See What's Happening in Your Pipeline:
The Future of Gas Plant Management

Author: Paul Stockwell, CEO, Process Vision

Abstract

This paper explores both the financial and the safety issues of allowing liquids into gas transmission networks that lead to $ms of lost revenue and pose serious safety threats.

The two fiscal measurements of flow and calorific value are compromised when liquids are present in normally dry gas streams. Monitoring gas flows with a new process camera system shows that many gas supplies, thought to be dry, actually contain liquids in mist flows and stratified flows. This paper shares real-world examples and tests showing that many gas processors are giving away BTUs in the form of NGLs without knowing it.

With the ability to look directly into high-pressure gas pipelines, this paper describes how this new technology is discovering that phase separation and NGL recovery systems are not necessarily performing to specification. Traditional analysis systems conforming to API standards to monitor water and hydrocarbon dewpoints can lead the industry to be unaware when fault conditions exist, allowing liquids to pass through custody transfer points without tripping alarms.

Using image processing and machine learning to categorize the severity of contamination turns interesting videos into data that is being used as a new metric for process control.

1. Introduction:

All dry gas flows have the potential to become wet gas flows, and accidental liquids in gas transmission networks create hidden financial costs and pose serious safety risks. Good phase separation at both the front and back end (NGL recovery) of gas processing are vitally important to ensure an efficient process and, in some cases, can provide an easy win to boost production, reduce maintenance and improve safety.

Liquid carryover is the number one cause of failures in gas processing, causing loss of production through foaming or the risk of foaming, fouling and the use of extra chemicals to de-foam and chemical scavengers to remove impurities.

Observations have shown that, unless phase separation is performed to a high level at low temperature, it is common for sales quality gas to be transported as a wet gas, despite water and hydrocarbon dewpoint systems indicating that a dry gas is present. Carryover of glycol from dehydration systems is common and yet currently not a parameter that is monitored at the custody transfer point.

The impact of liquid carryover in gas processing and gas transportation touches many different disciplines within the industry: asset integrity and reliability managers to process control managers, flow assurance managers and lost and unaccounted-for flow engineers. This paper aims to pull together the different disciplines that need to understand what is going on in the process or pipeline to better manage the performance of gas systems and reduce the frequency of liquid carryover events.

There is currently no permanent monitoring system for phase separation and filtration systems. These systems protect vital assets and processes, and their performance should be judged on the contamination allowed through rather than the contamination that is stopped.

For the first time, engineers are able to view inside a live pipeline and reveal that when these “dry gas” systems are monitored, often mist or stratified flows are present. With this monitoring in place, the performance of different gas processing trains on a gas treatment plant can be balanced to minimize carryover and the differences investigated. Action can be taken to improve phase separation to reduce the threat of foaming, comply with tariffs and reduce the cost of operations for Transmission System Operators (TSOs).

With gas sampling systems that comply with API standards, liquids in gas flows are removed to provide the gas analyzer systems with a representative gas sample. Therefore, with liquid carryover events and failures in phase separation systems going unnoticed and unreported, the industry is running blind. The impact is that crucial measurements such as flow, and calorific value are compromised, resulting in losses of $bns annually. Captured using innovative process camera systems, videos demonstrate how unseen liquids can slip past gas analysis systems undetected and leave operators unaware of problems until it is too late. This paper shows that validation of flow monitoring and calorific value measurements can be improved by monitoring with a process camera system.

2. Process Cameras

With commercial contracts and legal requirements that gas is shipped, bought and sold on a dry gas basis, using process cameras capable of imaging high-pressure gas pipelines and systems has, for the first time, allowed operators to see what is really happening in the pipeline. This has revealed that liquids are more prevalent than one might expect. The impact of liquids on dry gas flow measurement and gas analysis is enormous, and this new metric can be used to better understand and improve the performance of gas processing, gas transportation and the uncertainty budget for fiscal measurements.

Providing experienced process engineers with live-streaming video gives real-time feedback to operators and often produces data that questions the status quo.

3. A Camera on the Pipeline

The process camera is normally mounted vertically on a pipeline and provides views of the pipeline floor by illuminating and imaging through an isolation valve. This setup is for ease of installation by using existing tapping points. The images from the camera are a plan view of the pipeline floor. Liquid streams, solids and mist flows can be observed. Aerosols (liquids and solids) travel at, or very close to, the gas velocity, while stratified flows at the bottom of the pipe travel due to friction with the gas and travel much slower than the gas. There are many factors that determine the speed that stratified flows travel; density, viscosity, gas flow rate, pressure and surface roughness are some of the factors. When live streamed to the control room, there are often reports of liquid streams being present while no other alarms have been activated. The metadata of the image, for instance, the brightness returned to the camera (or the variation of brightness), is a useful parameter to show the stability of the gas flow and can be used as an alarm threshold. Using machine learning provides an automated alarm with a deeper understanding and categorization of the severity of the incident.

