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Liquid Carryover
The Gap Between Theory and Reality

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1. Introduction

Recent findings indicate that the presence of liquids in natural gas supplies is being significantly underreported across the pipeline industry. These undetected liquids pose serious implications for safety, financial performance, and regulatory compliance. With the most common method of determining Hydrocarbon dewpoint (HCDP) specification being the calculation of HCDP from its components, this paper illustrates the large errors that can be incurred by this method. Improved detection and control of liquid contamination not only enhance operational reliability but also offer substantial cost-saving opportunities — delivering measurable financial benefits for both gas suppliers and transmission operators.

For decades, hydrocarbon dewpoint (HCDP) has been the industry standard for determining gas “dryness” in natural gas transmission and distribution. However, emerging evidence indicates that relying solely on dewpoint calculation is insufficient to ensure gas dryness. Process cameras now offer real-time visualization of gas flows within high-pressure pipelines, directly revealing liquid contamination at ambient temperatures while the reported HCDP indicates that the gas would need to be cooled to sub-zero temperatures before liquids appear.

These developments highlight the awareness of the risks in delivering liquids into compressors and the variability in HCDP measurement methods that lead to these kinds of errors. With discrepancies reaching nearly 100°C (180°F) for a single gas mixture, the resulting undetected liquids are unreported in many gas pipelines until it is too late, and a compressor or gas turbine is damaged or worse, explodes. Even small amounts of liquid—whether as mist or stratified flows—pose risks to equipment, incur costly disruptions, and compromise safe operations.

Traditional dewpoint measurements, although pivotal in gas sales contracts, only provide inferred data based on pressure and temperature calculations. Process cameras allow operators to detect liquid mist, stratified flows, and small volumes of natural gas liquids (NGLs) that conventional calculations overlook.

This paper presents results from some field studies illustrating the errors in current methods and introduces a complementary approach that integrates real-time visual monitoring with traditional dewpoint analysis. By incorporating process camera systems, gas processors and transportation operators can more accurately assess pipeline conditions, swiftly address contamination issues and thereby enhance pipeline integrity, optimize maintenance and mitigate operational risks. Ultimately, this approach represents a transformative shift towards more reliable gas quality protocols, ensuring both accuracy and safety in gas transmission and distribution.

2. Methodology

The LineVu process camera system is designed to be installed on high-pressure gas pipelines. Normally installed on top of the pipeline using an existing tapping point, the camera and illumination system looks vertically down into the pipeline below providing images of the pipe floor and mist flow in the pipe (Figure 1). To achieve the level of safety required for use with high-pressure combustible gases, the Camara is certified to Class 1 Div 1, ATEX and IECEx Zone 1. The camera and illumination system are mounted in a secondary containment vessel capable of containing full line pressure up to 104.4 Bar (1,514 psi).

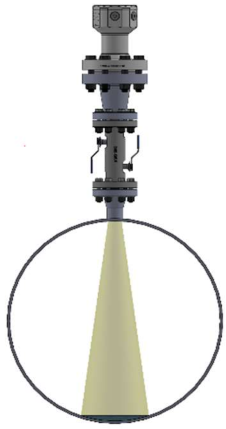

Figure 1, Process Camera installation

The heat produced by the illumination system is distributed to the pressure retaining sapphire window raising its temperature by around 5˚C (9˚F) thereby preventing condensation on the window, should condensing conditions exist within the pipeline. The camera is normally installed with an isolation valve allowing installation and removal between locations without a complete system shutdown. The short vertical section between the pipe and the camera means that the optics are recessed from the pipeline flow and contamination that may be in the gas flow does not reach the window. The camera is connected via a single Power over Ethernet (PoE) cable to a control unit (portable or fixed) providing local operators with a live view of pipeline activity (Figure 2).

Figure 2. A live view from inside a high pressure gas pipeline

The control unit is connected via a secure uplink to a remote server where data is analyzed using both human and machine learning systems so that alarms can be set and remote engineers can view the analysis and video.

When process data, e.g. flow, pressure, and HCDP can be provided, this can be overlaid on the video for more detailed analysis of events. Ultimately the system alarm functions can be connected to SCADA or DCS systems and a monitor can be installed in the control room.

3. Result

The four images below (Figure 3) show clean gas, stratified flow, and mist flow. Features on the pipe floor can provide points of reference. It should be noted that the still shots below do not convey as much information as the videos from which they are taken.

