An Effective Method for Modelling Stagnant Liquid Columns in Gas Gathering Systems

R.G. MCNEIL, D.R. LILLICO
Fekete Associates Inc.

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Abstract

Modeling of gas gathering systems is often complicated by the presence of localized pressure losses that are not easily explained using steady-state two-phase correlation packages. This often leads to inappropriate manipulation of base input parameters such as over use of tuning factors, or reduced pipeline diameter or even increase pipeline length to get a satisfactory pressure match. A more appropriate approach includes a review of the model inputs which typically includes rechecking the measurement of the key inputs, increasing the complexity of the model (inclusion of all fluid volumes, fluid property changes, elevation profiles) and confirmation of the appropriateness of the selected pressure loss correlation. This detailed review will often resolve the issue but a significant factor is sometimes overlooked.

It has been the authors experience that these unusual pressure losses often occur at pipeline river crossings and other depressions in the terrain. In situations where superficial gas velocities are high, two-phase correlations tend to work well, but where superficial gas velocities are low, liquids can stop flowing and become trapped even though gas continues to flow.

The goal of this paper will be to present case studies where liquids accumulate and where they continue to flow in a pipeline. The differences between the two situations will be highlighted and a procedure will be presented for correctly identifying when and where liquids are accumulating. These liquid accumulations, sometimes called Stagnant Liquid Columns, can significantly increase wellhead backpressures and adversely impact well productivity.

Introduction

The maturation of the natural gas production systems throughout North America has resulted in the majority of systems being operated well below their original design conditions. Consequently, it is not uncommon to identify excessive pressure losses when comparing calculated pressures with field measured pressure data. The reasons for excessive pressure loss are varied and most often relate to measurement issues, poor understanding of the pipeline and facility connections, and sometimes non-moving liquid accumulations called “Stagnant Liquid Columns”. Liquid accumulations are a concern because they increase backpressure for all upstream wells, which reduces well deliverability, and can result in localized pipeline corrosion.

One would think that the two-phase pressure loss equations should be capable of predicting when, where, and how much liquid accumulates while also predicting pressure loss.

The two-phase correlations do calculate liquid holdup but only in a steady-state sense. Simply stated, any liquid introduced into a pipeline must by definition be produced out the other end of the conduit. If the liquid enters the conduit and stays while the gas continues through, we no longer have steady-state flow and so the correlations will break down.
This leads to the question, how do we reliably identify stagnant liquid columns and how should they be modeled? To answer this question, a discussion of recommended modeling procedures is required.

## Discussion

### Friction versus Hydrostatic

Since total pressure loss is the sum of the friction and hydrostatic pressure loss, it is recommended that modelers always classify every scenario as either friction-dominated flow or hydrostatic-dominated flow. This is useful because it helps to keep us from using a friction-based tool to match a hydrostatic based problem and vice versa. Hydrostatic pressure loss can be thought of as a fixed pressure loss, especially as it relates to single phase flow. Friction pressure loss can be thought of as a curve or parabola. At low flowrates, friction pressure loss is minimal but as flowrates increase, pressure loss rises sharply. Figure 1 presents a chart of friction pressure loss for several pipelines sizes.

This simple classification system will hopefully help keep modelers from making use of extreme (not appropriate) strategies for matching system pressure loss. A solution can often be “forced” but the result is almost always a model that can reproduce only “current conditions”. These models invariably fail when simulating before and after conditions for field modifications that significantly change gas flowrates or operating pressures.

### General Rules for Pressure Loss Matching

Start by matching pipeline pressure losses only. Remove all other degrees of freedom. Model wells as fixed gas rates using measured line pressures and model compressors as simple fixed suction devices (set suction pressure at the current measured value and do not use horsepower or capacity limitations). Logs for wells and compressors are generally easily accessible and so can be a primary source of field performance data. Where possible, identify other facilities such as separators, dehydrators and line heaters that may affect apparent pipeline pressure losses. Pressure losses at these facilities are not generally logged on a regular basis and so it is usually up to the modeler to identify these locations and quantify the pressure loss. Matching pressure losses in pipeline systems should be conducted by first classifying the pressure losses as friction, hydrostatic, or other. The easiest way to make these classifications is to set up the base model to use fixed gas rates for the wells and model using a single-phase correlation without elevation profiles. An initial run of the model that matches all field measurements within reason indicates that the system is dominated by single-phase gas friction pressure loss only. Areas of the system where model pressures and measured pressures do not match become points of interest. These areas can usually be reconciled with a field trip by the modeler with a good quality pressure gauge. Measurements will identify gauges requiring re-calibration, non-functioning gauges, gauges upstream of a previously undocumented pressure loss, plugged filters, portions of the system dominated by two-phase flow (sometimes with and sometimes without elevations changes), and stagnant liquid columns.

