PRACTICAL HYDROCARBON DEW POINT SPECIFICATION FOR NATURAL GAS TRANSMISSION LINES

Jerry A. Bullin and Carl Fitz
Bryan Research & Engineering, Inc.
Bryan, Texas, U.S.A.

Todd Dustman
Questar Pipeline Company
Salt Lake City, Utah , U.S.A.

ABSTRACT

Hydrocarbon liquid dropout can cause a number of problems in gas transmission lines, including increased pressure drop, reduced line capacity, and equipment problems such as compressor damage. To avoid liquid dropout, most current operating specifications for gas transmission lines require that the lines be operated above the hydrocarbon dew point (HDP) or cricondentherm hydrocarbon dew point (CHDP). The HDP may be determined either by direct measurement such as the Bureau of Mines chilled mirror method or by calculation using an equation of state (EOS) with a measured composition. This project (GPA Project No. 081) was undertaken to determine a practical hydrocarbon dew point specification allowing small amounts of liquids that have no significant impact on operations. Results from the project show that 0.002 gallons of liquid per thousand standard cubic feet of gas (GPM) has a negligible effect on pressure drop and should not disrupt pipeline operations. Calculation of an accurate HDP from a GC analysis such as typically available at a custody transfer point may be useful but is highly dependent on the characterization of the heavy fraction. An extended analysis of the heavy fraction is best. However, an empirical method has been developed to predict the C6, C7, C8, C9 and heavier composition when only a lumped C6+ fraction characterization is available.

Practical Hydrocarbon Dew Point Specification
For Natural Gas Transmission Lines

INTRODUCTION

Gas transmission lines are one of the core assets of the energy infrastructure in the United States. As a result, the operation of these lines must be as trouble-free as possible. A major operational consideration for gas pipelines is hydrocarbon liquid condensation from the natural gas. Hydrocarbon liquid in gas pipelines can cause operational issues including increased pressure drop, reduced line capacity, and equipment problems such as compressor damage. In order to avoid hydrocarbon condensation or "liquid dropout" in gas pipelines, several different control parameters have historically been monitored and assigned limits including C6+ GPM (gallons of liquid per thousand standard cubic feet of gas), mole fraction C6+, hydrocarbon dew point (HDP) and cricondentherm hydrocarbon dew point (CHDP).

The HDP is defined as the point at which the first droplet of hydrocarbon liquid condenses from the vapor. It can also be thought of as the minimum temperature above which no condensation of hydrocarbons occurs at a specified pressure. The CHDP, illustrated in Figure 1, defines the maximum temperature at which this condensation can occur regardless of pressure. The CHDP is heavily influenced by the C6+ GPM as shown in Figure 2 for 40 natural gas mixtures from Dustman et al. [1] and Brown et al. [2]. However, the relationship between CHDP and C6+ GPM is not exact due to differences in composition of the lumped C6+ fraction. The CHDP of a gas with C6+ GPM of 0.07 ranges from about 28 to 55 ^{o}F (-2 to 13 ^{o}C) as shown in Figure 2. This is a 27 ^{o}F (15 °C) variability in the CHDP. This variability is overcome by specifying the acceptable CHDP directly.

Figure 1 Hydrocarbon Dew Point Curve for Typical Natural Gas Mixture

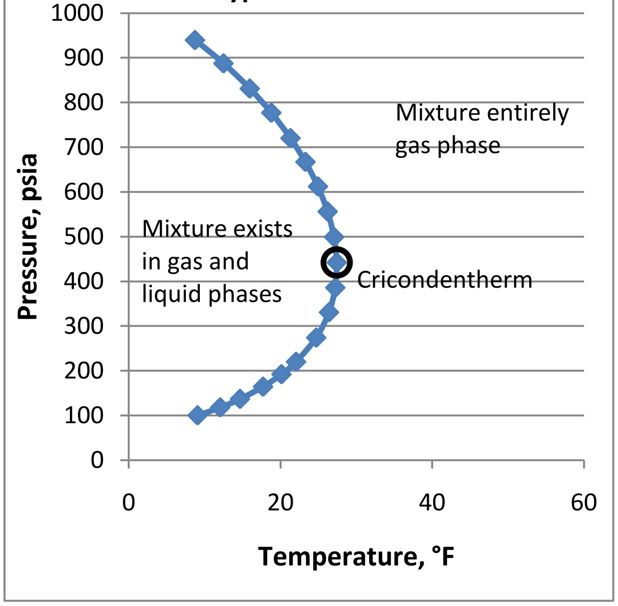
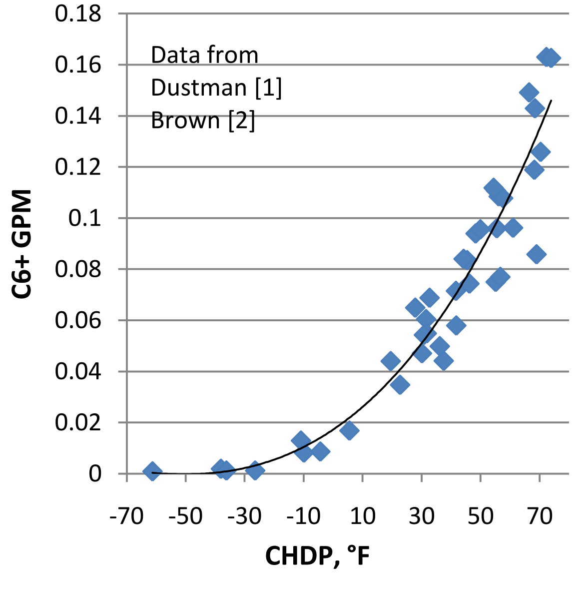


Figure 2 CHDP vs. C6+ GPM for Natural Gas



Most current operating specifications for gas transmission lines require that the lines be operated above the HDP or CHDP. The HDP may be determined by direct measurement using manual or automated dew point analyzers. In the field, HDP is commonly measured using the Bureau of Mines chilled mirror method, where the natural gas sample flows continually across the surface of a small mirror which is cooled by the flow of a low temperature gas on the other side. As the temperature is slowly reduced, the operator watches through an eyepiece for hydrocarbon condensation on the mirror surface. When condensation is detected, the dew point temperature and pressure are manually recorded (Starling [3], George and Burkey [4]).

When the gas composition is known, a convenient method of determining the HDP is by calculation using a validated equation of state (EOS). When the pressure and composition are specified, an EOS such as Peng-Robinson (PR) or Soave–Redlich-Kwong (SRK) can be used to accurately calculate the HDP. It must be noted that many variations of the generic PR and SRK EOS exist, and are not all equal. The most accurate contain modifications based on pure component properties and binary interactions. Therefore, it is necessary to validate an EOS by comparing to many sets of vapor-liquid equilibria (VLE) and dew point data.

