PRACTICAL APPROACHES TO TWO-PHASE FLOW PROBLEMS IN PRODUCING OPERATIONS

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ABSTRACT

The full scope of two-phase producing problems extends from sandface to separator, offshore to onshore. Both operational and design decisions are being made daily which require a thorough understanding of two-phase flow. The purpose of this paper is to highlight some of the major problems in each area and discuss current solutions or applicable technology.

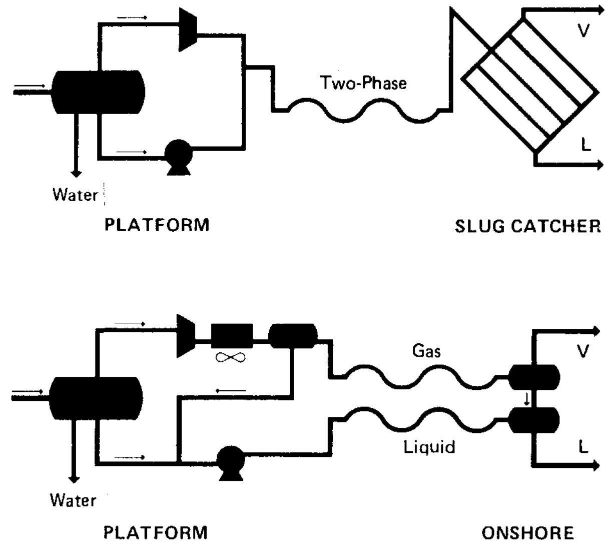
This paper describes gathering systems, terrain effects, sphering, sonic flow (pressure relief), black oil versus compositional liquid dropout, slug catchers, flow regimes, slugging, risers, gas lift, deliverability, and flow splitting.

INTRODUCTION

The full scope of two-phase producing problems extends from sandface to separator, offshore to onshore. Both operational and design decisions are being made daily which require a thorough understanding of two-phase flow. The purpose of this paper is to highlight some of the major problems in each area and discuss current solutions or applicable technology.

Figure 1 is a classic example of the need for a complete understanding of two-phase flow. A field producing wet gas has been discovered offshore. Should we build one pipeline or two? A single pipeline would experience multiphase flow due to liquid dropout and a relatively expensive slug catcher will be required to handle liquids during operational sphering or changing flow conditions. However, the offshore process facilities are much less complicated for a single pipeline than the alternative of complete separation on the platform. The two-phase pipeline will be a larger diameter than either single phase pipeline, but overall may cost less.

The final decision will depend on a detailed evaluation of investment and operating cost with full consideration of any serious operating problems. Pipeline design calculation accounting for two-phase flow will allow analysis of these costs and, therefore, heavily influence the decision.



- INVESTMENT COST
- OPERATING COST
- OPERATING PROBLEMS

FIGURE 1–ONE PIPELINE OR TWO?

In the design of pipelines which carry both vapor and liquid, two key parameters are pipeline *pressure drop* and *holdup*. Accurate analysis of both terms is of paramont importance for a proposed pipeline.

Prediction of pressure loss in pipelines which carry single phase gas or liquid has been the subject of many investigations; pressure drop in single phase flow can be accurately predicted to with a few percent through the use of well recognized formulas.

Pressure loss when multiple phases are present has also been investigated to a great extent, resulting however in design techniques and correlations that are not nearly as accurate.

Total pressure loss is a function of three terms:

1. Head (elevation)
2. Friction
3. Acceleration (usually negligible)

Pressure loss or gain due to elevation changes is difficult to predict due to the *slip* or *holdup* effect. When two phases are present in the pipeline one phase tends to move faster than the other—that is, it "slips" by the other phase. The slower moving phase tends to hang back, producing a "holdup" effect. The amount of slippage between phases is a strong function of pipeline inclination where angles of less than one degree can produce significant pressure changes due to head. In addition, liquid holdup in gas or gas-condensate pipelines can produce operating problems due to liquid slugs.

The slip effect is also one of the prime reasons for friction losses in multiphase pipelines usually being much greater than in single phase lines. Friction losses in two-phase flow can be two to three times greater than those for single phase flow.

FLOW PATTERN CONCEPTS

Two-phase design efforts in production operations are most often directed towards analysis of pressure drop and liquid holdup for a wide spectrum of pipeline operating conditions.

1. Liquid Dominated (little vapor)
2. Multiphase (significant liquid and vapor)
3. Vapor Dominated (little liquid)

Each operating condition experiences different flow regimes and, therefore, different problems. Figures 2 and 3 show some of the flow regimes that occur in horizontal and vertical flow. Since flow regimes can effect operating problems and holdup, it is important to map their relationship to each other. Although this is still an area of active research, Figure 2 shows a qualitatively correct representation of the regimes as a function of gas and liquid velocities. If the pipeline starts out operating in stratified flow and gas rate is increased with constant liquid rates, the flow regimes will transition to wave and then annular flow.

