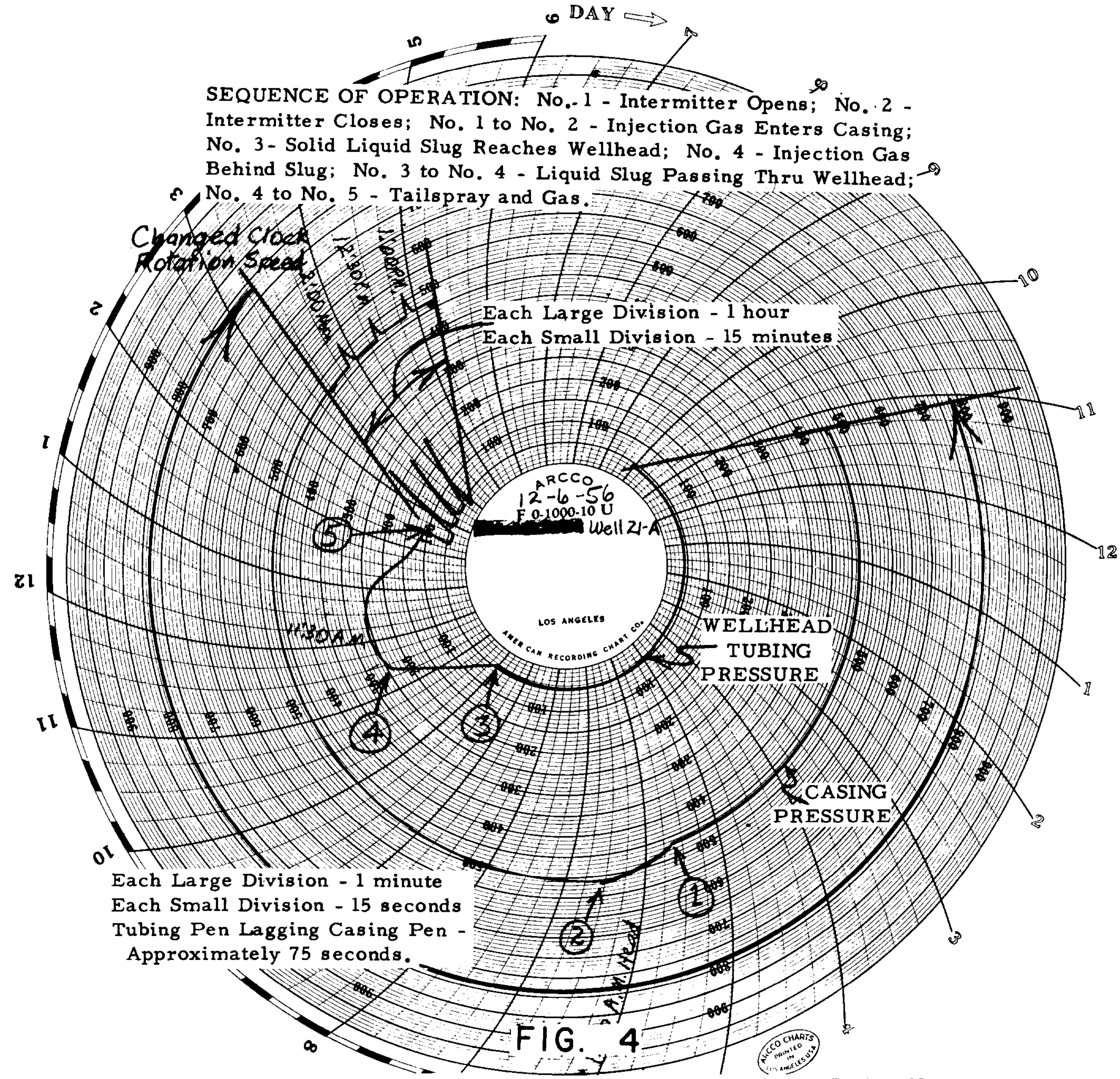
Figure 2. 24-Minute Rotation Tubing and Casing Pressure Chart of Efficiently Intermitting Well with 5/16-in. Port Valve at 5000 Feet.



24-MINUTE ROTATION TUBING AND CASING PRESSURE CHART OF INEFFICIENTLY INTERMITTING WELL

Depth of Operating Valve - 4500' Valve Port Size - 3/8"
Tubing Size - 2" EUE Production Per Cycle - 1.3 BF
Time Cycle Surface Controller Open - 35 seconds every 30 minutes
Time Intermitter Opened Until Slug Surfaced - 11 minutes, 15 seconds
Average Velocity of Slug - 400 feet per minute

Figure 3. 24-Minute Rotation Tubing and Casing Pressure Chart of Inefficiently Intermitting Well with 3/8-in. Port Valve at 4500 Feet.



COMBINATION 24-MINUTE AND 24-HOUR ROTATION TUBING AND CASING PRESSURE CHART OF EFFICIENTLY INTERMITTING WELL

Depth of Operating Valve - 4500' Valve Port Size - 3/8"
Tubing Size - 2" EUE Production Per Cycle - 2.0 BF
Time Cycle Surface Controller Open - 55 seconds every 30 minutes.
Time Intermitter Opened Until Slug Surfaced - 5 min. 38 secs.
Average Velocity of Slug - 800 feet per minute.

Figure 4. Combination 24-Minute and 24-Hour Rotation Tubing and Casing Pressure Chart of Efficiently Intermitting Well with 3/8-in. Port Valve at 4500 Feet.