While the dew point identifies the condition at which vapor first begins to condense to liquid, it provides no information about the quantity of condensation resulting from a small degree of cooling. The condensation rate of liquids in gas transmission lines may vary widely depending on the composition, temperature, and pressure of the system. Condensation rates resulting from cooling were studied by the National Physical Laboratory in the United Kingdom [2] for several different natural gases. The calculated condensation rate varied from practically nil at 9 ^oF (5 ^oC) below the dew point for a very lean natural gas to 500 mg/m^3 (0.006 actual GPM) only 1 ^oF (0.5 ^oC) below the dew point for another natural gas. A pipeline containing the lean natural gas could be operated quite satisfactorily 9 ^oF (5 ^oC) below the dew point with little liquid dropout. On the other hand, a large amount of liquid dropout would occur if a pipeline with the second natural gas were to operate 9 ^oF (5 ^oC) below the dew point. Clearly the dew point alone does not provide enough information to completely identify conditions at which a pipeline can be operated without liquids problems. More information is needed about the degree of condensation which takes place below the dew point.

The objective of the present work is to develop a “practical” HDP which considers both the hydrocarbon dew point curve and the degree of condensation which takes place below the dew point. The “practical” HDP should use the gas composition and an EOS to identify acceptable operating conditions for natural gas transmission lines. The current project is an extension to GPA Project 063 “Measuring Hydrocarbon Dew Points in Natural Gas” which produced Research Reports RR-196 [4] and RR-199 [5].

REVIEW OF EQUATIONS OF STATE TO CALCULATE DEW POINT

Equations of state which have been appropriately modified and validated can be used to accurately calculate the dew point of natural gas mixtures based on the composition. Two of the most popular generic equations of state (EOS) are the Peng-Robinson or "PR EOS" [6] and Soave-Redlich-Kwong or "SRK EOS" [7]. These equations use critical temperature, critical pressure, and acentric factor to describe the pure fluid. Mixtures require an additional one or two binary interaction parameters which may be temperature dependent and can be obtained by fitting binary VLE data. Adding to the complexity, different mixing rules have been developed to improve phase equilibria predictions [8] and numerous enhancements have been proposed such as Graboski and Daubert's modifications contained in the API version of the SRK [9]. Due to these possible variations and modifications, different computer programs that use the PR or SRK EOS will not necessarily produce the same answer. Potential dissimilarities between programs include utilizing different pure component properties or different (or missing) binary interaction parameters. The form of the PR or SRK EOS used by the different programs may or may not use the same modifications. Therefore, any computer program which is to be used for HDP calculations should be validated by comparison against accurate experimental VLE and natural gas dew point data over the temperature, pressure, and composition range of interest. Except where noted, all calculations in this work were made using the ProMax® process simulation program, Version 3.1, by Bryan Research & Engineering [10]. The PR and SRK EOS in ProMax use binary interaction parameters which have been fitted to experimental data. In addition, extensive comparisons to mixture data have been performed to verify accurate results.

A recent report by the National Physical Laboratory in the United Kingdom [2] contains HDP data on seven natural gas mixtures and five synthetic gas mixtures. A comparison of manual and automated (Condumax II) chilled mirror dew points for natural gas mixtures to calculations from ProMax PR EOS using measured compositions is presented in Figure 3. The calculated dew points are consistently between the automated and manual chilled mirror dew points for the five gases. The automated chilled mirror dew point measurement and the calculated dew point generally agree within 2 °F (1 °C), with a maximum difference of 8 °F (4 °C). The difference between the automated and manual chilled mirror measurements is considerably greater, ranging from 6 to 14 °F (3 to 8 °C). Thus, the calculated dew points match within the scatter of measured dew points using both automated and manual chilled mirror dew point instruments.

The GPA Research Report RR-196 entitled "Tests of Instruments for Measuring Hydrocarbon Dew Points in Natural Gas Streams, Phase 1" by George and Burkey [4] compares manual chilled mirror dew points to those obtained using two automated instruments: the Ametek 241 CE II and the Michell Condumax II. Two different manual chilled mirror dew points were measured: an iridescent ring dew point, which occurs first as the temperature is lowered, and the droplet dew point, which occurs several degrees cooler. The Ametek instrument was tuned by the manufacturer to match the iridescent ring dew point while the Michell instrument was tuned to match the droplet dew point. As shown in Figure 4, each automated instrument reproduced the corresponding manual method very well. The dew point from the version of the SRK EOS reported in RR-196 (not ProMax SRK EOS) is compared to the measured droplet dew point in Figure 5. The SRK calculated dew point given in RR-196 agrees slightly better with the manual droplet dew point than does the Ametek automated dew point which was tuned to the iridescent ring. As previously stated, the iridescent ring method should give higher dew point values than the droplet method. Overall, the SRK calculated dew points as well as all of the measured dew points (both manual and automated) agree remarkably well in the George and Burkey study.

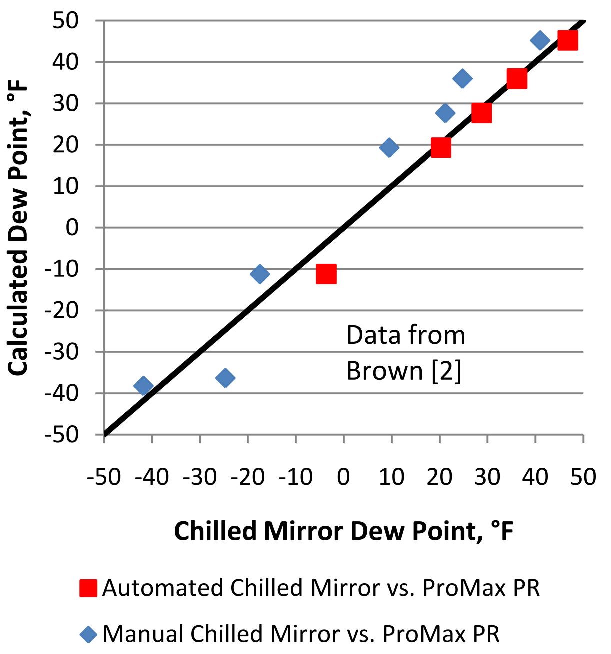


Figure 3 NPL Natural Gas Dew Points Manual & Automated Chilled Mirror vs. ProMax PR