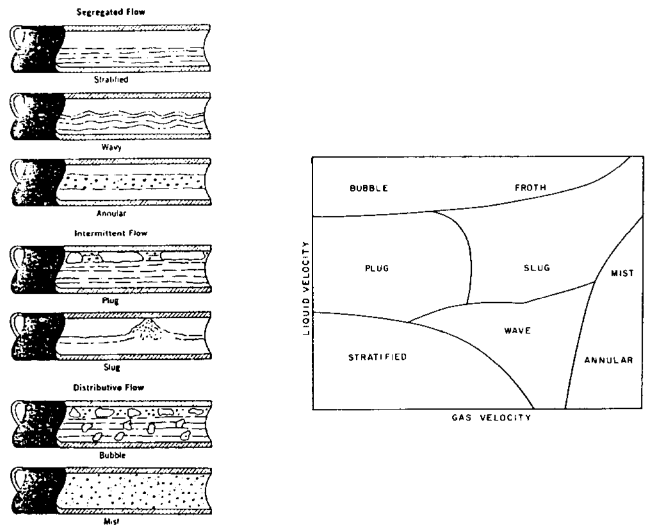


FIGURE 2—HORIZONTAL MULTIPHASE FLOW PATTERNS

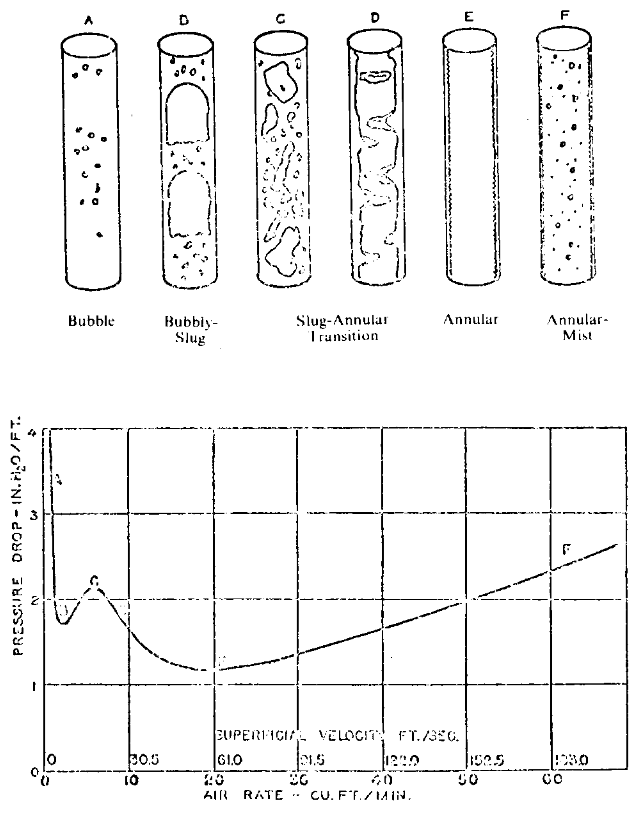


FIGURE 3—FLOW PATTERNS IN CONCURRENT VERTICAL TWO-PHASE FLOW AND A PLOT OF PRESSURE DROP VERSUS AIR RATE IN A 1" I.D. TUBE

Figure 3 emphasizes the fact that flow regimes can also control the pressure-drop behavior.

Bubble and slug flow tend to be head dominated with negligable friction, while annular mist flow is friction dominated. In head dominated flow, pressure drop is reduced with increased gas velocity (flow) with constant liquid velocity, since the fluid column head is being reduced more than the corresponding frictional pressure drop. With further increases in gas velocities, friction begins to dominate.

MULTIPHASE FLOW CORRELATIONS

Horizontal, inclined, and vertical two-phase flow pressure drop and holdup are usually determined by empirical correlations based upon laboratory data. In most field scale applications, we are forced to extrapolate these correlations beyond their original data range. Interpretation of results under these conditions is often referred to as the "art" of two-phase flow analysis.

Furthermore, we must understand that laboratory "steady-state" two-phase flow bears no relationship to field scale operations experience. The process shown on Figure 4 is referred to as steady by laboratory experimenters; but in production operations this is termed an "unstable" or transient flow pattern. The empirical correlations ignore the short-term transients and provide a macroscopic or global prediction of pressure drop and holdup based on the mean value. As a result, the correlations often ignore important transient phenomena such as slugging, a subject which will be discussed later.

Additional effects such as sonic flow, turndown, varying fluid properties and temperature must also be considered in the design or operational analysis of a system. Although the pipeline and facilities may be properly sized for full capacity, operation under blowdown (sonic) or turndown conditions can produce unexpected results. Both fluid properties and temperature will vary continuously with distance so that point-by-point accounting for these effects can be important in determining pressure drop, holdup, and flow patterns.

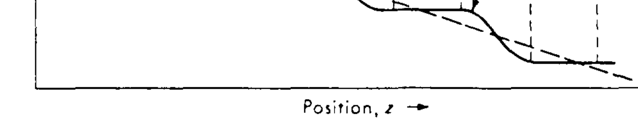


FIGURE 4

FLUID PROPERTIES

Another concept that must be defined is the distinction between black oil and compositional treatment of fluid properties. Figure 5 shows a schematic of the variation of fluid types with composition as shown in the following generalized table.

	Methane (mole%)	Intermediates (mole %)	Heptanes+ (mole %)
Black Oil	30	35	35
Volatile Oil	55	30	15
Gas Condensate	70	22	8
Dry Gas	90	9	1

The delineation between fluid types is not always clear cut, because fluid compositions vary widely between different producing locations. Traditional black oil treatments of fluid properties assume that only two components, gas and oil, make up the mixture. Fluid properties are predicted through use of the concept of solution gas with corresponding properties of formation volume factor and live oil viscosity. The compositional approach utilizes an equation of state to describe the interaction of multiple hydrocarbon components.

A pressure temperature (p-T) phase behavior diagram for a hypothetical pipeline fluid is given in Figure 6. The solid line ACB delineates the two-phase region of this mixture. The lines within the envelope indicate the volume percent which is liquid in the two-phase mixture. The point C at the apex of the volume percent lines is termed the "critical point" of the mixture and is defined as that point, on the two-phase envelope, where all distinction between the liquid phase and vapor phase disappears. That is, the composition, density, viscosity, and other properties of one phase become

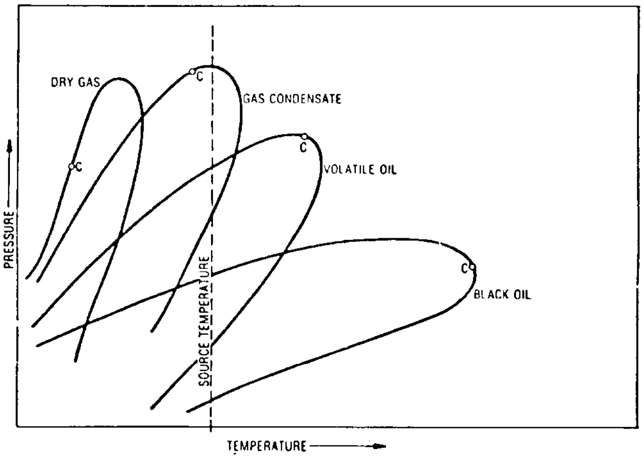


FIGURE 5—PRESSURE-TEMPERATURE DIAGRAM OF SEVERAL HYDROCARBON FLUID TYPES (AFTER MACDONALD)

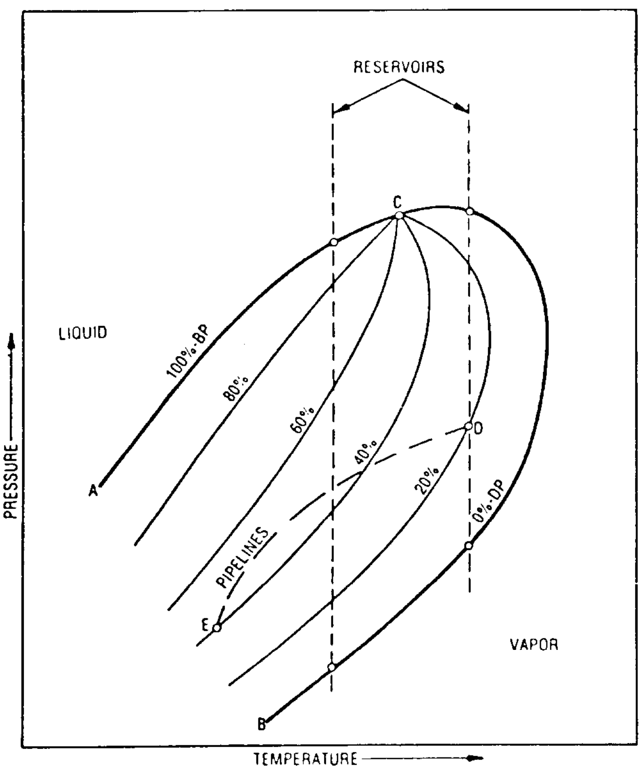


FIGURE 6—TYPICAL PRESSURE-TEMPERATURE DIAGRAM OF A HYDROCARBON SYSTEM

identical to the corresponding property in the other phase.

