WHAT'S IN YOUR PIPELINE?
(And do you really want to know?)

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Introduction

With the current demand for improved technologies in the area of natural gas measurement, the rush to the market place is raising as many questions as it is answering. In the last 25 years, the natural gas pipeline industry has transitioned from the supplier of clean, dry gas to the mover of billable gas energy; clean and dry or dirty and wet. Designing and creating improved products for the measurement of volume and quality has provided new challenges as the marketing and transportation of natural gas has changed.

Perhaps the single major issue that has created an interest in ascertaining the total picture of the natural gas pipeline system is "wet gas." The definition of "wet gas" as gas with more than 7 lbs. water per million cubic feet is almost history. Wet gas metering is redefining how we talk about wet gas. There is a white paper written by Dr. Parviz Mehdizadeh that describes wet gas. Wet gas in that multiphase white paper is defined as "gas, which contains some liquid. The amount of liquid can vary from a small amount of water or hydrocarbon to a substantial amount of water or hydrocarbon." Today's measurement issues are different from the past, but they are here to stay. We must either return to the insistence and requirement of a clean, dry gas pipeline system (separators, processing plants, dehydration systems, etc) or acknowledge the realities of the present. One of the biggest challenges is the multiphase system. Liquids cause corrosion, pulsation, freezing problems and basic maintenance issues that create concerns for a natural gas pipeline system. Their presence must be addressed.

This paper is presented with the desire to focus on the lessons learned from the past, review the technologies that we have at present and to consider the challenges that lie ahead. It is the author's desire to stimulate dialogue about the ultimate goal of measurement quality equipment for the industry as it operates in the real world today. In order to promote discussions, there has to be an awareness of the issues that impact the pursuit of new procedures or technology. The concerns of the natural gas measurement industry are real and legitimate concerns. However, in the race to find answers, we should not fail to keep in mind lessons that we have learned and have documented to be true in the past. If we keep that in mind, it will allow us to appreciate the current advancements and accept how we arrived at them. As we look for answers in the new world of gas pipeline measurement, we should not purge the data base of knowledge just to solve one aspect of the problem. We must incorporate that knowledge into the pursuit of future advancements. Technology can provide solutions to these new challenges but as we provide advancements in measurement, we must be cautious to not retreat from lessons that we have learned in the past.

In the last two to three years, a term has become very commonplace in our industry. A few years back the term was not to be found on the cover of an industry magazine. Today, it appears on the cover as many as 10 times during a 12 issue year. That term or phrase is **"Pipeline Integrity"** and its meaning is legion. To one person, it means billable quality and to another it means structural soundness and to yet another it means operational stability. But we all agree, it means and encompasses a lot more today than it did 10 years ago. Today, it means everything that is right or everything that could go wrong in the transportation of oil, natural gas and petrochemical products.

Let's look briefly at a few of the areas that are affected by the new interest in Pipeline Integrity.

Volumetric Measurement

Volume measurement has undergone a major change with the advent of Ultrasonic Metering (USM). Issues that caused alarm with an orifice plate in the line have all but disappeared. Liquid slugs that slam into meter stations and deform orifice plates are now allowed to pass through relatively unnoticed, past non-intrusive meter heads. Faster flow rates and improved flow information have been widely achieved throughout the industry and a tolerance for a harsher environment has been established.

However, with the liberties of a less restrictive environment comes the concern of not knowing what has passed through the station and down the pipeline. This is not to say that liquids and the like never existed before, but with all the maintenance issues and equipment that was required to handle those liquids correctly, came the knowledge that they were there. Today, there is a potential to forget about their presence.

Therefore, while we have seen great improvement with the advent of the USM, we cannot suddenly forget the lessons of the past and assume that the USM is the solution to the need for any form of liquid identification.

While liquids do not destroy a USM as they might do with an orifice plate, they still need to be identified and their presence acknowledged.

With the introduction of USM technology, there has been an increase of volume in the pipeline because of the removal of the orifice plate. That alone allows for higher flow rates and faster velocities. With higher velocities comes the realization of the need to check designs of equipment that insert into the line. Previous flow rates were slow enough to cause little concern, but with higher flowing speeds in the pipeline, wake frequencies, bending moments and shear calculations become something of which to be aware. Engineering departments need to look at physical stresses in a new light. Old knowledge cannot be forgotten with new advancements.