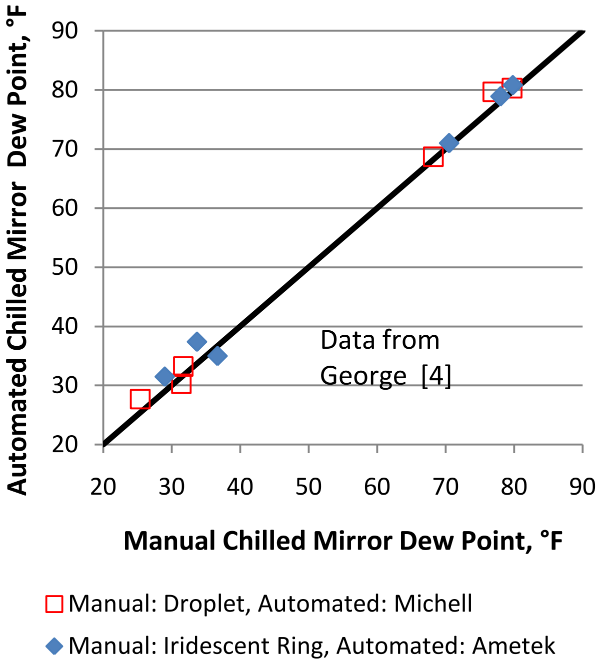


Figure 4 GPA RR-196 Natural Gas Dew Point Manual vs. Automated Chilled Mirror

An extended analysis of two natural gas mixtures was conducted by Paul Derks from Gasunie in the Netherlands and presented at the 72^{nd} GPA Annual Convention in 1993 [11]. Included was the measurement of the quantity of condensate formed at sub-dew point conditions, which ranged from 0.0002-0.003 GPM (20-250 mg liquid per normal cubic meter gas). As shown in Figure 6, the condensation curve for Gas A is predicted within 5 °F (3 °C) by the ProMax PR EOS. The upper end of the condensation is about 0.003 GPM, which corresponds to a mole fraction vapor of 0.9999 - 0.99995. Considering the ProMax calculations are not tuned to these particular data, the agreement is excellent.

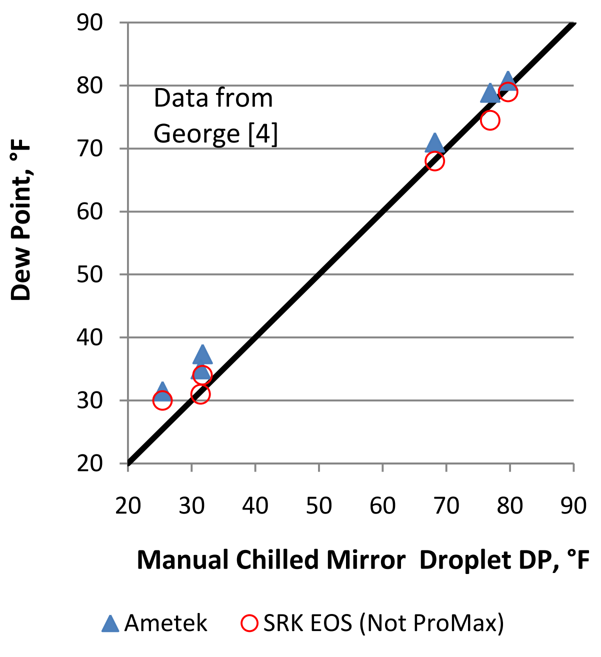


Figure 5 GPA RR-196 Natural Gas DP Chilled Mirror Droplet vs. SRK EOS

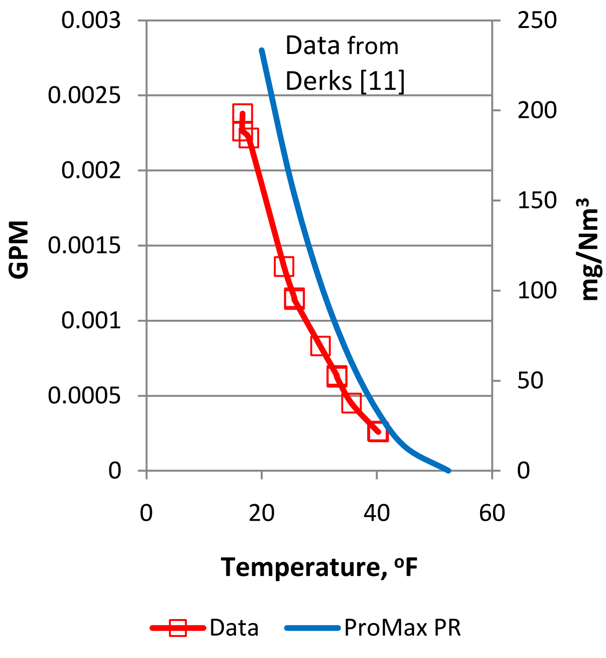


Figure 6 Condensation Rate of Derks Gas A at 595 psia

Several useful conclusions can be drawn from the preceding data comparisons. First, the measured dew point value depends on the measurement technique. The National Physical Laboratory results of Figure 3 show dew points measured manually and with an automated instrument (Condumax II) agree within about 6 °F (3 °C) at a temperature of 41 °F (5°C). This difference increases as the dew point temperature decreases and becomes 14 °F (8 °C) at a dew point of -18 °F (-28 °C). A second conclusion is that with accurate compositions, the dew point calculated by a verified EOS can be highly accurate and match the directly measured dew point very well. The final conclusion is condensation rates can also be calculated accurately using compositions and a verified EOS.

HOW TO ESTABLISH A PRACTICAL HYDROCARBON DEW POINT

What is a "practical" HDP? The HDP is defined as the point at which the first droplet of hydrocarbon liquid condenses out of the vapor. The dew point identifies the transition from an all vapor condition to a two phase condition, where a liquid phase is just beginning to be formed. From a pipeline operations perspective, a "practical" HDP should identify the condition with negligible liquid that does not impact pipeline operations.

Various pipeline contaminants can have a large effect on the measured HDP. One drop of compressor oil or glycol from upstream dehydration will raise the measured HDP substantially. Yet this one drop of liquid will have no meaningful effect on pressure drop or line capacity and will not cause operating problems. The dew point by itself provides no information on the quantity of condensation resulting from a small degree of cooling. More information is needed about the degree of condensation which takes place below the dew point. As discussed previously, the rate at which liquids condense due to cooling below the dew point varies significantly with gas composition. A pipeline could be operated quite satisfactorily 9 ^{o}F (5 ^{o}C) below the dew point with little liquid dropout with one gas but experience a large amount of liquid dropout with another gas. Clearly the rate at which liquid dropout occurs is an important factor in avoiding liquid dropout problems. A direct approach to determining the practical HDP would be to look at the issue in terms of actual GPM.

One possible way to put a lower bound on the practical HDP is to estimate the quantity of liquid required to form a drop in the manual chilled mirror apparatus or an automated instrument. Brown et al. [2] estimates that about 70 mg/m^3 (0.0006 actual GPM) of liquid is present when the dew point is detected using a manual chilled mirror and the Condumax II automated instrument at its standard sensitivity setting. Brown et al. compare the gas dew point measured with the Condumax II instrument to a liquid content of 70 mg/m^3 (0.0006 GPM) rather than to the classical thermodynamic (zero liquid) dew point calculated by the EOS. The agreement between the measured and calculated dew point is good. Brown recommends that the classical definition of dew point be modified:

> "… the issue that the current definition of hydrocarbon dew point cannot be measured in practice is under discussion within ISO/TC193/SC1. The recommendation being put forward is that dew point should be redefined as a 'technical' or 'measurable' dew point to aid convergence of the determined value from the different methods of measurement."