The limiting volume percent lines are the boundaries of the two-phase region. The 100 percent liquid line is the bubble point (BP) curve and the 0 percent liquid line is the dew point (DP) locus. On Figure 6, the critical point, C, lies at a lower temperature than the maximum of the phase envelope. However, this is not a requirement. In fact, the position of the critical point on the two-phase envelope helps to define the type of hydrocarbon fluid.

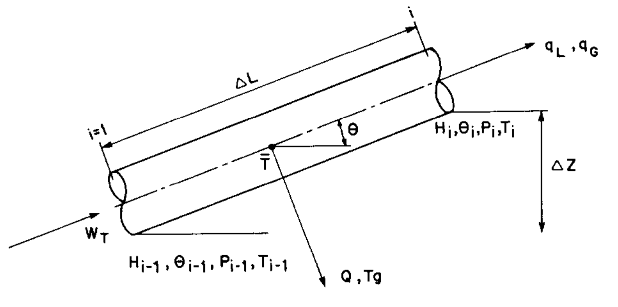
In petroleum reservoirs, the depletion processes are usually isothermal in nature and are represented as vertical lines on a p-T diagram. Figure 6 shows the two basic types of phase behavior encountered in reservoirs. Isothermal expansions at temperatures below the critical point result in a reduction of pressure until the bubble point is reached. Further reduction of pressures causes more vapor to form until the dew point line is reached and the system becomes all vapor.

Similar expansions above the critical temperature cause liquid to form as the dew point line is encountered. As the pressure is reduced, the liquid content first increases, and then it revaporizes until a second dew point is reached at lower pressure. The phenomenon of increasing liquid content under isothermal expansion is called "retrograde condensation."

Although some pipelines exhibit this retrograde behavior, they are relatively rare and the behavior usually occurs only at elevated pressure. The curve D to E on Figure 6 shows a more typical transverse of the phase diagram for pipelines. Sources typically enter hot with rapid cooldown towards ground temperature. At some point, pressure drop begins to dominate and the transverse tends to become more isothermal in nature. The severity of this transition becomes greater with lower velocities. It is clear that many two-phase pipeline problems will not be properly handled unless pressure, temperature and phase behavior effects are fully coupled and accounted for.

LIQUID DROPOUT

The problem of liquid dropout is a major concern in wet gas gathering and transmission. Its behavior is totally controlled by pressure and temperature, so that coupled heat and momentum balances are required to define the problem mathematically. Figure 7 shows a schematic of the system under consideration with pressure and temperature known at location "i-l." The corresponding fluid properties of enthalpy (H) and liquid dropout



HEAT BALANCE

$$H_i = H_{i-1} - Q - \frac{g}{g_c}\frac{\Delta Z}{J}$$

HEAT TRANSFER

$$Q = \frac{U\pi d\,\Delta L(\bar{T} - T_g)}{W_T}$$

MOMENTUM BALANCE

$$-\frac{\Delta P}{\Delta L} = \frac{1}{144}\left(\frac{\bar{\rho}\, g/g_c \sin\theta + \tau_f}{1 - Ac}\right)$$

where $\bar{\rho}$ = mixture density, τ_f = friction loss term $\Big\}\ \Phi(P, \theta, W_T)$

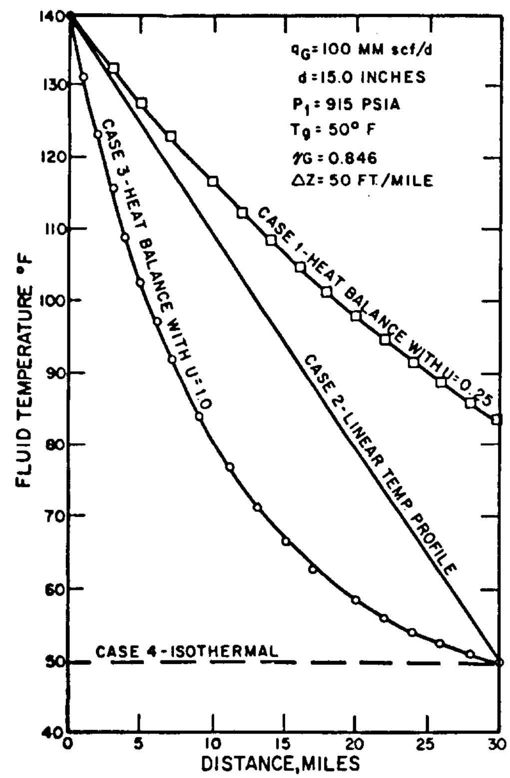
FIGURE 7—COUPLED HEAT AND MOMENTUM BALANCES

fraction (Θ) are determined by an equation of state at this location.

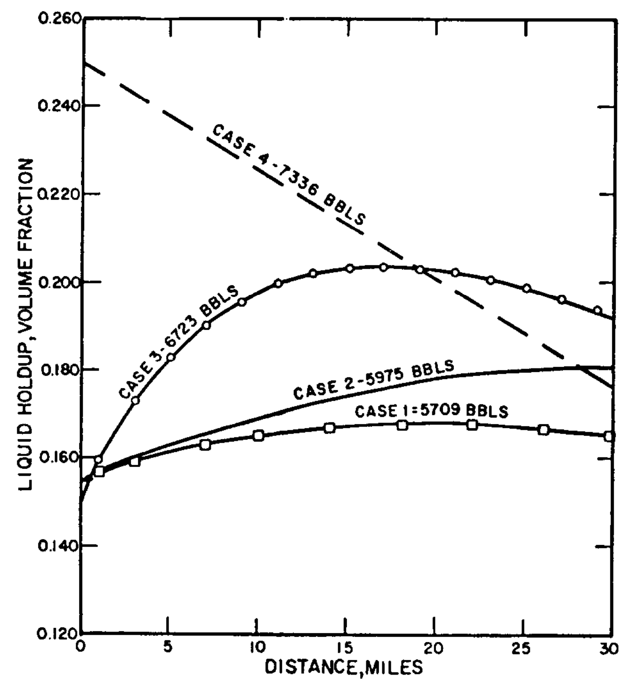
With the mass rate known, volumetric flow rates are determined and the pressure drop to location i can be computed. With the heat loss and elevation change known, the enthalpy at i can be computed. With enthalpy and pressure known, temperature is determined. The procedure is iterative because the *average* pressure and temperature between locations i and i + 1 must be used to determine liquid dropout and enthalphy.

