Review and Selection of Velocity Tubing Strings for Efficient Liquid Lifting in Stripper Gas Wells

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Abstract

This project generated a set of liquid lifting curves specifically for use with low-rate (<60 Mscfd) gas production wells. The curves were tested against a 300 well data set compiled from Great Lakes Energy Partners, LLC's Cooperstown gas field. From this data set, one study well was chosen to test a novel tubing installation. Although production difficulties occurred following velocity string installation, which did not allow a pre- to post-insertion performance comparison, several key insights for the determination of critical rate were made.

It was determined that liquid droplet shape can have a large impact on the terminal rate calculation. Since the drag coefficient is highly dependent upon the particle, calibration of the correct critical rate values to field observations is a necessary step when under taken a similar study. So, liquid lifting performance charts were generated using formulations by Turner (spherical droplet) and Li (flat-droplet). Further , the use of surface conditions to determine terminal velocities and then critical rates is an acceptable practice for tubing-completed wells, providing the tubing is set to the perforations.

In addition to the liquid lifting charts, the project conducted a coarse tubing availability survey to ascertain if small diameter (< 3 inch) tubing was readily available for "off the shelf" use.

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Executive Summary

For low-productivity (stripper) gas wells, the accumulation of liquid in the wellbore can be detrimental to the well's productive life. Quite often, the operator may turn to means other than the natural reservoir energy to lift the accumulated fluids. These may include mechanical pumping, adding wellhead compression, plunger lift, gas lift, soaping, siphon strings or a variety of other methods that can require significant capital investment as well as increased operating costs and equipment maintenance. However, the installation of smaller diameter tubing strings (velocity tubing), if properly identified, can minimize cost while improving well productivity.

When using small diameter completion strings (< 3 inches), large pressure drops that can be associated with two-phase (gas-liquid) flow in the tubing and the potential lack of tensile strength may be important factors to consider. Nonetheless, for stripper gas wells, the impact of frictional losses may be minimal due to the well's small production rate while the implementation of coiled tubing may provide the strength necessary for deeper and smaller applications.

This project surveyed tubing and coiled tubing suppliers in order to obtain performance measures such as outer diameter, wall thickness, relative roughness and tensile strength for compilation into a stand-alone reference. In addition, regional availability of tubing and coiled tubing providers as well as inventory was determined.

Further, a literature review identified those two-phase correlations that are most applicable for stripper gas wells and small diameter production tubing. This review served as the basis for the construction of liquid lifting performance curves for use in sizing tubing strings for low rate gas wells.

The project team tested the liquid lifting performance curves on a candidate pool of wells provided by Great Lakes Energy Partners, LLC. It was determined that Turner's formulation for terminal velocity, and therefore critical rate, understated the ability of the Cooperstown Medina gas wells to lift liquids under their own energy. However, a formulation developed by Li, et al, demonstrated that while Turner's concept was correct, the assumption of spherical droplets was erroneous when applied to wells within the study reservoir, resulting in the use of Li's formulation for development of the improved liquid lifting charts.

From this study set, a test well was chosen. This well had its existing completion string (1-1/2 inch nominal, 2.75 #/ft) pulled in order to install a smaller diameter PL Resin *Thermoflex* velocity tubing string (1 inch nominal), allowing the well to produce under its natural energy. Although the well experienced production difficulties soon after installing the velocity tubing string, resulting in no tangible, comparative results, several key conclusions and insights were made during this research project.

- It was determined that liquid droplet shape can have a large impact on the terminal rate calculation. Since the drag coefficient is highly dependent upon the particle, calibration of the correct critical rate values to field observations is a necessary step when under taken a similar study. So, liquid lifting performance charts were generated using formulations by Turner (spherical droplet) and Li (flat-droplet).

- The use of surface conditions to determine terminal velocities and then critical rates is an acceptable practice for tubing-completed wells, providing the tubing is set to the perforations.

- Tubing providers have on hand, for the most part, tubing sizes in the range of 1 to 3 inches. However, little/no roughness information exists for aid in the determination of friction pressure drop.

- When computation of downhole pressure drop is necessary, formulations by Hagedorn and Brown were found to be the most precise.

- Frictional pressure drop can be greatly reduced through the use of lower-cost, higher-strength plastic (smooth) pipes. These low-friction tubulars are best applied in shallower applications.

- Turbulence damping was also found to reduce friction, suggesting a high-strength seam on the inside of tubulars may be beneficial.

Introduction

When produced gas no longer provides the energy necessary to lift liquids out of a well, the result is the bottomhole accumulation of liquids (liquid loading). This event can be characterized by a production rate that is no longer able to keep the liquid phase moving in the wellbore. It has been reported that to effectively remove liquids from the well, the required gas velocity must be at least 5 to 10 ft/sec for hydrocarbon liquids and 10 to 20 ft/sec for produced water[1,2,3]. If this minimum velocity is not met, liquid loading will occur, creating an additional backpressure on the formation from which the well typically cannot recover without operator intervention.

Once liquid loading occurs, the operator may have several options for unloading wellbore liquids and restoring production. These often include adding compression, mechanical pumping, plunger lift, smaller tubing, siphon strings, gas lift, soap injection and flow controllers. However, many of these techniques, require higher capital and operating costs as well as an increased maintenance frequency[4]. Further, the use of small diameter tubing strings for the removal of liquid can effectively curtail production due to larger pressure drops in the production string. Therefore, the operator must carefully consider the total cost and impact of the application with regard to the expected production benefit.

For low productivity wells; however, the influence of the frictional pressure drop may be negligible when considering the impact of down-sizing the production string and its increased ability to remove wellbore liquids and increase productivity. In fact, Hutlas, et al reported that although the installation of small diameter tubing may have limited utility due to large associated pressure drops at high flow rates, it can be an ideal, cost-effective application for wells near the end of their productive life[5]. Nevertheless, several authors have reported on the installation of velocity tubing strings in wells producing in excess of 300 Mcfd with a degree of success[2,6], suggesting low productivity stripper wells may benefit.

With the introduction of coiled tubing for use as permanent completion equipment, the production engineer was presented with an additional set of options. Smaller diameter coiled tubing can now provide the necessary strength for placement either in deeper wells[7] or to be used as a conventional, yet slimmer completion. In 1999, it was estimated that nearly 15,000 wells have implemented the use of coiled tubing as a velocity or siphon string[8]. Today a wide variety of coiled tubing options are available for implementation in a range of sizes as small as 0.25 inches, creating a multitude of choices for the production engineer.

In order to make the correct choices regarding well and reservoir development, the production engineer must often manage with the concept of minimizing expenditure while maximizing the return on investment. To aid the operator in this endeavor, ARI proposed to generate easy to use, liquid lifting performance curves for small diameter tubing.

Background

The initial work on the subject of critical rate to maintain liquid removal from oil and gas wells dates back to 1961. Duggan studied gas condensate wells and determined that a linear velocity of 5 ft/sec (at the wellhead) was sufficient for continuous liquid removal[1]. Later studies were able to expand upon Duggan's work to account for water-gas systems, which ultimately suggested that 5 to 10 ft/sec was necessary for hydrocarbon liquids while 10 to 20 ft/sec was required to lift produced water[2,3].

However, the classic work on the subject was conducted in 1969 by Turner, Hubbard and Dukler[9]. Two physical models for the transportation of fluids up vertical conduits (tubing) were created: 1) the liquid film model and 2) the liquid droplet model. The liquid film model concerned itself with the removal of accumulated liquids on the walls of the pipe while the droplet model centered about the removal of liquids in the gas stream. During the study the authors were able to show that the liquid droplet model was the dominant liquid transport mechanism and that it should be considered for further understanding the liquid lifting process.

Turner, et al was able to show that when drag forces equate to acceleration forces for a free-falling liquid particle, the particle will reach terminal velocity, which is the maximum velocity it will attain under the influence of gravity. This velocity is a function of the shape, size and density of the liquid particle as well as the density and viscosity of the lifting medium (gas). Therefore, to suspend a liquid droplet, the gas velocity should equal the terminal velocity of the drop and any incremental gain in gas velocity should result in upward movement of the droplet. The resulting relationship showed that the larger the droplet, the larger the terminal gas velocity, and the larger the gas rate necessary to remove the droplet from the well.

The study assumed that all droplets were spherical and had a maximum Weber number of 30. Further, the investigators assumed the drag coefficient for a sphere (**Figure 1**) lied between Reynolds numbers of 1,000 and 200,000, which on average is a value of 0.44. This resulted in the familiar form of Turner's equation:

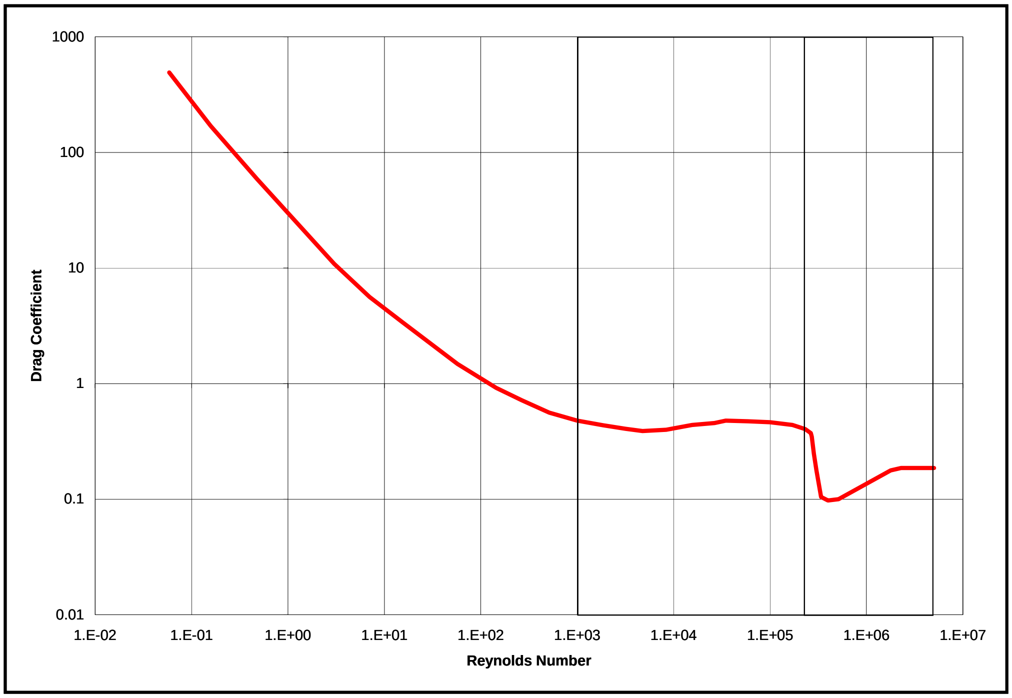
$$v_t = \{17.6\ \sigma^{0.25}(\rho_L - \rho_g)^{0.25}\} / \rho_g^{0.5}$$

When the investigators compared their formulation to the data set, they realized that a nearly 20% upward adjustment of the equation was necessary to match the data. The following is Turner's adjusted equation:

$$v_t = \{20.4\ \sigma^{0.25}(\rho_L - \rho_g)^{0.25}\} / \rho_g^{0.5}$$

In 1991, Steve Coleman, et al published a series of journal articles discussing the various aspects of understanding and predicting gas well load-up[10]. The authors, working the same gas field as Turner, showed that the 20% upward adjustment was unnecessary to match the observed field behavior, at that time. Further, they were able to demonstrate that wellhead conditions (pressure, temperature) controlled the ability to lift fluid from

Figure 1 – Drag Coefficient vs. Reynolds Number for Spherical Elements



the well, that liquid-gas ratios below 22.5 bbl/MMscf had no influence in determining the onset of liquid loading, and that the amount of condensed water increases in the production stream with declining reservoir pressure.

Additional work on the topic was provided by Nosseir, et al, who recognized the deficiencies of Turner's work and developed critical velocity correlations for varying flow regimes, such as the transitional and highly turbulent, which supported Turner's turbulent flow equations[11]. The investigators also deduced that the differences between Turner's and Coleman's work was due to Reynolds number and its impact upon drag coefficient.

Initially, Turner had assumed that valid Reynolds numbers for the field were from 1,000 to 200,000, where in fact the Reynolds numbers actually exceeded 200,000, when calculated by Nosseir. This should have resulted in a smaller drag coefficient (**Figure 1**) and therefore a larger critical velocity, supporting Turner's 20% increase. Nosseir's work also shows that those same wells, during Coleman's study, actually exhibited Reynolds numbers from 1,000 to 200,000, supporting Coleman's use of Turner's equation without the 20% increase.

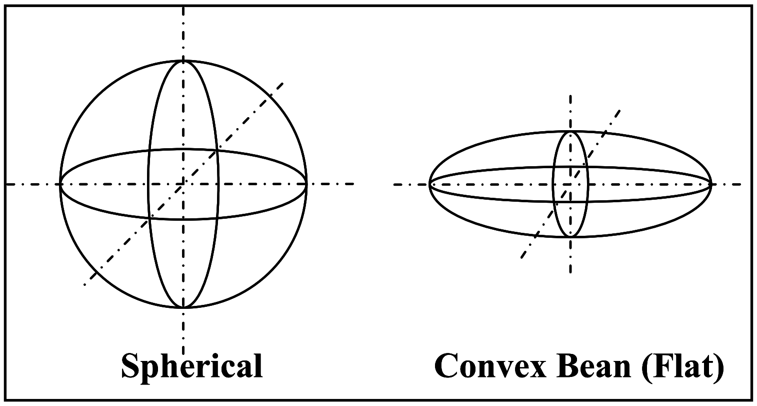
Finally, in 1991, Li et al showed that by varying the shape of the droplet from spherical to disk-shaped (flat), they were able to better match field behavior [12]. **Figure 2** depicts a comparison of spherical and convex-bean (flat) shaped droplets. Through this droplet shape model change, the investigators were able to show that the increase in drag coefficient (1.0) reduced the necessary critical velocity. Their formulation was as follows:

$$v_t = \{8.2\ \sigma^{0.25}(\rho_L - \rho_g)^{0.25}\} / \rho_g^{0.5}$$

For all formulations, terminal velocity can be used to determine the critical rate using the following formulation:

$$q_c = 3.06\ p\ v_t\ A / T\ z$$

Figure 2 – Comparison of Spherical and Bean (Flat) – Shaped Droplets



Methodology

The production behavior of stripper gas wells can best be characterized by many years of relatively stable gas production with moderate decline rates. When the gas rate falls to the point at which liquids cannot be removed from the well, the column of fluid creates an additional backpressure on the well that after a time can lead to severely reduced gas production rates.