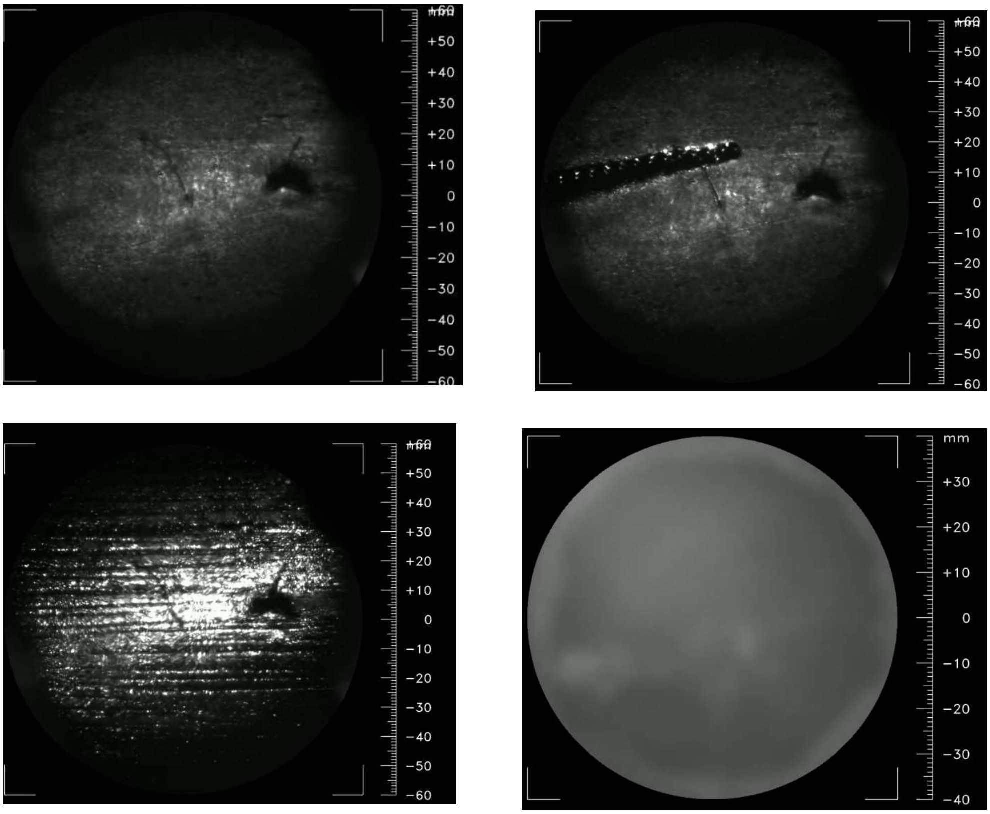

Figure 3. Top left - dry gas. Top right - stratified flow of compressor oil.

The images above show gas flow in real-world installations in a 36 in. (0.91 m) pipeline with various contamination flows. The gas pressure was 63.4 Bar (920 psi), and the gas flow velocity was around 4.6 m/sec (15 ft/sec). The top left is dry gas flow, and the top right is a stratified flow of compressor oil with a surprising worm-like shape. The bottom left is a stratified flow of condensate in many small streams, and the bottom right, a severe mist flow where the pipeline features are completely obscured by the mist. Stratified flow and mist flow can occur independently and simultaneously. Computational fluid dynamics (CFD) models would indicate that stratified flows occur at low gas velocities and mist flows occur at high velocities. However, observations of stratified flows have occurred at both low and high velocities, and mist flow observations at both high and extremely low and even stationary gas flows. Many parameters affect the way contamination moves in a mixed-phase flow in large-diameter pipelines, e.g., a mist flow in a 100-km (62 miles) pipeline can turn into a stratified flow if there is a momentary gas flow rate. Temperature, liquid density, liquid viscosity, pipe surface roughness, bends, and flange joints all have a part to play. It is common to see mist and stratified flows at the same location on separate occasions and occasionally at the same time.

a. Stratified Flow - Significant Errors in Reporting Hydrocarbon Dewpoint and Btu

When liquids are present in a gas flow, they can be conveyed in either a mist flow, a stratified flow or a combination of both. Figure 4 shows the view from the top of the pipeline in a gas flow at a custody transfer point in a 12" diameter pipe. A stratified flow of condensate can be seen and a large volume of liquid streaming on the pipe wall. While liquids are present, the gas phase does not contain mist, and the reported HC dewpoint was -43°C while the process temperature (and therefore the actual dewpoint of the saturated gas phase) was +25°C.

Figure 4, Condensate flows at the bottom of the pipe.

During this study, the gas flow was stopped for 4 hours and the reported HCDP increased from -43°C to -5.3°C. The calorific value (Btu) of the gas also increased from 1,075 to a maximum of 1,088 during the outage as can be seen in Figure 5 below.