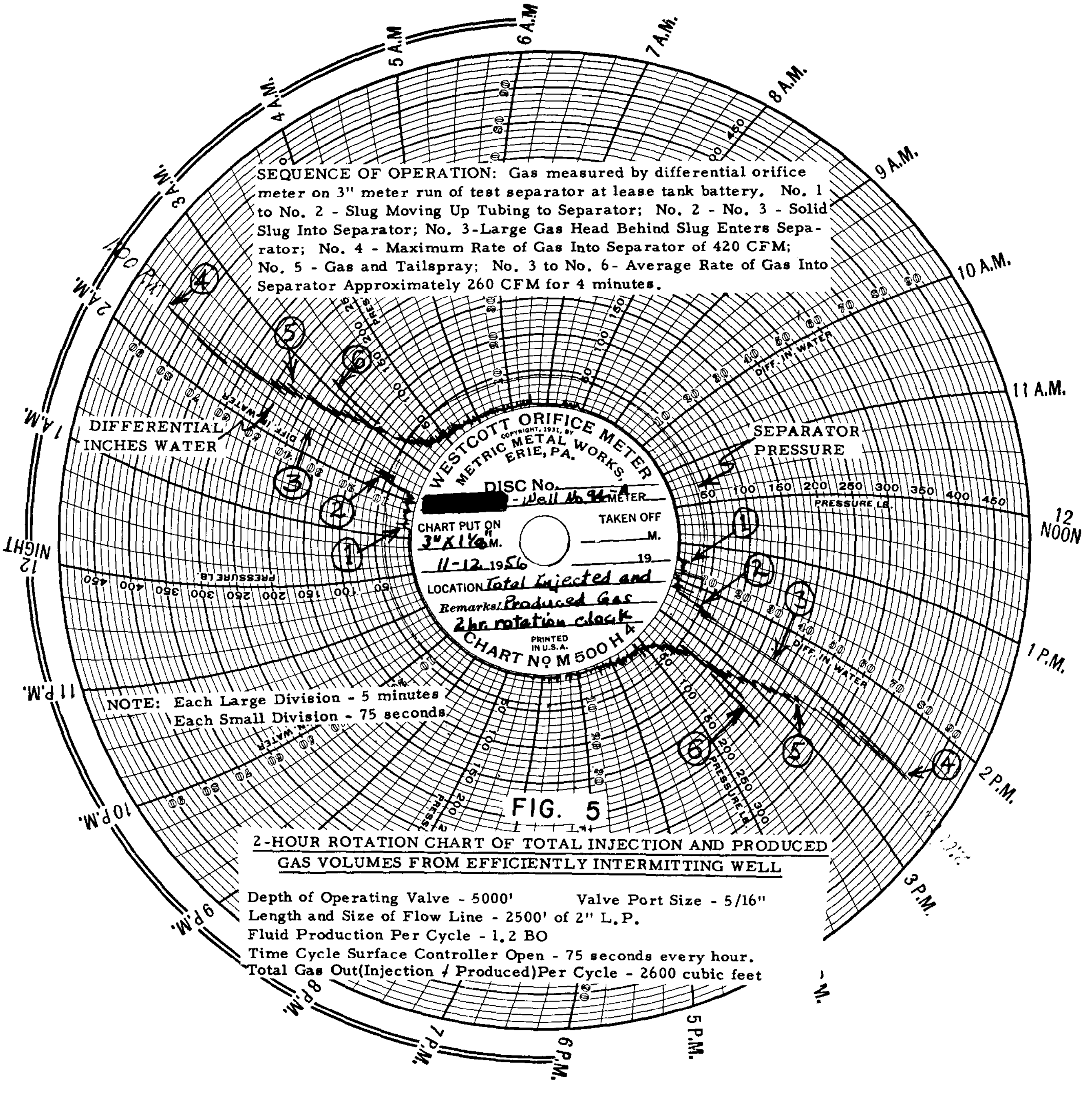


Figure 5. 2-Hour Rotation Chart of Total Injection and Produced Gas Volume from Efficiently Intermitting Well with 5/16-in. Port Valve at 5000 Feet.

The compressibility factor was included in the preceding Equation (1) to permit accurate gas volume calculations of the high-pressure system. These compressibility factors can be found in the *Natural Gasoline Supply Men's Association* (*NGSMA*) *Engineering Data Book, The Power of Gas,* and other publications dealing with gas calculations. However, for preliminary design estimates the compressibility factors can be neglected, and the equation given for the low-pressure system can be employed.

After sufficient volume has been designed into the system to provide the difference between the compressor output and the per-minute demand for the intermitting wells, the gas lines should be checked for excessive pressure loss. The pressure losses for intermitting wells should be based on a rate equivalent to the per-minute injection gas requirements to lift the wells efficiently. Weymouth's formula is the most widely used equation for determining the pressure loss in gas lines.

Weymouth's formula is generally expressed in a form which will give the rate of flow though a pipe of known inside diameter and length when the inlet and the terminal pressures are given. The pressure loss in a line for a given rate of flow and upstream pressure is required for the proper design of the high- and the low-pressure systems. These derterminations can be made by using an alignment chart for the solution of Weymouth's formula and by working the problem in reverse. These alignment charts are available in many publications such as the *NGSMA's Engineering Data Book.* Weymouth's formula can be expressed in terms of pressure loss in a line as follows:

$$\Delta p = 0.000504\left(\frac{P_s}{T_s}\right)^2 \left[\frac{(Q_s)^2 \, L\, G\, T}{P_m \,(d)\ 5.333}\right] \quad \text{Equation (2)}$$

Where:

- d - Internal diameter of pipe, inches
- Δp - Pressure loss in pipe line, psi
- G - Gas gravity of flowing gas (Air = 1.0)
- L - Length of line, feet
- P_m - Mean pressure in line which is equal to initial pressure plus terminal pressure divided by 2, psia
- P_s - Standard pressure base, psia
- Q_s - Rate of gas flow in 1000 cubic feet per day at standard conditions, mcfd
- T_s - Standard absolute temperature base R
- T - Absolute temperature of flowing gas, R

For standard conditions of 14.65 psia and 60 F (520 R), gas gravity of 0.6 and gas flowing temperature of 60 F (520 R), the equation can be simplified as follows:

$$\Delta p = 0.000125 \left[\frac{(Q_s)^2 L}{P_m \ (d)\ 5.333}\right]$$

The exact pressure loss can be calculated by trial and error, assuming a mean pressure in the line for each attempt. The alignment chart for the solution of Weymouth's formula is less laborious than the above equations. The difference in the initial and the terminal pressures squared is obtained from the chart, and the terminal pressure can be calculated from this difference for a known initial pressure.

The following tabulation is useful in calculating the volumes and pressure losses in both the high- and the low-pressure systems:

TABLE I: API LINE PIPE DATA

Size (in.)	I D (in.)	Cubic Feet per 1000 ft	$(d)^{5.333}$
2	2.067	23.30	48.1
2-1/2	2.469	33.25	124.0
3	3.068	51.34	395.1
4	4.026	88.40	1,682.5
6	6.065	200.63	14,965.0

LOW-PRESSURE GAS-GATHERING SYSTEM

The low-pressure system should provide adequate storage of gas to prevent starving the compressors between intermissions and to prevent venting gas if more than one well intermits at the same time. The volume of the suction reservoir includes the low-pressure system between the check valves in the flow lines and the suction regulator at the compressor station. Since check valves are generally installed in the flow lines near the tank battery, the flow lines between the wells and the checks should not be considered part of the suction volume. The separator and the make-up gas line, the low pressure sales line, and the vent line between the separator and the regulators all become part of the low pressure suction volume.

No check valves or pressure regulators should be installed between the separator and the suction of the compressor, except the suction regulator at the compressor station. If low-pressure gas is being sold or piped away for other uses, the pressure regulator should be located as far away as possible from the compressor station, to increase the volume in the low-pressure system. The same consideration should be given to the location of the make-up gas regulator. If the gas is being taken from a low-pressure gas well, the regulator should be near the well and not near the battery, in order that the flow line can be included in the low-pressure system. If the make-up gas is obtained from a residue line, the regulator and the checks should be as far from the station as possible for the same reason. The suction volume can be increased by using abandoned wells.