Quality

The level of interest in effective and accurate gas sampling techniques is currently at a very high priority within the natural gas industry. With the recent dramatic increase in natural gas prices, exploration interests, profitability, deregulation and consolidation of the work force, recoverable revenue must be found and reported. At large volume delivery points, a 3-5 BTU error in energy determination can cost companies tens of thousands of dollars within a very short time period. Accurate sampling techniques must be implemented with equal interest as that given to accurate volume measurement. MMBTU is the total of volume and energy. Sampling is the energy determination delivery system for this equation, and the results have a dramatic influence on the volume measurement totals.

With the combination of USM and higher demands, our natural gas pipelines are seeing changes within the pipeline, relative to quality. Liquids are present for a number of reasons. One dramatic reason is simply the cost of natural gas. Producers are trying to meet the demand and sell product. In so doing, gas processing is being streamlined or reduced. Liquids are being passed along in the interest of providing energy. Another is a change in operations. Today, we pull from our storage domes harder and faster than ever before. This tends to increase the presence of liquids in the system. Deeper wells and colder pipelines in deepwater production is yet another source of liquids.

In the past 35 years, sampling systems have been refined to meet more exacting requirements of the industry and sampling standards have been revised to reflect the latest reliable knowledge and techniques. The equipment available today is truly "state of the art." Samplers, cylinders, probe regulators, protective filtration systems, separators, membranes, protective shut in devices for analyzers, enclosures and the like are available from a number of known manufacturers. Historically, natural gas was sampled as natural gas. Most equipment used in the gas industry is not designed to account for and handle liquids. Liquids have typically been removed and handled as a liquid product. Today, that is not always the case in a multiphase system. However, the quality of the pipeline product cannot be represented as accurate, if the method of taking a sample incorporates a technology or procedure that is designed to reject or isolate liquids that are present. Using a separator, coalescing filter or a membrane designed to reject the intrusion of liquids, is not providing the complete answer for the pipeline measurement department. If liquids never show up in the sample, but continue to be found in headers, river crossings and drips, then something in the procedure or technology is not allowing for a truly <u>representative</u> analysis to be attained. We must capture a representative sample regardless of the effort. Then, we need to develop a technology or procedure for correctly and accurately handling the combined sample. That is the challenge. Not ignoring, rejecting or masking the liquids! We figured out how to do that long ago. That is not sufficient anymore.

It is noteworthy, that the current and updated gas sampling standards all make the clear statement that they are to be used in gas streams that are clean, dry, non-saturated and above the hydrocarbon dew point of the flowing gas stream. Therefore, lessons learned in the programs need to be presented accurately and honestly. While there are indeed few issues with taking a sample of 1012 BTU gas at 80° F, it is not likely a good practice to infer from that data that there are few issues to be seen with 1348 BTU gas at 58° F. While it is true that a probe is not required in a laboratory test of nearly pure methane, it might be considered questionable to extrapolate that to a 10 year old 8 inch meter run installation in North Dakota with1246 BTU gas and only a bottom tapping and a valve for a sample point. While we continue as an industry to find new answers, we must not forget the lessons learned over the last 45 years.

If we state that we have taken a representative sample from a flowing stream, then it must represent ALL the components present in that stream. Not simply all the gas phase components of the stream. In the quest for pipeline integrity, we must know all the components of the gas stream. Not all the components act the same, flow at the same speed or stay equally dispersed across the pipeline inside diameter. It is not as simple at sampling a dry gas stream. That is the challenge involved in sampling a multiphase stream.

And, it bears repeating over and over again. Most flow equations receive the specific gravity portion of the equation from the analysis of the gas sample. If the analysis is deprived of the total picture, how can the volumetric answers be relied upon as representative of the total system. The error is compounded and the integrity of the system is compromised.

Allocation

In today's world, the natural gas industry is in a continual battle to provide energy to the consumer as quickly and efficiently as possible. In times past, individual companies explored, produced, processed and delivered their own product. Today, especially with the cost of offshore production, the picture has changed. Several companies may participate on one platform. Other systems may have multiple individual producers, but they all use the same pipeline to reach the shore. Gathering fields may have mixed partners and processing facilities. All of this is exciting and helps the end user with a steady supply of energy, but the difficulty comes on the business side. Companies are trying to make money and meet shareholder expectations. They want a fair allocation of the end result. Bluntly, you want to be paid equitably for the energy that you put into the system. Since much of the production goes into a common pipeline, there is a need for determination of volume and quality before it is processed and ready for normal measurement systems. Business integrity demands a method of determining the total content of the pipeline in a production phase, not just a processed phase.