In the event that liquid production is not being removed, this work presents a beneficial system of charts for determining if the installation of smaller tubing will benefit a particular well. When sized appropriately, velocity strings can provide the operator with many years of stable production using the natural energy of the reservoir to produce wellbore liquids. These liquid lifting performance charts present a variety of tubing sizes less than three inches. Benchmarking was conducted against a pool of potential candidates, from which one test well was selected for the installation of a permanent small diameter velocity flow string.

This project also surveyed tubing and coiled tubing suppliers in order to obtain performance measures such as the outer diameter, wall thickness, thread type (tubing), relative roughness and tensile strength for compilation into a stand-alone reference. In addition, regional availability of tubing and coiled tubing providers and inventory was determined to estimate the type/size of tubing readily available.

Additionally, literature was reviewed to identify those two-phase correlations that were most applicable to stripper gas wells and small diameter production tubing. This review served as the basis for the construction of liquid lifting performance curves for use in sizing tubing strings for low rate gas wells.

Work Plan

In order to complete this work, ARI formulated a thorough and cost-effective strategy for the creation of well performance charts for use with low-productivity wells. This work was divided into six main tasks, which are discussed in detail below.

Task 1 (Survey and Technical Review) – The project team conducted a provider survey concerning tubing and coiled tubing availability and performance standards. Properties such as outer diameter, wall thickness, thread type (for tubing), relative roughness and tensile strength were requested, while maintaining regional diversity.

Following the provider survey, a detailed literature review was conducted to identify the most technically relevant pressure drop and liquid lifting methodologies for use in the creation of the low-productivity liquid lifting performance charts. Each correlation was reviewed with regard to its applicability with stripper gas production wells and small diameter (> three inches) production tubing.

Task 2 (Liquid Lifting Performance Charts) – Combining the results of the technical review and the tubing/coiled tubing supplier review, liquid lifting performance charts were constructed for a wide variety of wellhead pressure values. Liquid density was also considered in order to account for hydrocarbon liquids and high-density brine.

Task 3 (Test Well Classification and Selection) – The project team worked closely with the operator, Great Lakes Energy Partners, to select candidate test wells that would benefit from the installation of small diameter tubing. Initially, a significantly larger pool of candidates was reviewed on a well-by-well basis to ascertain the applicability of velocity tubing strings. This necessitated the creation of and electronic completion dataset and the organization of a production database for over 300 Cooperstown gas wells.

Next, the liquid lifting charts were reviewed to ascertain whether or not the well is currently producing at a gas rate sufficient to lift liquids. If so, the well was not considered a candidate and would be removed from the test well pool. If the charts indicated small diameter tubing may be beneficial, the well was categorized as a candidate. From this final group of wells, up to three wells with the most promising upside would be selected as the final test wells.

Task 4 (Tubing Replacement) – Once the candidate wells were selected, the operator made the appropriate preparations for installing the small diameter tubing string. Generally this process involved the removal of the existing tubing string and the insertion of the smaller diameter tubing string.

Task 5 (Monitor Production) – Following the insertion of smaller diameter tubing in the gas wells, the project monitored production performance for the duration of the program. Well production volumes were collected for comparison to pre-workover production rates.

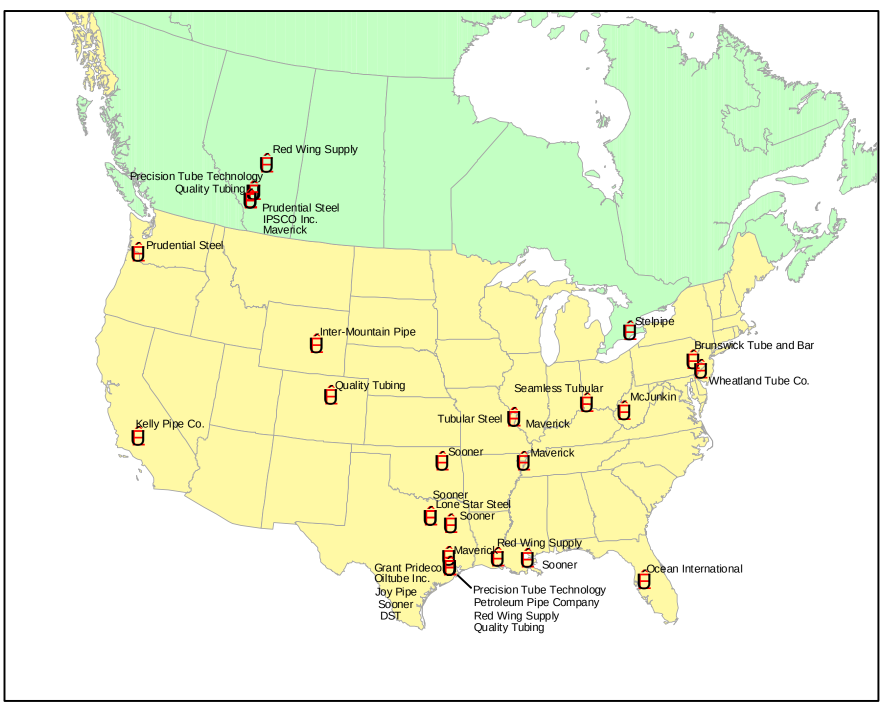
Results and Discussion

Supplier Survey

The project team conducted a provider survey concerning tubing and coiled tubing availability and performance standards. Properties such as outer diameter, wall thickness, thread type (for tubing), relative roughness and tensile strength were requested, while maintaining regional diversity. **Figure 3** depicts the geographic diversity of those who responded to the survey while **Table 1** shows the results of the survey, highlighting the available sizes and grades.

For the responding coiled tubing suppliers and those tubular suppliers that sold made to order (MTO) tubing, all diameters could be fabricated but required lead-time. All suppliers cited American Petroleum Institute (API) standards for their tubing, note the designated grades on **Figure 3**. However, none of the suppliers were able to provide roughness information. **Appendix A** contains contact information for all suppliers contacted.

Figure 3 – Tubing Supplier Survey Respondents



Literature Review

Following the provider survey, a detailed literature review was conducted to identify the most technically relevant pressure drop and liquid lifting formulations for use in the creation of the low-productivity liquid lifting performance charts. Each correlation was reviewed with regard to its applicability with stripper gas production wells and small diameter (> three inches) production tubing. See **Appendix B** for an annotated bibliography.

For pressure drop correlations, Brill and Mukherjee were able to show that a modified Hagedorn and Brown formulation was superior to all other formulations, including those of Duns and Ros, Orkiszewski, and Beggs and Brill[13]. Since the Hagedorn and Brown formulation was developed on data gathered in a 1,500 foot deep well, with tubing diameters of 1, 1-1/4 and 1-1/2 inches[14], it appears to be the formulation for use when the determination of bottomhole pressure data is necessary from surface data. However, when considering the velocity necessary to lift liquids from the wellbore, several authors have shown that wellhead conditions are the limiting factor, when tubing is properly installed to the perforations[2,9,10].

Further, the literature was able to show that pressure drops can be reduced through the use of internally coated or smooth pipes[15,16]. However, scale and/or tool running can degrade this benefit. In addition, Azouz, et al, were able to demonstrate that seamed coiled tubing actually exhibited lower frictional pressure drops than seamless coiled tubing due to turbulence damping[17]. However, interviews with coiled tubing providers indicated that this seam presents an erosion and corrosion base for the gas/liquid/oil[18].

Liquid Lifting Performance Charts

Based on the results of the literature survey conducted during Task 1, ARI had decided to begin the construction of the liquid lifting charts using formulations developed by Turner,

Table 1 – Small Diameter Tubing (< 3 inches) Survey Results by Respondent

			Common Sizes							Variable Sizes				Grade				
Vendor	Location	Coiled	1"	1 1/4"	1 1/2"	2 1/16"	2 3/8"	2 7/8"	3"	<1"	1"-2"	2"-3"	MTO	J	K	L	N	P
McJunkin	Charleston WV																	
Ocean International	Lakeland FL																	
Lonestar Steel	Dallas TX																	
Stelpipe	Welland ON																	
Precision Tube	Houston TX, Red Deer AB																	
Prudential Steel	Longview WA, Calgary AB																	
Quality Tubing	Houston TX, Denver CO, Red Deer AB																	
Oiltube Inc.	Houston TX, Aberdeen UK																	
Grant Prideco	Houston TX																	
Red Wing Supply	Lafayette LA, Houston TX, Edmonton, AB																	
Sooner	Texas Locs, New Orleans LA, Tulsa OK																	
Brunswick Tube & Bar	Allentown PA																	
Petroluem Pipe Co	Houston TX																	
Joy Pipe USA	Houston TX																	
Tubular Steel Inc	St. Louis MO																	
Maverick	St. Louis MO, Conroe TX, Calgary AB, Hickman AR																	
Wheatland Tube	Collingswood NJ																	
Inter-Mountain Pipe Co	Casper WY																	
Steel Group Inc.	Chicago IL																	
DST	Houston TX																	
Kelly Pipe Co	Bakersfield CA																	
IPSCO Inc.	Calgary AB																	
Seamless Tubular	Newport KY																	
Koppel Steel	Ambridge PA																	
Consolidated Pipe & Supply	Birmingham AL																	
Benoit	Houma LA																	

MTO = Maid-to-order

Hubbard, and Dukler[9], without the 20% upward adjustment. Since this formulation was valid for Reynolds Number values between 1,000 and 200,000, it should be very similar to those conditions for low-productivity gas wells. Further, the literature review showed that it would be acceptable to utilize surface conditions (pressure) for the determination of the critical lifting rate. The test site for these liquid lifting performance charts was the Dempseytown quadrangle of Great Lakes Energy Partner's (Great Lakes) Cooperstown gas field, which spans Crawford and Venango counties, Pennsylvania.

For the dataset, Great Lakes supplied paper copies of the completion information for 394 gas production wells and electronic version of all gas and limited water production data. Within this subset of wells, there existed newer wells that still produced under their own energy as well as older wells that produced with rabbits and surfactants. The field is, for the most part, equipped with 1-1/2 inch nominal tubing to the top, or very near, of the perforations. Relevant data for the Cooperstown gas field is shown in **Table 2**.

Table 2 – Study Reservoir Properties

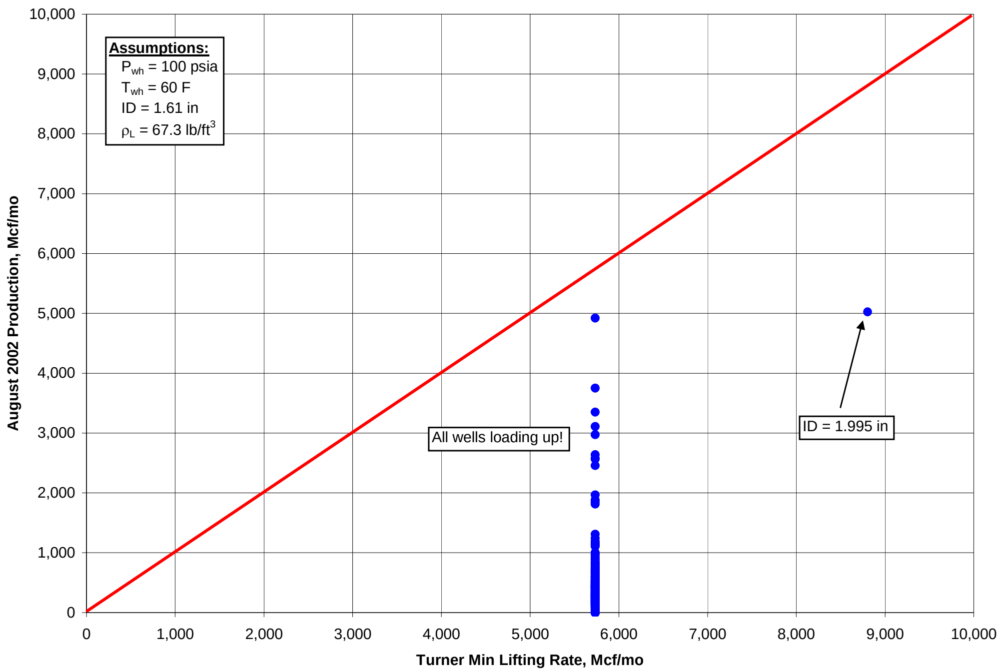
Location: Cooperstown Gas Field, Dempseytown Quadrangle			
Reservoir		Production	
Formation:	Medina	Relevant Date:	Aug-02
Number of Wells:	394	Cumulative Gas:	64.4 Bcf
Average Depth:	5,323 feet	Cumulative Water*:	68 Mbbl
Average Perf Thickness:	61 feet	Average Cum Gas:	163 MMcf
Average Gas Gravity:	0.6	Best Avg. GasYear:	47 MMcf
Average Water Density:	9 ppg		

*132 wells reporting from 1986 to 1997

Figure 4 depicts the August 2002 production rates for the 394 well dataset plotted against Turner's predicted minimum lifting rate. This plot takes the observed field gas production rates, in Mcf per month, and plots them against the expected critical velocity in the same units. The red diagonal depicts the division between observed field rates sufficient to lift fluids (above the red diagonal) and observed field rates insufficient to lift fluids (below the red diagonal). Following the construction of this figure, a conversation with Great Lakes reinforced the fact that a number of these Medina gas wells (+/- 5) were new wells and still producing under their own energy, lifting liquids and should have been plotting above the diagonal line.