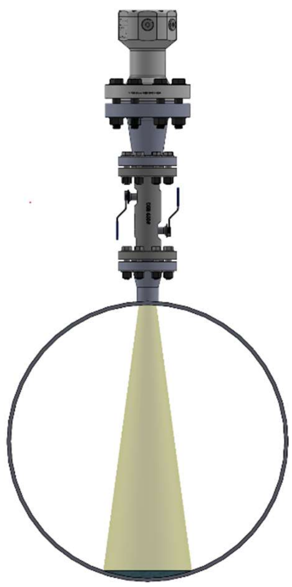


Figure 1. LineVu mounted on a gas pipeline.

The live streamed video and the associated data is proving to be a useful new metric for process control of gas processing plants providing engineers with a better understanding of what is happening at the outlet of a phase separation system and other parts of the gas treatment process. TSOs are using the data as an additional quality check on gas entering the gas network.

4. The Gas Journey

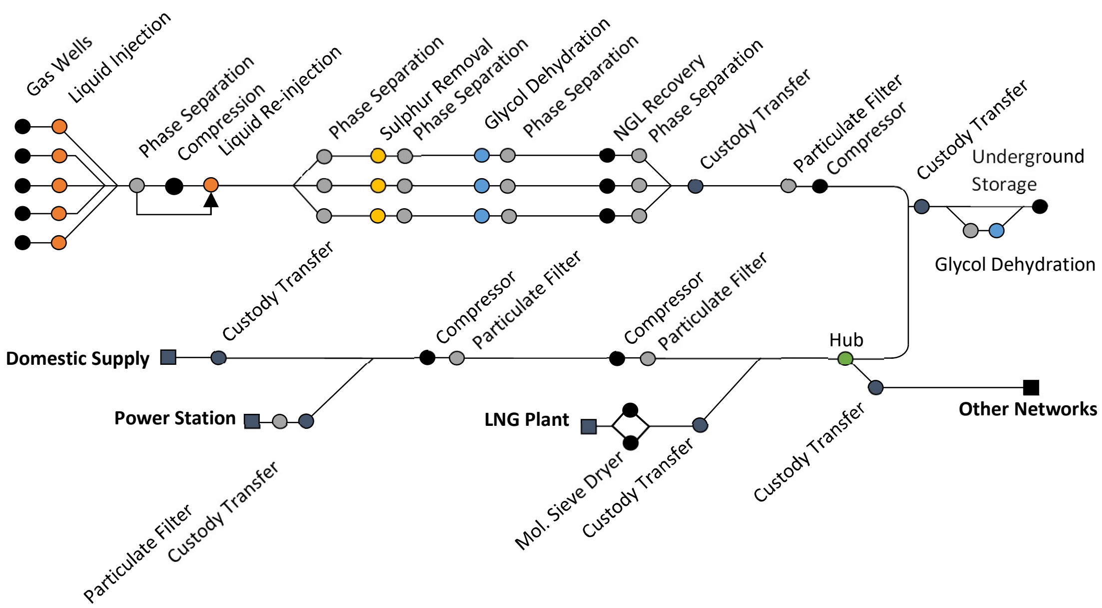


Figure 2. The Gas Journey

Figure 2. is a simplified diagram of the journey the gas takes from the gas well to the points of use. At the gas well, crude oil, condensate, water and sand are usually present. In addition, further liquids are added: hydrate mitigation, corrosion inhibitor and bactericides are common. At this stage, it is an intentionally mixed phase flow, but all add to the liquid loading of the gas entering the front-end phase separation at the gas treatment plant. There may be a compressor between the gas wells and gas processing plant where liquids are removed and, if local disposal is not economical, re-injected. So compressor oil can be added to the possible contaminants of the gas as it enters the gas processing plant.

5. Liquid Carryover in Gas Processing

Ideally, only gas enters gas processing as, in a detailed survey by Amine Experts[1] indicates, the efficiency of the front-end phase separation is vital. 400 amine plant failure cases were included in the survey finding three main causes shown in *Figure 3*:

Each of the 400 cases had a cost to the operators of between $250k to $250m.

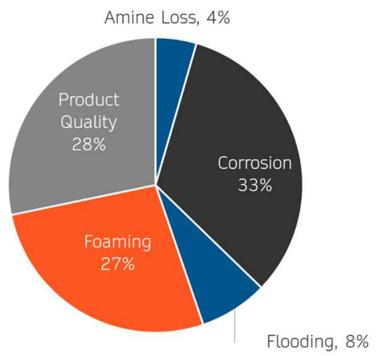


Figure 3. The three main causes of amine plant failure [1]

The survey concludes that the main causes of:

- Corrosion is poor amine quality or insufficient regeneration;
- Foaming is contaminated gas at the inlet;
- Product quality is insufficient heat.

Two out of the three causes of plant failure (poor amine quality and contaminated gas at the inlet) highlight the need for better filtration and phase separation at the gas entry to processing plants. The results of the survey (*Figure 4*) show the causes of foaming.