Thus, it is reasonable to set the lower limit of a practical HDP to the amount of liquid required for detection by the manual chilled mirror apparatus, which is about 0.0006 actual GPM.

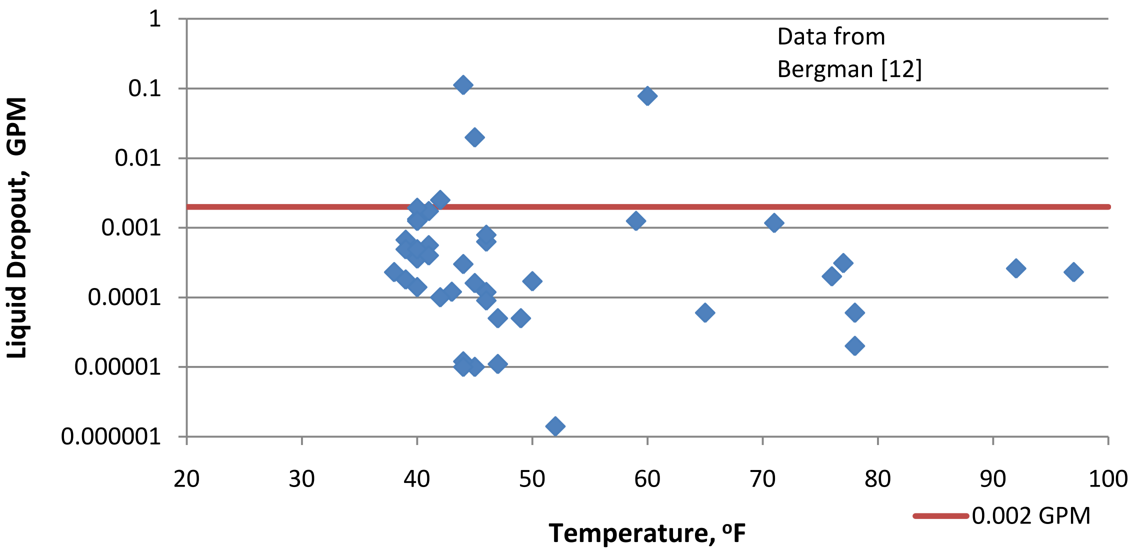
This quantity of liquid required for detection is supported by earlier work of Bergman et al. [12] in their description of the manual chilled mirror dew point technique. Bergman writes that as the gas is cooled, the first observation is of a faint ring of hydrocarbon condensing. With additional cooling, droplets are observed. With still more cooling, the droplets coalesce to form a film (referred to as "flooding"). According to Bergman:

> "the droplet stage might be thought of as 0.3 to 0.5 gallon per MMcf (0.0003 to 0.0005 GPM) while the flood stage (on the mirror) is from 1 to 1.5 gallons per MMcf (0.001 to 0.0015 GPM)."

Bergman's higher estimate for the droplet stage is 0.0005 GPM, which agrees well with the Brown estimate.

A survey of condensate formation in natural gas pipelines was performed as part of an AGA project in 1974 by Bergman et al. [12], and the results are plotted in Figure 7. Various separation devices were used, including drips, separators, filters, scrubbers, and strainers. A 0.002 GPM line is included on the plot for reference. Liquid dropout up to 0.1 GPM was measured. The amount of liquid dropout recovered in many instances was small due to the poor separation efficiency of some of the devices such as drips and the relatively moderate gas temperature. Only a few observations were below 40 °F (4 °C).

Figure 7 AGA Survey of Condensate Formation in Natural Gas Pipelines, 1974



In sufficient quantities, liquids can increase the pressure drop and reduce the capacity of a pipeline. However, the effect of very small quantities of liquids on pressure drop is negligible. The calculated pressure drop of dry gas is compared to gas with 0.002 GPM liquids at 60 °F, 500 psia (15.6 °C, 34.47 bar) in Table 1. None of the two phase pressure drop correlations show a significant pressure drop increase due to the small amount of liquid. The calculated liquid holdup at the outlet is small, about 9 x 10^{-6}. The computer code for the Beggs and Brill correlation in the book “Two-Phase Flow in Pipes” by Brill and Beggs [13] uses 10^{-5} (dimensionless) no slip holdup as the transition point between dry gas and two-phase behavior. The no slip holdup is calculated by Ql/ (Qv + Ql), where Qv is the actual volume flow rate of gas. Thus, Beggs and Brill’s transition point depends on pressure and, to a smaller degree, temperature. At 60 °F and 900 psia (15.6 °C, 62 bar), this transition point corresponds to 0.001 GPM. At 60 °F and 500 psia (15.6 °C, 34.47 bar), this transition point increases to 0.002 GPM and at 60 °F and 100 psia (15.6 °C, 6.9 bar), it increases further to 0.010 GPM. Below this transition point Beggs and Brill considered the effect of liquids to have a negligible effect on pressure drop. Thus, according to Beggs and Brill, liquids on the order of 0.002 GPM do not contribute significantly to pressure drop.

Table 1 Calculated Pipeline Pressure Drop from Various Correlations Using ProMax PR
100 mile long, 500 psia, 60 °F inlet conditions
0.002 GPM liquid in, Isothermal operation

	16 inch 40 MMscfd			20 inch 75 MMscfd	
Correlation	Liquid Holdup	ΔP psi		Liquid Holdup	ΔP psi
Dry Gas 100% Vapor	0	99.35		0	104.15
Lockhart-Martinelli	9.4E-06	99.41		9.3E-06	104.23
L-M Modified	9.4E-06	99.41		9.3E-06	104.23
Beggs and Brill	9.4E-06	99.41		9.3E-06	104.23
Dukler et al	9.4E-06	99.41		9.3E-06	104.23
Mandhane-Gregory-Aziz	9.4E-06	99.41		9.3E-06	104.23

The 0.002 GPM liquid content criterion was applied to 33 natural gas compositions obtained from Questar [1]. Phase envelopes for a lean and a rich natural gas have been calculated and compared to a quality line showing a liquid content of 0.002 GPM. For the lean natural gas shown in Figure 8, there is about 20 °F (11 °C) difference between the cricondentherm temperature and the 0.002 GPM quality line. For the rich natural gas shown in Figure 9, there is little difference between the dew point line and the 0.002 GPM quality line. These results demonstrate that in general the difference between the cricondentherm temperature and the 0.002 GPM quality line is greater for the lean gases than for the rich gases.