Thus, a comparison of Turner's work with Cooperstown gas field production data has shown that the Turner formulation does not correlate with the observed field production behavior. That is, Turner's correlation has understated these well's ability to produce gas and liquids naturally. Conceptually, wells plotting below the red diagonal line should be experiencing liquid load-up behavior and wells plotting above the red diagonal should produce fluids naturally. As shown in **Figure 4**, all wells should be "theoretically" loading-up.

Figure 4 – Critical Rate Determination using Turner's Method



This effect was also witnessed in methane production wells in China by Li, et al[12], where the operators often were required to compute the Turner minimum lifting rate and adjust it downward by as much as 2/3. The authors then presented formulations similar to those of Turner, implementing a bean-shaped (flat) droplet in lieu of the spherical droplets used by Turner. This new formulation, when applied to the production data set, was able to identify approximately ten wells that were able to produce liquids under their own energy (**Figure 5**).

Again, observed gas production rates are plotted against the computed critical lifting rates. However, in this instance, a handful of gas wells plot above the diagonal line, demonstrating their ability to produce reservoir fluids under their own energy and agreeing with field data observations. A comparison of Turner's adjusted and unadjusted formulations for critical rate determination to that of Li's is presented in **Figure 6**, with Great Lakes wellhead operating pressures highlighted within the yellow band.

Using Li's formulation for low pressure wells, liquid lifting curves were generated for a variety of nominal tubing diameters between ¾ and 2 inches using the following water density and gas gravity values:

> **Figure 7** – Water density of 9 ppg and gas gravity of 0.60.
> **Figure 8** – Water density of 9 ppg and gas gravity of 0.65.
> **Figure 9** – Water density of 10 ppg and gas gravity of 0.6.

A Microsoft Excel worksheets has been included to calculate critical rate using Li's formulation (Tubing Charts – Flat Droplet.XLS). A comparison of the variation between these parameters (**Figure 10** for one inch nominal tubing) is presented for review. From **Figure 10**, it is clear that while liquid and gas properties can affect the lifting rate, the bigger impact is a change in the tubing size (as shown on **Figures 7-9**).

Candidate Well Selection

Once the liquid lifting performance charts were constructed, the next step in the process was to select appropriate candidate wells for tubing replacement. The ideal candidate wells were those that would benefit most, from a production standpoint, by down-sizing the production tubing string. In general, the qualities of these wells are:

1. Relative gain in productivity
2. Higher than normal reservoir pressure
3. Competent wellbore condition

This procedure was further complicated by the fact the Medina formation in the Cooperstown gas field is sufficiently deep (>5,000 feet). Thus, the use of conventional "off-the-shelf" one inch nominal steel tubing and plastic (smooth) tubing was implausible since each would pull themselves apart under their own weight.