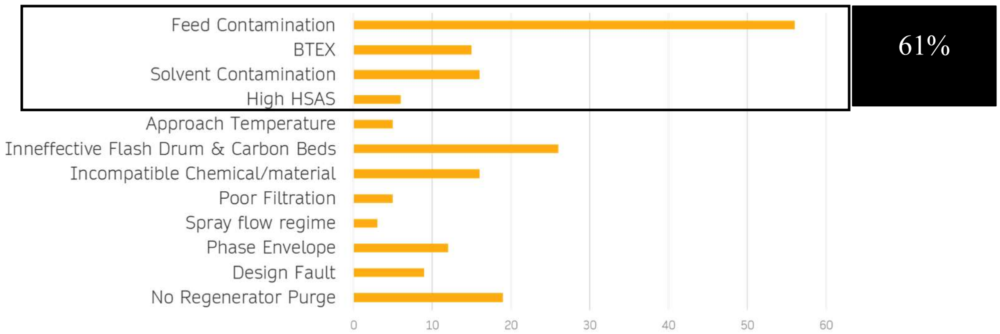


Figure 4. Main causes of foaming[1]

Four causes are due to contamination of the inlet gas, indicating that incorrect phase separation is the number one cause (61%) of foaming events. With better knowledge and understanding of the condition of the gas at this stage of the process, immediate action can be taken to add de-foamer early and avoid a foaming event, rather than have to cut the gas flow in order to get foaming under control. De-bottlenecking studies can be taken to understand when and how break-through occurs, implement better maintenance practices on demister pads, justify the cost of improving the phase separation if required and prove that the solution has worked.

As foaming is a major risk, many gas plants limit the gas flow and are running under the optimum flow rate to give a "margin" in case of foaming. The greater confidence that a process camera brings allows operators to run a little closer to the optimum in the knowledge that they can react quickly if a liquid event occurs.

As the gas moves through de-sulphuration and de-humidification, large quantities of liquid come into intimate contact with the gas. If not separated, liquid carryover will contaminate the next stage of the process, NGL removal. Once the gas is sweet and dry, the usual method of extracting as much NGLs as possible is to reduce the temperature of the gas, force the gas below its hydrocarbon (HC) dewpoint and separate the liquids.

When temperature reduction is achieved totally or partially by pressure reduction, it creates the right environment on a flowing gas to produce a sub-micron mist flow; the most difficult type of liquid to filter out. In many cases, the temperature is achieved, but while good technology is available to separate mist flows, it is not commonly implemented. As the gas warms back up, the liquids vaporize, making the vapor phase saturated with respect to hydrocarbons, and the pressure HC dewpoint and temperature are the same. The situation is exacerbated as sample systems intentionally separate anything that has already changed phase (*See Section 12)*.

When pipelines are pigged, one of the frequent components removed is glycol. Similar to compressor oil, it is not a liquid that is vaporized easily, and gas analyzers cannot monitor glycol carryover as the vapor pressure is so low. For glycol to be present in gas pipelines, it has to pass through two-phase separators, and it is unlikely that glycol would pass through the phase separator at NGL recovery without allowing NGLs also pass through. In these cases, operators do not gain the full financial benefit of NGL recovery but still have the expense of reducing the temperature of large volumes of gas.

6. How Much is Too Much?

When observing contaminated gas flows, the question is, how much is too much? The usual term of reference for sales gas is the tariff between the gas processor and the TSO. The wording of a typical interstate pipeline contract is shown below:

> "The gas shall be commercially **free from** objectionable odors, bacteria, solid matter, dust, gums and gum-forming constituents, **free liquids, crude oil, and any other substance that might** interfere with the merchantability of the gas, or cause injury to or **interference with proper operation** of the lines, meters, regulators, compressors, processing plants, or appliances through which it flows."

FERC – Cimarron River Pipeline, LLC

While there are no numbers quoted in the same way as moisture and hydrogen sulphide limits, the wording gives the TSO the authority not to accept the gas if it is likely that it will damage compressors or other assets downstream. This sets the bar pretty low, as damage to dry gas seals in compressors is caused by contaminated gas.

7. Compressor Damage

A survey performed by the Health and Safety Executive in the UK[4] examined 71 compressor failures. Each failure cost \$60k - \$120k plus loss of production. Both compressor manufacturers and users were asked what the design life requirements are of dry gas seals. Actual life was determined by the survey:

- Design Life Requirements (Manufacturers and users): 5 Years
- Survey Results: 1 Year 20 days (average)

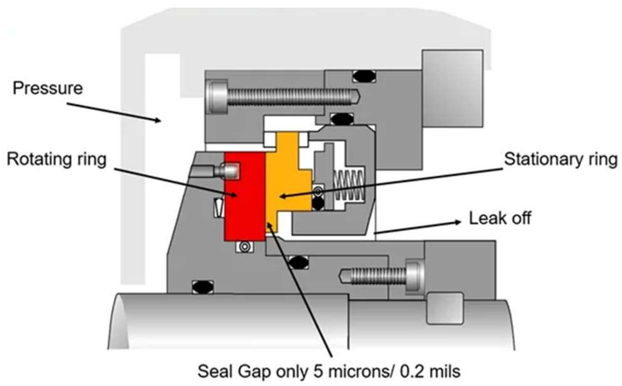


Figure 6. Simplified diagram of a compressor dry gas seal

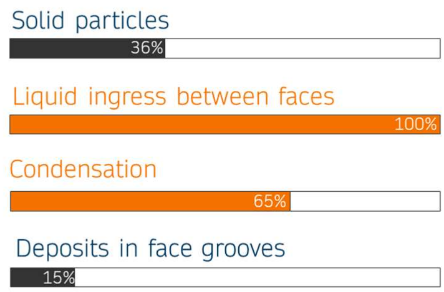


Figure 5. Causes of dry gas seal failures

Dry gas seals are usually labyrinth seals where the gap between static and rotating components is around 5 microns, as seen in *Figure 6.*

The survey found that the main cause of failures was contaminated gas (*Figure 5*) where 100% of failures showed liquids were found between the faces of the seal. The gap is controlled by gas pressure, and when liquids or solids are present, they bridge the gap allowing a greater temperature to be conducted which compromises the gap. When the two parts touch, excessive wear takes place, shortening the life of the seal significantly and, in some cases, causing a loss of containment.