The gas volume which can be stored in the low-pressure system, like that of the high-pressure system, is a function of pressure difference and pipe capacity. This pressure difference is the separator pressure less the suction pressure, and these pressures are controlled as shown in the flow diagram in Figure 6. For a given suction pressure, the volume of gas in the low-pressure system increases proportionally with an increase in separator pressure. As a general rule, intermitting gas lift wells can be produced against higher separator pressures than wells being gas lifted by continuous flow can without significantly increasing the injection gas requirements. A closed rotative system consisting of intermitting wells can be designed to take advantage of the higher separator pressure in order to increase the gas volume of the low pressure system.

The compressibility factor is neglected in the following equation for calculating gas volumes in the low-pressure system:

$$V_s = (P_L - P_i)\left[\frac{V_L\ T_s}{P_s\ T_L}\right] \quad \text{Equation (3)}$$

Where:

- P_L - Pressure in low-pressure system, psia
- T_L - Temperature of gas in low-pressure system R
- V_L - Capacity of low-pressure system, cu ft
- P_i, T_s, and V_s - previously defined under Equation (1)

The importance of adequately sizing the low-pressure system for intermitting wells cannot be over emphasized where make-up gas is costly or not readily available. When the gas from the intermitting wells reaches the surface, it will be vented or sold through a low-pressure sales line if the system is undersized. Once this gas has left the system, it cannot be recycled for lifting purposes. For this reason, systems which include mostly low-formation gas-oil ratio wells must have ample low-pressure storage, whereas systems with high gas-oil ratio wells will work satisfactorily with smaller storage because excess gas is being produced from the wells.

COMPRESSOR SELECTION

Detailed sizing of the compressors should be left to the compressor manufacturer because of its complexity. The following information will assist the compressor manufacturer to propose the most suitable unit or units:

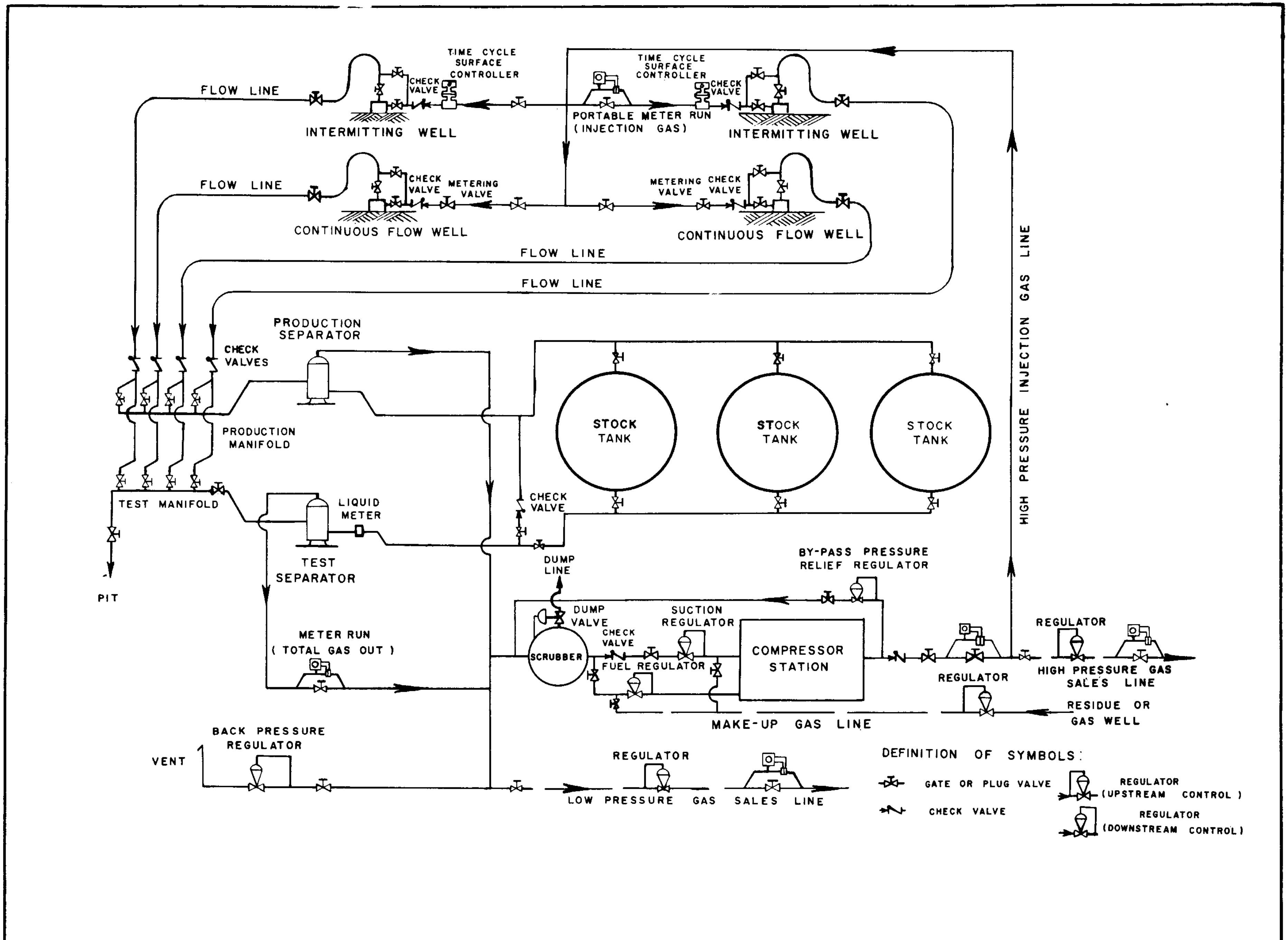


Figure 6. Flow Diagram of Closed Rotative Gas Lift System

1. Total gas requirements per day, hour, or minute at a specific temperature and pressure base.
2. Suction and discharge pressures clearly stated in psig or psia.
3. Atmospheric pressure at the station site.
4. The N value (ratio of specific heats - C_p / C_v) of gas and/or gas gravity. The N value of the gas can be approximated from the gas gravity.
5. Preference for integral or belt-driven compressors and the size of units. If the compressor is to be driven by a prime mover other than a gas engine this should be noted
6. Temperature of inlet gas (suction temperature) and outlet gas (discharge temperature) at the compressor. Availability of water for cooling.