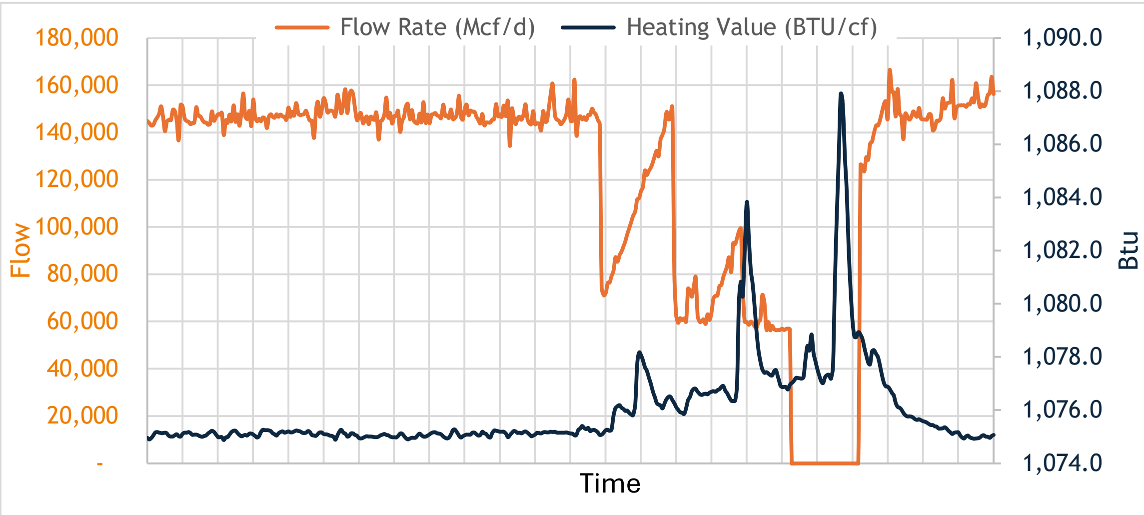

Figure 5. Btu Vs Flow

It was believed that, during the outage, volatile liquids at the bottom of the pipe were vaporizing into the gas phase causing an increase in the reported values. The gas chromatograph (GC) data was investigated to examine what was happening to the gas components during this time. Fig. 6 shows the % change of each component during the outage.

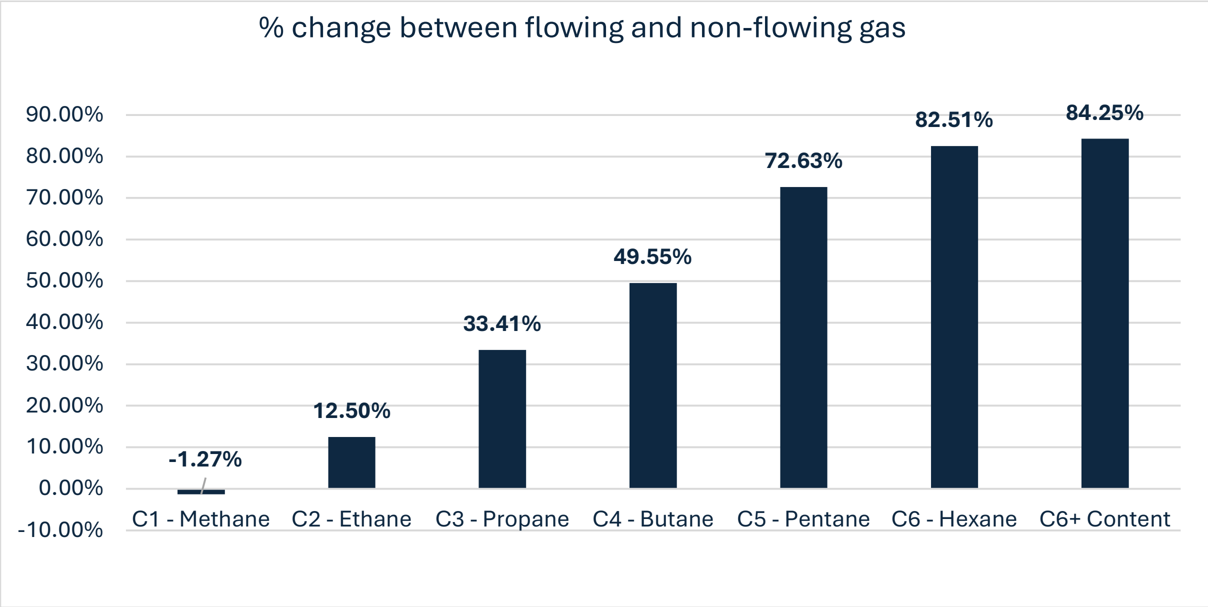

Figure 6. Change in gas phase HC Components

It is worth noting that thermodynamics would expect that as a gas cooled to below its HCDP the heavy ends (C6+) would condense first and only the C6+ components would be present in the HC liquid at the bottom of the pipe. *However, all the hydrocarbon components above methane (C1) also increased showing that the liquid contained a mixture of hydrocarbon components.*