8. Examples of Contaminated Gas Flows

The four images below *(Figure 7.)* show clean gas, stratified flow and mist flow. It can be seen that 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.

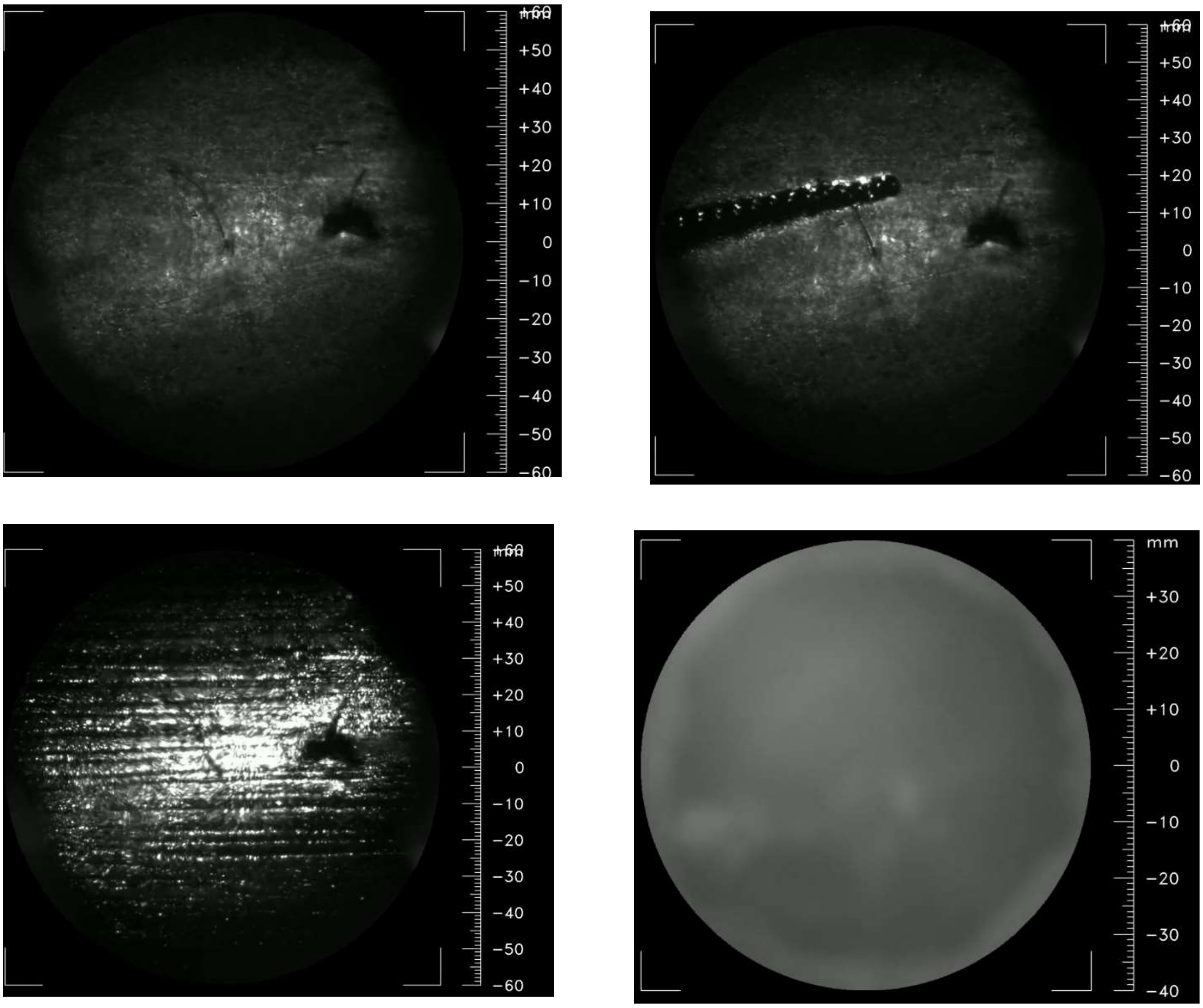


Figure 7. Top left - dry gas. Top right - stratified flow of compressor oil.
Bottom left – stratified flow of condensate. Bottom right - mist flow

The figures above show gas flow in real-world installations in a 36” pipeline with various contamination flows. Gas pressure was 920 psi and gas flow velocity was around 15ft/second. Top left is dry gas flow, top right a stratified flow of compressor oil with a surprising worm-like shape. Bottom left is a stratified flow of condensate in many small streams, and bottom right, a severe mist flow where the pipeline features are completely obscured by the mist**Error! Reference source not found.Error! Reference source not found.**. Stratified flow and mist flow can occur independently and simultaneously. Computational fluid dynamic

(CFD) models would indicate that stratified flows occur at relatively low gas velocities and mist flows occur at relatively high velocities. However, observations of stratified flows have occurred at both low and high velocities, and mist flow observations at both high and very low and even stationery 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-mile-long pipeline can turn to a stratified flow if there is a momentary drop in 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 different occasions and occasionally at the same time.