The brake horsepower of a compressor varies with the compression ratio. The approximate brake horsepower required to compress one million cubic feet per day at 14.4 psia and suction temperature is given in Figure 7. For example, to compress one mmcfd of gas from 30 psig to 600 psig represents a compression ratio of 13.8 and requires approximately 176 bhp. A compression ratio of only 8.2 is needed to compress the gas from 60 psig to 600 psig, and the horsepower requirements are approximately 139 bhp per mmcfd. Although a high-suction pressure requires less compressor horsepower for the same discharge pressure and gas volume, this does not necessarily mean an over-all savings in compressor cost in a gas lift installation. The injection gas-fluid ratio increases with the tubing back pressure. An example of suction pressure versus compressor horsepower requirements is shown in the following tabulation which was prepared for a nine-well closed rotative gas lift system in Louisiana. The depth of the wells is 8000 feet and the estimated total fluid production from all nine wells is 3100 befd (2).

Compressor Discharge psig	Compressor Suction psig	Total Injection Gas MCFD	Cost Compressor
800	40	932	$22,600
800	100	1592	48,000
800	200	3269	54,000

The final selection of smaller units versus a large unit or units and belt-driven versus integral compressor is dependent on many factors which vary from installation to installation. The smaller units have many advantages. The initial investment is lower provided that the initial gas requirements are less than ultimate and the compressor station is designed for the present needs. A station with several small compressors permits the repair of a single unit with little or no loss of production. The majority of small rotative gas lift systems use skid-mounted belt-driven compressors as shown, in Figure 8, because the smaller units cost considerably less than the integral compressors. This difference in cost increases as the brake horsepower decreases. The skid-mounted unit can be transferred from lease to lease for testing as well as for use as permanent installations. The problems associated with belt-driven units have been minimized by using heavy mounting skids, and the belt losses represent approximately five per cent of the compressor horsepower. The largest belt-driven package compressor presently available is around 300 brake horsepower.

The larger compressor stations, as shown in Figure 9, generally consist of integral compressors because they are more heavily constructed, more rugged units which require less detailed attention and maintenance. Their longer life and lower maintenance costs result from a low-speed prime mover instead of a higher speed automotive-type engine; from heavier frame load allowables; and from elimination of sheaves, jack shafts with bearings, coupling or clutch, and belts. In the larger sized compressors where it would require two or more belt-driven units for one integral-type compressor, the integral compressor becomes competitive in cost with the belt-driven unit.

The fuel consumption of both the belt-driven and the angle-type compressor is comparable when both types of prime movers are operating properly. The fuel consumption in cubic feet per day can be estimated by multiplying the compressor horsepower by 240 (4). This figure represents approximately ten cubic feet per break horsepower-hour of a 900- to 1000-Btu gas.

FLOW DIAGRAM AND GAS REGULATION OF A CLOSED ROTATIVE GAS LIFT SYSTEM

A flow diagram of a closed rotative gas lift system is shown in Figure 6. This diagram must be altered to meet the requirements for the individual installations and may include dehydration equipment, a simple or an elaborate distillate recovery plant, and so on.

The regulator selection and the location are extremely important for efficient operation of the system. The suction pressure regulator prevents overloading and stalling the compressors. This regulator is set lower than the maximum pressure in the low-pressure system which is controlled by the back pressure regulator on the vent or gas sales line. If a low-pressure gas sales outlet is available, this regulator will control the volume of gas which can be stored in the low-pressure system by providing a pressure difference between the suction pressure and the separator pressure. The regulator on the vent is used as a relief valve and is set higher than the sales regulator.

The make-up gas regulator is set to open at a pressure slightly below the set pressure of the suction regulator. The make-up gas line should be connected into the suction line between the suction regulator and the compressors.

The by-pass pressure regulator at the compressor should be set to open at a higher pressure than the regulator on the high-pressure gas sales line. Both regulators are employed to prevent excessive pressure build-up on the high-pressure system.

A variation in pressure regulation of the low-pressure system is used in some compressor installations where surplus produced gas is always entering the system. This excess gas is generally supplied by flowing wells. The suction pressure of the compressor is controlled by either the back pressure regulator on the vent or by the low-pressure gas sales line if there is a sales line. The suction regulator at the compressor is eliminated, and there is no storage in the low-pressure system. The gas available for compressing at suction pressure is only those cubic feet entering the system, and there is no surplus in case the excess gas is temporarily cut off.

CONSIDERATIONS FOR EFFICIENT OPERATION

The rated discharge pressure of the compressor should be 100 to 200 psi above the expected operating gas lift pressure. This additional pressure provides gas storage in the high-pressure system and permits the use of higher opening pressure gas lift valves for unloading to the operating valve.

A choke can be used in conjunction with the time-cycle surface controller to lengthen the injection time for intermitting wells. The choke must pass more gas than the operating valve passes to assure efficient lifting of the liquid slug. Increasing the injection time from one minute to two minutes with a choke would reduce the per-minute injection gas requirements by one-half.

The separators of nearby batteries with flowing wells should be tied into the low-pressure gathering system, when possible, to provide adequate suction volume for the compressors. Additional gas and storage volume can be obtained from the casing annulus of pumping wells by connecting the