It is also worth noting that, if the gas phase has time to come into better equilibrium with the liquid phase during a period of zero flow, it follows that during normal flow conditions the two phases are not in equilibrium and normal sample system designed in accordance with API 14.1[1] would not detect the increase in Btu and HCDP as the sample probe for the gas analyzers is within the middle third of the centreline of the pipe.

b. Mist Flow - Significant Errors in Reporting Hydrocarbon Dewpoint and Btu

Image processing can show the severity of a mist flow and categorize the trend in the following methodology:

0	Clear gas	Very clear views of the pipe floor
1	Light mist flow	Some shadows/light areas/obscuration observed
2	Light to medium mist flow	Heavy continuous shadows/lighter areas/obscuration
3	Heavy mist flow	Totally obscured pipe floor

Trending mist flow in this way allows video to be converted to useful data and presented in charts and heat maps. In Figure 7, a repeating pattern of mist clearing is seen as temperature rises. As the temperature of the gas increases, the mist disappears and returns as the temperature drops – appearing and disappearing at around the same temperature on a steady-state gas flow for several days. This is a fundamental observation of dewpoint.

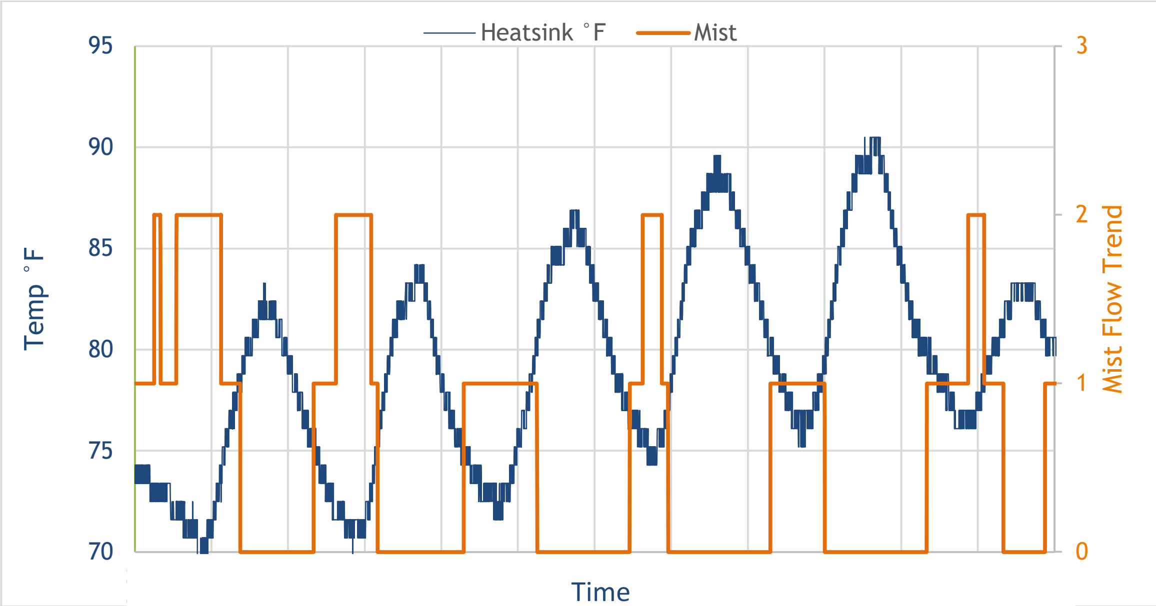

Figure 7. Temperature Vs Mist flow showing the temperature dependant appearance of mist- day to night

Alternatively, a heat map (Figure 8) displays significant amounts of data quickly highlighting areas of concern. Each row in the heat map is one day of data, and each column represents a 30-minute period from midnight through the 24-hour period to midnight for each day. Presenting data in this way shows repeating patterns.

