A CURRENT PERSPECTIVE ON MEASUREMENT
The Impact of Measurement in a Changing Business Environment

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INTRODUCTION

The measurement of hydrocarbons has evolved significantly through the years, from both a technical and business application perspective. Developments and advances in technology have made the measurement of hydrocarbons more precise, efficient and available. Changes in the energy business environment have placed the measurement of hydrocarbons into a more significant role within organizational and industry business processes.

A Historical Perspective of the Need to Measure

The Roman's discovered the value in measuring and controlling the flow of water throughout the aqueducts of their cities in order to better manage resources and serve the needs of the populace. The Chinese first developed pipeline systems made of bamboo and wood to transport hydrocarbons and water from supply regions to consumption areas. These early concepts and applications of natural resource acquisition, delivery and management were provisional to the needs of primarily Agrarian societies. The resources were consumed within the context of meeting the basic needs of people within the scope of their existence.

The onset of the Industrial Age changed the value and applications of the available natural resources to societies. No longer were these resources only applicable to agriculture, cooking, and lighting (via torches and lamps). These resources now were used as energy sources to ultimately create products and power. Oil and gas could be burned to create steam from water, which in turn could be applied to drive machinery that could produce more work output than humans alone.

As the properties of hydrocarbons became better understood, such could be processed and refined into sub products that had even greater uses. These products could be used as raw materials to create other products, such as textiles, fertilizers, chemicals and additives for other products, or as end products such as fuels. As the uses for hydrocarbons grew, so did the value. The measurement of hydrocarbons and the subsequent refined products began to take on greater importance because of the increased value of such.

One of the greatest technological innovations that dramatically affected the hydrocarbon industry was the invention of the internal combustion engine. This invention enabled the direct use of hydrocarbons as a fuel to power machinery. Since the energy contained within the hydrocarbons could be directly utilized to drive the machine, rather than indirectly as with the generation of steam, machines became more compact and mobile. Machines became available to virtually everyone as an affordable means of transportation, such having revolutionized the means by which the entire world functions.

But, the key to it all was still the hydrocarbon. The hydrocarbon based fuel must be available to operate the machinery around which the world functions. This has given even greater value to the hydrocarbon and the ultimate measurement and quantification of such. As technology has continued to advance, not only are the quantities of hydrocarbons important, but the composition and quality of the hydrocarbons as well.

Measurement in the "Old" Energy Business

The "Energy" business was born per the Industrial Age. Fuels were needed to power machines. An entire industry evolved from the need to discover, gather, transport, refine and deliver fuels. Because these fuels were of value, such had to be measured.

The measurement of fluids was accomplished by physically determining the amount of the fluid that passed a given point. The principals of these measurements were founded in applying the physical properties of the fluids to the principals of geometry and physics of the medium in which the fluid traveled. These measurements were part of operating the transport systems to move the fluids from one point to another.

The measurement of fluids was accomplished by strictly mechanical means. The most common means to measure was by passing the fluids though a restriction to create a pressure drop. The drop in pressure would be measured and related to the conditions under which the fluid was contained and a rate of flow determined. Devices were developed to record the measurement of pressure drop (differential pressure), static pressure, and temperature of the fluid. These recordings were then interpreted in relation to time in order to determine quantities.

The most common means of measuring hydrocarbon fluids became the orifice plate. A thin plate was placed in the pipe. The plate had a bore (usually concentric within the plate and pipe) through which the flowing fluid would pass. The pressure on each side of the plate would be measured to determine the pressure drop. This means of measuring the flowing fluid proved very reliable in that the systems withstood very harsh conditions and required little maintenance.

Other types of meters were also developed to measure hydrocarbon fluids. Turbine meters, wedge meters, displacement meters and others began to become commonly employed to measure hydrocarbons. All were mechanical systems and were employed per the conditions that existed relative to the needs and quantities of the fluids to be measured. The systems employed to record the measurements of the fluids were also of strictly mechanical means, and required subsequent interpretation to determine quantities.

Measured quantities of hydrocarbons were then reported to administrative groups within the energy organization. The accountants would then apply the price per unit of fluid to the total quantity for the time period and a statement would be forwarded to the party with which the transaction took place. The process was no different than any other business transaction, such as dry goods or groceries. The product was priced, the quantities measured or counted, the total price determined and the transaction finalized. The sequence of events in creating and finalizing the transaction were fixed and very simple. A to B, B to C, C to D, and so on. The need to measure or count units was just a necessary step in the process and was a physical function left to those who operated the pipeline systems.

These were the means by which the energy business and the measurement of hydrocarbons existed for many, many years. Subtle changes would occur per the development of some new mechanical measuring or recording systems, but for the most part, no significant impacts were realized as far as the role of measuring within the organization.