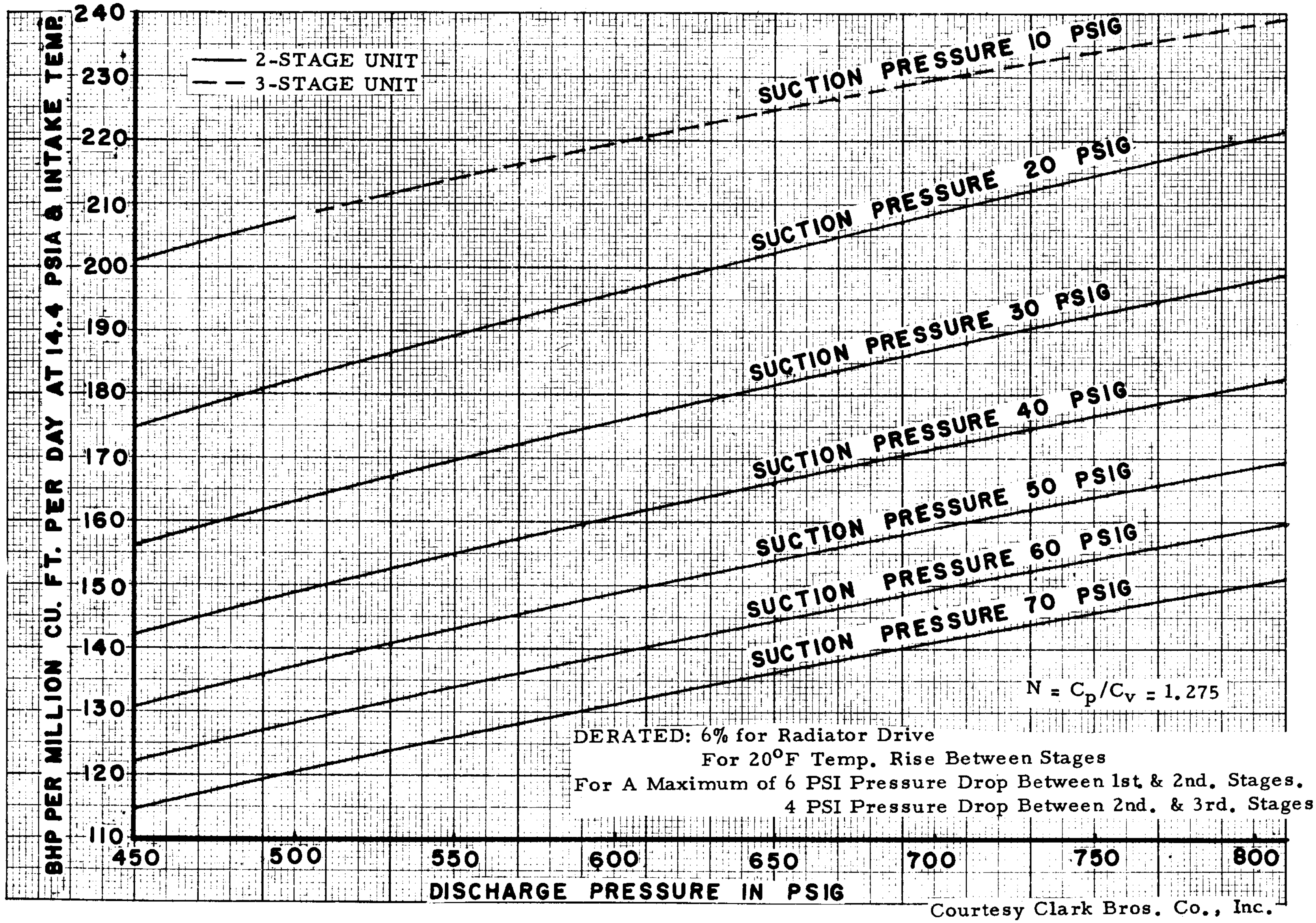


Figure 7. Approximate Brake Horsepower per Million Cubic Feet per Day at 14.4 PSIA and Inlet Temperature for Suction Pressures from 10 to 70 PSIG and Discharge Pressure from 450 to 800 PSIG.

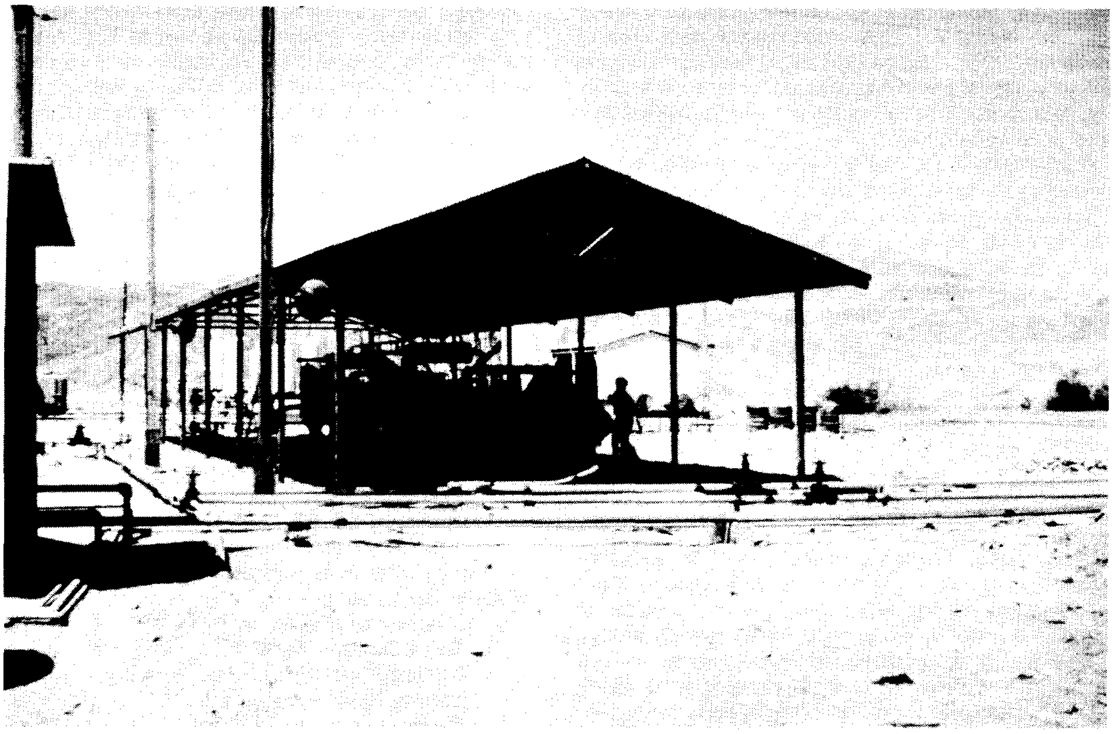


Figure 8. Skid-Mounted Belt-Driven Packaged Compressors Used for Gas Lifting Wells in Small Closed Rotative System.

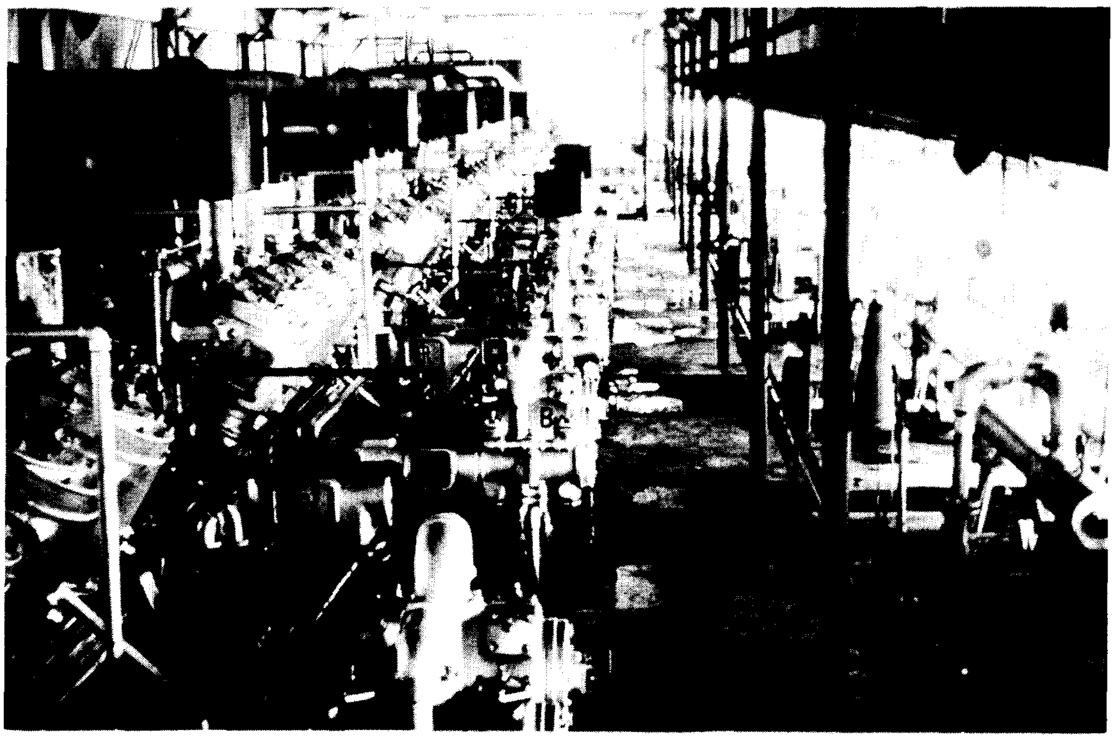


Figure 9. Integral-Angle-Type Compressors for Gas Lifting an Entire Field with Single Large Compressor Station.