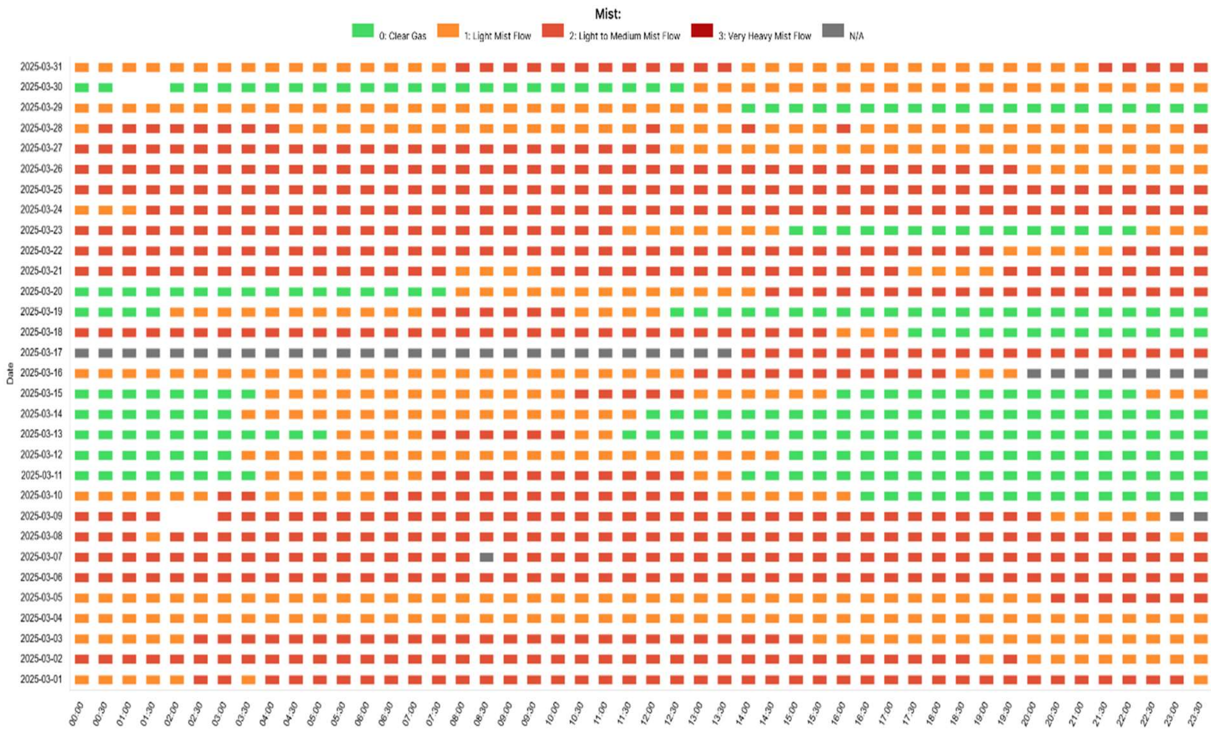

Figure 8. Heat Map

Using this fundamental observation method can validate other techniques that measure dewpoint by cooling a sample of gas to its dewpoint and observing condensation form on a cooled surface. However, it provides dewpoint data that is significantly different from calculated HCDP.

4. Discussion

Several different common practices for calculating the hydrocarbon dew point from a GC analysis were investigated by Embry[2] using a typical gas composition of:

Taking a typical gas composition as an example:

	Component	Mole %		Component	Mole %
N	Nitrogen	1.9580	C4	Butanes	0.0190
CO_2	Carbon Dioxide	0.0070	C5	Pentanes	0.0020
C1	Methane	96.7878	C5	n-Pentane	0.0010
C2	Ethane	1.1470	C6+	C6+	0.0042
C3	Propane	0.0750		HHV (Btu/SCF)	1001

The example gas meets gas quality specifications in terms of inert gases, energy content and C6+. But, using the HCDP calculation method from the gas constituents, 6 possible models are available:

Method	Method Description
C6 Only	Treat C6+ as n-hexane only.
60:30:10	Common practice of splitting C6+ into n-hexane, n-heptane and n-octane at a ratio of 60:30:10
47:35:17	Common practice of splitting C6+ into n-hexane, n-heptane and n-octane at a ratio of 47:35:17
60:30:10 Exp	Common practice of splitting C6+ into n-hexane, n-heptane and n-octane at a ratio of 60:30:10 while expanding the C8 as a C8+ using an exponential distribution using n-paraffins out through C16+ with C16+ treated as n-C16. Exponent rate determined by C6+/C8+ ratio.
C10 Only	Using an analysis out through C9+ and treating the C9+ as n-C10
C6+/C9+ Exp	Using an analysis out through C9+ and expanding the C9+ using an exponential distribution using n-paraffins out through C16+ with C16+ treated as n-C16. Exponent rate determined by C6+/C9+ ratio.