Figure 5 – Critical Rate Determination using the Li, et al Formulation

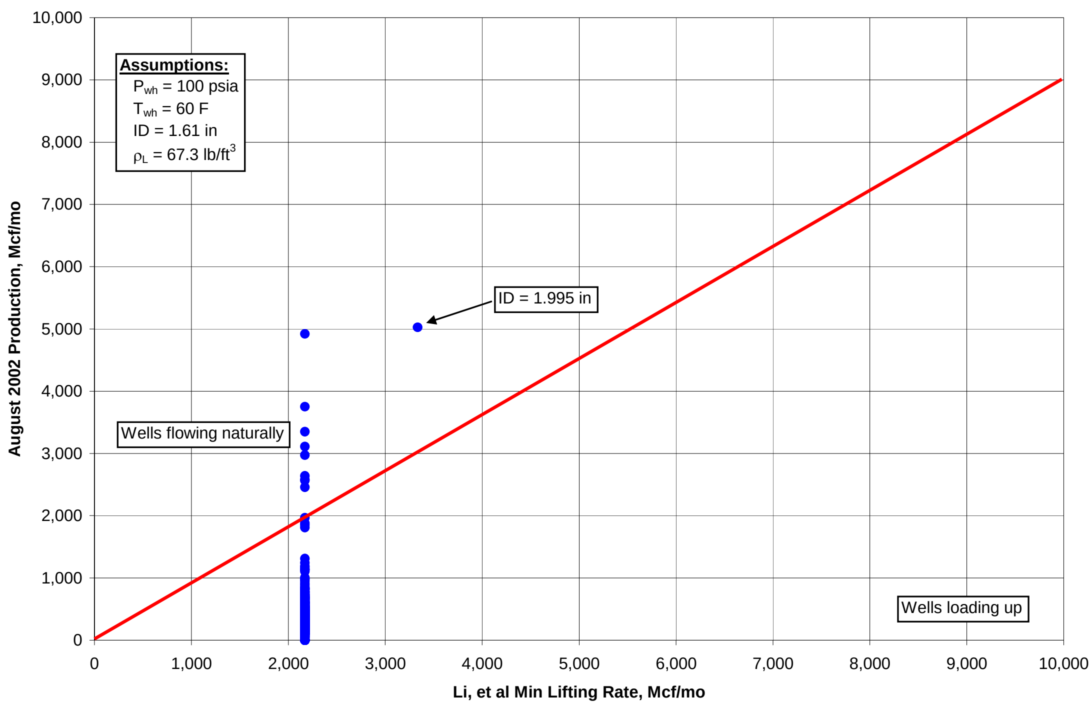


Figure 6 – Comparison of Critical Rate Formulations

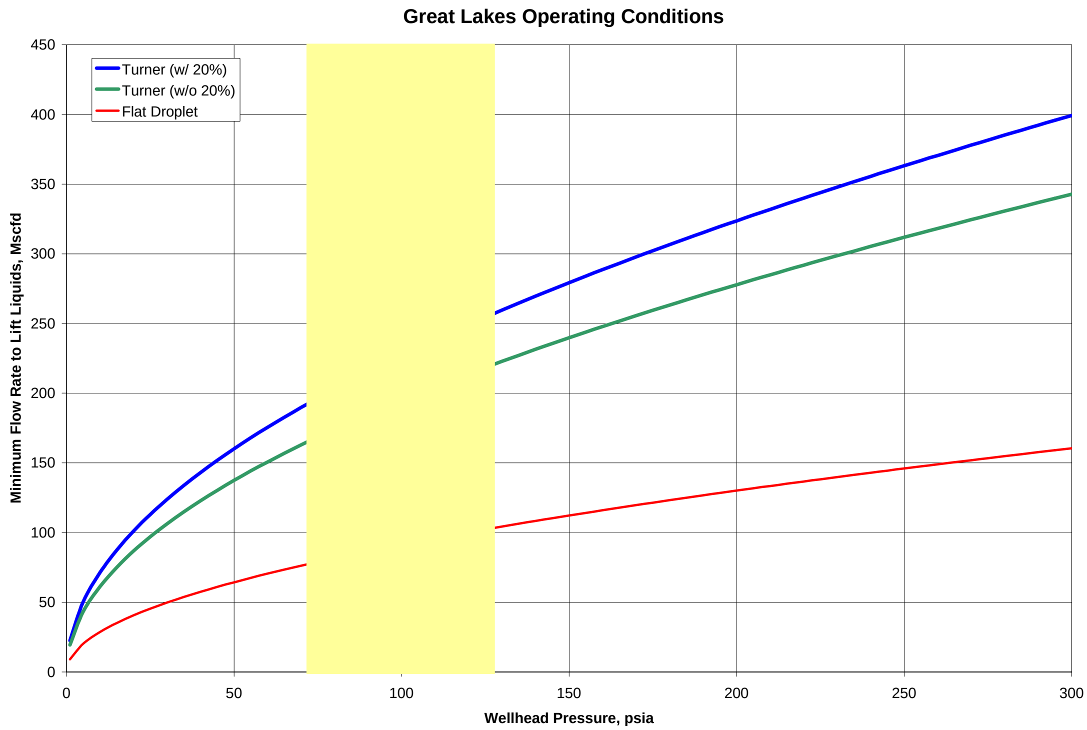


Figure 7

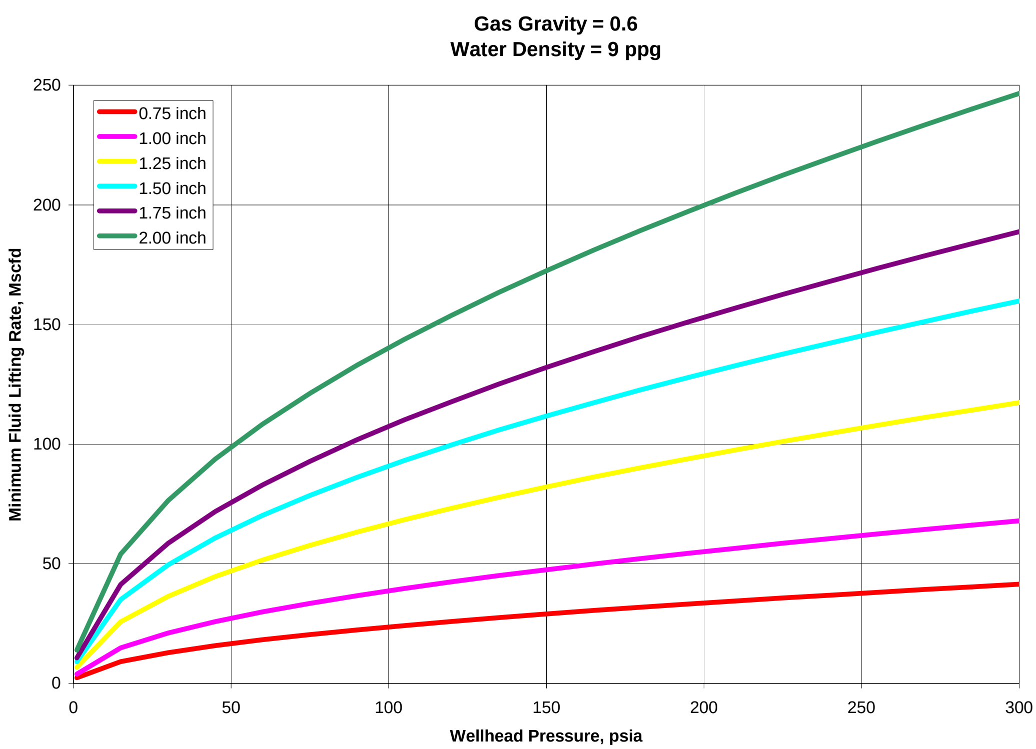


Figure 8

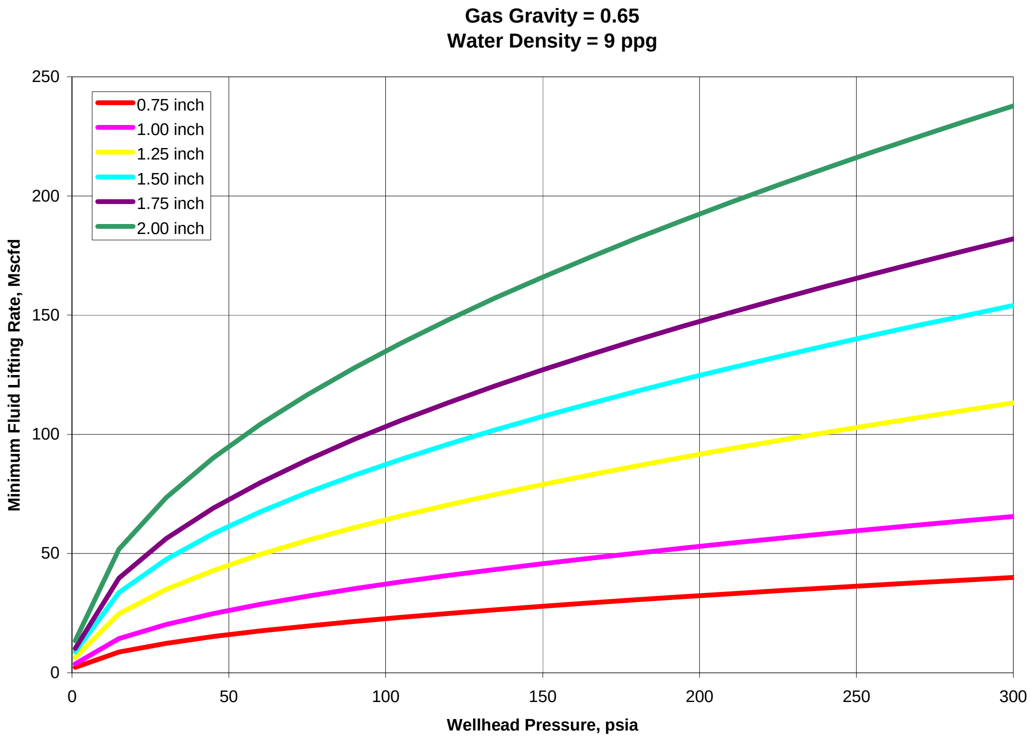


Figure 9

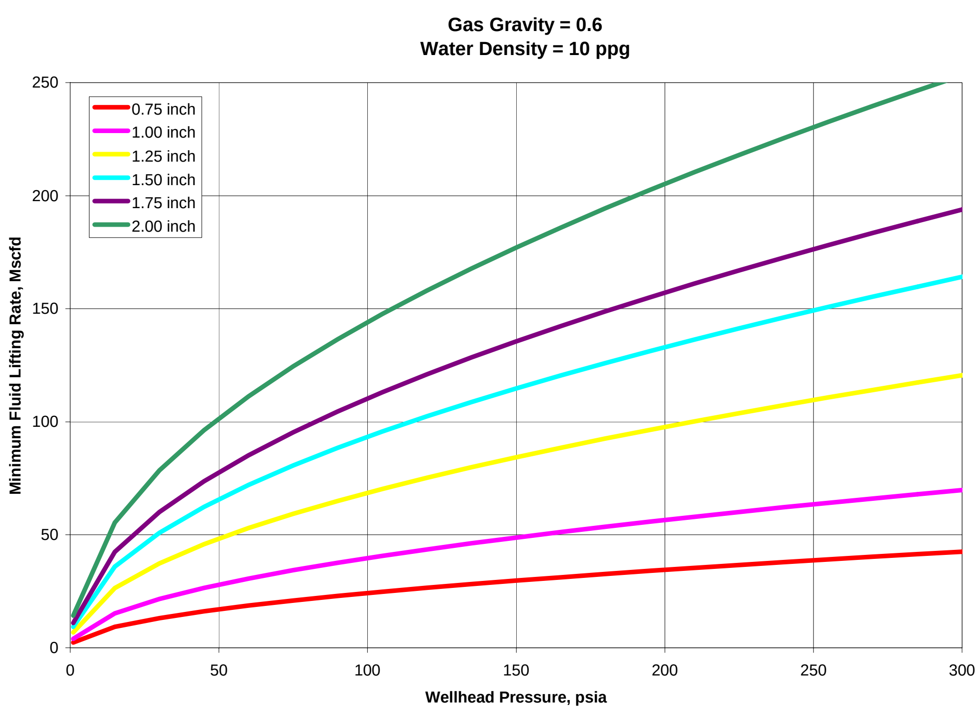
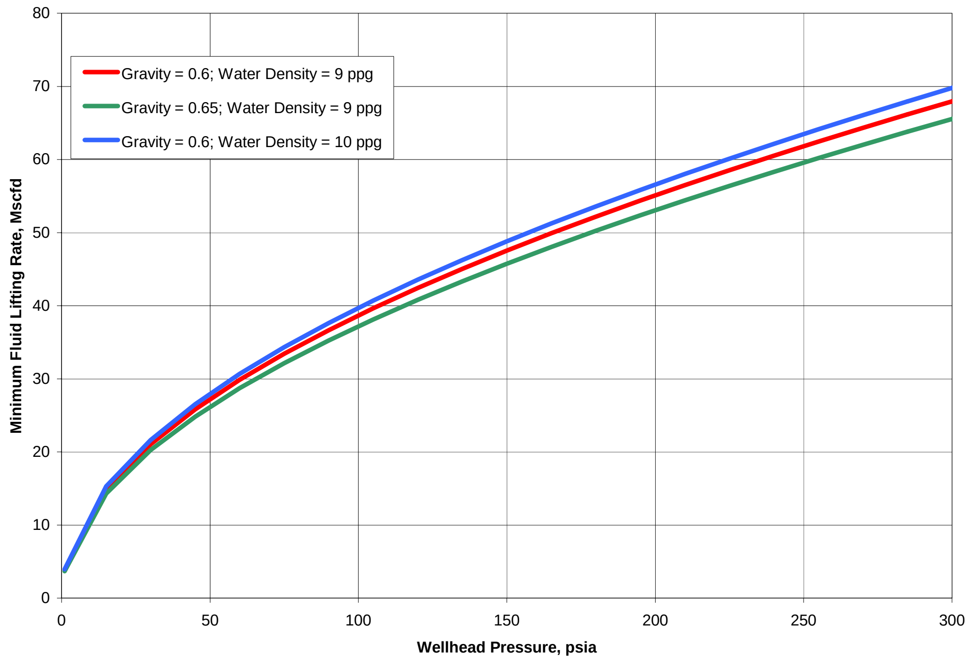


Figure 10 – Impact of Gas Gravity and Liquid Density Variations on Critical Rate (1” Nominal)



So, when Honeywell offered to allow the testing of their new PL Resin *Thermoflex* continuous velocity tubing string in a Great Lakes well, it seemed like a natural fit. Unfortunately, due to cost consideration of implementing this particular type of continuous velocity string and its unproven nature meant that only one candidate well would be tested under this project. **Figure 11** depicts and provides a description of the tubing.

Great Lakes, Advanced Resources International and Honeywell came to an agreement that of the potential test wells in the study area, the Two Mile Run #8 (TMR8) was the ideal candidate. As a newer well, the TMR8 would exhibit higher than average reservoir pressure, which would contribute directly to long-term productivity gain, and a relatively high-quality completion. Typical completion and production parameters for the TMR8 are shown in **Table 3** and a production plot of the well’s natural flow history is shown in **Figure 12.**

Table 3 – Study Well Properties

Location: Two Mile Run Park #8			
Reservoir		Production	
Total Depth:	5,868 feet	First Date of Prod.:	6-Sep-02
Top Perforation:	5,645 feet	Production to:	3-Feb-03
Bottom Perforation:	5,697 feet	Cumulative Gas:	11 MMcf
Average Perf Thickness:	52 feet	Peak Gas Rate:	94 Mcf/D
Tubing String:	5,660', 1-1/2", 2.75 #/ft	Cumulative Water:	165 Bbl
Installed Spring Plunger:	3-Feb-03	Average Water Prod:	1.3 Bpd

Figure 11 – Thermoflex Velocity Tubing String Properties (after Honeywell)

A comparison of Turner's and Li's critical rate formulations to the TMR8's pressure and production history again shows (**Figure 13**) that the Li formulation is superior for this field. While the Turner estimates for critical rate are more than twice the actual production rate for the natural flow history of the well, the flat droplet theory formulation tracks production in a more reasonable manner. Note that the well produced under its own power until early February of 2003, when a spring and plunger were installed in the well. **Figure 14** depicts the production profile of the well prior to installing the velocity tubing string.

Tubing Replacement

Installation of Honeywell's PL Resin *Thermoflex* reinforced flexible tubing was undertaken on December 9, 2003. The installation consisted of pulling the existing 1-1/2 inch tubing and swabbing approximately 80 feet of fluid, which corroborated on earlier Echometer survey indicating a liquid column in the well. This was followed up by rigging up Lenape Resources' spool truck containing the 1 inch flexible tubing (**Figure 15**).

A mule shoe was connected to the tubing end and the velocity string was run in the hole to a depth of approximately 1,812 feet, where a steel tubing splice was installed before

Figure 12 – TMR8 Production History

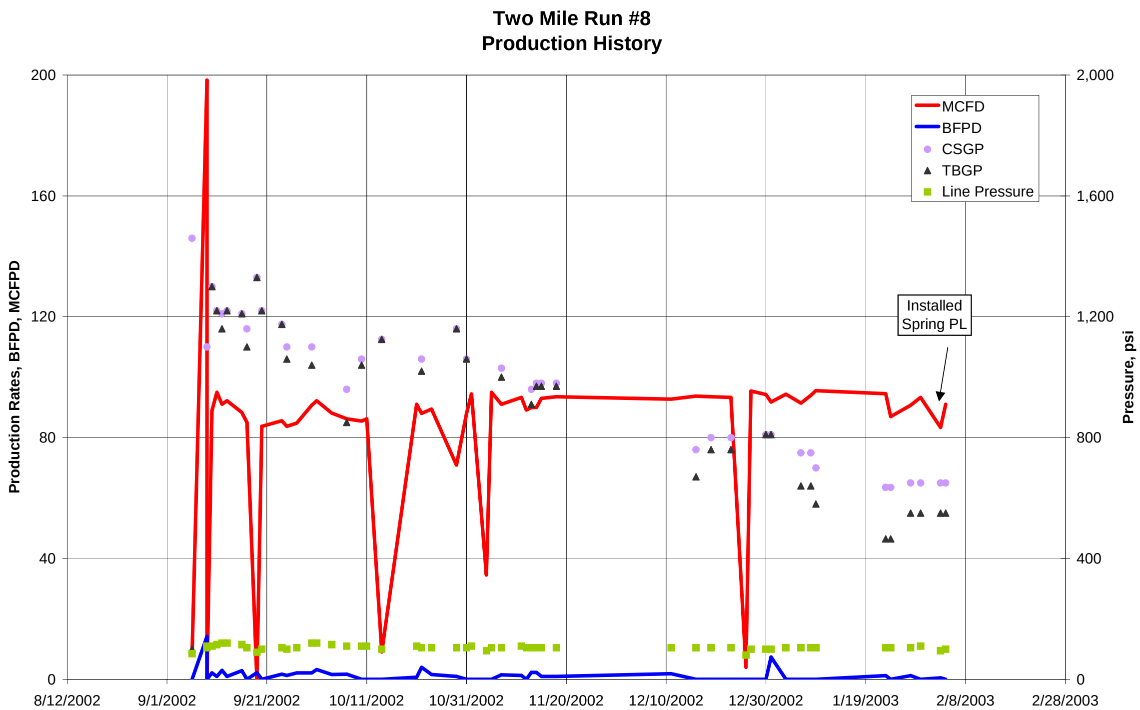


Figure 13 – Turner, Li Critical Rate Formulation Compared to TMR8 Production Rate

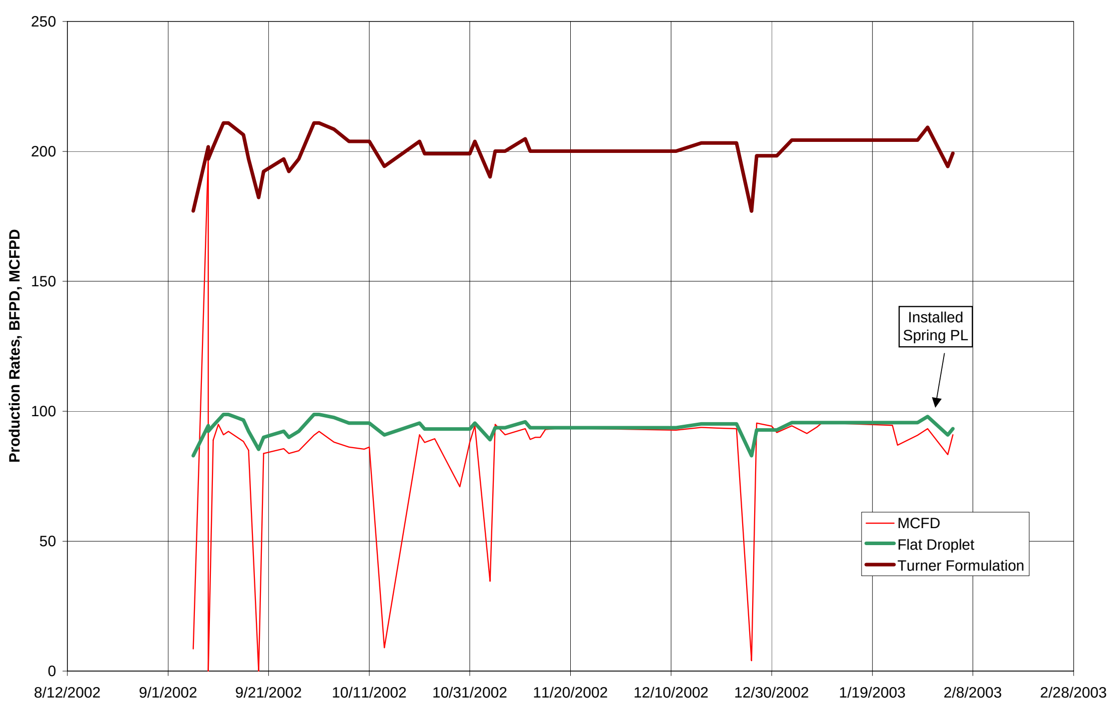


Figure 14 – TMR8 Production Performance Prior to Velocity String Installation

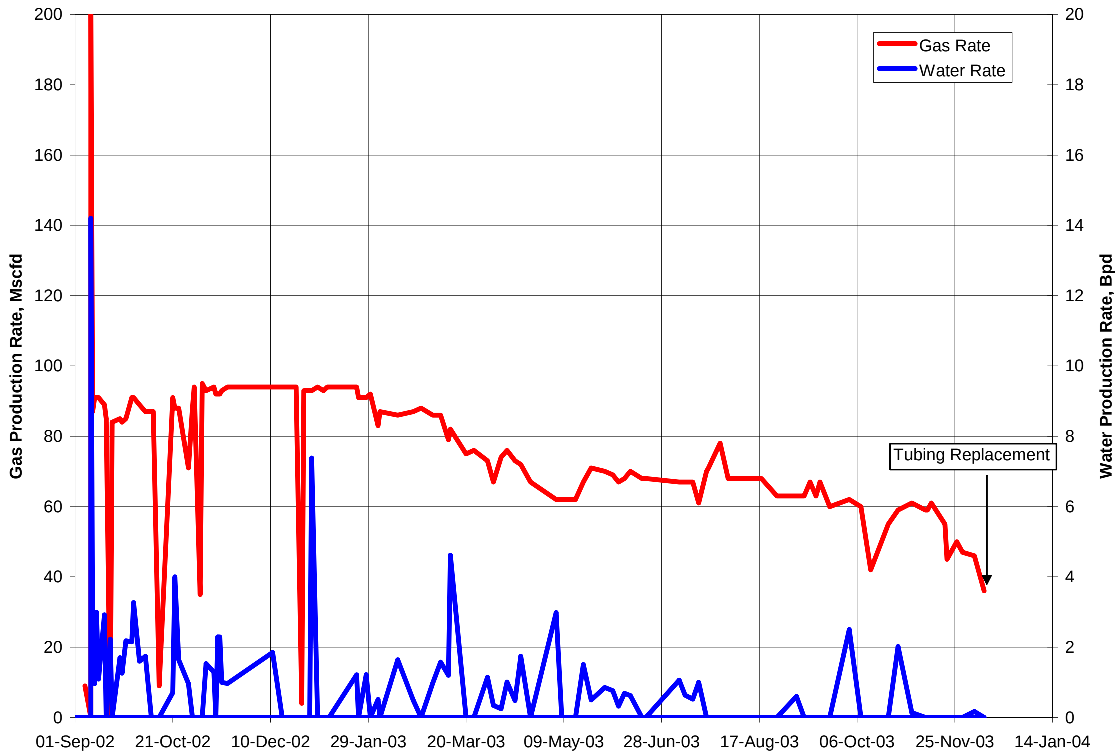


Figure 15 – Rigging-up Flexible Tubing Spool

connecting the two sections of the flexible velocity string (**Figure 16**). Depth was approximated using a sand line and depthometer.