casing outlets of the wells into the gathering system. If a high pressure gas line is near the compressor station, the station can be partially justified and paid-out by the sale of high-pressure gas.

The injection gas lines, suction lines, and flow lines selected should provide sufficient capacity for depletion of the wells. Initial laying of a large line will generally be less expensive than looping or paralleling smaller lines at a later date. This is particularly true of wells with buried lines and high-water cuts at abandonment.

Automatic dump valves should be located in the suction and the interstage scrubbers of the compressors. These traps should have shut-down devices on the magnetos or on the fuel line in case the dump valves fail.

Many times a pulsating condition in the high-pressure system results in poor metering of the discharge gas from the compressors. A large choke which causes little pressure loss will generally eliminate severe pulsations.

In a rotative system where make-up gas is scarce, the wells should be closed-in during a compressor station shut-down to prevent venting gas after the low-pressure gathering system has filled.

EXAMPLE CALCULATIONS FOR A CLOSED ROTATIVE SYSTEM

It is proposed to build a closed rotative gas lift installation on a lease which is producing from two formations. Four wells are producing from a depletion-type reservoir and four wells are producing from a reservoir which has an active water drive. The wells in the depletion-type reservoir are being lifted at present with gas from a nearby gas well which is near depletion. These intermitting wells have low-productivity indices between 0.02 and 0.04 barrels per psi draw-down. Chambers will be installed to deplete the reservoir at a later date.

The flowing wells will gradually go to water, and the predicted water-oil ratio at abandonment is 19:1. The static bottom-hole pressure at abandonment will be approximately 1650 psig. A water-flood project is planned to maintain this pressure later in the life of the reservoir.

The compressor station will be designed to meet the present requirements for the four wells with gas lift equipment and will be increased as additional wells are added to the system. The injection lines, flow lines, and gathering lines will follow lease roads, as shown in Figures 10 and 11. The compressor site will be centrally located near the entrance to the lease. The initial installation will include adapting the present injection lines for the intermitting wells. The remaining injection lines will be installed as additional wells go on lift. Large suction lines are proposed between the two four-well batteries and the compressor station to provide adequate storage in the low-pressure system for the intermitting wells.

Average current well data and estimated gas lift requirements for the Intermitting Wells (Producing Zone A):

- Number of Wells - 4
- Total Depth - 5200 ft.
- Casing Size - 5 1/2-in. OD
- Tubing Size - 2-in. eue
- Depth of Operating Valve - 5000 ft
- Producing Rate - 30 bopd
- Per Cent Water - Trace
- Producing GOR - 800:1
- Injection GFR - 1600:1
- Injection Cycle - 1 minute every hour

Average Current Well Data for the Presently Flowing Wells (Producing Zone B):

- Number of Wells - 4
- Total Depth - 5400 ft
- Casing Size - 5 1/2-in. OD
- Tubing Size - 2-in. eue
- Producing Rate - Flowing 50 bopd
- Per Cent Water - None
- Producing GOR - 500:1
- Productivity Index - 4
- Static BHP - 2200 psig

A tabulation of the estimated gas requirements for present and future are as follows:

TABULATION 1: PRESENT AND DEPLETION ESTIMATED GAS LIFT DATA PER WELL

	PRESENT				DEPLETION			
Well	Production Oil (BOPD)	Water (BWPD)	Inj. Gas (MCFD)	Point of Inj. (Ft)	Production Oil (BOPD)	Water (BWPD)	Inj. Gas (MCFD)	Point of Inj. (Ft)
Zone A	30	Trace	50	5000	5	Trace	10	5000
Zone B	50	None	None	----	30	570	240*	2500

*Zone B injection gas requirements at abandonment are based on an injection gas-fluid ratio of 400 cu ft per barrel of fluid lifted. The required injection gas-fluid ratio was calculated for a surface injection pressure of 500 psig by the method outlined in The Power of Gas.

TABULATION 2:
TOTAL INJECTION GAS REQUIREMENTS

Well	No. Wells	Gas Requirements Present (MCFD)	Ultimate (MCFD)
Zone A	4	200	40
Zone B	4	0	960
Total Requirements		200	1000

After the gas requirements have been determined as shown above, the compressor station should be sized for both the present and the ultimate requirements. Careful consideration should be given to the sizing of individual units to avoid having a number of small units at the time of depletion. An excessive number of small units increases the detailed attention and maintenance and results in a higher final total cost of the station. In this example, the following additional data are used in the selection of the compressors:

- Suction Pressure - 30 psig
- Low-Pressure Sales Regulator - 60 psig
- Discharge Pressure - 650 psig
- Injection Gas Gravity - 0.6
- Injection Pressure for Gas Lifting - 500 psig
- Flowing Gas Temperature in Low- and High-Pressure Systems - 100 F
- Pressure and Temperature Base - 14.7 psia and 60 F

Proposed Compressor Sizing, Present and Future:

From Figure 7 for 30 psig suction and 650 psig discharge:
Approximate Horsepower = 182 bhp/mmcfd at 14.4 psia and 100 F
= 200 bhp/mmcfd at 14.7 psia and 60 F

For present requirements of 200 mcfd at 14.7 psia and 60 F:
Approximate Horsepower = 40 bhp

For ultimate requirements of 1000 mcfd at 14.7 psia and 60 F:
Approximate Horsepower = 200 bhp

Since the initial gas requirements represent only 20 per cent of the ultimate and since too many small units are undesirable, it is proposed to set one 80-bhp compressor at this time and to add two more 80-bhp packaged units as needed. These compressors should provide adequate capacity to permit servicing or repair of a single unit with little or no loss in production during the final stage of gas lifting, when the gas requirements are at a maximum.