The results show a wide range of HCDP at the cricondentherm temperature:

Method	HCDP at Cricondentherm °C (°F)
C6 Only	-69.4 (-92.9)
60:30:10	-51.9 (-61.4)
47:35:17	-48.2 (-54.7)
Low Sep Exp	-5.5 (+22.0)
C9+ as C10	-14.9 (+5.1)
C6+/C9+ Exp	+34.2 (+93.5)

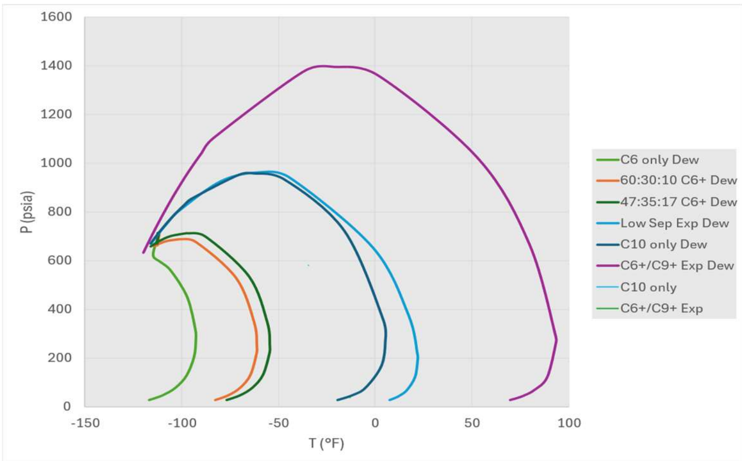

Figure 9. The wide span of results from the 6 commonly used methods

These data show HCDP results from -69.4°C (-92.9°F) to

+34.2°C (+93.5°F) a span of 99.1°C (186.4°F) and significantly compromises the conclusions that can be made by reporting HCDP in this way.

Enbry[2] then conducted further work demonstrating the impact of phase change on HCDP. Calculating that 10 ppm of the above gas mixture had changed phase to liquid hydrocarbons and were present in the gas stream as a mist flow — effectively creating a wet gas condition. The study compared HCDP values before and after phase change across various hydrocarbon models:

Model	Cricondentherm HCDP	
	Dry °C (°F)	Mist °C (°F)
C6 Only	-69.4 (-92.9)	-70.7 (-95.2)
60:30:10	-51.9 (-61.4)	-57.9 (-72.3)
47:35:17	-48.2 (-54.7)	-53.8 (-64.9)
Low Sep Exp	-5.5 (+22.0)	-52.8 (-63.0)
C9+ as C10	-14.9 (+5.1)	-25.8 (-14.5)
C6+/C9+ Exp	+34.2 (+93.5)	-23.7 (-10.6)

In all cases, the results show a significant shift toward a lower (dryer) dewpoint — giving the impression of "drier" gas. This occurs because a portion of the heavier hydrocarbons has transitioned to the liquid phase and is no longer available for detection by a gas-phase analyzer, such as a gas chromatograph (GC). Consequently, the operator would incorrectly conclude that the gas is within acceptable dryness limits, even though the model reflects a wet gas condition.

This misrepresentation is further compounded by the inherent complexity of liquid-gas equilibrium in flowing systems, as discussed earlier. As a result, many engineers relying on HCDP calculations overestimate gas quality and remain unaware of the presence of substantial free liquids in the pipeline.

Where process cameras are employed to visually confirm the presence or absence of liquids, GC-based measurements — including Btu calculations — can then be interpreted with far greater confidence and accuracy. Without such direct confirmation, however, there is a significant risk of underreporting the presence of liquids and overestimating gas quality leading to substantial downstream complications.

The presence of liquids in what is expected to be a dry gas stream creates challenges across several critical dimensions of gas transportation and measurement:

a. Errors in Fiscal Metering

Accurate fiscal metering is essential for custody transfer, billing, and contractual obligations between suppliers and purchasers. The presence of liquids interferes with measurement accuracy, leading to disputes, financial discrepancies, and potential regulatory non-compliance.

Even minor measurement errors can have significant financial implications. For instance, a 0.25% error in gas volume measurement at a transfer rate of 3 million standard cubic meters per day, priced at $5.00 per million Btu, can result in an annual financial risk of approximately $480,000 per year[2].

A study by CEECI[4] indicates that orifice plate and ultrasonic flow meters will exhibit errors from -2% to +15% depending upon the level of liquid present.