At a depth of approx 2,400 feet, the tubing began an uncontrolled spool-off into the well, whereby an unknown amount of tubing ran into the well (estimated at 200 feet) before the tubing stopped by itself. It is determined that the tubing became detached from the wooden spool, allowing it to spin off of the spool without any breaking action.

So, tubing slips were set at wellhead to secure tubing in the well and the remaining tubing was spooled-off (approximately 2,500 feet) and laid on the ground (**Figure 17**). The tubing was reattached to the end of the wooden spool, re-wound, and then run into the well. From subtraction of the remaining product length on site, the final length of the installed velocity string was determined to be 5,607 feet.

Figure 16 – Tubing Splice

Figure 17 – Laying Down the Velocity String

Production Monitoring

The well was placed on production immediately following the installation of the *Thermoflex* velocity string and the production monitored. **Figures 18 and 19** depict the production and pressure behavior for the TMR8 well.

Anecdotal reports from the operator within the well's first week of velocity tubing production indicated that the well was producing about 50 Mscf/d on a constrained pressure of approximately 135 psig, with the well producing trace amounts of liquid. The constrained condition was then removed, which was expected to result in a gas production rate of about 80 Mcf/d. This gas production rate would be in excess of the well's pre-replacement gas rate.

Once the well began producing in an unrestricted fashion, tubing pressure declined to line pressure (85 psig) and the gas rate was determined to be approximately 60 Mcf/d, with no liquid production. With the decline in tubing pressure, it was noted that the casing pressure was increasing. **Figure 19** exhibits this behavior over a time period of several months. Further, the well, although still producing gas at a reduced rate, was no longer producing reservoir liquids, indicating that 1) the tubing was possibly being choked-back by fluids in the surface lines, or 2) there was a restriction to flow in the wellhead assembly and/or tubing string.

In late January, field operations were conducted in an attempt to remediate the TMR8 production difficulties. First, all surface lines were blown down back to the wellhead, where approximately 5 gallons of water was collected. Subsequent operations included the placement of about 3 gallons of methanol down the tubing to eradicate any hydrate blockage near the surface. Field observation following these procedures indicated nearly an immediate equalization of tubing and casing pressures. However, over the next several weeks of production, the well did not produce liquids nor did the tubing and casing pressures remain near-equalized as the casing pressure again increased over that of the tubing and the well continued to under-perform.

To mitigate the abnormally high casing pressure, the operator installed a pressure regulator on the annulus. This installation helped reduce the casing string pressure by selling-off the annular gas. While this did reduce casing pressure, gas and liquid production was not enhanced.

Recently, the wellhead assembly was broken down and inspected. The operator was able to detect an obstruction within the top of the tubing string, indicating at least partial blockage to gas flow. Plans to remediate and/or remove this blockage to encourage natural production are currently underway and will be based on the nature of blockage present.

Figure 18 – TMR8 Production History

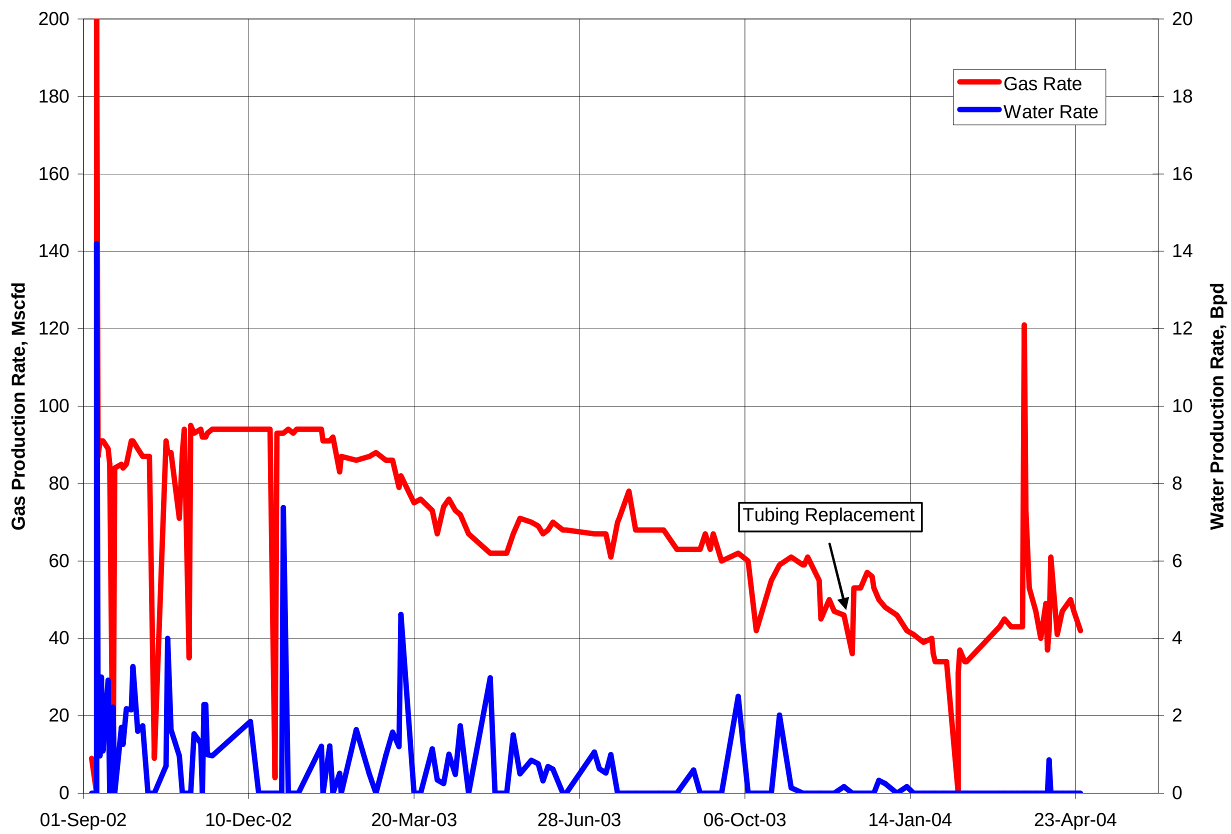
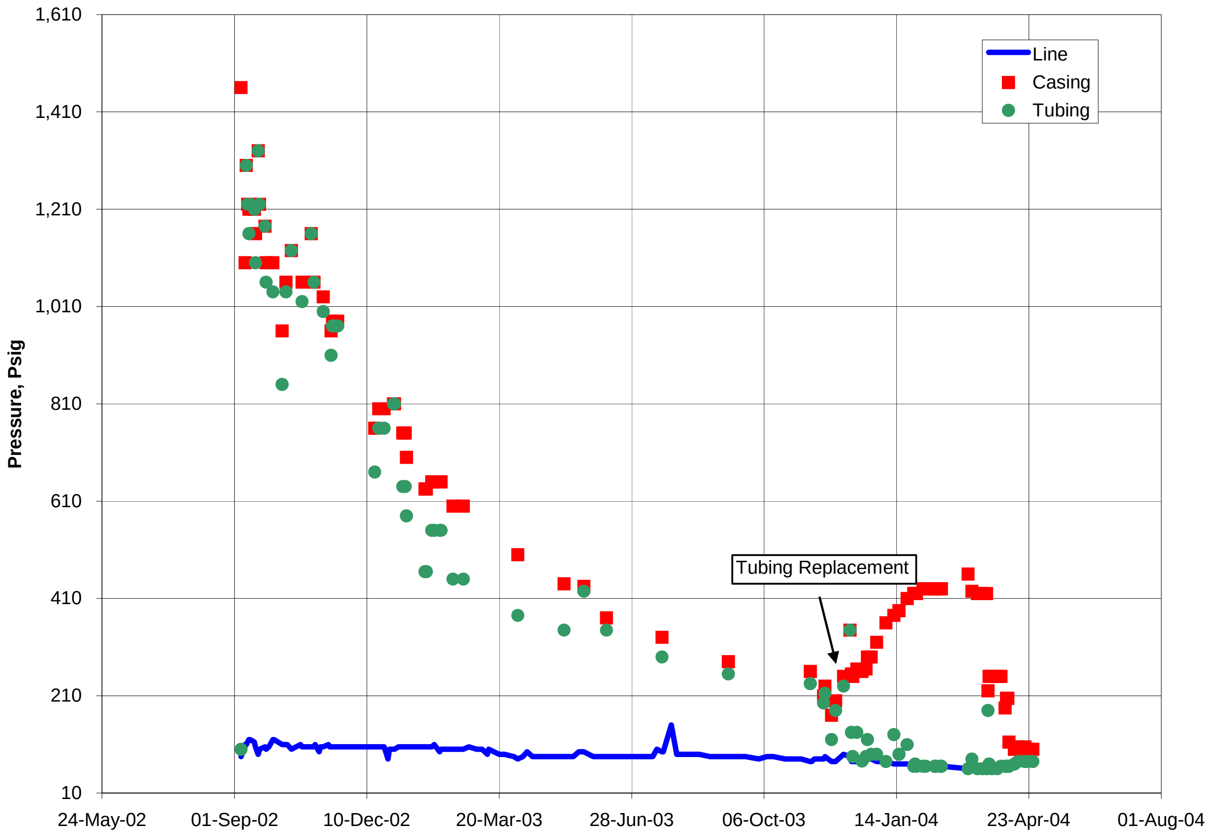


Figure 19 – TMR8 Pressure History



Conclusions

- The project generated liquid lifting performance charts using both Turner's (spherical droplet) and Li's (flat-droplet) formulations. A Microsoft Excel spreadsheet is included for the computation of flat-droplet terminal velocity and critical rates.

- Liquid droplet shape can have a large impact on the terminal rate calculation. Since the drag coefficient is highly dependent upon the particle, calibration of the correct critical rate values to field observations is a necessary step when under taken a similar study.

- The use of surface conditions to determine terminal velocities and then critical rates is an acceptable practice for tubing-completed wells, providing the tubing is set to perforations.

- Tubing providers have on hand, for the most part, tubing sizes in the range of 1 to 3 inches. However, little/no roughness information exists for aid in the determination of friction pressure drop.

- When computation of downhole pressure drop is necessary, formulations by Hagedorn and Brown were found to be the most precise.

- Frictional pressure drop can be greatly reduced through the use of lower-cost, higher-strength plastic (smooth) pipes. These low-friction tubulars are best applied in shallower applications.

- Turbulence damping was also found to reduce friction, suggesting a high-strength seam on the inside of tubulars may be beneficial.

Acknowledgements

Advanced Resources International, Inc. would like to thank Great Lakes Energy Partners, LLC., the project's industry partner, for initially seeing the value of this work and agreeing to provide a suitable test site in the Cooperstown gas field. The Great Lakes staff was always willing to provide time, data and guidance to the project.

Additionally, ARI would like to thank Mr. Peter Han of Honeywell, Inc., Mr. John Holko of Lenape Resources and Mr. Robert Gleim from PolyFlow for donating time, materials and efforts for the installation of the *Thermoflex* velocity string.

Finally, the project team would like to thank the Stripper Well Consortium for seeing merit in this work and providing funding through the United States Department of Energy and the State of New York.

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List of Acronyms, Abbreviations and Symbols

v_t	terminal velocity (ft/sec)
σ	surface tension (dynes/cm)
ρ	density (lb mass/ft^3)
A	flow area of conduit (ft^2)
C_d	drag coefficient (dimensionless)
p	pressure (psia)
q_c	critical rate (MMscf/D)
T	temperature (^oR)
z	gas compressibility factor