In this style of model matching, the modeler only makes the model more complicated at points in the system where it is warranted. Some common themes encountered in model matching are discussed below.

The selection of a pressure loss correlation is generally best done up-front based on specific knowledge of the current flowing fluids. The selection of a correlation should not be used as a tuning parameter. Even though our current correlation suite is still very much dominated by empirical equations and in the case of the mechanistic models still require the use of empirical closing equations, these correlations are generally very good within their stated boundaries. Therefore, when attempting to match current operating conditions, the modeler needs to trust the correlations more and expand their search for other factors.

One of the most powerful techniques for identifying other factors that impact the match is a field trip. A simple field tour will not usually suffice; the modeler must go to the field armed with specific questions. It is recommended that the modeler utilize information generally gathered as part of the “normal field operation” for a preliminary pipeline pressure diagnosis. Targeted data should include field logs or remote sensing data for well flowing pressures and flowrates plus compressor suction and discharge pressures. The initial model should not be “tuned” but rather used as a key for identifying problem areas. Armed with a list of problem areas, the modeler should then go to the field prepared to take independent pressure measurements using a calibrated good quality gauge for all measurements. This will eliminate most tuning conflicts. Some common problems found during field trips are undocumented pipeline connections, undocumented facilities such as separators, line heaters and chokes, and gauges requiring re-calibration.

The use of tuning factors and the concepts of equivalent diameter and equivalent length assume all pressure loss is friction-based. In some cases, use of tuning factors may be OK. The key is to recognize when the use of tuning factors (roughness and flow efficiency) on pressure loss is reasonable. Pipelines operating below capacity will be insensitive to friction-based tuning factors. Pipelines operating near or in excess of their capacity will be sensitive to friction-based tuning factors.

Figure 2 presents a chart of pressure loss due to friction calculated from Fanning for a horizontal pipeline segment at various values of roughness. Using a default roughness of 0.0006 inches, pressure loss is very sensitive to changes in flowrate above 1 MMscfd and is quite insensitive to changes in flowrate below 1 MMscfd. A current operating point is also plotted in this chart. Note that increasing the roughness by a factor of 100 to 0.06 inches was not sufficient to produce a match. However, it still had a significant impact on the calculation of friction pressure loss at rates above 1 MMscfd.

Figure 3 presents a chart of pressure loss due to friction calculated from Modified Panhandle for a horizontal pipeline segment at various values of flow efficiency (FE). Using a default flow efficiency of 80 %, pressure loss is very sensitive to changes in flowrate above 1 MMscfd and becomes very insensitive to changing flowrates below 1 MMscfd. In this case, the current operating point can be matched using a flow efficiency of just over 10%.

In both Figures 2 and 3, pressure loss is very sensitive to the tuning factors above about 1 MMscfd and insensitive below about 1 MMscfd. Use of friction-based tuning factors in the insensitive region is not recommended. In Figure 3, a match is achievable at a flow efficiency of just over 10% and a flowrate of 0.300 MMscfd. If the gas flowrate is increased to 1 MMscfd for this pipeline match, the frictional portion of the pressure loss would increase to over 200 psi. Using the default flow efficiency of 80%, the frictional pressure loss should be only 10 psi!
Figure 4 presents a chart of pressure loss due to friction and hydrostatic from Beggs & Brill\(^\text{1}\) for an inclined (45 degree upward) pipeline segment. The slope change that occurs in the hydrostatic component at just below 1 MMscf/d is due to a change in flow regime from segregated to distributed flow. In this case, a satisfactory pressure match was achieved with no changes to any tuning parameters. A match like this is rare, however, because this case (100 Bbls/d of water with 0.300 MMscf/d gas => LGR of 333 Bbls/MMscf) has more water flow than most systems encountered in project work. Most systems operate at much lower liquids-gas ratios, usually less that 20 Bbl/MMscf.

Figure 5 presents another chart of pressure loss due to friction and hydrostatic from Beggs & Brill for an inclined (45 degree) pipeline segment. In this case (6 Bbls/d of water with 0.300 MMscf/d gas => LGR of 20 Bbls/MMscf) does not result in a satisfactory match. How do we get a satisfactory match in a case where we have confirmed the base input data and the pressure measurements? This is not an uncommon problem.

It is even quite common to encounter a system that does not continuously produce liquid at the plant inlet but still has very high well backpressures that cannot be modeled in single-phase and cannot be modeled in two-phase because there is no continuous liquid production. A common scenario is that liquids when produced to the plant are at quantities usually much less than 20 Bbl/MMscf. Field personnel monitor well backpressures and once a preset pressure level is reached, the pipelines are pigged and the liquids are recovered at the plant. Backpressures at the wells decrease significantly and liquid rates cease for a period of time sometimes lasting hours, days, even weeks but then return to previous levels. This operating scenario is probably familiar but a practical way to model it is not obvious.