Figure 10 below outlines the typical financial losses incurred by gas suppliers (typically gas processing facilities) due to liquid carryover into the export pipeline, based on a flow rate of 100 million standard cubic feet per day (MMscf/D). Since mist-phase liquids travel at the same velocity as the gas stream, significant volumes of valuable hydrocarbons can be inadvertently transported. Importantly, these entrained liquids are not captured in the Btu-based gas sales measurements, leading to unaccounted product losses. The cost estimates presented are calculated using a five-year average of composite liquid prices.

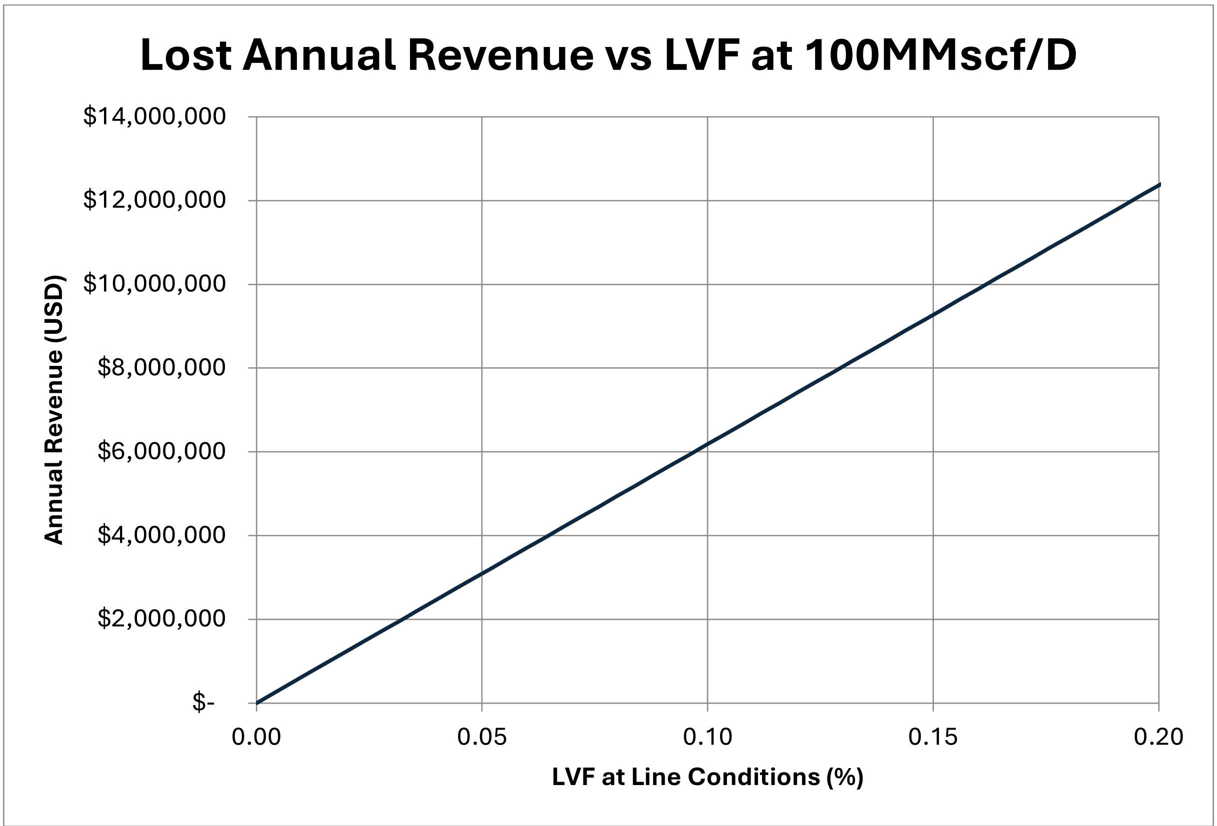

Figure 10. Lost Revenue with low levels of mist flow

b. Increased Pressure Drop

Liquids in a gas pipeline increase turbulence and frictional resistance, contributing to a higher pressure drop across the system[5 & 6]. This can force compressor stations to operate at higher power levels, driving up operational costs and reducing overall energy efficiency.

c. Reduced Line Capacity

Pipeline systems are engineered based on assumed flow conditions. The introduction of liquid phases reduces the effective cross-sectional area for gas transport and alters the flow regime, which diminishes throughput capacity and may lead to flow assurance issues.

d. Increased Compressor Servicing

Entrained liquids can lead to mechanical wear, erosion, and fouling of compressor components. This not only shortens equipment lifespan but also increases maintenance frequency[7], unplanned downtime, and associated servicing costs. In natural gas processing, 60% of plant failures are attributed to liquid carryover at the inlet to the gas treatment process.

e. Increased Pigging Costs

Liquids accumulating in pipelines must be removed to maintain flow integrity. This often necessitates more frequent pigging operations—adding to labor, equipment, and safety management expenses. In extreme cases, slugging may lead to pipeline instability or even damage.

f. Pipeline Integrity

Allowing liquids into gas pipelines significantly increases the risk of internal corrosion, decreasing asset life and increasing the risk of pipeline rupture when liquids pool at a low point in the gas network. As happened near Carlsbad, NM on August 19th in 2000[8].