List of Conversions

1 dyne/cm = 7.376E-05 lbf/ft

Appendix A

Tubing Supplier Contact List

Name	Address	City	State	Phone	Website	Email
Consolidated Pipe & Supply	1205 Hilltop Pkwy, Birmingham, AL 35204 (Var. Locs.)	Birmingham	AL	205-323-7261		
Smith Fiberglass Products, Inc.	2700 W. 65th St., Little Rock, AR 72209	Little Rock	AR	501-568-4010	www.aosmith.com/sfp	jbrummet@aosmith.com
American Pipe and Tubing Co.	2157 Mowawk, Bakersfield CA 93308	Bakersfield	CA	805-323-0343		
BST Lift Systems	1604 Morse Ave., Ventura CA 93003	Ventura	CA	805-654-1696		kelley@west.net
Bakersfield Pipe & Supply, Inc.	2903 Patton Way, Bakersfield, CA 93308	Bakersfield	CA	805-589-9141		
Equipment & Material Exchange, Inc.	P.O. Box 246, Taft, CA 93268	Taft	CA	805-763-1323	www.usedeq.com	usedeq@usedeq.com
Independent Pipe & Steel, Inc.	P.O. Box 2422, Bakersfield, CA 93303	Bakersfield	CA	805-325-0398		
Keenan O.C.T.	One World Trade Center, #450, Long Beach, CA 90831	Long Beach	CA	562-495-6396		
Kelly Pipe Co.	11700 Bloomfield Ave., Santa Fe Springs, CA 90670	Santa Fe Springs	CA	310-868-0456	www.kellypipe.com	sales@kellypipe.com
Mill Man Steel Inc.	7901 E. Bellview Ave. #215, Englewood, CO 80111 (other locs)	Englewood	CA	1-800-748-2928		
National Pipe & Casing Corp.	9615 S. Norwalk Blvd., #200, Santa Fe Springs, CA 90670	Santa Fe Springs	CA	310-699-9900		
Polyethylene Piping of California, Inc.	7501 Downing Ave., Bakersfield, CA 93308	Bakersfield	CA	805-589-8223		
Seaboard Tubular Products	3333 S. Malt Ave., Los Angeles, CA 90040	Los Angeles	CA	818-330-2888		
State Pipe & Supply Co.	9615 S. Norwalk Blvd., Santa Fe Springs, CA 90670	Santa Fe Springs	CA	310-695-5555		
Sumitomo Corp. Of America	444 S. Flower St., Suite 4800, Los Angeles, CA 90071	Los Angeles	CA	213-627-4783		
Tubular Sales & Equipment Inc.	3003 Fairhaven Dr., Suite C, Bakersfield, CA 93308	Bakersfield	CA	805-328-5510		
Tubesales	2211 Tubeway, Los Angeles, CA 90040 (also TX and LA)	Los Angeles	CA	213-728-9101		
Jensco Pipe & Equipment, Inc.	5524 S. Jasper Way, Aurora CO 80015	Aurora	CO	303-766-9164		
Ipsco Tubulars Inc.	2011 Seventh Ave, Camanche, IA 52730	Camanche	IA	319-242-0000		
IPSCO Tubulars, Inc.	2011 Seventh Ave., Camanche, IA 52730	Camanche	IA	319-242-0000		
Leavitt Tube	1717 W. 115th St., Chicago, IL 60643	Chicago	IL	1-800-532-8488		
Midwest Pipe, Inc.	800 W. High St., Olney, IL 62450	Olney	IL	618-392-0666		
Plexco (Div of Chevron Chemical Co.)	1050 IL Rt. 83, Suite 200, Bensenville, IL 60106	Bensenville	IL	630-350-3728	www.plexco.com	info@plexco.com
Cresline Plastic Pipe	955 Diamond Ave. Evansville, IN 47711	Evansville	IN	812-428-9300		
Kramer Oilfield Service	P.O. Box 646, Wellsville, KS 66092	Wellsville	KS	913-883-4871		
RAS Oilfield Supplies, Inc.	R R 3, Box 15, Eureka, KS	Eureka	KS	316-583-7496		
Wichita Valve & Fitting Co.	326 Wabash, Suite 1, Wichita, KS 67214	Wichita	KS	316-262-6111		
BWI Pipe & Supply	616 S. Columbia St., Albany, KY 42602	Albany	KY	606-387-6411		
Glasgow Well Supply	251 Kentucky St., Glasgow, KY 42141-1650	Glasgow	KY	502-651-6101		
Newport Steel Corp.	9th & Lowell Sts., Newport, KY 41072	Newport	KY	606-292-6804		
Aztec Pipe Inc.	920 W. Pinhook Road Ste 240, Lafayette, LA 70503	Lafayette	LA	318-233-4990		
Blowout Tools Inc (Coiled)	P.O. Box 32121, Lafayette, LA 70593	Lafayette	LA	318-264-1098		
Ferguson Pipe & Supply	305 Friedrichs Ave., Metairie, LA 70005	Metairie	LA	504-833-0633		
51 Oil Corp.	3227 Hwy 90 E., Broussard, LA 70518	Broussard	LA	318-234-2264		
Martin Oil Country Tubular Inc.	4209 Cameron St., Lafayette, LA 70506	Lafayette	LA	318-233-7036		
Midland Pipe Corp.	3636 N. Causeway Blvd., #300, Metairie, LA 70002	Metairie	LA	504-837-5766		
Norman & Associates (Macaroni)	613 N. 5th St., West Monroe, LA 71291	West Monroe	LA	318-325-4315		
Pellerin's Tubular Service Inc.	Hwy 14 W, New Iberia, LA 70560	New Iberia	LA	318-365-1033		
Tube-Alloy Corp.	3106 Grand Cailou Rd., Houma, LA 70363	Houma	LA	504-876-2886		

Name	Address	City	State	Phone	Website	Email
Pipe & Piling Supplies (USA)	244 Kincheloe Road, Kincheloe, MI 49788	Kincheloe	MI	906-495-2245	www.pipe_piling.com	
Standard Stanchion & Pipe Supply	2149 Fyke Dr., Milford, MI 48381	Milford	MI	248-684-4100		
Tubular Steel, Inc.	1031 Executive Pkwy., St. Louis, MO 63141	St. Louis	MO	314-851-9200	www.tubularsteel.com	info@tubularsteel.com
Trident Steel Corp.	1000 Des Peres Rd., Suite 116, St. Louis, MO 63131	St. Louis	MO	314-822-0500		
St. Louis Pipe & Supply	16321 Westwoods Bus. Park, Ellisville, MO 63021	Ellisville	MO	314-391-2500		
Victor Pipe & Steel, Inc.	Hwy. 79 N, Winfield, MO 63389	Winfield	MO	1-800-264-6315		
Lockett Pipe Company, Inc.	2812 First Ave. N., Suite 401, Billings, MT 59101	Billings	MT	1-800-927-4731	www.mcn.net/~lockett	lockett@mcn.net
Redlon and Johnson	200 Gay St., Manchester, NH 03103 (various locations in ME)	Manchester	NH	603-669-8100		
Hoke, Inc.	One Tenakill Park, Cresskill, NJ 07626	Cresskill	NJ	201-568-9100		
Caprock Pipe and Supply	P.O Box 1535, Lovington, NM 88260	Lovington	NM	505-396-5881		
Milford Pipe and Supply, Inc.	1224 W. Broadway Pl, Hobbs, NM 88240 (also Odessa TX)	Hobbs	NM	505-397-6400		
AST USA Inc.	10 Bank St., White Plains NY, 10606	White Plains	NY	914-428-6010		
LTV Steel Tubular Products Co.	1315 Albert St., Youngstown, OH 44501	Youngstown	OH	1-800-445-7473		
RMI Titanium Company	1000 Warren Ave., Niles, OH 44446	Niles	OH	330-544-7633		
The Swagelok Companies	31400 Aurora Road, Solon, OH 44139 (other locations)	Solon	OH	216-349-5934	www.swagelok.com	
Red Man Pipe & Supply Co.	8023 E. 63rd Pl., Suite 800, Tulsa OK 74133	Tulsa	OK	918-250-8541		
Performance Pipe Corp.	513 Boren Blvd., Seminole, OK 74868	Seminole	OK	405-382-3522		
Pipe Source Co.	304 Callahan, Muskogee, OK 74402	Muskogee	OK	918-682-0940		
Steel Service Oilfield Tubular	4200 E. Skelly Dr., Suite 620, Tulsa, OK 74135	Tulsa	OK	918-495-1420		
Arvine Pipe & Supply Co., Inc.	1708 Topeka Dr., Norman, OK 73069	Norman	OK	405-364-1950		
Bethlehem Pipe Sales Inc.	2651 E. 21st St., Suite 501, Tulsa, OK 74114	Tulsa	OK	918-745-2212		
C & Y Casing Pulling, Inc.	250 S. Eastland Dr., Duncan, OK 73534	Duncan	OK	405-255-4453		
Erlanger Tubular Corp.	5610 Bird Creek Ave., Catoosa, OK 74015	Catoosa	OK	918-266-3970		
Keefer Oil Co.	131 E. Cottage, Ada, OK 74820	Ada	OK	405-332-0395		
Lillard Pipe & Supply, Inc.	177 S. Benson Park Rd., Shawnee, OK 74801	Shawnee	OK	405-273-6200		
Spartan Steel Products	1032 W. Main, Suite 200, Duncan, OK 73533	Duncan	OK	1-888-373-7675		ssproducing@aol.com
Vantuyl & Fairbank Inc.	394 Station St., Petrolia, ON N0N 1R0, Canada	Petrolia	ON	519-882-0230		
Armco Inc.	P.O. Box 11, Sharon PA	Sharon	PA	412-347-7771		
Crispin-Multiplex	600 Fowler Ave, Berwick, PA 18603	Berwick	PA	1-800-247-8258		
Damascus Bishop Tube Co., Inc.	795 Reynolds Industrial Park Rd. Greenville, PA 16125	Greenville	PA	724-646-1500		
Energy Products Co.	P.O. Box 809, McMurray, PA 15317	McMurray	PA	412-942-1000		energyprod@earthlink.net
Hajoca Corp.	127 Coulter Ave., Ardmore, PA 19003	Ardmore	PA	610-649-1430		
Interstate Pipe & Supply Co	P.O. Box 215, Clintonville, PA 16372	Clintonville	PA	814-385-6633		
Koppel Steel Corp.	PO Box 750, Beaver Falls, PA 15010	Beaver Falls	PA	1-800-992-3702	www.koppelsteel.com	sales@koppelsteel.com
Petroleum Pipe & Supply Co.	Industry Way, Carnegie, PA 15106	Carnegie	PA	412-279-7710		
Sandvik Steel Co.	982 Griffin Pind Rd., Scranton, PA 18411	Scranton	PA	717-587-5191		
Foster, L. B., Co.	415 Holiday Dr., Pittsburgh, PA 15220 (TX and GA also)	Pittsburgh	PA	412-928-3400	www.lbfoster.com	dseybert@ix.netcom.com
Dresser Oil Tools	4949 Joseph Hardin Dr., Dallas, TX 75236	Dallas	TX	214-331-3313		
Joy Pipe USA, LLC.	16225 Park 10 Pl. Dr., #400, Houston, TX 77084	Houston	TX	281-579-0388	www.joypipe.com	info@joypipe.com
Maverick Tube Corp.	15333 JFK Blvd., Suite 160, Houston, TX 77032	Houston	TX	281-442-1093		
Phillips Driscopipe	2929 N. Central Expwy., #300, Richardson TX 75083	Richardson	TX	214-783-2666	www.phillips66.com	
Pipe & Tube Supplies Inc.	4201 W. Orange St, Pearland, TX 77581	Pearland	TX	281-485-3133		
Van Leeuwen Pipe and Tube Inc.	15333 Hempstead Road, Houston, TX 77404 (various locations)	Houston	TX	713-466-9966		
Star Fiber Glass Systems, Inc.	2425 S.W. 36th St., San Antonio, TX 78237	San Antonio	TX	210-434-5043	www.onr.com/star/	
Abbot's Oilfield Supply, Inc.	1151 W. Second, Odessa, TX 79763	Odessa	TX	915-337-7335		
Adler Pipe Co.	7414 Leopard, Corpus Christi, TX 78409	Corpus Christi	TX	512-289-6607		
Alloy Tubular Products Co.	P.O. Box 910, Channelview, TX 77530	Channelview	TX	713-457-1280		
Algoma Tube Corp.	800 Gessner, Suite 290, Houston, TX 77024	Houston	TX	713-465-8998	www.algoma.com	

Name	Address	City	State	Phone	Website	Email
Bays Oilfield Supply Co. Inc.	P.O. Box 753499, Dallas, TX 75275	Dallas	TX	405-235-2297		
Bellville Tube Corp.	P.O. Box 220, Bellville, TX 77418	Bellville	TX	409-865-9111		
Bob Beck Tubulars	P.O. Box 9726, Midland, TX 79708	Midland	TX	915-682-3131		
Bourland & Leverich Supply Inc.	P.O. Box 778, Pampa, TX 791065 (various locs, TX, OK, CO)	Pampa	TX	806-665-0061		
BTS Limited Inc.	13164 Memorial Dr. #120, Houston TX, 77079	Houston	TX	713-461-6760		rbaron3810@aol.com
Bunker Steel Corp.	800 Bering Dr. Suite 340, Houston, TX 77057	Houston	TX	713-789-8750		
Carbide Blast Joints, Inc.	21283 Foster Road, Spring TX 77388	Spring	TX	713-353-6750		
Centron International, Inc.	600 FM 1195 S., Mineral Wells, TX 76068	Houston	TX	940-325-1341		centron@eastland.net
Champions Pipe & Supply Inc.	952 Echo Lane, Suite 200, Houston, TX 77024	Houston	TX	713-468-6555		
Chichasaw Distributors Inc.	800 Bering Dr. Suite 330, Houston, TX 77057	Houston	TX	713-974-2905		chickasaw@attmail.com
Cinco Pipe & Supply Inc.	1601 Welch, Houston, TX 77006	Houston	TX	713-658-0700		
Colorado Tubulars Company	2121 W. Spring Creek Pkwy, Suite 232, Plano, TX 75023	Plano	TX	972-491-5590		
Conestoga Supply Corp.	15915 Katy Frwy, Suite 600, Houston TX 77094	Houston	TX	281-579-8811		
Cressman Tubular Products Corp.	3939 Belt Line Rd., #360-20, Dallas, TX 75244	Dallas	TX	214-352-5252		
CSI Steel & Supply Co.	South Houston, TX 77587	South Houston	TX	281-997-8340		
East & Associates, Inc.	P.O. Box 691566, Houston, TX 77269	Houston	TX	713-580-3363		
Fiberglass Systems LP	2425 S. W. 36th St., San Antonio, TX 78237	San Antonio	TX	210-434-5043		
Gulf Coast Pipe, Inx.	P.O. Box 1335, Pearland, TX 77588	Pearland	TX	281-992-6700		
Holiday Pipe Co.	P.O Box 6529, Pasadena, TX 77506	Pasadena	TX	713-475-9044		
Klockner Steel Trade	1800 St. James Pl., Suite 603, Houston, TX 77056	Houston	TX	713-627-7310		
Kurvers Inc.	1500 S. Dairy Ashford, Suite 444, Houston, TX 77077	Houston	TX	281-496-3375		kurversusa@kurvers.com
Kyser Co.	2019 McKenzie, Suite 150, Carrollton, TX 75006 (other TX Locs)	Carrollton	TX	972-488-1811		
Marubeni Tubulars, Inc.	7500 San Felipe, Suite 950, Houston TX 77063	Houston	TX	713-780-5600		
Master Tubulars, Inc.	24 Smith Rd., Suite 250, Midland, TX 79705	Midland	TX	915-682-8996		
Maverick Tube Corp.	15333 JFK Blvd., Suite 160, Houston, TX 77032	Houston	TX	281-442-1093		
MC Tubular Products, Inc.	580 Westlake Park Blvd., #1610, Houston TX 77079	Houston	TX	281-870-1212		
McEvoy, Mike Companies, Inc.	1800 Augusta, Suite 212, Houston, TX 77057	Houston	TX	713-783-0517		
Mitsui Tubular Products Inc.	1000 Louisiana, Suite 5700, Houston, TX 77002	Houston	TX	713-236-6160		
Moore, Wayne Pipe & Supply Co.	Anson Hwy., Abilene, TX 79604	Abilene	TX	915-673-5732		
M W Commodities	20214 Braidwood Dr. Ste 160, Katy, TX 77450	Katy	TX	281-492-1415		
Padre Tubular Inc.	711 N. Carancahua, #1102, Corpus Christi, TX 78475	Corpus Christi	TX	512-887-0861		
PK Pipe & Tubing Inc.	P.O. Box 2470, Uvalde, TX 78802	Uvalde	TX	830-278-6606		
Posey Pipe & Equipment, Inc.	P.O. Box 10172, Midland, TX 79702	Midland	TX	915-685-3447		
Pyramid Tubular Products, Inc.	2 Northpoint Dr. Suite 610, Houston, TX 77060	Houston	TX	281-405-8090		
Reliable Tubular & Supply, Inc.	2601 E. I-20, Midland, TX 79704	Midland	TX	915-684-8488		
Sabine Pipe & Supply Co. Inc.	1900 Industrial Blvd., Kilgore, TX 75662	Kilgore	TX	903-984-3094		
SIM-TEX, Inc.	12605 E. Frwy., Suite 103, Houston, TX 77015	Houston	TX	713-450-3940		
S.I.W. Pipe & Supply, Inc.	6149 W. 10th, Odessa, TX 79769	Odessa	TX	915-381-0501		
South Star Oil Field Equipment	410 W. First, Odessa, TX 79760	Odessa	TX	915-335-0602		
S & S Pipe & Supply Co.	3112 Pleasant Green, Victoria, TX 77901	Victoria	TX	512-573-4322		
System Pipe & Supply Inc.	6211 W. N.W. Hwy., Suite 253D, Dallas, TX 75225	Dallas	TX	214-692-0100		
Texas Tubular Products	FM 250, P.O. Box 0388, Lonestar, TX 75668	Lonestar	TX	903-639-2511		
Tex-Isle Supply Inc.	10830 Old Katy Rd., Houston, TX 77024	Houston	TX	713-461-1012		
Triad Pipe & Steel Company	9225 Katy Frwy., Suite 102, Houston, TX 77024	Houston	TX	713-467-5242		
Tubular Corp. of America	363 N. Sam Houston Pkwy. E., Suite 1660, Houston TX 77060	Houston	TX	281-774-3500		