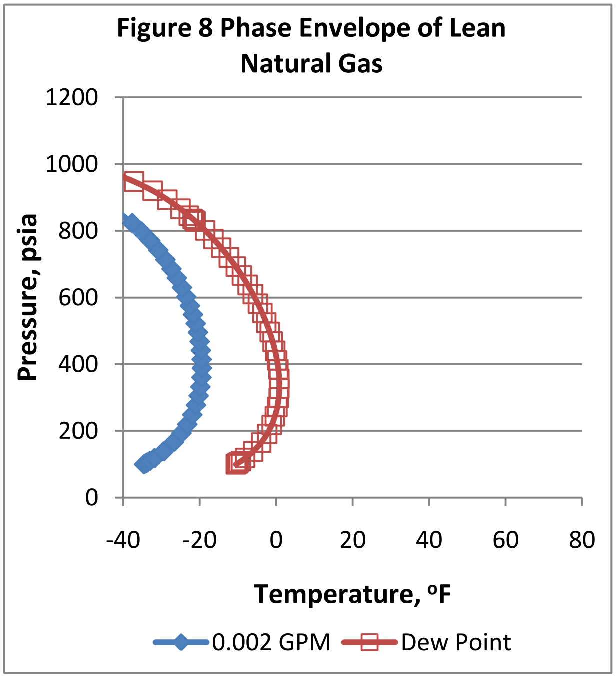


Figure 8 Phase Envelope of Lean Natural Gas

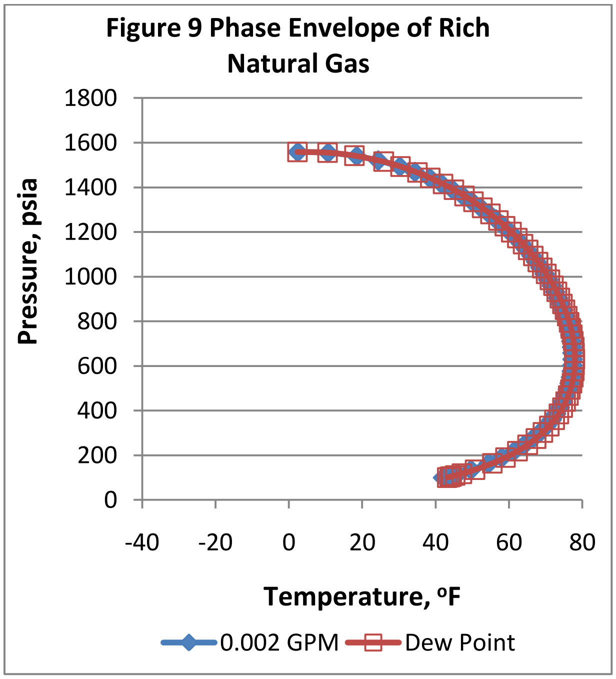


Figure 9 Phase Envelope of Rich Natural Gas

Based on the considerations described in this section, a practical HDP can be adopted based on the 0.002 GPM quality line. A small amount of gas must be condensed to liquid in order to identify the dew point for both manual and automated dew point analyzers. For perspective, a 0.002 GPM value represents only 3-4 droplets of liquid condensed on the mirror of a Bureau of Mines dew point analyzer. Results from work by Beggs and Brill on pressure drop demonstrate 0.002 GPM liquid content has a negligible effect on pressure drop. Using the 0.002 GPM quality line as a control parameter results in a lower acceptable temperature than the corresponding dew point temperature.

TESTING OF PROPOSED PRACTICAL HYDROCARBON DEW POINT WITH OPERATING PIPELINE DATA

Data from two pipelines (reported as Pipeline A and Pipeline B) have been used to test the proposed practical HDP. These data consist of several years' worth of operating data and over 1300 different measurements with a wide range of compositions. The analysis procedure is demonstrated using a PT diagram as shown in Figure 10. The average daily temperature, pressure, and composition of the gas were measured at the pipeline delivery point indicated as position 1 on the PT diagram. The pressure P2 was also measured after step-down to the customer and the temperature T2 was calculated using ProMax PR assuming a JT expansion with no heat transfer. From the measured gas composition, the phase envelope was calculated and the JT expansion line tangent to the phase envelope was located. At the measured pressure P2, ΔTJT = T2-TJT was calculated. If ΔTJT is positive, no liquids should form as the pressure is reduced from the original pressure, P1. If ΔTJT is negative, there is potential for liquids formation as the pressure is reduced from P1. The more negative the ΔT the greater the potential for liquids formation.

One specific case for Pipeline A is shown in Figure 11. For this condition the delivery temperature and pressure (T2 and P2) falls to the left of the JT line and ΔTJT is negative. The downstream T2 and P2 fall inside the phase envelope and lie on the 0.007 GPM line. This indicates the potential amount of liquids is 0.007 GPM, which exceeds the 0.002 GPM from the practical HDP.

Figure 10 Analysis of pipeline data to determine liquids formation potential

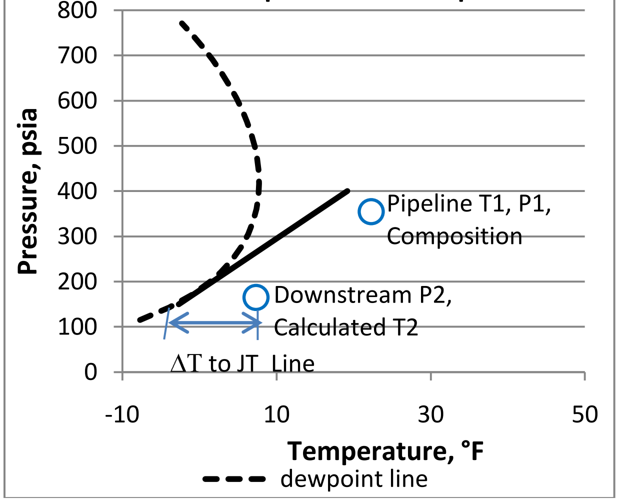
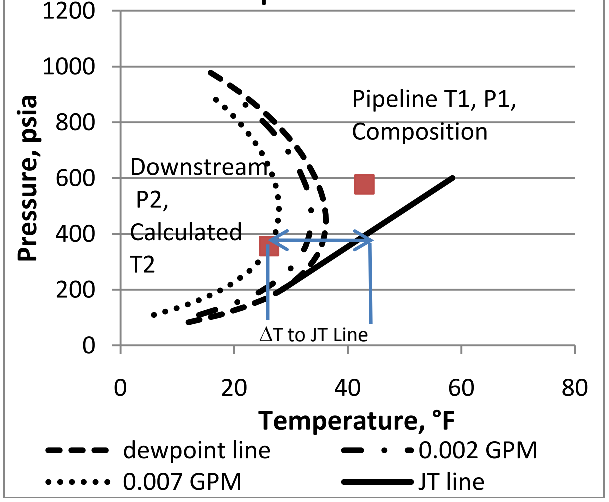