An Evolutionary Step

Along came the microprocessor, a small silicone based chip that could perform a multitude of mathematical functions that normally required the efforts of many people operating many machines to reach the same result. Computing had been around for a while, but such was not available to everyone. Large mainframes dominated the information management world and the use of such was limited in scope to the rigid structural environment of the system. Mainframe time was limited and expensive. The PC microprocessor introduced affordability and accessibility into the equation.

Until this time, hydrocarbons were traded virtually in terms of only quantity. "How much" was the only real issue. Content of the quantity and how much total energy was available were not so important. Gas was still cheap and the determination of quantities was very labor intensive. Detailed determinations of compositions and energy values were even more complex and had marginal monetary value to the transaction.

This all changed in 1978 per the passage of the Natural Gas Policy Act. This legislation was the cornerstone for the means by which natural gas is traded today, in terms of energy rather than just quantity. Sudden and dramatic increases in the value of natural gas, as well as other hydrocarbon based fuels, brought to light the need to consider the quality of the product, not just the quantity. It became the difference in buying a bicycle or a sports car. Both are transportation vehicles to get you from point A to point B, but one has significantly more features and performance characteristics than the other, and thus, the difference in value to the consumer.

Now natural gas was exchanged in terms of BTU's or Therms. The total amount of energy delivered was the basis for the transaction. Computing equipment had been implemented into the business processes, but measurement still was very labor intensive.

Measurement and Energy Go "High Tech"

The introduction of the microprocessor meant a new era for measurement. Computers could now be employed to record measurements, calculate volumes, store information and communicate with other information systems. Microprocessors also allowed the development of gas quality systems that could be implemented at the measurement facility. Such instruments were previously limited to the central laboratory. Fluid composition and quality could now be determined "On Site".

Various devices could be interfaced together in order to combine the recordings of measured physical variables, compositions and thermal values to render a total delivered energy quantity. This information could be made available to business units within organizations much faster in order that such could be applied to commercial transactions on a more timely and precise basis.

Energy could now be transacted upon in virtual "Real Time". The historic waiting period to gain access to vital information because of energy measurement, data processing and information provision to business units had been reduced tremendously by the development and implementation of computing and information technologies.

The microprocessor also enabled new research and development to occur with existing primary measurement devices, as well as the development of new primary measurement systems. Greater precision could be obtained by employing newly developed measurement and calculation mechanisms per the acquisition and implementation of better research data. New primary measuring elements, such as ultrasonic meters, were developed for use in measuring fluid flows. Computing power enabled these meters to be implemented on a production basis because the huge amounts of data acquisition and processing required to precisely and successfully utilize these systems could now be accomplished.

These technologies that spawned the creation of new measurement, recording and communication systems created huge amounts of data to be managed. Client-Server based information systems were developed to efficiently receive, process, validate and transmit this information to business systems. More and better information could now be derived, processed and utilized with much less required work and human intervention.

Energy Gets "Real Time"

Readily available and precise information changed the scope of the energy business. Energy could now be traded in "Real Time". Precise quantities of energy could be transacted upon on a daily or even hourly basis, at different prices and under different conditions. The energy market place now resembled the stock market.

A key to this market concept being successful, though, was the integration of the measurement of products into the business cycle mainstream. No longer could measurement be maintained as an upstream process whose product slowly trickled into the business cycle for "end of period" processing. The function had to be an integral part of the dynamic process that enabled business to be conducted and finalized "Now". Huge monetary benefits to all interested parties were at stake. Not only was measurement an engineering and operations process, but now a vitally integrated business necessity.

Because of this new integration into the business relationship, measurement personnel had to be more knowledgeable of the energy business process. Also, personnel had to have greater cognizant understanding of other business processes, such as accounting, finance, contract administration and commodities trading practices and implications. Measurement was now a truly "Business" process, not just another step that was necessary in the core operation of the pipeline system.

This also created a need for measurement personnel with new skills and education. Not only were engineering and operations principals important, but also proficiencies in business disciplines and processes. The new "Measurement Man" was now required to wear more hats, have broader understandings of the entire engineering, operations and business processes, and continually develop new proficiencies as technologies and business practices progressed.

Discussions among today's industry measurement managers not only focus upon the engineering and operations aspects of the process, but as much upon the business related implications of the measurement processes as well. Highlighted topics at today's industry conferences are often the impact of LAUF (Lost and Unaccounted For) product, minimizing the "after the fact" processes of having to "scrub" measurement data in order that such may be immediately applicable to current business transactions, and the continuing development and implementation of measurement information technologies that are integrated directly into the primary business system platforms of the organization.