Volume of High-Pressure System

The volume of the high-pressure system must be adequate for the present and the ultimate stages of gas lift. The present gas lift program represents the major problem because the first four wells must be intermitted. The input gas required to lift the wells efficiently is 2000 cubic feet of gas per minute from the well data given. The proposed injection lines, shown in Figure 10, represent a present capacity of 191 cubic feet. With the use of Equation (1), the maximum volume of gas which can be stored in the system is the following:

$$V_s = \left[\frac{664.7}{0.915} - \frac{514.7}{0.935}\right] \frac{191(520)}{14.7(560)} = 2120 \text{ cu ft}$$

In actual practice, it is better to design the high-pressure system for intermitting wells with sufficient storage to supply the total gas requirements for one complete injection cycle from storage only. The output of the compressor is purposely neglected in case the actual gas requirements should be higher than those which were estimated.

Since high-pressure gas will be injected into each well approximately one minute every hour, it will be assumed that the injections can be staggered. The 80-bhp compressor has a rated output of 278 cubic feet per minute at 650 psig; therefore, the 2000 cubic feet required per injection will be replaced in the system in approximately seven minutes. Little difficulty with interference between wells should be encountered because it is possible to have fourteen minutes between gas injections if the intermitters are properly synchronized.

The injection system will be increased with 4620 feet of two-inch line to the continuous-flow wells by the time the intermitting wells are being lifted by chamber installations, representing an additional 1200 cubic feet of injection gas volume at 650 psig. The additional volume will assure ample injection gas to lift the larger liquid slugs efficiently from the chambers. Since the producing rate will require only two or three gas injections per day, interference between injections will present no problem.

Pressure Losses in High-Pressure System

The maximum pressure loss in the intermitting well system will occur through the 660 feet of two-inch feeder line between the three-inch trunk line and the well. The 2000 cubic feet per minute represents 3170 mcfd at 14.4 psia and 100 F. By using Weymouth's alignment chart and a mean inlet pressure of 575 psig, (650 + 500)/2, the pressure loss is only 31 psi; therefore, the line sizes are adequate for injection pressure build-up at the well.

The maximum pressure loss in the continuous-flow wells' system will be in the first 660 feet of two-inch line downstream of the compressor, because the injection gas for all four wells must pass through this section. The ultimate daily requirements of 960 mcfd at 14.7 psia and 60 F is equal to 1055 mcfd at 14.4 psia and 100 F. From Weymouth's alignment chart, the pressure loss in this 660 feet of two-inch line is only 4 psi for an average inlet pressure of 575 psig. Two-inch line is proposed for the entire continuous-flow system, because it is readily available and only slightly higher in cost than the 1 1/2-in. or the 1 1/4-in. line.

Volume of Low-Pressure System

It is proposed to complete the entire gathering system for the initial compressor installation. Figure 11 shows the lines between the two batteries and the compressor station. The capacity of the entire system is approximately 375 cubic feet. With the use of Equation (3) for a suction pressure of 30 psig and a separator pressure of 60 psig, the maximum volume of gas which can be stored in the low-pressure system is the following:

$$V_s = \frac{30(375)\,520}{14.7(560)} = 710 \text{ cu ft}$$

The low-pressure system presents no problem in this installation because the Zone B wells deliver 100 mcfd of formation gas into the system. If these wells are produced continuously, the 695 cubic feet per minute of formation gas supplies excess gas for fuel and compression.

Pressure Losses in Low-Pressure System

The rated capacity of three 80-bhp compressors is 834 cubic feet per minute at 14.7 psia and 60 F. The maximum pressure loss would occur if all the gas entered the system from one separator. By the use of Equation (2), the pressure drop through 1320 feet of four-inch line is only 3 psi for 1200 mcfd at a flowing temperature of 100 F and a mean separator pressure of 45 psig, (60 + 30)/2.

Excess or Make-Up Gas Calculation

The fuel requirements for the initial 80-bhp compressor will be approximately 19,200 cubic feet per day. The fuel consumption will increase to approximately 57,600 cubic feet per day when all three 80-bhp compressors are in service. The estimated excess formation gas in cubic feet per day for low-pressure sales at present can be calculated as follows:

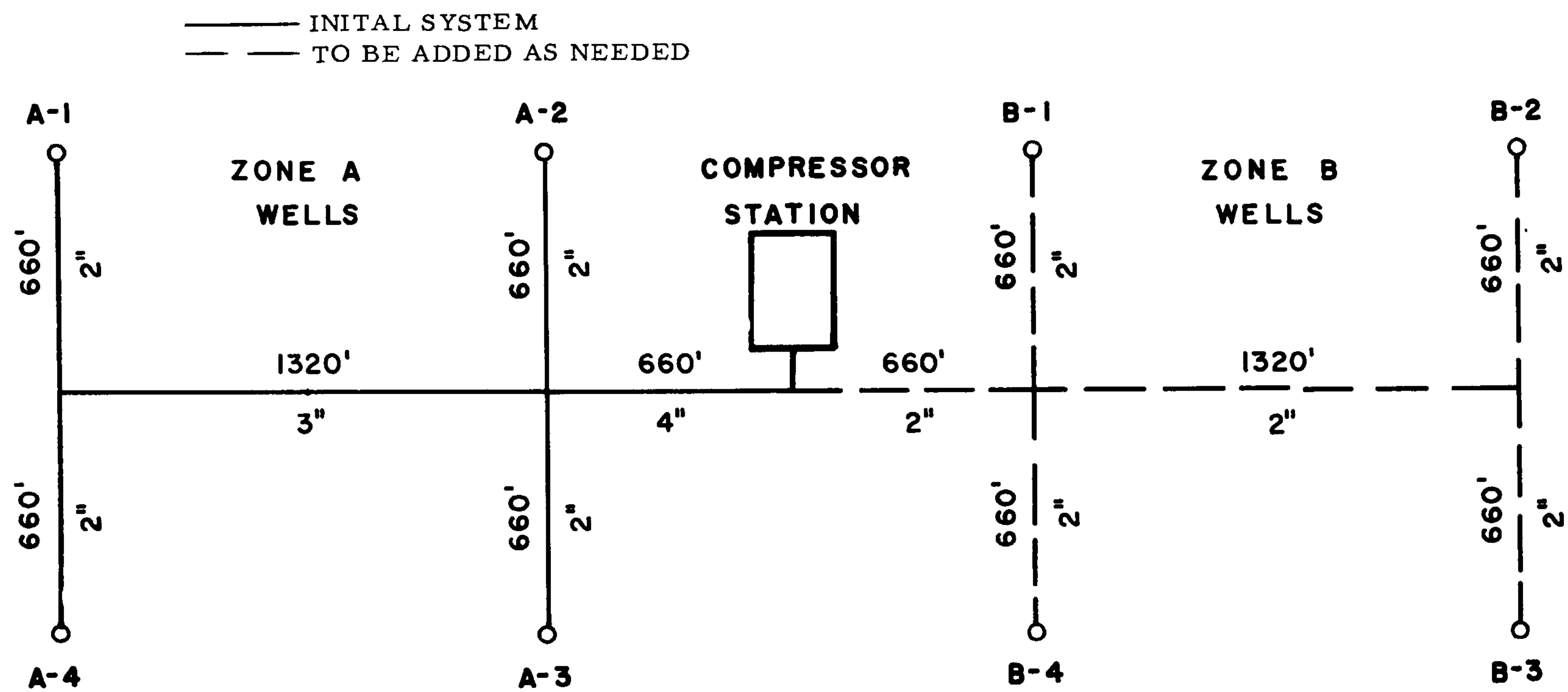
Formation Gas from Zone A =	96,000
Formation Gas from Zone B =	100,000
Total Produced Gas:	196,000
Initial Fuel Requirements:	-19,200
Excess Produced Gas:	176,800