9. Diurnal Changes

When mist flow is present, it is common to observe diurnal changes. The level of mist flow increases during the day, and decreases at night. It is very repeatable, and in some cases, the pipe floor is completely obscured at the maximum point of mist flow. This phenomenon is similar to diurnal variations in water dewpoint on overground pipelines. While the dewpoint may be -40°F with a 5 -10 °F variation, it is explained by the pipeline being heated by the sun during the day and any water vapor in the pipe wall (and the material on the pipe wall) out gasses into the gas flow and "wets" the gas as shown by a small increase in the dewpoint. At night the reverse happens, and water vapor achieves equilibrium with the pipe wall (and the material on it) in the reverse direction, and the dewpoint decreases again.

It is therefore believed that the presence of repeatable diurnal changes indicates that a volatile gas is present, most likely NGLs.

10. Dry Material Conveyed in a Pipeline

Figure 8. shows grease-like contamination that, once gas flow was initiated, developed small liquid flow streams on its surface. Rapid gas flow across the top of slurries and grease-like material draws off the lighter end liquids. Over a period of a few weeks, this material becomes much drier, and so explains the mechanisms behind dry material being removed when lines are pigged. With stratified flows, liquids move down the pipe because of friction with the gas. These events contain solid material. As the liquid is moving, the quicker-moving gas above progressively dries out the liquid, leaving denser liquids and a higher solid content to a point where the contaminant is sufficiently dense and viscous to slow and then stop. It then continues to dry as stationery material on the pipe floor.

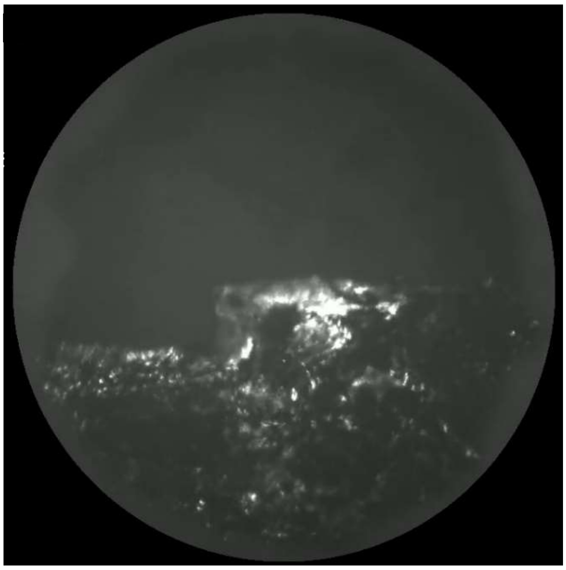


Figure 8. Grease-like contamination

11. Liquid Separation Within the Pipeline

Figure 9. indicates a phenomenon observed in a 36" diameter pipeline. It shows two stratified flows, compressor oil, the worm-like flow at the top and bottom of the field of view, and a stream of liquid in the center. It would appear that these two different-density liquids have separated in the pipeline. It is hoped that this data can be fed back to improve CFD models.

Gas flow is from left to right, and the liquid flow is at an angle to the "apparent" gas flow. As the installation was 10 ft from the second of two 90° bends, it is likely that the gas flow is twisting and, as liquid flow is derived from friction with the gas flow, the gas is pulling the liquid flows up the side of the pipeline. Full annular flow in large-diameter pipelines has not been observed to date.

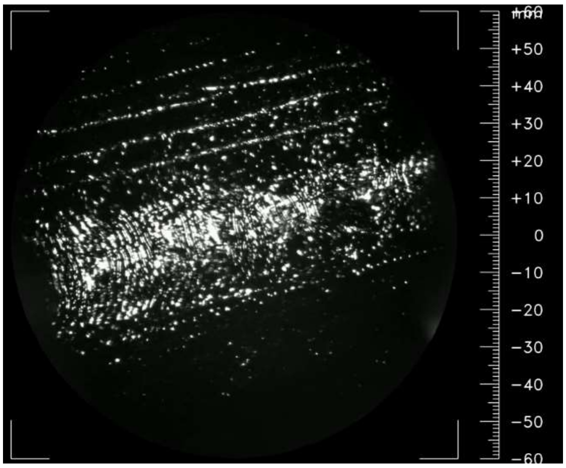


Figure 9. Duel liquid flow

12. Errors in Fiscal Measurements - Calorific Value

It is important that gas chromatographs (GCs) and other gas analyzers are protected from liquids. API and GPA standards require that a stabbing probe or quill are used to remove the gas samples from the middle of the pipeline (*Figure 10.*) to avoid any contamination on the pipe wall. Additional membrane or coalescing filters are used between the tapping point and the gas analyzer to ensure long-term, uninterrupted service. The sample system is therefore providing a representative *gas* sample to the analyzer where any liquids present in the pipeline (glycol, amine and NGLs) are not included in the sample to the GC and other gas analyzers.