Knowledge from Wellbore Flow

A way to deal with this situation was derived from work in wellbores. Gas wells have long been the subject of liquid load-up studies. Turner et al\(^\text{1}\) developed an equation based on a droplet model that relatively accurately calculates the critical gas flow rate below which liquid load-up will occur. Turner does not describe or calculate any of the aspects of how a well will die or continue to produce once loading has occurred.

Coleman et al\(^\text{2,3,4,5}\) added a series of papers that describe the physical processes that occur as a well loads-up. Key points included in Coleman’s description of the load-up phenomenon are that liquid production ceases, condensation can be a major contributor to liquid load-up and the terminal event has gas flow percolating through a liquid column and then continuing up to the wellhead in single phase gas flow. The increased backpressure caused by the liquid head is much greater than the fluid load experienced prior to load-up and so sandface flowing pressure increases significantly causing gas flowrates to decrease dramatically.

An example of a well exhibiting liquid loading behavior is included as Figure 6. Liquid production initially ceases but gas continues to flow throughout at much lower values than experienced prior to liquid load-up. Liquid production subsequently recommences after load-up probably due to periodic blow-down or use of a plunger lift system. It is not uncommon to find wells that continue to produce gas while liquid loaded.

Parallels – Pipelines and Wellbores

There are strong similarities between a liquid loaded wellbore and a liquid loaded pipeline. Where liquids are present and gas flowrates are high, both can be modeled successfully using two-phase correlations but as gas flowrates decline both experience “holdup” of the liquids such that flow of liquid ceases for periods of time and both require mechanical methods to efficiently remove the liquid.

It has long been understood that non-moving liquid in pipelines accumulate in the valleys, river crossings and any place in the terrain where the fluid can run downhill and then must lifted by the gas up the hill on the other side. As gas velocity declines, it is less able the move the liquids out of the trap. Figure 7 presents a visual interpretation of what this scenario may look like.

Since the flow of liquid and gas is uphill out of the trap and the angle of inclination can be quite severe, it was theorized that perhaps the Turner correlation could be used to predict the gas velocity required to move liquids out of the trap. Since the angle of inclination can vary widely from close to horizontal up to near vertical, it is expected that it would not be as accurate as it is for wellbores. A modified version of the Turner correlation, plotting velocity versus pipeline operating pressure is included as Figure 8. In this plot, the upper black line is the Turner velocity whereas the lower red line is the lower limit for effective two-phase flow assuming a minimum upward angle of inclination of 10 to 20 degrees. The red (lower) line is largely experience-based and so could have significant errors. The graph has been further annotated to indicate where a stagnant liquid column will occur, where it may occur and where it is not expected.

Use of a Stagnant Liquid Column

Stagnant liquid columns can occur in systems where there is no apparent liquid production and in systems with known liquid production. Regardless, this technique should only ever be used if the following tests are passed. The current rules employed are:

1) There must be a significant localized pressure loss over and above that predicted by the pressure correlations. This is also often identified in gathering systems as a “Step Change” in pressure.
2) There must be a creek, river crossing or some place where the liquids must first flow downhill and then flow uphill. The uphill angle should be at least a 20 degree above horizontal.
3) The velocity of the gas is insufficient to move the liquids effectively as determined from Turner et al chart (Figure 8) as modified for pipeline systems.
4) The measured pressure step-change must not exceed 0.3 psi/ft\(^*\)h, where “h” is the uphill flow elevation change.

Example Cases

Example 1

Figure 9 presents a portion of a gas gathering system model. In this model, the calculated backpressures for the first three wells (02-10, 11-02 and 06-01), working sequentially away from the plant, match closely. The next two wells (06-27 and 07-36) do not match. In well 06-27, the line “WH 644 L 638” designates that the measured wellhead pressure is 644 psia and the measured line pressure is 638 psia.

Note the calculated line pressure for 06-27 well is 124 psi lower than the measured line pressure and the calculated line pressure for the 07-36 well is 114 psi lower than the measured line pressure. Since the calculated line pressures are approximately 120 psi lower than the measured values for both these wells, it is fair to conclude that the problem area is most
likely in the common pipelines or headers from the 11-02 well to common header for the 06-27 and 07-36 wells. This may also be categorized as a step change. A check of topographic maps indicates this section of the pipeline crosses a river that rises 500 feet from the valley floor. It is known that some liquids are produced by these wells but there are no measured volumes available.