A computerized version of the foregoing analysis yields liquid dropout predictions used for slug catcher, dehydration and inline heater sizing. Figure 8 shows a sensitivity analysis of temperature profiles and their effect on liquid holdup profiles in a typical pipeline. Widely different temperature profiles can result, depending on how the heat balance is treated. Generally, temperature tends to drop exponentially toward ground temperature, with the actual profile controlled by heat loss and flow rate.

Figure 8 also shows the liquid dropout profiles that result from the Beggs and Brill correlation. Case 3 shows that as temperature drops, initially liquid dropout increases; but as pressure drop becomes more dominant, liquid actually revaporizes. This phenomenon can be observed in some gas pipelines which are dry at inlet and outlet but produce liquid when sphered.



Temperature profile Sensitivity



Liquid Profiles For Each Case.

FIGURE 8

The integration of holdup along the length of the pipeline is used to compute slug catcher size. Ignoring phase behavior effects, this is approximately the amount of liquid that must be handled at the slug catcher if the line was sphered. The isothermal temperature profile gives the most conservative estimate of slug catcher size. However, this can easily be in error by substantial amounts, depending upon the problem. Accurate temperature and terrain profiles must be obtained in order to estimate slug catcher and liquid handling capacities.

Computed temperature and liquid dropout profiles can also be critical in gathering system analysis. Figure 9 shows a schematic of the system used to simulate the April, 1974 pressure survey from Hudson's Bay Oil and Gas Co. Sour gas with 20 to 30 percent H_2S is being transmitted to a central site over a distance of about 12 miles. There is a dehydration unit (11-14) downstream of wells 7-13, 10-4 and 10-10 to knock out all free water.

The pressure is regulated downstream of this unit at 1268 psia. A dry, sour gas stream (11-26) enters

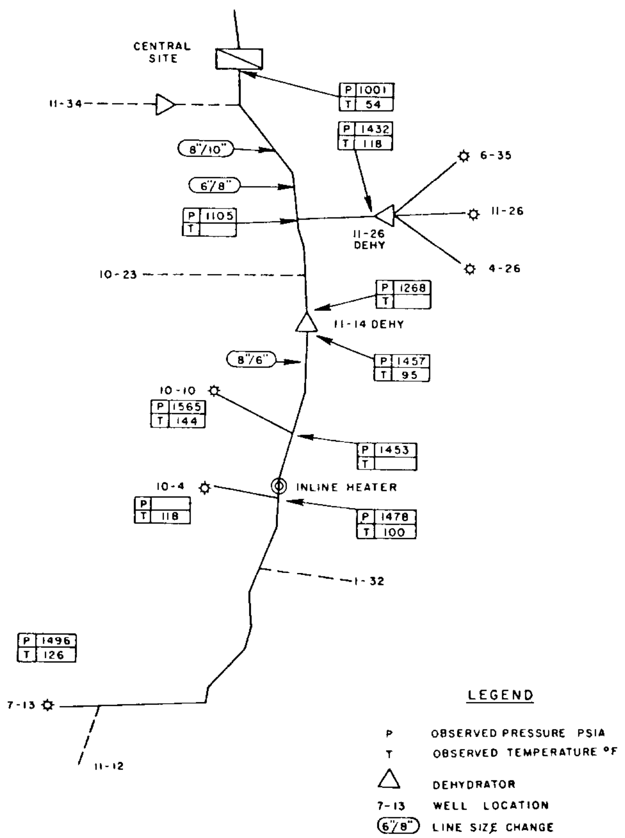


FIGURE 9—SCHEMATIC OF GATHERING SYSTEM SHOWING APRIL, 1974 PRESSURE SURVEY

the transmission line between the regulator and the central site. An in-line heater was in operation during the survey just downstream of the 10-4 tie-in point. The ground temperature was assumed to be 40°F.

Figure 10 shows the terrain profile and the location of sources and equipment. The profile is generally downhill except for the final sharp rise to the central site. Subsequent experience has shown that the computed pressure drop is sensitive to the number of profile points used.

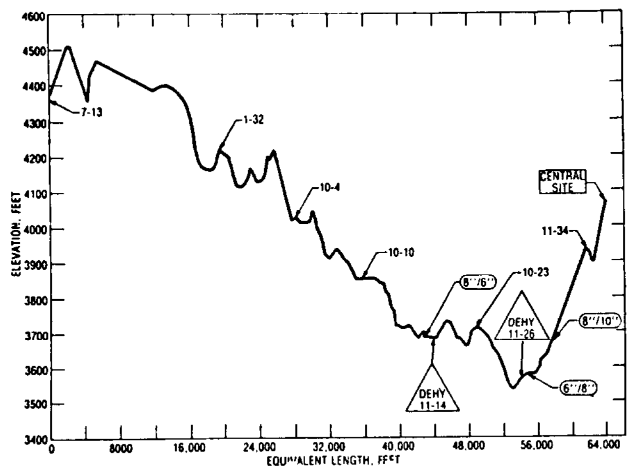


FIGURE 10—ELEVATION PROFILE OF THE GATHERING SYSTEM

Figure 11 shows a comparison of computed and observed pressures and temperatures. An overall heat transfer coefficient of 0.2 BTU/ft^{2}hr°F was used up to the in-line heater and 1.5 was used from there to the central site. The temperature match is reasonably good, considering that the actual burial conditions of each piece of pipe are not known. The sharp changes in the temperature profile reflect the effect of adding relatively warm sources to the main flow stream.

The computed pressure profile also shows a reasonable match with the measured values. This problem is generally downhill dominated for which there are no proven two-phase flow correlations. Several different methods were tried and the Eaton holdup-Dukler friction method with Flanigan's uphill correction seemed to work best.