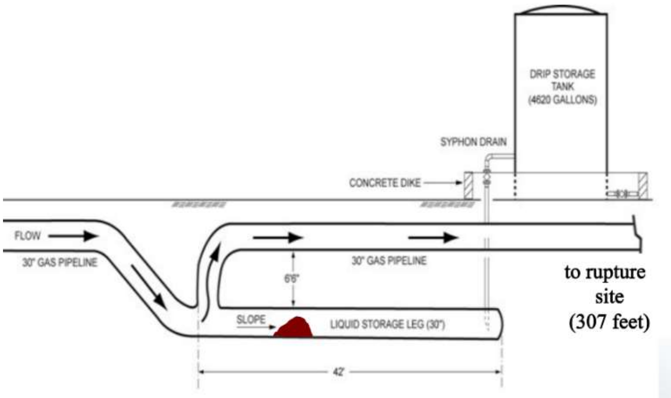

Figure 11. The Drip showing the solid material conveyed by liquid events blocking the entrance to liquid storage leg

In a 30" diameter pipe a liquid separation system known as a "drip" (Figure 11) upstream of the rupture site was blocked by solid material accumulating in the throat of the liquid storage leg. This effectively forced the entrained liquid further downstream where it pooled at a low point 307 feet away from the drip. The explosion killed 12 people and caused significant damage.

The National Transportation Safety Board investigation found severe internal corrosion at the rupture site. Figure 12 shows the fireball after the initial explosion. The bridge support structures at 85 feet (25.9m) indicate the scale of the fireball. The escaping gas created a 51-foot (15.5m) crater. 49-foot (14.9m) section of the pipeline was ejected from the crater.

Figure 12. Post rupture fire. At the lower left of the fireball can be seen an 85-foot tall support structures for a pipeline suspension bridge.

5. Conclusion

This paper has demonstrated that the current industry practice of calculating hydrocarbon dewpoint (HCDP) from gas composition data introduces significant and often dangerous inaccuracies when assessing gas dryness. Field data and case studies confirm that liquid contamination is frequently present in gas streams when standard dewpoint calculations suggest otherwise. Discrepancies of nearly 100°C (180°F) in dewpoint estimates highlight just how misleading these models can be, particularly when liquid-phase hydrocarbons are no longer represented in the gas sample.

The consequences of underestimating liquid content are far-reaching: from errors in fiscal metering and reduced pipeline capacity to increased compressor wear, pressure drops, and unplanned downtime. These operational and financial risks are compounded by the industry's continued reliance on inference-based measurements, which cannot provide the real-time visibility needed to prevent costly incidents.

Process cameras capable of operating in high-pressure combustible gases offer a complementary solution by enabling operators to visually confirm the presence, severity, and behavior of liquids in high-pressure gas pipelines. This capability transforms gas quality assessment from a theoretical model to an observed reality—allowing gas processors and transmission operators to respond with far greater confidence and precision.

By integrating visual monitoring with traditional measurement systems, operators can more accurately assess risk, optimize system performance, and uphold safety and compliance standards. In doing so, the industry moves closer to operational excellence and a more robust and reliable approach to gas quality assurance—one that aligns predictive modelling with on-the-ground operational realities.

6. Acknowledgments

The authors would like to thank the technical teams at National Gas, ConocoPhillips, and various unnamed operators for their collaboration and the valuable data provided during field studies and site trials. Their openness in sharing operational insights and allowing the use of real-world footage and performance data has been instrumental in demonstrating the practical implications of undetected liquid contamination in natural gas pipelines.

We also acknowledge the contributions of the engineering, research, and data analysis teams at Process Vision, whose continued development of real-time monitoring technologies—particularly the LineVu system—has enabled the observations and findings outlined in this paper.

Special thanks to the individuals involved in reviewing the visual data and supporting the validation of mist flow classification and Btu analysis trends. Their expertise has greatly strengthened the technical credibility and practical relevance of this work.

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