Figure 11 Pipeline A Potential for Liquids Formation



As previously mentioned, several years' worth of operating data for Pipeline A were analyzed. A plot of ΔTJT versus calculated downstream delivery temperature is shown in Figure 12. It should be noted that every point is unique with a different pipeline delivery temperature and pressure, downstream pressure, and pipeline delivery composition and associated tangent JT line. Over 1300 different observations were analyzed using the ProMax process simulator Scenario Tool to automate the calculations. For every delivery temperature, pressure, and gas composition the downstream temperature is calculated at the measured downstream pressure and the ΔT to the JT line is determined. The gas composition at the delivery point varied significantly over all of the observations due to seasonal variations and changes in gas supplied to the pipeline. A straddle plant processed the gas for dew point control. Only 4% of the cases (shown by the plus symbols) fall to the left of the JT expansion line and have a negative ΔTJT. Of this 4% with liquid potential, 65% of the cases had less than 0.002 GPM. The maximum potential liquid at the downstream location was 0.009 GPM.

Operating data from another source are shown for Pipeline B in Figure 13 and were analyzed in a similar fashion. Only 3% of the cases fell to the left of the JT line and had potential liquids. Of these cases, all had potential liquids of 0.002 GPM or less.

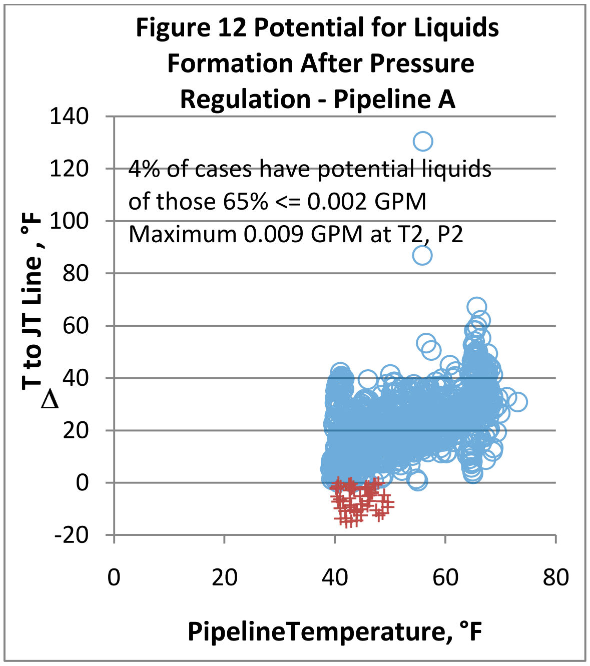


Figure 12 Potential for Liquids Formation After Pressure Regulation - Pipeline A

4% of cases have potential liquids
of those 65% <= 0.002 GPM
Maximum 0.009 GPM at T2, P2

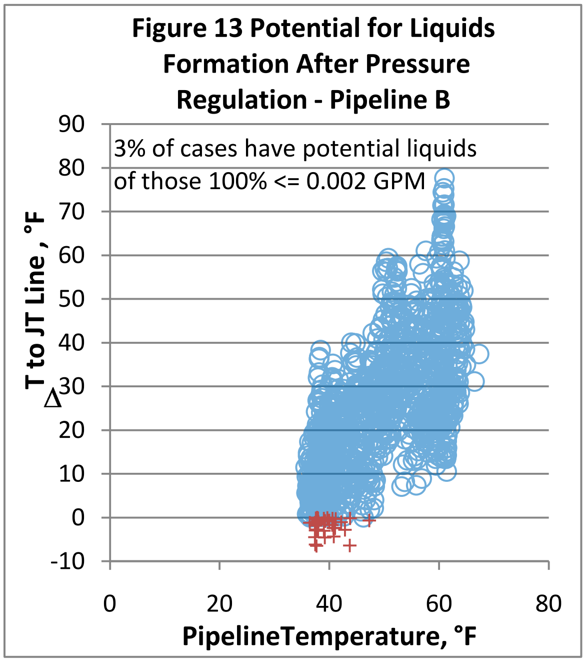


Figure 13 Potential for Liquids Formation After Pressure Regulation - Pipeline B

3% of cases have potential liquids
of those 100% <= 0.002 GPM

In these calculations, the downstream temperature T2 was obtained by a JT calculation which did not include heat transfer and represents a temperature minimum. In reality, T2 will usually be warmer by the amount of heat transfer which takes place from the warmer ground to the cooler gas. The minimum temperature and maximum liquids potential will be at the location where the pressure is regulated. As the gas moves further down the line, the temperature will increase. Any small amount of liquids which may have formed at the regulation point will vaporize as the temperature warms. This process will be repeated as the gas goes through additional stages of regulation. With proper design, any liquids in the gas pipeline will be vaporized before the gas is delivered to an end user. It is important to note that no liquids were observed by the pipeline operations for the 1300 cases during the time period covered by these data and end users did not report any instances of liquids. Another factor limiting the potential of downstream liquid formation in Pipeline A is the very small amount of time operating conditions resulted in liquid loading of greater than .002 GPM – less than 1.5% of the time. This low exposure time would indicate that any liquids formed downstream of regulation would usually not have time to accumulate in significant quantities.

These operating pipeline data analyses indicate that after pressure step-down sufficient JT cooling may occur to produce liquids on the order of 0.002 GPM or somewhat greater. However, operating histories indicate no reported liquids problems. By proper choice of operating conditions and equipment any liquids which may have formed were vaporized before the gas was delivered to the end user.

CHARACTERIZATION OF C6+ COMPOSITION FOR CALCULATION OF HYDROCARBON DEW POINT

The composition of the natural gas including the C6+ fraction must be known in order to accurately calculate the HDP using an EOS. A complete detailed analysis including all the heavies can be obtained by laboratory gas chromatography using a representative sample and performing an offsite analysis. Process chromatographs analyze the C6+ fraction in a variety of ways. Some process chromatographs lump all the C6+ components into one fraction, while others analyze the C6+ fraction through C9 or higher. Even the results from different laboratory chromatographs are not the same when the very same sample is analyzed [14]. When only a lumped C6+ fraction is available, two historical techniques for obtaining a split are to assume a 60/30/10 C6/C7/C8 split as recommended by GPA [15], or assume a 47/36/17 C6/C7/C8 split as recommended by Daniel [16]. Each of these splits yields a different calculated dew point and the difference compared to the true dew point can be quite large. An improved method, called the GPA 2010 C6+ method, has been developed as part of this project and can be used to predict the composition of the C6+ fraction based on the mole fraction of C5 and C6+ in the gas.