The superficial gas velocity for the pipeline segment between the 11-02 well and the common header for the 06-27 and 07-36 wells is less than 1 foot/second. Utilizing Figure 8, it can be seen that liquids entering this section of pipeline would not be moved efficiently by gas flow.

A fixed pressure loss facility was introduced in Figure 10 at about the mid-point of this segment of pipeline to model the hydrostatic nature of this pressure loss (120 psi). The line pressures at the 06-27 and 07-36 wells now match quite closely.

Example 2

Figure 11 presents another case where a stagnant liquid issue was identified. In this case, the operator argued that the line had been pigged and was dry. On further questioning, it was determined that the line was last pigged several years previously. The line was subsequently pigged and a large volume of condensate was recovered. Total gas rates from upstream wells also increased by over 1 MMscfd.

Example 3

Figure 12 presents a case run using a single-phase correlation. It can be seen that there is no match between the measured and calculated flowing pressures in the system. It is known that liquid production is occurring in this system. A check on gas velocities (generally > 20 ft/s) indicates that use of a two-phase correlation and input of appropriate elevation changes may resolve the match.

Figure 13 presents the same case after input of liquid rates, input of elevation changes and switch to a two-phase correlation. The match is much improved and considered reasonable given the accuracy of the measurements. The field trip may serve to tighten this match.

Conclusion

A modeling process has been outlined that simplifies modeling of pipelines systems by stressing categorization of measured pressure losses as friction-based, hydrostatic-based or other. Issues identified by this process are then resolved via a targeted field trip by the modeler.

In cases where very little liquid or no liquid production occurs, an important source of pressure loss is stagnant liquid columns. These should be modeled as a fixed pressure loss since they are hydrostatic-based pressure losses.

The method of stagnant liquid columns is a definite improvement on the tendency of modelers to use friction-based tuning methods to match measured pressure losses but it is an approximation. Further work needs to be done to more accurately describe the phenomenon of stagnant liquids and its impact on gas gathering system analysis.

REFERENCES


FURTHER READING

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3. Young, J., McNeil, R., Knibbs, J.; Case Study: Including the Effects of Stagnant Water in Gas Gathering System Modeling; SPE Paper No. 75946; Presented at the SPE Gas Technology Symposium held in Calgary, Alberta; 30 April – 02 May 2002
**FIGURE 1 - Single-Phase Gas Friction Pressure Loss**

**Assumptions**
- Roughness (k) = 0.0006 inches
- Pipeline Length = 5280 feet
- Outlet Pressure = 100 psia
- Gas Temperature = 40 deg F
- Gas Gravity = 0.65
  - N2 = 0%
  - CO2 = 0%
  - H2S = 0%

**FIGURE 2 - Pressure loss due to Friction (Fanning)**

**Assumptions**
- Pipeline ID = 6 inches
- Pipeline Length = 5280 feet
- Outlet Pressure = 100 psia
- Gas Temperature = 40 deg F
- Gas Gravity = 0.65
  - N2 = 0%
  - CO2 = 0%
  - H2S = 0%

- Increase Pipe Roughness (k)
- Decrease Pipe Roughness (k)
FIGURE 3 - Pressure loss due to Friction (Modified Panhandle)

Assumptions
- Pipeline ID = 3 inches
- Pipeline Length = 5280 feet
- Outlet Pressure = 100 psia
- Gas Temperature = 40 deg F
- Gas Gravity = 0.65
- N₂ = 0%
- CO₂ = 0%
- H₂S = 0%

FIGURE 4 - Two Phase Pressure Loss

Assumptions
- Pipeline ID = 3 inches
- Pipeline Length = 500 feet
- Elevation Change = 500 feet
- Roughness = 0.0006 inches
- Outlet Pressure = 100 psia
- Gas Temperature = 40 deg F
- Gas Gravity = 0.65
- N₂ = 0%
- CO₂ = 0%
- H₂S = 0%
- Water Rate = 100 Bbls/d
FIGURE 5 - Two Phase Pressure Loss

Assumptions
- Pipeline ID = 3 inches
- Pipeline Length = 500 feet
- Elevation Change = 500 feet
- Roughness = 0.0005 inches
- Outlet Pressure = 100 psia
- Gas Temperature = 40 deg F
- Gas Gravity = 0.65
- N2 = 0%
- CO2 = 0%
- H2S = 0%
- Water Rate = 6 Bbls/d

FIGURE 6 - Gaswell Exhibiting Liquid Loading Behaviour
FIGURE 9 - Example of a Pressure Loss Step Change

FIGURE 10 - Example of a Modeled Stagnant Liquid
FIGURE 11 - Example of a Modeled Stagnant Liquid

FIGURE 12 - Modeled using Single-Phase Correlation; No Match
FIGURE 13 - Modeled using Two-Phase Correlation; Good Match