Where dry gas occurred, the AGA method was used. A dry gas pressure gradient was used to compute downhill pressure recovery. This

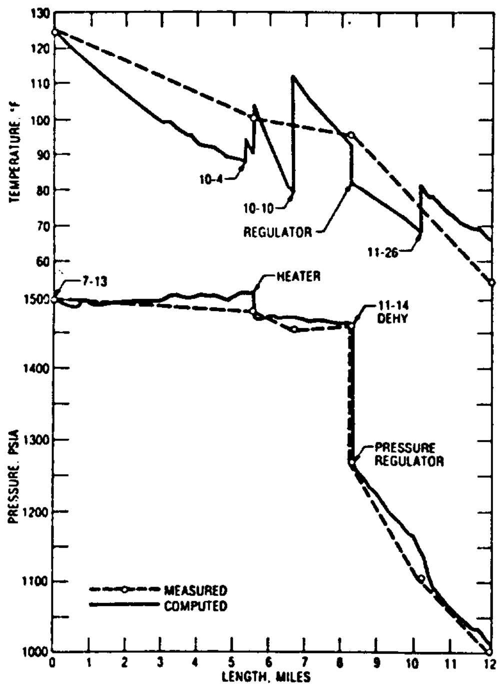


FIGURE 11—COMPARISON OF MEASURED AND COMPUTED RESULTS

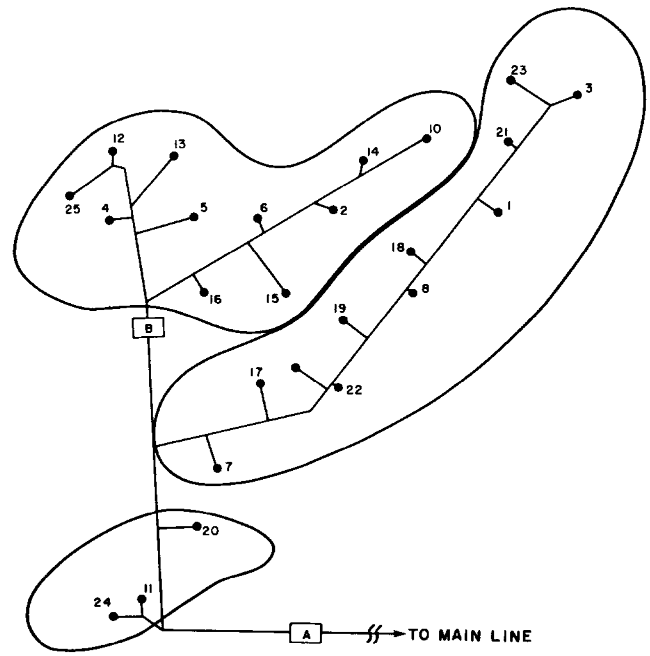


FIGURE 12—TYPICAL FIELD GATHERING SYSTEM

modification of Flanigan's method is required for consistency in vapor dominated flow problems with significant terrain.

GATHERING SYSTEMS

Figure 12 shows a typical field gathering system with multiple reservoirs and multiple wells. Complete analysis of the system as a whole is required for most practical production problems. We find that the best design for a gathering system is not always based on initial well capabilities; rather design should consider the effects of reservoir decline and well interference over time. That is, it may be better to blow down a strong production area early and then produce other areas later in order to meet long-term deliverability requirements.

Alternatively, it may be better to choke back the best producers early to prevent gathering system bottlenecks or even backflow into weaker production wells. Total system deliverability can sometimes be improved if the best wells are restricted since many more weaker wells are allowed to produce against lower back pressures. Liquid holdup and terrain effects can also affect the facility design and operating philosophies, since a wet well may need to be restricted to prevent bottlenecks, liquid dropout, or hydrate formation.

The gathering system is realistically a continuous flow problem from source to sink, reservoir to separator, as shown on Figure 13. Analysis methods tend to concentrate on the vertical multiphase flow problems or the horizontal flow problems or facilities; but unless a system approach is taken, the interaction between each of these can be overlooked. The old saying that "facility planners only talk to reservoir engineers by memo" is still true and can result in neglecting the coupled interaction of formations, wells and gathering systems.

The long-term problem of facility scheduling is illustrated in Figure 14 for a wet gas field with two reservoirs. Each reservoir pressure will decline continuously at different rates with cumulative production. Their individual flow capacities will also change correspondingly so that the total system deliverability is declining with time even though production rate is constant. When deliverability becomes less than contract requirements, more facilities are required, such as compression, new wells, looped lines, or gas-lift.

FLOW SPLITTING

Interestingly, looped lines do not always yield expected results when two-phases are present. In single phase flow, a uniform separation is expected