Name	Address	City	State	Phone	Website	Email
Vallourec & Mannessmann Tubes Corp.	1990 Post Oak Blvd., Suite 1400, Houston, TX 77056	Houston	TX	713-479-3200		
Vallourec, Inc.	1990 Post Oak Blvd., Suite 710, Houston, TX 77056	Houston	TX	713-961-2468		valloure@vallourec_inc.com
Vantage Tubulars, Inc.	701 N. Post Oak Road, Suite 220, Houston, TX 77024	Houston	TX	713-683-7232		
Wilson Industries, Inc.	1301 Conti, Houston TX 77002	Houston	TX	713-237-3700		
American Protectors, Inc.	3407 Dalworth, Arlington, TX 76011	Arlington	TX	817-649-8843		
Ameron International Fiberglass Pipe Div.	5300 Hollister, Suite 111, Houston, TX 77040	Houston	TX	713-690-7777		
Cinco Pipe & Supply Inc.	1601 Welch, Houston, TX 77006	Houston	TX	713-658-0700		cpipe@swbell.net
Davis, Paul Pipe & Supply	P.O. Box 6112, Abilene, TX 79608	Abilene	TX	915-698-2293		
Vinson Supply Company	Two Northpoint, Suite 500, Houston, TX 77060	Houston	TX	1-800-877-2636	www.tubulars.com	
Wing Pipe & Supply	6440 N. Central Expwy., LB6, -#300, Dallas, TX 75206	Dallas	TX	214-750-8888		
Dependable Pipe and Supply Co.	Rt. 33 E, Box 606, Spencer WV 25276	Spencer	WV	304-927-1660		
Bock Specialties Inc.	P.O. Box 2880, Mills, WY 82644	Mills	WY	307-237-2207		
Grinnell Supply Sales Co.	Various Locations	Various Locations				
Marmon/Keystone Corporation	Various Locations, USA and Canada	Various Locations		724-283-3000	www.marmonkeystone.com	
The Panila Group of Companies, Inc.	1165 J 44 Ave. S.E., Calgary, AB T2G 4X4, Canada	Calgary	AB	403-243-7930		
Prudential Steel, Ltd.	P.O. Box 1510, Calgary, AB T2P 2L6, Canada	Calgary	AB	403-267-0300	www.prudentialsteel.com	info@prudentialsteel.com
Oil Pro Oilfield Production Equip. LTD.	1230, 630 6th Ave. S.W., Calgary, AB T2P 2Y5, Canada	Calgary	AB	403-215-3373		

Appendix B

Annotated Literature Review

Duggan, J., "Estimating Flow Rates Required to Keep Gas Wells Unloaded," **SPE No. 32**, Journal of Petroleum Technology, December 1961, pp. 1173-1176.

Created a chart to showing the minimum flow rate required to keep condensate gas wells unloaded at a linear velocity of 5 ft/sec (wellhead).

Observed from field data that a wellhead velocity of about 5 ft/sec is necessary to keep condensate wells unloaded.

With available data, a negligible effect was seen between unloading wellhead velocities of lean and rich condensates.

v = q*T / (5.898*A*ptf)
where, v = linear velocity, ft/sec
q = well volume, mscfd
ptf = wellhead flowing pressure, psia
A = cross-sectional area, ft2
T = WHT/520 Rankin, dimensionless

A velocity of 5 ft/sec may not be necessary to keep a (condensate) well on production if the wellhead flowing pressure is sufficiently above the delivery pressure. Some unpublished tests indicate that a well can sustain production in small diameter tubing at velocities as low as 3 ft/sec if the unloading flowing wellhead pressure is at least 300 psig above the line pressure.

Included data table of condensate well tests.

Gaither, O., Winkler, H., Kirkpatrick, C., "Single- and Two-Phase Flow in Small Vertical Conduits Including Annular Configurations," **SPE No. 441**, Presented at the 37th Annual SPE Fall Meeting, October 7-10, 1962, Los Angeles, CA.

Showed that certain existing two-phase fluid pressure drop correlations, when applied to the gas water mixture investigated in this study, cannot be extended to small conduits.

Darcy friction = 4*fanning friction,

Experimentally derived two-phase (gas-water) data tables for 1, 1.25 and 1 X 2 in tubing are presented.

New correlating parameters are given which, when properly applied, should prove valid for most fluid mixture systems.

Hagedorn, A., Brown, K., "Experimental Study of Pressure Gradients Occurring During Two-Phase Flow in Small Diameter Vertical Conduits," **SPE No. 940**,

Presented at the 39th Annual SPE Fall Meeting, October 11-14, 1964, Houston, TX.

Studied the pressure gradients occurring during continuous two-phase flow through 1, 1.25 and 1.5 inch (nominal) diameter tubing over a 1,500 feet vertical distance.

In contrast to single-phase flow, the pressure losses in multiphase flow do not always increase with a decrease in the size of the conduit or an increase in the production rate. This is attributed to the presence of the gas phase that tends to slip by the liquid phase without actually contributing to its lift.

Relative roughness is accounted for, although the effect for two-phase flow is very small (referenced another author).

Included dimensionless correlations.

Orkiszewski, J., "Predicting Two-Phase Pressure Drops in Vertical Pipe," **SPE No. 1546**, Presented at the 41st Annual SPE Fall Meeting, October 2-5, 1966, Dallas, TX.

Data from 22 Venezuelan heavy oil wells presented and used in addition to data provided by Poettmann and Carpenter, Baxendell and Thomas, Fancher and Brown, and Hagendom and Brown to yield a total of 148 data points for the study.

Uses a modified Griffin-Wallis correlation with a standard deviation of about 10% (error in pressure drop computation).

Method outperformed Duns and Ros and Hagedorn and Brown methods.

Appendix A contains the description of the model.

Appendix D contains an example calculation.

Turner, R., Hubbard, M., Dukler, A., "Analysis and Prediction of Minimum Flow Rates for the Continuous Removal of Liquids from Gas Wells," **SPE No. 2198**, Presented at the 43rd Annual SPE Fall Meeting, September 29 - October 2, 1968, Houston, TX.

Identifies the existence of two proposed physical models for the removal of gas well liquids: (1) liquid film movement along the walls of the pipe and (2) liquid droplets entrained in the high velocity gas core.

The film model is outlined in Appendix A.

The larger the drop, the higher the gas flow rate necessary to remove it.

vt = 17.6*(surf tens)^ .25*(rho,l - rho,g)^.25 / rho,^0.5
where, vt = terminal velocity of free falling particle, ft/sec surf tens = surface tension, dynes/cm
rho,g = gas density, Ibm/cu ft
rho,l = liquid density, Ibm/cu ft

A 20% upward adjustment was made to correct the data.

Wellhead conditions tended to control the study and the droplet removal was found to be the limiting liquid removal mechanism.

Surface tension measurements are 20 dynes/cm for condensate and 60 dynes/cm for water while density values were 45 Ibm/cu ft for condensate and 67 Ibm/cu ft for water, respectively.

qg = 3.06*p*v*A/(T*z)
where, qg = gas rate, MMscfd
p = pressure, psia
v = velocity, ft/sec
A = cross sectional area, sq ft T =temperature, R
z = gas deviation factor

Determination of minimum necessary flow rates by the determination of the flow rate that will remove the largest drops of liquid, calculated using particle and drop break-up mechanics. **However, the equation was adjusted upward by 20% to match data.**

The gas-liquid ratio does not influence the minimum lifting velocity in the observed ranges of liquid production up to 130 bbl/MMscf.

Tek, M., Gould, T., Katz, D., "Steady and Unsteady-State Lifting Performance of Gas Wells Unloading Produced or Accumulated Fluids," **SPE No. 2552**, Presented at the 44th Annual SPE Fall Meeting, September 28 - October 1, 1969, Denver, CO.

The authors introduce the concept of lifting potential, which relate the characteristics of two-phase flow to the mechanics of flow through the porous media.

Includes a series of plots relating lifting potential to depth, WHP, BHP, etc.

Hutlas, E., Granberry, W., "A Practical Approach to Removing Gas Well Liquids," **SPE No. 3473**, Presented at the 46th Annual SPE Fall Meeting, October 3-6, 1971, New Orleans, LA.

Discussed history of loaded fluid removal in Kansas' Hugoton Gas Field.

Three "best current methods" of liquids removal are pumping units, liquid diverters and gas lift, and 1 inch tubing strings.

Run 1 inch tubing inside the production string (2-3/8 inch) to produce gas and liquids. Amoco had ten such installations at the time of this paper - four successfully doubled flow rate.

Economics of a system are evaluated using stabilized backpressure curve, requiring stabilized flow rate, flowing bottomhole pressure, static reservoir pressure and the slope of the backpressure curve.

Libson, T., Henry, J., "Case Histories: Identification of and Remedial Action for Liquid Loading in Gas Wells - Intermediate Shelf Gas Play," SPE No. 7467, Presented at the 53rd Annual SPE Fall Meeting, October 1-4, 1978, Houston, TX.

This paper discusses how liquid loading in gas wells inhibited gas production in the Intermediate Shelf gas play in southwest Texas. Actual case histories are used to illustrate how to identify and remedy liquid loading in low-volume gas wells. Methods such as plunger lift, beam pump, small-ID tubing, foam injection, and flow controllers are discussed and illustrated.

Critical velocities were found to be close to 1,000 ft/min (16.7 ft/sec).

Casing pressures reflecting more than a 200 psig differential above flowing tubing pressure generally was indicative of excessive liquid accumulation.

The depth at which the critical flow rate becomes important is at the surface.

Beam pumps were moderately successful, plunger lifts increased productivity by an average of 20 Mscfd, smaller tubing (1.9" OD, 1.61" ID) increased gas production by 50 Mscfd.

Field plans included wells producing >340 Mscfd that declined to 154<rate<340 Mscfd would receive small tubing and wells in the 154<rate<340 Mscfd range would be put on plunger lift or soap injection. Field-wide rotation of the smaller tubing would be enacted for those wells producing less than 154 Mscfd.

MacDonald, R., "Fluid Loading in Low Permeability Gas Wells in the Cotton Valley Sands of East Texas," **SPE No. 9855**, Presented at the 1981 SPE/DOE Low Permeability Symposium, May 27-29, Denver, CO.

A modified calculation procedure, based on actual flow data, for the determination of fluid loading is presented.

Perm ranges from .01 to .001 and and porosity from 0 to 10%. BHT and BHP average 265F and 4600 psig, respectively. Depth is about 10,000 ft. Gross thickness is 1,400 ft. Average production characteristics are a 0.63 gravity gas, a 55 API condensate and 75 bbl/MMcf of water.

A Newtonian fluid (spherical) with a Reynolds number between 1,000 and 200,000 has a drag coefficient equal to 0.44.

Included is a table with a 5-well response to compression (900 psi FTP to about 130 psi FTP). One well received 1.315" OD tbg prior to compression and was in an unloaded state.

Greene, W., "Analyzing the Performance of Gas Wells," **SPE No. 10743**, Presented at the 1982 SPE California Regional Meeting, March 24-26, San Francisco, CA.

The author defines inflow, outflow and tubing performance curves.

Inflow performance computations conducted using the Russel, et. al. method.

The outflow performance of a completely dry gas well will have not apex (flowpoint). At a zero flow rate, the vertical difference between the two performance curves represents the static weight of the dry gas column in the tubing string.

Although tubing performance curves are useful, the author prefers outflow and inflow curves.

Lea, J., Tighe, R., "Gas Well Operations with Liquid Production," **SPE No. 11583**, Presented at the 1983 Production Operations Symposium, February 27 - March 1, Oklahoma City, OK.

The author sets forth the pertinent engineering considerations and production options the engineer has in dealing with the determination of liquid loading.

Increases critical velocity by 20%, likeTurner.

Determines that Turner's method should be used in conjunction with a pressure drop correlation to estimated bottomhole pressure, and then Turner's critical velocity should be compared to the calculated velocity at bottomhole conditions.

Indicates that Turner's method is conservative when using the Ros correlation and the IPR intersection, because it indicates a higher rate than necessary to maintain continuous liquid unloading than determined from inspection of the last possible "J" curve-IPR curve intersection.