Extended analysis compositional data were available for seven gases from the U.K.'s National Physical Laboratory (NPL) [2] to C12+ and 33 gases from Questar [1] to C9+. By trial and error, it was determined that the mole fraction of C6-C9 can be predicted from the mole fraction of C5 and C6+ in the gas using an equation of the following form:

$$yi = A\,(yC5)^{B}\,(yC6+)^{C}$$

The fitted equations and plots of measured vs. predicted for C6-C9 are shown in Figures 14-17 and

Figure 14 Fit of Mole Fraction Total C6

$yC6 = 0.6456\ (yC5)^{0.22}\ (yC6+)^{0.7976}$

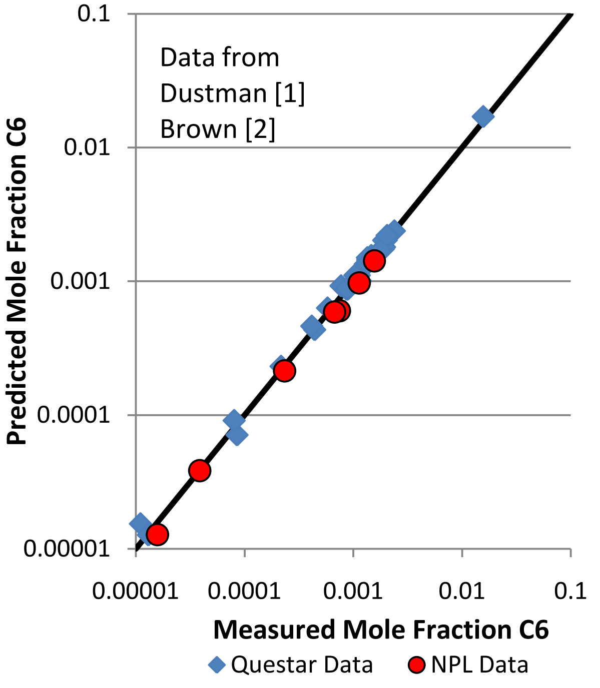


Figure 15 Fit of Mole Fraction Total C7

$yC7 = 0.5044\ (yC5)^{-0.2673}(yC6+)^{1.3375}$

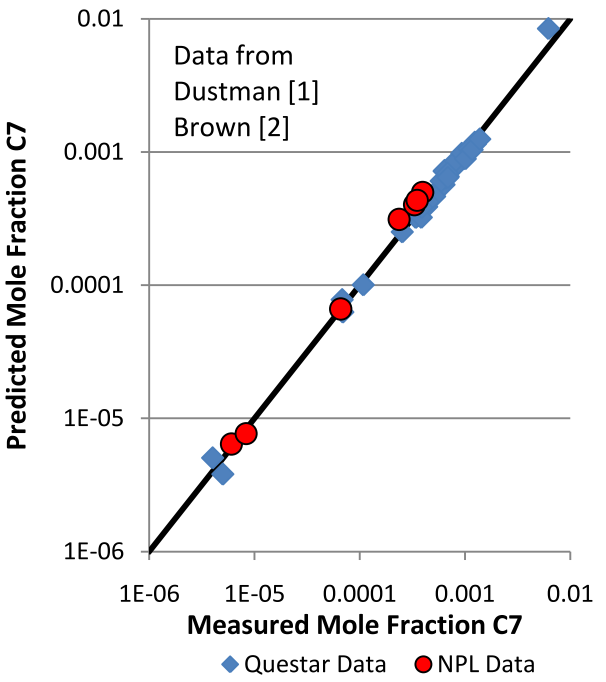


Figure 16 Fit of Mole Fraction Total C8

$yC8 = 0.07014\ (yC5)^{-1.0097}(yC6+)^{2.040}$

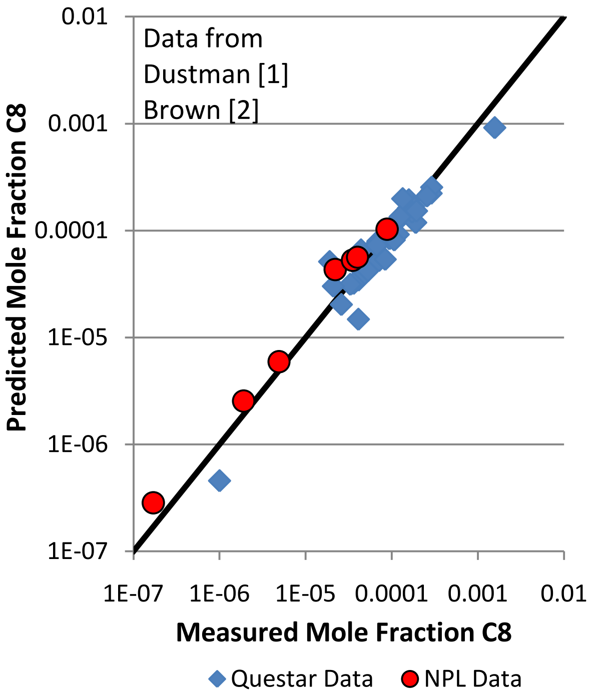


Figure 17 Fit of Mole Fraction Total C9

$yC9 = 0.006149(yC5)^{-1.5176}(yC6+)^{2.4312}$

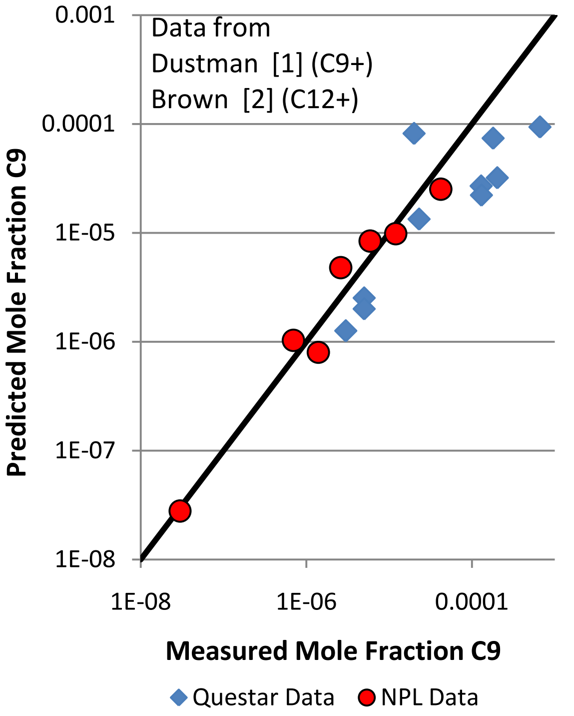


Table 2. Good fits are obtained for C6, C7, and C8. The fitting of C9 is complicated by the fact that the Dustman data is actually C9+ while the Brown data is just C9. C9 is still highly correlated, but the deviations are larger than for the lighter hydrocarbons. The amount of C10 and above is calculated by the relation:

$$\log(yi+1) = \log(yi) + m$$

where m = log(yC9) – log(yC8). This is the same as plotting carbon number versus log(yi) and extrapolating the slope from C8 to C9 as a straight line.