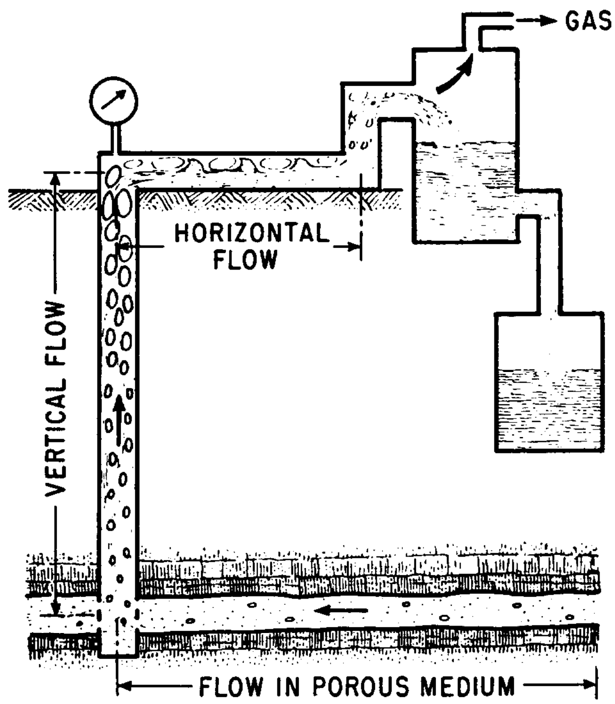


FIGURE 13—CONTINUOUS TWO-PHASE FLOW PROBLEM

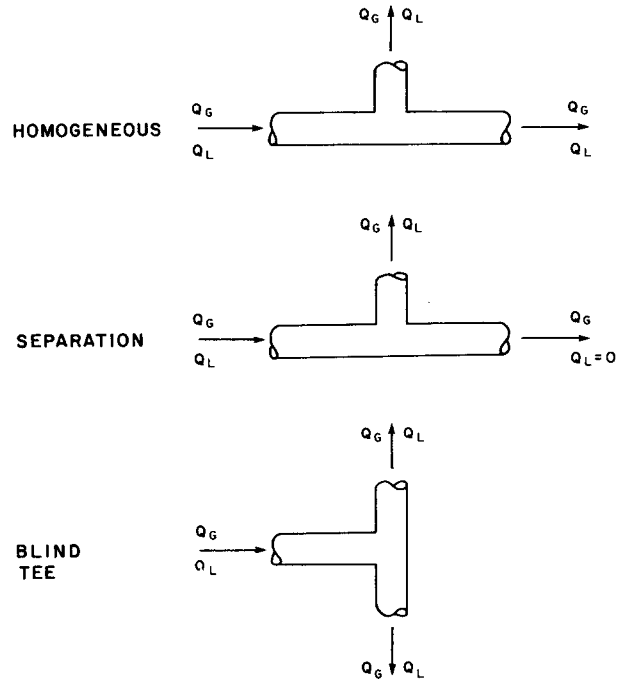


FIGURE 15—TWO-PHASE FLOW SPLITTING

at a forward split (tee). However, in two-phase systems, a forward split will usually result in a non-uniform separation of the phases which changes with flow conditions.

Figure 15 shows a schematic of this effect and a practical solution to the problem, a blind tee. Under certain conditions, all liquid flowing down the main line will be separated at the tee to flow down the lateral. This phenomenon was first recognized in Holland at river crossings when one side of the dual line system would load up with liquid. Investigation showed that under certain flow conditions, almost all liquid would be separated at the tee and sent down the branch instead of the main line.

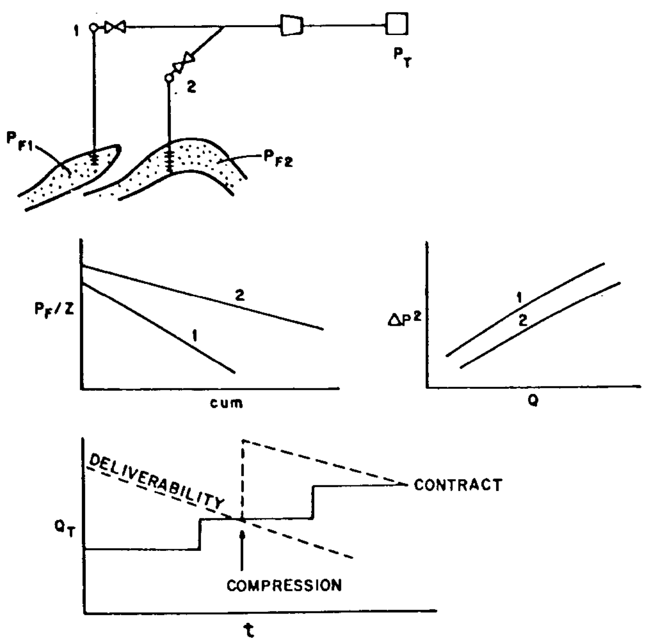


FIGURE 14—DELIVERABILITY

Full understanding of the mechanics of this problem awaits future research.

FLOW EFFICIENCY

Another important concept for vapor-dominated production system analysis is flow efficiency. The dry gas flow equation can be rearranged in the following form.

$$Ep = \frac{q_G}{C_2 (\Delta p^2)^{0.5394}}$$

Here Δp^2 is computed from two-phase correlations and C_2 is consistent with Panhandle "A" or another transmission factor. Figure 16 shows a comparison of several widely accepted correlations as a function of liquid loading based on a gas gravity of 0.7 and a liquid gravity of 40°API. The pipeline is strictly horizontal with an internal diameter of 15.0 in.

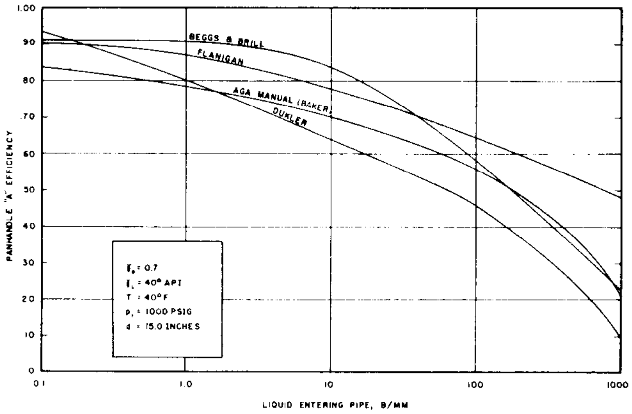


FIGURE 16

At a common liquid loading of 10 bbl/MMscf, these curves show an efficiency range of 64 to 84 percent. There is obviously a question as to which of these curves, if any, are reliable. However, the problem is even more complicated when variation of efficency with terrain and flow rate is also considered.

Figure 17 shows the efficiency reduction at low flow rate because of varying amounts of rise using the Beggs and Brill correlation. The liquid loading used was 20 bbl/MMscf. The rise values on this figure correspond to different degrees of terrain roughness as classified by the AGA. These values are summarized in the following table.

Rise	Terrain
5 ft/mile	Smoothest offshore sea bottom
20 ft/mile	Level country
40 ft/mile	Gently rolling country
80 ft/mile	Rolling Terrain
120 ft/ mile	Hilly Terrain

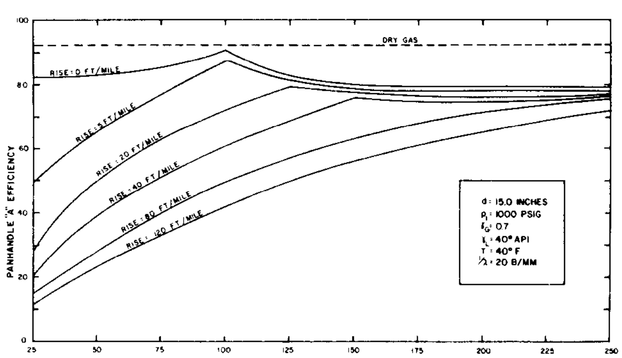


FIGURE 17 - EFFICIENCY REDUCTION AT LOW FLOW RATE DUE TO RISE USING BEGGS & BRILL CORRELATION

Of course, the terrain may be quite smooth in offshore pipelines but the water depth dictates the overall rise. Once the rise of a given pipeline has been established, one curve for each liquid loading should be prepared.

It is also interesting to note the peak shown on the curve for a strictly horizontal pipeline. This corresponds to a discontinuity that was accidently worked into the Beggs and Brill friction correlation. They recommended that a linear extrapolation be made across the discontinuity "gap." This linear correction causes the peak to form on Figure 17. Resolution of this problem is a subject of research.

SLUGGING AND RISERS

The AGA Design Manual for Two-Phase Flow (1970) recognized that the problem of unstable flow is present under normal multiphase pipeline operating conditions. However, the authors could only make the following observations.