Corrosion

Corrosion is an aspect of the total pipeline operation and integrity question that must get the whole picture. If the corrosion department is not informed of the total contents of the pipeline, then how are they to take the appropriate steps to protect and preserve the structural soundness of the pipeline system? If corrosive elements are present, but are overlooked by a procedure or technology that masks their presence, that is not helping the integrity issue. If we cannot ascertain all the information from a single source, then we need to state that clearly and provide guidance on the direction for attaining the missing information. There are sensors and methods to detect contaminants in the flowing stream. Those must be used if we are to be able to maintain the total package of "Pipeline Integrity." And there is new technology to be developed that can see the complete package. None the less, we cannot forget the lessons that we have learned and the principles that we currently know to be true.

Where are we?

There is excellent technology available in the industry. We have samplers and cylinders that allow us to maintain pipeline conditions and get a representative sample to the lab. We have the latest in flow measurement equipment that allows for higher degrees of accuracy than ever before. We have convenient systems for the removal of collected raw liquids from river crossings, ring mains and other natural low points, while not interrupting the pipeline operation. We have equipment for the detection of corrosion and methods for reducing corrosive environments in the pipeline system. We have advancements in processing and production that continually improve the total issue of pipeline integrity.

We have procedures and standards that supply correct techniques and guidance on how to prepare, handle and transport samples and train technicians in that process. We have the latest in standards that direct the industry in flow measurement devices and calculations. We have superior monitoring protocols for the protection of the natural gas infrastructure. All these elements continue to improve the industry and the quest for the very best overall approach to Pipeline Integrity.

We now need to look closely at procedures and technologies to pool this vast cornucopia of knowledge and refine it to meet the needs of a changing industry. Do we have the right equipment but the wrong procedure? Do we have the right understanding but the wrong application? Do we have the correct concept but the wrong equipment? Or do we have everything we need, but just not in the right order yet?

Conclusion

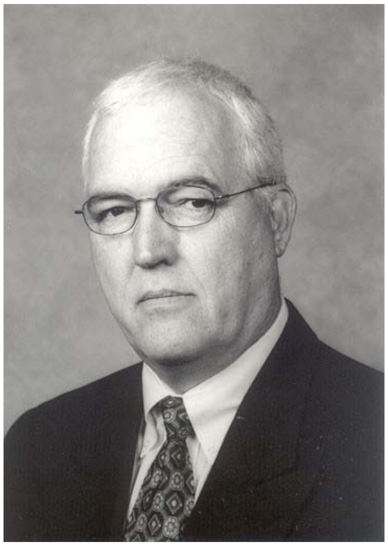
Much of the basis for this paper and its content is the result of the fact that we now see gas pipelines with more liquid content than before. Many are in fact, multiphase pipelines. At times, we are led to believe that our leaders of the past never faced or thought of this issue. This is why the author reflects in this paper about not forgetting the lessons of the past. Here is an interesting paragraph from a paper presented to the International School of Hydrocarbon Measurement in 1982. 22 years ago!

> "The ability to "tame" liquids when they appear in the gas sample streams or cylinders is now at hand with the availability of high quality new equipment. The capability of determining the heating value of the <u>gas</u> at any pressure and temperature condition can be determined with reasonable accuracy by conditioning the sample as it is directed to the measuring instrument. However, there is a need to more precisely define a "liquid" in our contracts and state how to account for the heating value of the fluid when liquid is present as an aerosol or otherwise. Should the Btu be determined on the gas at flowing conditions, or should it be determined at a greatly reduced pressure and elevated temperature? Should a pressure and temperature be selected for determining the Btu that would correspond with the average annual ground temperature and average annual pipeline pressure? These and other points must be resolved before any determined effort can be instituted to standardize Btu determination procedure on aerosol gasses."

And we are still working on that question today. It is all a part of this issue. We can no longer look for only one thing. We have to know what is there. All of it! The question of Pipeline Integrity centers on a very clear point………

What is in your Pipeline?

Do you know?



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Various Standards of AGA, GPA, API, ASTM and ISO

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