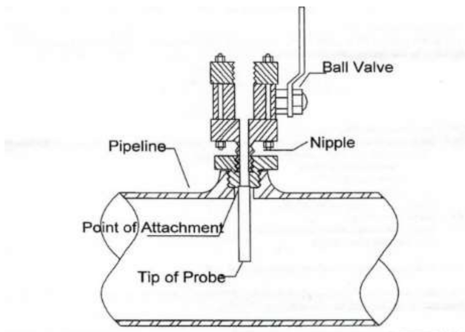
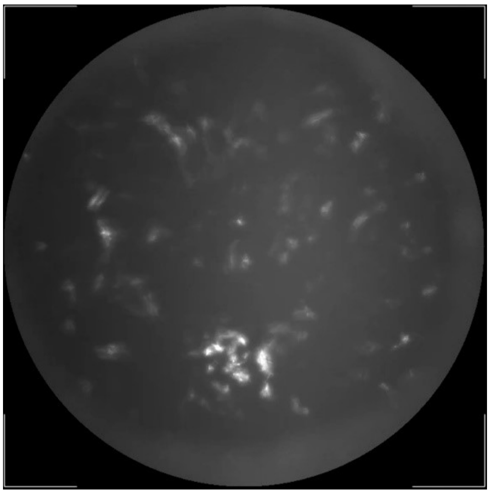


Figure 10. Stabbing probe for gas analysis

When liquid onset starts, as in the example (*Figure 11.)* a stratified liquid flow across the full field of view can be seen. The graph of both water and HC dewpoint shows no response from either analyzer system. It



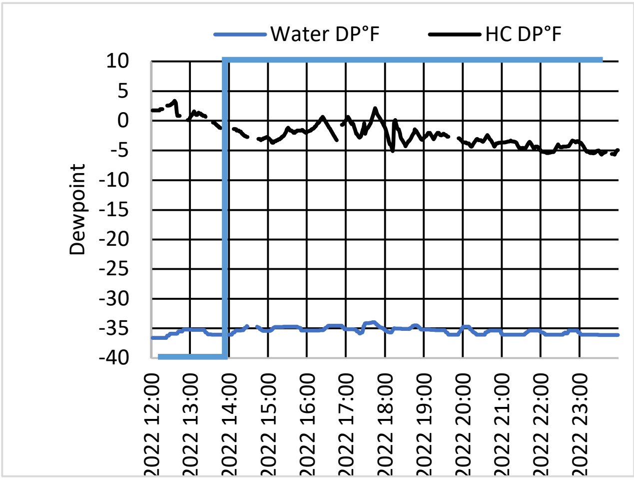


Figure 11. Stratified flow of NGLs on the floor of a pipeline and dewpoint trace indicating no change at the onset of the contamination event.

was assumed, therefore, that the liquids must be glycol. However, when the gas flow was stopped, the pipeline de-pressurized, and purged with nitrogen before introducing air, the liquid evaporated over 24 hours. As the liquid was volatile, it rules out glycol (MEG and TEG) and compressor oil, leaving only NGLs as the possible suspects. As described above gas analyzer sample systems are designed to avoid and remove any liquids. While this is good practice for the long-term service of gas analyzers, it leaves operators unaware that these large-scale liquid events are happening. In addition, calculating HC dewpoint from GC data can also produce a false sense of security as, in many cases, measured HC dewpoint is much wetter than calculated HC dewpoint.

It is important to note that during periods of mixed-phase flow, there will be large errors in calorific value (>40 btu). Getting a true picture of the calorific value of the fluid stream in mixed-phase flows is complex. Even with iso kinetic sampling operating at high temperatures and a GC that can process both gas and liquids, stratified flows will still not be included, and liquids in the mist flow coalesce on the sample pipework causing large spikes. Gas analyzers can only report on the portion of fluid they are presented with, and at present, this means that:

- Measurements made at custody transfer points are wildly in error when a two-phase flow is present, and
- Operators are unaware when mixed-phase flow is present.

Installation of a process camera validates gas analyzer measurements when there is single phase flow and alerts operators when a mixed-phase flow is present.

13. Errors in Fiscal Measurements of Flow

The flow assurance and uncertainty budgets for fiscal flow measurements are required to detail and account for potential errors. Sarbanes-Oxley compliance [3] addresses lost and unaccounted-for (LUAF) flows in natural gas and means that errors should be accounted for. Unexpected liquids in dry gas systems add a substantial amount to the uncertainty budget for flow measurement[2]. It is an important parameter that should be included in all flow uncertainty budgets. Liquid events can interfere with flow measurements in two ways.

Firstly, when liquids are present, dry gas flow meters will read in error[2]. With these errors being up to 2% of reading, one way to reduce the uncertainty is to have an undisputable monitor on the gas flow as an assurance that the gas is actually a single phase.