1. An increasing gas velocity can sweep large amounts of liquid out of the line. This can sometimes cause a decrease in pressure drop.
2. A decreasing gas velocity tends to cause an increase in the amount of liquid in the pipeline. Under certain conditions, this can cause an increase in pressure drop.
3. Separation facilities at the outlet of a two-phase line should be designed to handle substantially more than the design liquid flow rates in the line, due to increasing gas velocity possibly sweeping out large volumes of liquid.
4. Care must be taken to protect against high mechanical stresses due to rapidly moving slugs of liquid which may occur in two-phase lines.

Figure 18 shows a schematic of this problem in an offshore pipeline and riser system. Large slugs of liquid are accumulated in low spots which are swept out under transient conditions such as accelerating flow. The arrival of these large slugs may appear to operators as "random" but is usually the result of accumulated liquid being swept out.

There are three recognized types of slug flow behavior that occur in the pipeline and riser system.

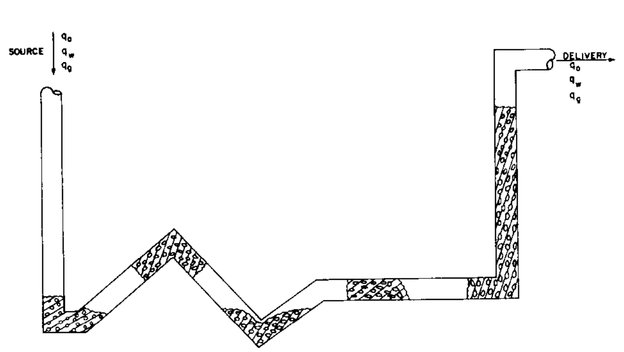


FIGURE 18—PIPELINE/RISER SYSTEM SCHEMATIC

1. Large "random" slugs
2. Natural slugging (periodic)
3. Severe slugging (heading)

In all cases, the characteristics of the pipeline upstream of the riser are recognized to control the riser performance. Since the random slugs are the result of liquid accumulation in the pipeline, they are much larger than the other two types of slugs and tend to cause damage to facilities upon arrival if not properly handled.

Smaller slugs cause operational and vibration problems which must also be accounted for. The smaller naturally occurring slugs are generated due to flow regime effects and their periodic frequency has been correlated. With the slug frequency known, the slug length is determined based on average flow rate. The slug length allows direct computation of pressure variation at the top of the riser. The Tulsa University Fluid Flow Project (TUFFP) has been very active in research on this problem. Schmidt with TUFFP has also developed correlations for the severe slugging frequency that occurs due to liquid fallback and accumulation at the bottom of the riser.

Figure 19 shows a schematic of slug formation under "steady" conditions in a valley. Liquid accumulates in a low spot until "bridging" occurs. At this point, the vapor sweeps a large liquid slug through the line until the riser is encountered. The behavior of the fluids at the bend and the riser itself will control the delivery performance of this liquid slug onto the platform.

Prior to bridging, gas is forced through a narrow restriction, causing Joule-Thompson cooling. After bridging, some liquid fallback occurs as the slug travels uphill causing counter current flow to occur.

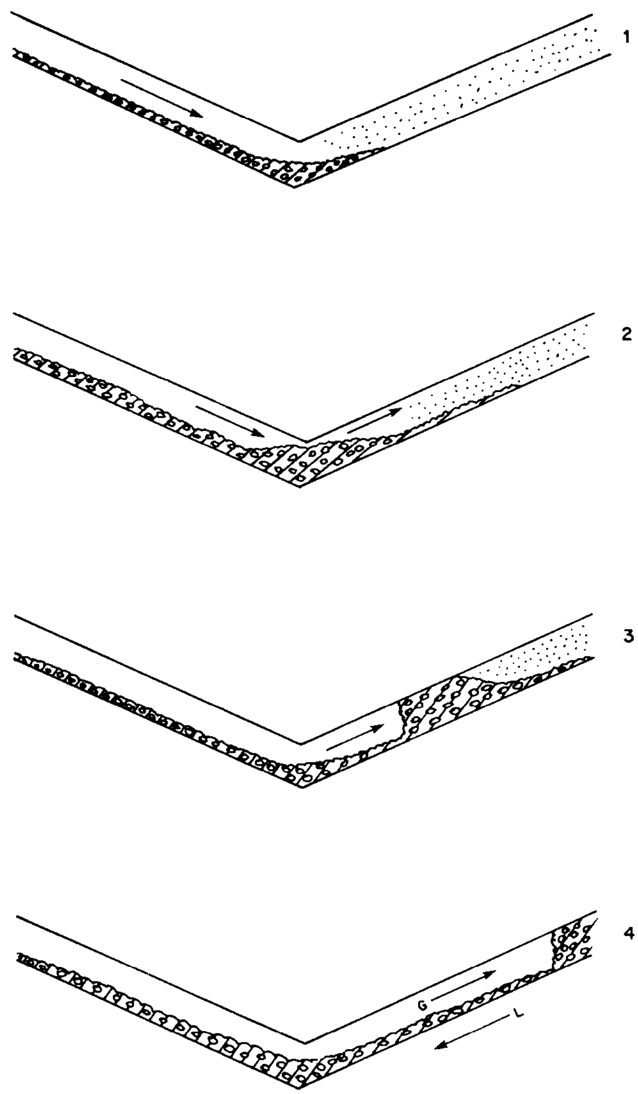


FIGURE 19—SLUG FORMATION SCHEMATIC

SPHERING

Although sphering is used on a regular basis to improve pipeline flow efficiency, very few analysis techniques exist which can assist the engineer with production problems. Figure 20 shows the chart most commonly used for this purpose from the AGA design manual. Unfortunately, the concept of using a single flow efficiency chart for all vapor-dominated pipelines is completely in error.