Table 2 Coefficients for $yi = A\,(yC5)^{B}\,(yC6+)^{C}$

	A	B	C
yC6	0.6456	0.22	0.7976
yC7	0.5044	-0.2673	1.3375
yC8	0.07014	-1.0097	2.04
yC9	0.006149	-1.5176	2.4312

Figure 18 shows that for NPL natural gas dew points the GPA 2010 C6+ method is only slightly less accurate than using the complete analysis composition, and more accurate than the fixed 60/30/10 C6/C7/C8 split or the 47/36/17 split. The gas compositions from the NPL data (but not the dew points shown in Figure 18) were used in the development of the GPA 2010 C6+ method.

A more severe test is to use the C6+ predicted compositions outside the dew point range for which it was developed. A comparison of the CHDP calculated using the measured C6-C13 composition versus that calculated using the predicted C6-C13 composition is given in Figure 19. Background information on these data and its accuracy is unknown. The calculated dew points for these data range from 70 °F (21 °C) to just under 110 °F (43 °C), while the highest dew point temperatures used in the correlation were slightly above 70 °F (21 °C). Also shown on Figure 19 are dew points

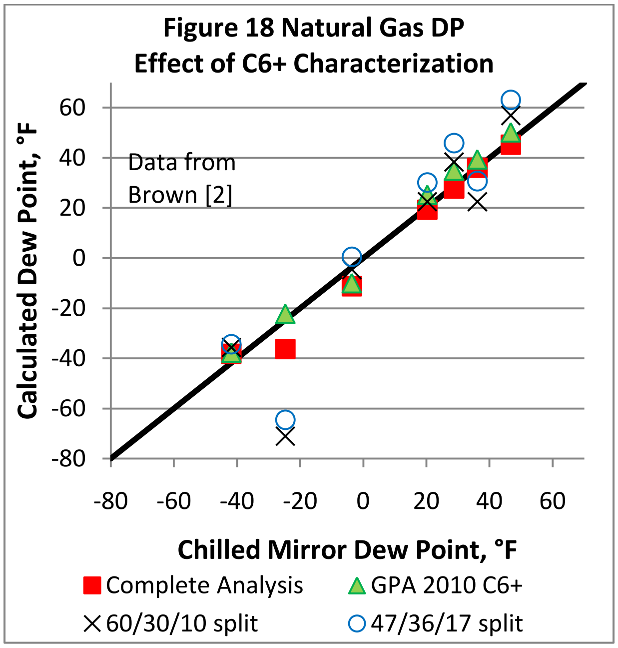


Figure 18 Natural Gas DP
Effect of C6+ Characterization

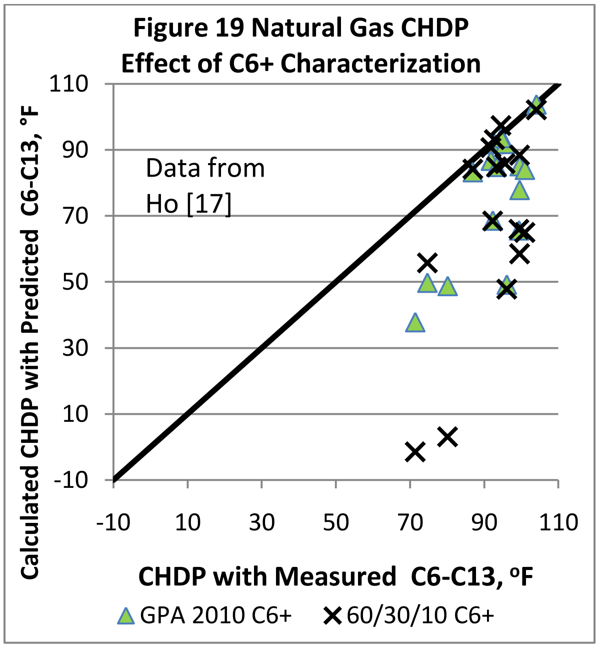


Figure 19 Natural Gas CHDP
Effect of C6+ Characterization

calculated with a fixed 60/30/10 split. For this data set, both techniques result in dew points that are substantially low in some cases. In addition, the fixed 60/30/10 split resulted in dew points that were low by 70-80 °F (39-44 °C) in two instances.

These results demonstrate that it is possible to calculate dew points for many natural gases with reasonable accuracy using only compositional information for the lighter components and a lumped C6+ analysis. It should be recognized that the proposed correlation is empirical in nature and is highly dependent on the data used in its development. It should not be used to calculate dew points above 70 °F (21 °C). Use of this correlation for natural gas mixtures whose dew points are above the range of fit can result in large errors. The correlation was developed using measured compositions and no fitting was performed using dew point data. Therefore, the GPA 2010 C6+ method can be used with any equation of state which is properly calibrated. It is not restricted to the PR or SRK EOS.

The intended use of the GPA 2010 C6+ prediction method is in the calculation of pipeline quality gas dew points. In order to improve the accuracy of the method, it is suggested that natural gas extended analysis through C9 or heavier be obtained from as many pipeline companies as possible. These data should be used to improve the correlation accuracy and generality.

SUMMARY AND CONCLUSIONS

A validated equation of state along with compositions from an online gas chromatograph (GC) or laboratory GC can accurately calculate the hydrocarbon dew point (HDP) for natural gas mixtures as measured by the chilled mirror method. In addition to dew points, accurate condensation curves can also be calculated with a validated equation of state (EOS).

A practical HDP using the 0.002 GPM quality line (gallons of liquid per thousand standard cubic feet of gas) has been developed which takes into account not only the dew point curve but also the degree of condensation as the gas is cooled. At the 0.002 GPM practical hydrocarbon dew point, operational issues due to liquid condensation are negligible. Several years' worth of data from two operating pipelines have been used to test this proposed practical HDP concept. The operating pipeline data analyses indicate that, in very few cases at the delivery points, the JT cooling with pressure step-down may cause liquid condensation on the order of 0.002 GPM or slightly greater. However, operating histories indicate no reported liquids problems.

Calculation of the HDP or CHDP requires an accurate measurement of the composition. An extended analysis which characterizes composition through at least C9 should be used to obtain the most accurate predictions. When detailed characterization of the heavy fraction is unavailable, empirical equations have been developed which more accurately predict the C6, C7, C8, C9, and heavier components. These equations are a function of the mole fraction of C5 and C6+ fraction. The intended use of this new C6+ prediction method, known as the GPA 2010 C6+ method, is in the calculation of pipeline quality gas dew points. To further improve the accuracy of the method, it is suggested that an extended analysis through C9 or heavier be obtained from as many pipeline companies as possible. These data should then be used to tune the correlation and improve its accuracy and generality.

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