THE BUSINESS IMPACT OF MEASUREMENT

Errors in measurement, product sampling and analysis can result in significant financial implication to operating organizations. The value of employing measurement, sampling, conditioning and analytical processes and procedures that help ensure the representative measurement of fluids and components is vital to the optimization of product economic value. Subsequently, the optimization of product economic value is critical to the financial health and performance of operating organizations. First, the fluids that we are measuring and sampling are important to understand.

<u>Fluids</u>

Natural Gas

Natural gas is a naturally occurring hydrocarbon gas mixture primarily composed of methane, ethane, propane and heavier hydrocarbons; carbon dioxide; nitrogen; and may contain other diluents or contaminants such as hydrogen sulfide or water vapor. Natural gas is priced per the Decatherm (Dth) or Million British Thermal Units (MMBTU). The most commonly referenced pricing index in the United States is Henry Hub.

Condensate & Crude Oil

Natural gas condensate is a mixture of hydrocarbon liquids that are present as gaseous components within raw natural gas at various concentrated amounts. The heavier components condense out of the raw natural gas as the flowing temperature of such drops below the hydrocarbon dewpoint. Some condensate is termed as "produced condensate" as such is actually produced at the well and does not occur within pipelines that are downstream of the production equipment. This indicates that the condensation of the hydrocarbons occurs within the well due to the combination of pressure, temperature and fluid composition, and the produced gas emanates from the condensate. Hydrocarbon liquids are generally categorized as condensate when such have an API Gravity of 45° or greater.

Crude oil is petroleum liquid, generally of an API Gravity of 45° or lower, that possesses large amount of heavier hydrocarbons. These heavy hydrocarbons are categorized as Alkanes (Paraffins), Cycloalkanes (Naphthenes), Aromatics and Asphaltics. The amount of each class of heavy hydrocarbons in oil compounds varies greatly across production areas.

Both natural gas condensate and oil are priced per the US Barrel (42 gallons). The pricing indexes used are primarily classified by the geographic region of production, the most commonly referenced domestically being West Texas Intermediate (WTI) and internationally Brent.

<u>Operational Parameters</u>

Initial Production (Flow) Rates (IP)

Initial Production (IP) is an important and challenging aspect of measurement system design, both from the operating and economic perspectives. At points of production, wells will experience IP rates that are very often much greater than the sustained production rates that will be realized as the well operates over time. This challenges the operator to implement measurement systems that can accommodate the high initial flow rates at the well site, and subsequently provide satisfactory accuracy as the flow rates decline. Subsequently, the composition of the produced fluids often vary in relation to these declining rates of production as the lighter hydrocarbons are often produced in greater amounts initially, and more of the heavier hydrocarbons are produced in greater amounts as rates decline.

Sustained and Declining Production (Flow) Rates

As the initial production rates decline, the measurement system must be able to accommodate these changes in flow rate and compositional variability with acceptable levels of accuracy and uncertainty. As stated previously, this offers a challenge in designing systems that can perform satisfactorily under varying conditions. Sometimes, a single measurement system can accommodate these changes by changing meter configurations (i.e. orifice size). Depending upon the type of system employed, a single meter may be able to perform acceptably over very wide ranges of flow rates. For example, an ultrasonic meter has a very broad turn-down ratio, enabling the metering system to measure widely varying flow rates. Other situations may require that multiple meters are employed at various flow rates in order to measure the flowing fluid accurately while accommodating the change in flow rate. Additionally, changes in flowing conditions can result in the produced fluids having variances in composition as the pressure and temperatures vary. Gases can contain greater amounts of heavier liquefiable hydrocarbons as such experience changes of state within the flowing stream.

Multiple Sourced Fluid Flows

Another challenge to system design is when the fluid flows are from multiple sources of varying quantities and compositions. This situation results in the fluid composition being very dynamic depending upon the quantity and composition of the individual sources that comprise the fluid stream. As the flow rates of these individual sources vary, so does that volume and composition of the composite stream. System design must be considerate of these changes in order that representative compositional and quality determinations may be made as conditions vary.

EQUIPMENT, PROCESSES AND OPERATIONS

Volumetric Metering Systems

In order to understand and evaluate the economic implications of metering, the application and performance of such must be understood. No one meter type will necessarily perform optimally with all fluids under all conditions. Therefore, a prudent operator must evaluate the meter type with consideration of fluid and operating conditional service in order to wisely employ initial investment capital, minimize measurement uncertainties and operating costs, and meet the needs of all parties involved.

Orifice

Orifice meters continue to be the most commonly used for gas measurement service. Orifice meters are relatively inexpensive to employ in a one-to-one comparison with other meter types due to the standardized design, no moving parts, low cost of operation and service resiliency. Orifice meters are artifact meters, meaning that when such are constructed per established design criteria that has been previously characterized per empirical testing, such will perform within specified levels of uncertainty when employed in services that emulate physical and flowing conditions that were experienced during characterizing tests.