With the assumption that the gas-oil ratios do not change, the excess gas in cubic feet per day at abandonment is the following:

Formation Gas from Zone A =	16,000
Formation Gas from Zone B =	60,000
Total Produced Gas:	76,000
Ultimate Fuel Requirements:	-57,600
Excess Produced Gas:	18,400

Actually, the intermitting wells in Zone A will increase in gas-oil ratio as the reservoir is depleted and will produce more gas than shown above. Gas used for heaters, treaters, pumps, and other lease needs will have to be subtracted from the above figures. Provided that excessive gas is not used for lease purposes, this closed rotative system should not require any make-up gas. The system can be filled initially with gas from the Zone B flowing wells. The wells can be gas-lifted to depletion with the formation gas supplying the make-up requirements.

INITIAL AND ULTIMATE HIGH-PRESSURE INJECTION GAS SYSTEM FOR 8 WELLS ON 40-ACRE SPACING

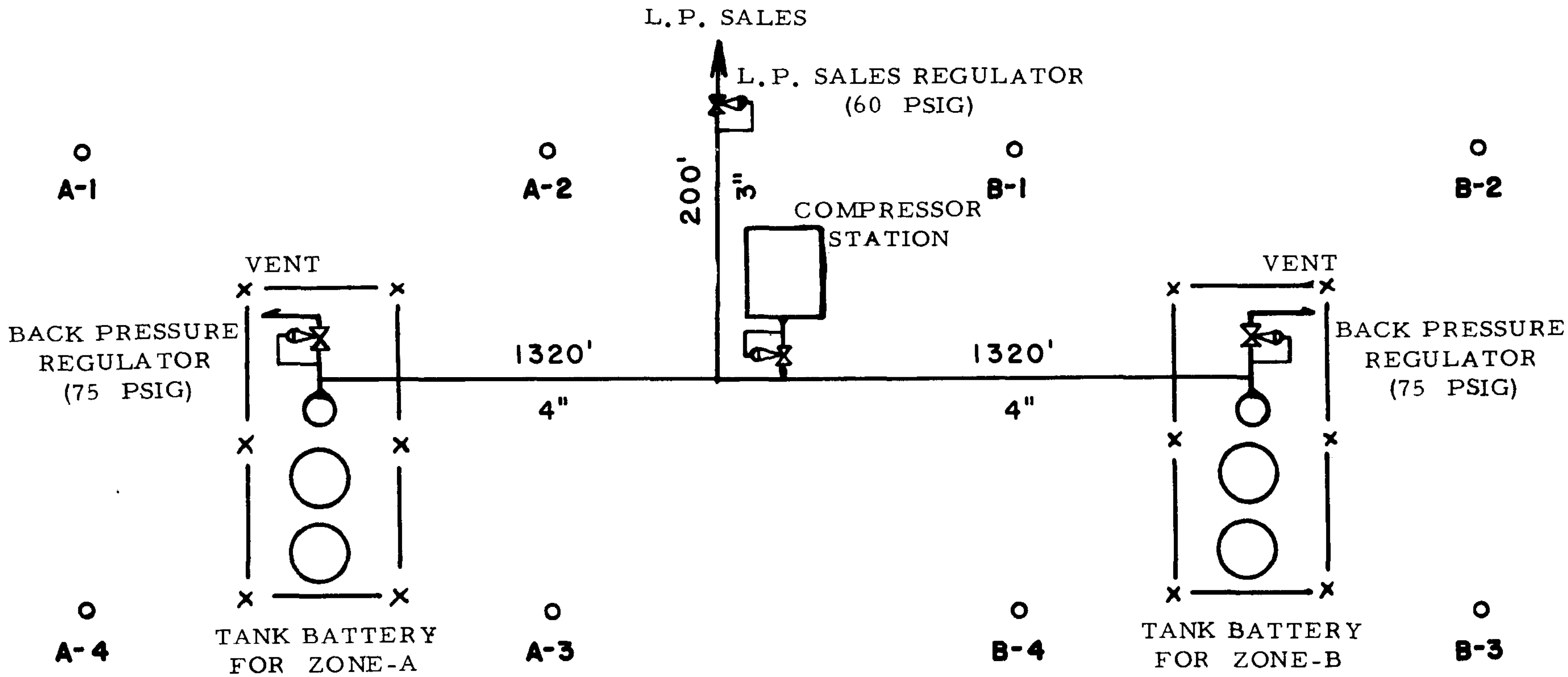


CAPACITY OF HIGH PRESSURE SYSTEM:

INITIAL SYSTEM:	2640' of 2"	=	61 cu. ft.
(ZONE-A)	1320' of 3"	=	68
	660' of 4"	=	58
MISC. PIPING AT STATION		=	4
INITIAL TOTAL CAPACITY:		=	191 cu. ft.
FOR ZONE-B	4620' of 2"	=	108
ULTIMATE TOTAL CAPACITY:		=	299 cu. ft.

Figure 10. Initial and Ultimate High-Pressure Injection Gas System for Lifting Eight Wells on 40-Acre Spacing.

LOW-PRESSURE GAS GATHERING SYSTEM FOR 8-WELL INSTALLATION SHOWN IN FIGURE 10



CAPACITY OF LOW PRESSURE SYSTEM:

2640' of 4" =	230 cu. ft.
300' of 3" VENT =	15
200' of 3" L.P. SALES =	10
SEPARATORS =	70
SCRUBBER & MISC. PIPING =	50
TOTAL CAPACITY:	375 cu. ft.

Figure 11. Low-Pressure Gas Gathering System for Eight-Well Installation Shown in Figure 10.

CONCLUSIONS

Closed rotative gas lift systems offer a flexible means of producing an oil reservoir to depletion with low operating costs. Gas lifting by continuous flow presents no problem in the design of the rotative installation. Intermitting wells must have gas volume storage incorporated in the high- and the low-pressure systems to lift the wells efficiently, and to prevent venting injection and formation gas. Most wells will produce adequate formation gas to run the compressors' prime movers and to make up any minor losses which may occur throughout the system.

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