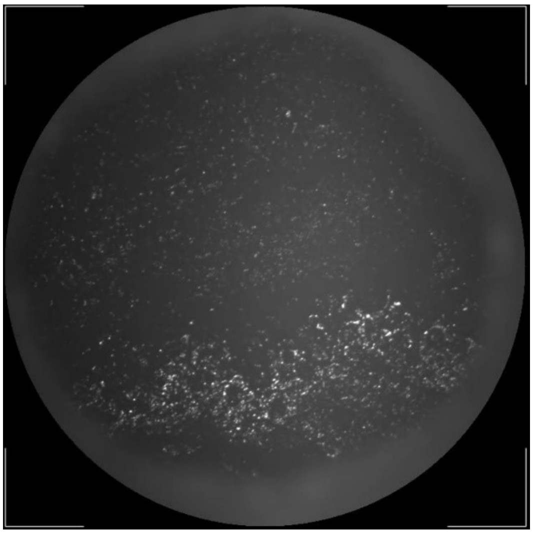


Figure 12. Material on the pipe floor after a liquid event

Process cameras have observed that when liquid stratified flows occur, they often transport solids that, once the liquid event is over, are dumped on the pipe floor (*Figure 12.*). These solids can be a mixture of iron sulphide, scale and other particles that have either evaded filtration or are a product of reactions with the gas and pipe wall. They are conveyed as a slurry that, with the rapid gas moving above, slowly drys to solid matter and creates a permanent reduction in pipeline diameter. When this happens in flow metering stations, even small amounts (2 or 3 mm) can produce errors of 0.3%. With the overall uncertainty target for fiscal flow measurement being <0.5%, this creates a significant and permanent offset. It should be noted that this error is independent of the flowmeter calibration or type of flow meter used. Flow stations are usually unpiggable sections of the pipeline system that should be inspected and cleaned regularly.

14. Pressure Drop Across the Gas Network

As liquid accumulates in the low points of a gas transmission system, it reduces the diameter of the pipeline in that area. Thousands of gallons of liquid hold-up can be present when phase separators are inefficient or fail. The restriction in this area means that there are higher compressor costs to move the gas at the required flow rate.

15. Cost of Pigging and Disposal of Contaminants

With traditional pigging costs estimated at between \$2.5m to \$3.3m for a 30-mile section[5], pigging is a costly and risky operation. The risk of a stuck pig often means that lines are pigged with progressively more aggressive pigs prior to a smart pig being deployed. If asset integrity managers and pigging crews knew that contamination ingress had been managed and minimized with process cameras noting the contamination events, the risk of pigging operations can be reduced and the frequency optimized. With less pigging, methane emissions would reduce from venting at the pig launcher and receiver. For TSOs with cameras at the inlet custody transfer points, stopping contamination events could substantially reduce pigging requirements and, if contamination has been allowed to enter the gas network, the costs of cleanup (pigging and disposal of the resulting materials) could be allocated to the party that supplied the contaminated gas to the TSO.

16. Pipeline Corrosion - Internal

Liquid hold-up in pipelines creates an additional risk of corrosion that can lead to pipeline rupture, as happened at the incident at Carlsbad, NM[6]. The cause of the incident was the failure of a "drip" separator (*Figure 15*). The drip is an underground spur off the main pipeline. The spur is lower than the main line and, therefore, should collect stratified flows of liquid. At Carlsbad, the liquid had also conveyed solid material, which accumulated in the throat of the drip. 80% of the cross-sectional area was blocked by solids. Liquids continued into the pipeline and accumulated in the low point section. The investigation found significant internal corrosion had occurred, causing the rupture. *Figure 14 & Figure 13* show the ensuing fire and damage caused by the incident that killed 12 people. Monitoring pipelines for liquid carry-over lets operators know if mist or stratified flows are occurring.

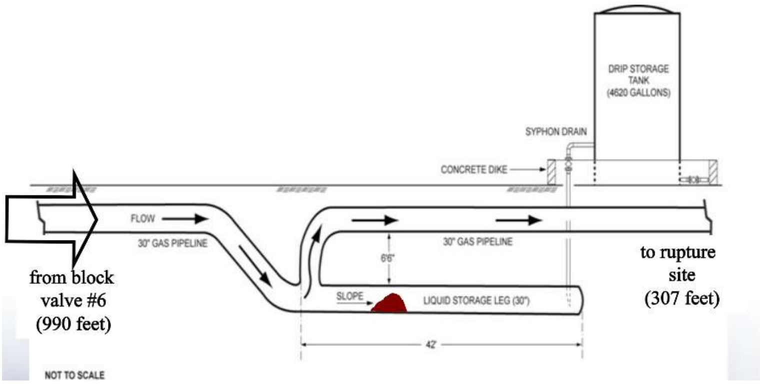


Figure 15. Solid Material in the throat of the drip was the cause of the liquid carryover.

Figure 14. The fire after the initial explosion

Figure 13. Rupture site showing crater and bridge supports

17. Pipeline Corrosion - External

Underground pipelines are usually protected from external corrosion by the use of cathodic protection (CP) systems. A small DC voltage is set up between the underground pipe and a sacrificial anode, thereby protecting the pipe section from corrosion when pipeline coatings and coverings are breached. In order to function properly, an isolating joint is inserted between under-ground and over-ground sections. However, when solid material is conveyed along the pipeline, it breaches the isolating joint and, being electrically conductive, compromises the CP system.