The author outlines a methodology for intermitters, siphon strings, plunger applications, foaming agents, compression, gas lift and pumping methods.

Asheim, H., "MONA, an Accurate Two-Phase Well Flow Model Based on Phase Slippage," **SPE No. 12989**, Presented at the 1984 SPE European Petroleum Conference, October 25 - 28, London, UK.

The author has developed a computer model (slanted hole) for two phase pressure drop. Field data is available for the Forties Field, Ekofisk Field and Prudhoe Bay flowlines.

Peffer, J., Miller, M, and Hill, A., "An Improved Method for Calculating Bottomhole Pressures in Flowing Gas Wells with Liquid Present," **SPE No. 15655**, Presented at the 61St Annual Technical Conference and Exhibition, October 5-8, 1986, New Orleans, LA.

The authors have modified the Cullender and Smith method to include the contribution of entrained liquid to gravitational gradients.

Determined that an absolute roughness of approximately 0.0018 inches improved the pressure drop correlations, as compared to Cullender and Smith's value of 0.0006 inches, which was for new pipe, improved the pressure drop correlations, as compared to Cullender and Smith's value of 0.0006 in which was for new pipe.

Data tables are available (condensate) from Govier and Fogarasi's paper and 50 Texas Railroad Commission Wells.

Upchurch, E., "Expanding the Range fro Predicting Critical Flowrates of Gas Wells Producing from Normal Pressured Water Drive Reservoirs," **SPE No. 16906**, Presented at the 62 Annual Technical Conference and Exhibition, September 27-30, 1987, Dallas, TX.

This model is for determining critical rates in wells producing more than 150 bbl/MMcf, which is probably not relevant for stripper oil and gas wells.

Oden, R., and Jennings, J., "Modification of the Cullender and Smith Equation for More Accurate Bottomhole Pressure Calculations in Gas Wells," **SPE No. 17306**, Presented at the SPE Permian Basin Oil and Gas Recovery Conference, March 10-11, 1988, Midland, TX.

The authors modify the Cullender and Smith equation by adding as gas¬water ration tem and a friction factor term as given by the explicit Jain Swamee correlation.

Improvement was shown that using an apparent roughness of 0.0023 inches instead of an absolute roughness of 0.0006 inches further reduced error in the computation of flowing bottomhole pressures.

The technique is for smooth-turbulent and rough-turbulent flow of water and gas in the wellbore.

Data is compiled from SPE No. 15655.

Rendeiro, C., and Kelso, C., "An Investigation to Improve the Accuracy of Calculating Bottomhole Pressures in Flowing Gas Wells Producing Liquids," **SPE No. 17307**, Presented at the SPE Permian Basin Oil and Gas Recovery Conference, March 10-11, 1988, Midland, TX.

This technique is a refinement of the average temperature and pressure method through the use of an adjustment in gas gravity to account for the presence of well stream liquids.

The authors used data from SPE No. 15655.

Chuandong, Y., "Design Study for Optimization of Tubing String Producing Gas with Water from Wells," **SPE No. 17850**, Presented at the SPE International Meeting on Petroleum Engineering, November 1-4, 1988, Tianjin, Peoples Republic of China.

Flow at the tubing shoe is reviewed to determine critical rates.

Neves, T., and Brimhall, R., "Elimination of Liquid Loading in Low-Productivity Gas Wells," **SPE No. 18833**, Presented at the SPE Production Operations Symposium, March 13-14, 1989, Oklahoma City, OK.

This paper discusses factors affecting methods to alleviate liquid loading problems and guidelines for selecting, in advance, the optimum method to be used when liquid loading occurs.

The authors constructed a computer program to 1) calculate the existing gas velocity profile and the critical gas velocity profile as a function of depth, 2) predict the flowing bottomhole pressure, and 3) study the effects of various parameters on long-term gas production.

Used the Beggs and Brill multiphase pressure drop correlation was used to determine the pressure at various positions in the wellstring. The Turner equation was used to calculate the critical velocity profile.

Alternate flow/shut-in periods, swabbing, smaller diameter production tubing, foaming agents, plunger lift, sucker rod pumping and gas lift techniques were reviewed.

No rationale for selecting optimum lift methods was apparent. However, the authors suggest producing the well using its own energy as long as possible, using smaller tubing, foaming agents, and plunger lift, then revert to rod pumping or gas lift.

Oudeman, P., "Improved Prediction of Wet-Gas-Well Performance," **SPE No. 19103,** SPE Production Engineering, August 1990, pp. 212-216.
There is a discussion of published liquid loading predictive models (Turner, Gray tubing performance) and their drawbacks.

The Turner method **DOES NOT** predict a well's minimum flow rate.

There is a critical pressure drawdown below which fluid does not enter the wellbore.

Coleman, S., Clay, H., McCurdy, D., and Norris, H. "A New Look at Predicting Gas-Well Load-Up," **SPE No. 20280**, Journal of Petroleum Technology, March 1991, pp. 329-333.

The test wells have WHFPs less than 500 psi, where Turner's were greater than 500 psi.

The amount of condensed water increases with a decline in reservoir pressure.

The authors were able to match their data without the 20% upward adjustment Turner enforced.

In most cases, wellhead conditions controlled the onset of liquid load-up.

The liquid/gas ratios for the data ranged from 1 to 22.5 MMscf and had no influence on the determination of liquid load-up.

The primary source of water was condensed water.

Slugging water production will not follow the liquid droplet methodology because a differing transport mechanism is occurring.

In most cases, wellbore conditions can be used to determine the onset of liquid loading. However, for concentric tubing strings where the tubing/packer is a significant distance from the completion interval, flowing conditions of the largest diameter segment should be used to predict the wellbore critical rate.

Coleman, S., Clay, H., McCurdy, D., and Norris, H. "Understanding Gas-Well Load-Up Behavior," **SPE No. 20281**, Journal of Petroleum Technology, March 1991, pp. 334-338.

The time for a well to load-up and die is inversely proportional to the rate of liquid influx into the wellbore.

Coleman, S., Clay, H., McCurdy, D., and Norris, H. "The Blowdown-Limit Model," **SPE No. 20282**, Journal of Petroleum Technology, March 1991, pp. 339-343.

To blow down a well successfully, three criteria must be met.

1. Differential wellbore pressures must be capable of inducing reservoir flow.

2. A bottomhole superficial gas velocity of 5 to 10 ft/sec is required to initiate slug removal.

3. For a well to have a successful blowdown, it must be capable of delivering gas above its critical rate fro a minimum of 3 hours.

Coleman, S., Clay, H., McCurdy, D., and Norris, H. "Applying Gas-Well Load-Up Technology," **SPE No. 20283**, Journal of Petroleum Technology, March 1991, pp. 344-349.

A table of alternate depletion methods is included.

Typical post-critical rate deliverability is about 43% of a well's potential deliverability.

Henderson, F., "Producing the Oriskany in Southwestern Pennsylvania," **SPE No. 23430**, Presented at the 1991 SPE Eastern Regional Meeting, October 22¬25, 1991, Lexington, KY.

Remedial acts have including well blowing, with and without surfactant and plunger lift installation on six wells. Two wells were receptive to the plunger lift technique.

Adams, L., and Marsili, D., "Design and Installation of a 20,500-ft Coiled Tubing Velocity String in the Gomez Field, Pecos County, Texas," **SPE No. 24792**, Presented at the 67th Annual Technical Conference and Exhibition, October 4-7,

1991, Washington, DC.

Two coiled tubing velocity string applications (1-1/2 inch) were performed in the Delaware Basin prior to this installation.

Installation of 1-1/4 inch coiled tubing (20,500') was selected as the optimum configuration.

Coil was run with a live well.

Martinez, J., and Martinez, A., "Modeling Coiled Tubing Velocity Strings," **SPE No. 30197**, Presented at the Petroleum Computer Conference, June 11-14, 1995, Houston, TX.

A coiled tubing velocity of 7 to 12 ft/sec in the lower third of the tubing is best.

The authors recommend the use of the Beggs/Brill correlation for flow and the Lasater correlation for solution gas.

A Liquid hold-up of 0.2 or less and the achievement of the lowest pressure at the perforations while maximizing rate are ideal considerations.

Elmer, W., "Tubing Flowrate Controller: Maximize Gas Well Production from Start to Finish," **SPE No. 30680**, Presented at the 71St Annual Technical Conference and Exhibition, October 22-25, 1995, Houston, TX.

A table of critical flowrates is presented based on tubing size (3/4 to 2-3/8 inch) and tubing pressure (50 to 500 psia).

Cox, S., "Gas Well Optimization: Using Velocity as the Key Component in Choosing Tubing Size," **SPE No. 35579**, Presented at the SPE Gas Technology Conference, April 28-May 1, 1996, Calgary, Alberta, Canada.

The author uses nodal analysis (tubing performance and inflow curves) to optimize tubular selection based on velocity.

Low pressure, low productivity wells may perform better with smaller tubing due to the smaller cross-sectional area. A siphon string, run inside the existing tubing, may be a superior alternative, allowing internal or annular flow to exist.

When tubing is found to be too large, down hole chokes should be considered as an alternative to running smaller tubing.

Ouyang, L., and Aziz, K., "Development of New Wall Friction Factor and Interfacial Friction Factor Correlations for Gas-Liquid Stratified Flow in Wells and Pipelines," **SPE No. 35679**, Presented at the SPE Western Regional Meeting, May 22-24, 1996, Anchorage, AK.

Developed friction factors to predict liquid holdup values, based on Minami and Beggs test values.

Gunawan, R., and Dyer, G., "Tubing Size Optimization in Gas Depletion Drive Reservoirs," **SPE No. 37001**, Presented at the SPE Asia Pacific Oil and Gas Conference, October 28-31, 1996, Adelaide, Australia.

The authors use nodal analysis and gas load-up technology to identify optimum tubing size.

Tubing size was increased from 2-3/8 to 3-1/2 inch in seven wells, yielding a 50 MMcfd increase in productivity.

Field results show that the Gray correlation (Tubing Performance) underpredicts the actual FBHP in wells with low WHFP.

High-permeability (2,000 and-ft) reservoir abandonment pressure is not affected by tubing size. Otherwise, tubing size is important.

Azouz, I., Shah, S., Vinod, P., and Lord, D., "Experimental Investigation of Frictional Pressure Losses in Coiled Tubing," **SPE No. 37328**, Presented at the SPE Eastern Regional Meeting, October 23-25, 1996, Columbus, OH.

This paper presents an experimental investigation of tubular frictional pressure loss in coiled tubing and straight sections of seamed and seamless tubing.

Fluids investigated include water, linear guar gum and hydroxypropyl guar (HPG), and borate-crosslinked guar gum and HPG.

Results obtained with water indicate tubing curvature as well as the seam impact frictional pressure drop while non-Newtonian fluids are impacted by curvature only.

In straight sections of tubing, seamless tubing had a higher friction factor, due to innate roughness, as compared to the seamed tubing, which was much closer to true smooth pipe. The authors conclude that the seam alters the turbulence spectrum by damping the high turbulence frequencies. This causes a decrease in the pressure drop.

$f(\text{seamed}) = 1.667 * (Nre^{-0.049}) * f(\text{seamless})$……for water

Nosseir, M., Darwich, T., Sayyouh, M., and Sallaly, M., "A New Approach for Accurate Prediction fo Loading in Gas Wells Under Different Flowing Conditions," **SPE No. 37408**, Presented at the SPE Production Operations Symposium, March 9-11, 1997, Oklahoma City, OK.

Developed critical velocity correlations for the transition (1 < Nre < 1000) and highly turbulent ($2*10^5$ < Nre < 10^6) flow regimes, while Turner's original (non-adjusted equation) was valid for 10^4 < Nre < $2*10^5$.

Has a graphical representation of drag force and three data tables re-studying Turner's and Exxon's Data.

Farshad, F., and Garber, J., "Relative Roughness Chart for Internally Coated Pipes (OCTG)," **SPE No. 56587**, Presented at the 75th Annual Technical Conference and Exhibition, October 3-6, 1999, Houston, TX.

The relative roughness of internally coated pipes (phenolic, epoxy and modified phenolic-epoxy) are given based on two roughness measurement devices. In addition, the average roughness value from the two measurements is given versus diameter for coated and commercial steel.

Best-fit equations (though unreadable at this time) are presented.

Scott, W., and Hoffman, C., "An Update on Use of Coiled Tubing for Completion and Recompletion Strings," **SPE No. 57447**, Presented at the SPE Eastern Regional Meeting, October 21-22, 1999, Charleston, WV.

An estimated 15,000 wells have coiled tubing installed in them as velocity or siphon strings.

Medjani, B., and Shah, S., "A New Approach for Predicting Frictional Pressure Losses of Non-Newtonian Fluids in Coiled Tubing," **SPE No. 60319**, Presented at the 2000 SPE Rocky Mountain Regional/ Low Permeability Reservoirs Symposium, March 12-15, 2000, Denver, CO.

Fanning Friction (f) = 0.0079 / Nre^0.25
For Newtonian fluids in straight pipe (Blasius Formula)

Li, M., Sun, L., and Li, S., "New View on Continuous-removal Liquids from Gas Wells," **SPE No. 70016**, Presented at the SPE Permian Basin Oil and Gas Recovery Conference, May 15-16, 2001, Midland, TX.

Liquid droplets are deduced to be flat instead of round, resulting in a drag coefficient value of 1.

Equations are in metric.

Farshad, F., Rieke, H., and Mauldin, C., "Flow Test Validation of Direct Measurement Methods Used to Determine Surface Roughness in Pipes (OCTG)," **SPE No. 76768**, Presented at the SPE Western Regional Meeting, May 20-22, 2002, Anchorage, AK.

There is a very beneficial advantage in the use of internally plastic coated pipes for improving the flow performance by lowering wall surface roughness and friction factor values.

Moody friction is 4 times fanning friction.

The John Gandy Corporation of Conroe, Texas supplied the oil field country tubular goods.

All data showed that Rzd (mean peak to valley height) derived friction factor gave the best correlation with the flow test results.