Comparison of Figure 20 to Figure 17 shows one conceptual problem. Flow efficiency is a function of both flow rate and terrain so that the time between spheres curve (no sphering) on Figure 21 must be uniquely determined for each pipeline profile and

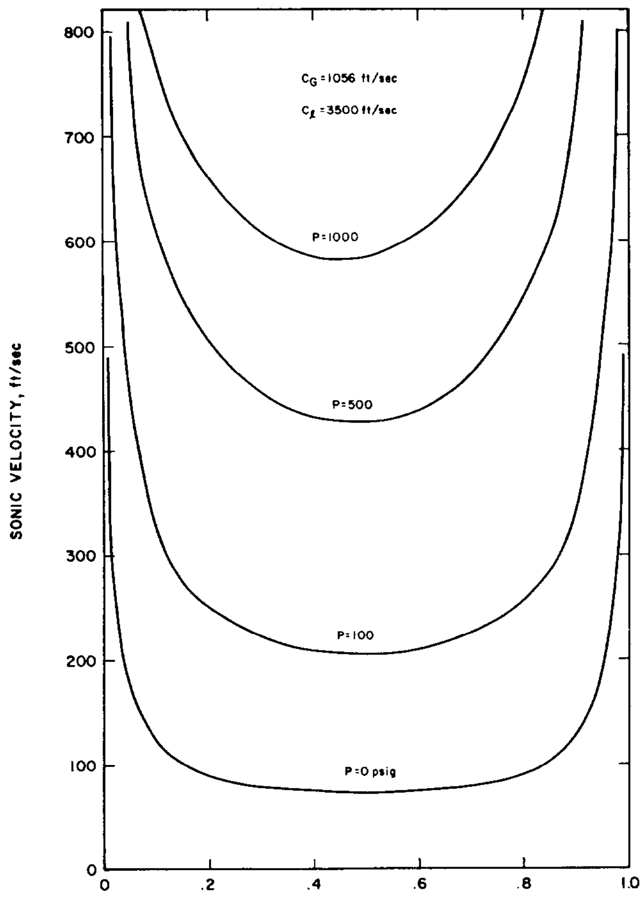


FIGURE 20 HOMOGENEOUS TWO-PHASE MIXTURE SONIC VELOCITY

flow condition. In addition, the curves on Figure 20 showing continued improvement with increased sphering, frequency can also be misleading. Some point of dimished return must be achieved and is probably different for each pipeline.

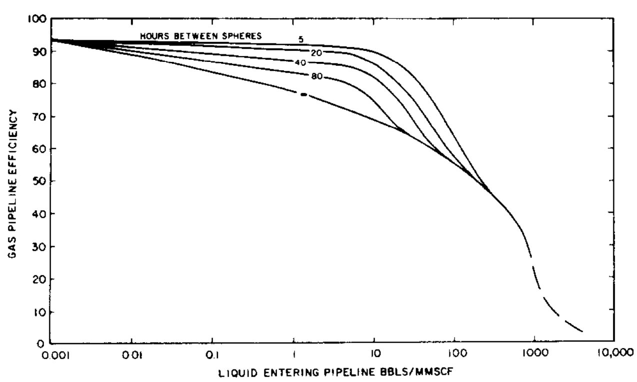


FIGURE 21 EFFECT OF SPHERES ON THE FLOW EFFICIENCY OF TWO-PHASE LINES

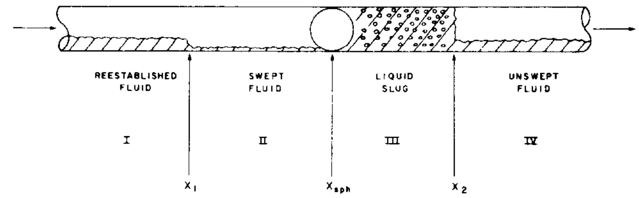


FIGURE 22 SCHEMATIC OF FLUID REGIONS DURING SPHERING

Figure 21 shows a schematic of the sphering process which involves four district regions of flow within the pipeline.

1. Re-established fluid
2. Swept fluid
3. Liquid slug
4. Unswept fluid

Since the sphere travels at a gas velocity on the order of 10 ft/sec, it takes several hours to completely sweep a line. During this period, two-phase flow is re-established over a significant section of the line. Since some liquid leaks past the sphere, the swept region is slightly wet. The liquid slug in front of the sphere is also a two-phase mixture but the increased density causes the pressure gradient of this region to

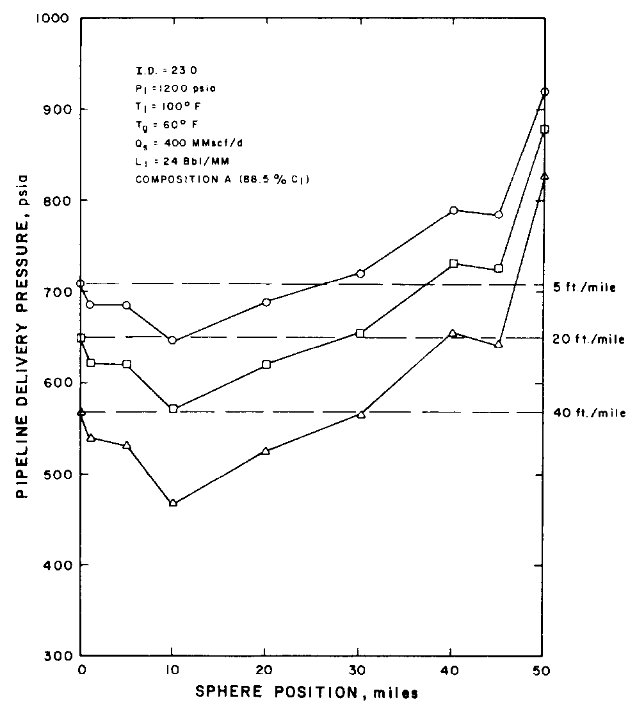


FIGURE 23—VARIATION OF DELIVERY PRESSURE WITH SPHERE POSITION USING EATON HOLDUP & DUKLER FRICTION

be an order of magnitude greater than the surrounding vapor dominated regions. And finally, the unswept region still contains undisturbed two-phase flow.

Simulation of the sphering process by succession of steady-state techniques gives the results shown in Figure 22 for a typical wet-gas pipeline. As the liquid slug builds up to occupy several miles of the pipeline, its increased friction gradient can cause the delivery pressure to decrease below the steady-state value for significant time periods. The sharp rise in pressure at the end is characteristic of slug delivery.

If we realize that "efficiency" is a time averaged function, it is not clear that the improvements shown on Figure 20 are reliable for all conditions. In some field-scale installations, multiple sphering has been found to reduce overall efficiency. Alternatively, some sphering may be required simply to reduce slugging and inhibit corrosion.

Analysis of the sphering problems is still an area of active research. The example shown in Figure 22 is idealized since the inlet pressure is held constant. In actual practice, the sphere and slug combination will slow down upon encountering an upslope until the inlet pressure rises enough to push the sphere over the hill. On the downslope, the sphere accelerates, which can cause a "runaway" problem in severe terrain. This is a fully transient process that can only be approximated with currently available techniques.

SUMMARY

There are many tools and methods existing to aid the production engineer in the analysis of two-phase design and operating problems. This paper has given an overview of some of these techniques. However, many two-phase production problems are still the subjects of active research.