18. Increase Risk to Power Stations

By the time the gas reaches the power station, a number of factors increase the likelihood of contamination:

- Glycol and NGLs contaminating the gas at the inlet to the transmission system
- Lubrication grease from valve operations
- Compressor oil leaking into the gas
- Iron sulfides collected from the pipe wall

All contribute to contaminated gas reaching the power station and causing a number of maintenance issues:

- Stratified flow causes uneven combustion around the turbine, putting high stresses into the turbine
- High wear on fuel nozzles
- Hot spots on turbine blades, causing some turbine blade holes

Most power stations will heat the gas to 300°F, which should vaporize low-level NGLs if they are present, but will not vaporize glycol or compressor oil. It should also be noted that this heat is not available at start-up, and flow starts and flow ramps are where the majority of stratified flows have been observed, leaving power stations vulnerable to liquid events and flow meter errors due to high levels of solid material in the flow meter lines.

Figure 16. Fuel nozzle

19. The Lifecycle of a Stratified Flow Event

Figure 17 shows the total brightness returned to the camera, one of the parameters that is used as an alarm threshold. This liquid event was caught on two process camera systems on the same pipeline, one on the supply side, the other with the TSO around 900ft downstream of the first camera. When the gas is dry and stable, the difference between the maximum (blue) and minimum (red) values is small. The liquid event was a stratified flow of liquids which started around 8:30 pm on the supply side when the difference between the maximum and minimum values rapidly increases but did not reach the TSO side until around 1:00 am the next morning. On the supply side, the event was completed and returned to dry gas but was extended by the time the liquids got to the TSO side. As the camera systems were able to demonstrate that the event was over on the supply side, even though the TSO was still seeing liquids it was decided, on that occasion, to allow the gas to continue to flow in the expectation that the liquid flow would decrease and stop within the following few hours.

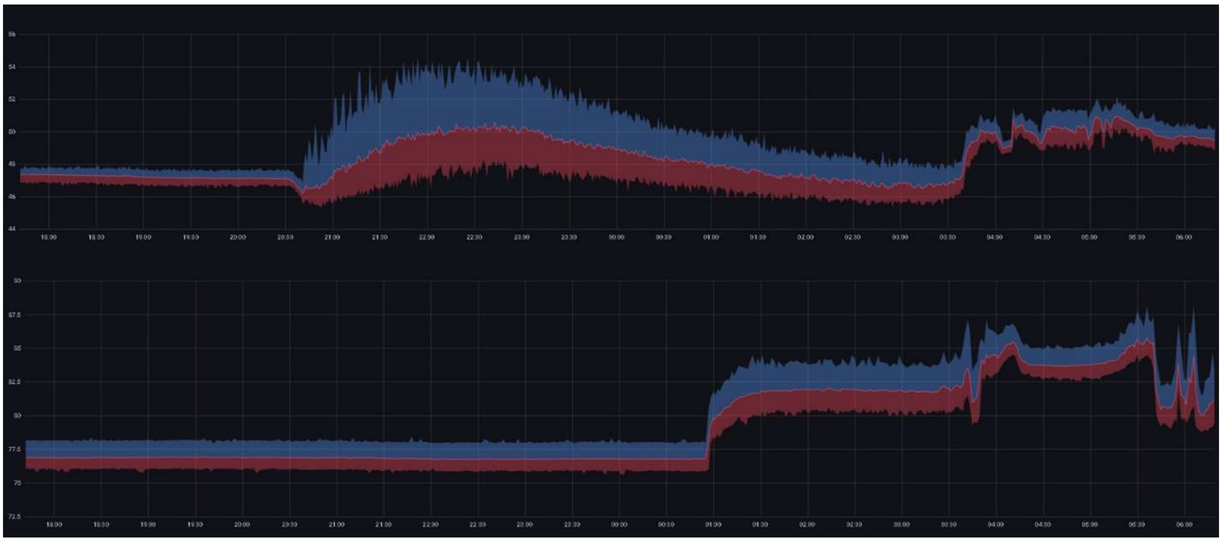


Figure 17. The lifecycle of a liquid event

20. Summary

Process cameras can be used to great effect as a cost-effective method to:

- Increase production in gas plants
- Improve NGL recovery
- Lower flow meter errors
- Lower pigging and disposal costs for TSOs
- Lower compressor servicing costs

21. References

[1] *Trends in Tragedy – An in-depth study of Amine system failures, Amine Experts*

[2] *Comparisons of Ultrasonic and Differential Pressure Meter Responses to Wet Natural Gas Flow, Richard Steven, Josh Kinney & Charlie Britton, Colorado Engineering Experiment Station Incorporated*

[3] *Gas Measurement Has Key Role In Sarbanes-Oxley Law Compliance, Tim Nesler, EMS Pipeline Services, Houston, TX*

[4] *Hydrocarbon Release – dry gas seal integrity survey report – Offshore Technology Report 2000/070*

[5] *American Pipeline Solutions.com*

[6] *Pipeline Accident Report Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico August 19, 2000*