Turbine

Turbine meters remain popular for clean gas and clean liquid service, such as residue gas and NGL's at the tailgate of processing plants, etc. Turbine meters employ a rotor within the meter body that rotates with relative linearity to the amount of fluid that is flowing through the meter. Thus, turbine meters are referred to as "Linear Meters". The internal moving mechanisms result in mechanical wear and deterioration that requires greater periodic maintenance than do meters with no moving mechanisms. Turbine meters do offer greater range of measured flow rates than single orifice meters.

Ultrasonic

Ultrasonic flow meters are becoming more and more popular for both gas and liquid service. The ultrasonic meter is a transit time meter, meaning that the meter differentiates between the time-of–

flight of a sound pulse from one point to another and back along the same path. The difference in the time-of-flight is relative to the fluid flow within the meter body when taken in consideration with the meter geometry and fluid properties. These meters offer very high levels of accuracy when characterized, installed and operated in order to optimize the system efficiencies and capabilities. Also, the meters offer substantial turndown ratio, allowing for broad flow rate ranges and enabling the operator to employ the meters in services where wide flow rate variances may be experienced. This results in system cost savings per the minimization or elimination of additional valves, actuators, controllers, piping and header systems, or other peripheral equipment that may be necessary for other metering types. The meters require external power for operation of the system electronics and transducers, which is a cost of installation that must be considered. Additionally, the systems within which the ultrasonic meter is installed should be designed in order to minimize the deleterious effects that harmonic frequencies produced by valves, piping, filtration and other mechanical systems may have on the meter's performance.

Coriolis

Coriolis meters have been popular in liquid service for some time, and are becoming popular for gas service as well. Coriolis meters are mass meters that perform relative to the properties of the fluid which flow through such. As fluid composition changes, and along with it the fluid density, the Coriolis meter differentiates these changes by variation of frequency of vibration of the sensing tubes in the meter. These vibration frequencies are relative to the mass of the fluid flowing through the meter. Therefore, the meter can infer the mass of the fluid and render a total mass of product flowing per unit of time. These mass measurements may be converted to equivalent volumes for accounting purposes.

Positive Displacement

Positive Displacement (PD) meters remain popular in low volume service as generally experienced in distribution systems. PD meters can be employed in both low and high pressure service applications. The name of the meter describes the meter principle; the meter renders a positive displacement of a known quantity of fluid as such passes thought the mechanism, either a diaphragm or a rotating cavity. No inference is necessary to determine actual volumes of fluid displacement. Other measured parameters such as temperature and pressure may be used to correct quantities to standard conditions as desired.

Other Meter Types

Other metering technologies offer benefit in specific applications. Several of these include cone, venturi, wedge and thermal dispersion, to name just a few.

Recording and Communication Systems

Another major component of measurement facilities is the recording and communication system. Recording systems can be mechanical (chart recorders or totalizers) or, more likely in today's operating environment, electronic flow measurement (EFM) systems. While the EFM system requires greater initial capital investment, the capabilities offered by the system ultimately result in lower cost of ownership due to significantly lower requirements for personnel (chart changing, chart integration, etc.), consumables (charts, pens, etc.) and storage (manual filing systems). Additionally, most of today's EFM systems are equipped with remote communications technologies, enabling operators to access flow information on a frequent basis without on-site human intervention. Such can be incorporated into an organization's Supervisory Control and Data Acquisition (SCADA) system as well. This enables the operator to have real-time information and control capabilities, enhancing the information availability, safety and compliance aspects of the operation. Additional savings are realized per the elimination of the need for personnel to integrate mechanical recordings for interpretation and calculation of measured quantities. The EFM performs the calculations as measurements are taken, thereby offering greater efficiencies in tertiary processes.

Fluid Sampling/Quality Determination Systems

It is necessary to take samples of the fluids which are being produced, measured and transported in order that the composition and quality of such may be determined. As with volumetric measurement, product sampling and quality determination can be performed by various means at varying costs. The justification of the means and associated costs lie within the product variances and the subsequent quantification of content, quality and residual values over substantive time periods.

Spot Sampling

The easiest and least expensive means of acquiring samples of fluids is per the employment of the "spot" sampling technique. The name implies that a sample is taken that will be representative of the moment in time and the composition of the fluid that was immediately present when the sample was acquired. The associated costs for determining fluid composition and quality from spot sample acquisitions include required personnel time, equipment (including transportation, sampling equipment such as cylinder and valves, shipping containers, etc.), laboratory analysis and reporting.

Composite Sampling

A more comprehensive means of acquiring fluid samples is the employment of composite sampling systems. Composite sampling involves the use of a mechanism that acquires a product sample periodically. The sample is taken from the flowing fluid stream, injected and stored in a sample containment vessel for storage. Multiple samples are collected over a time period and the stored collection of many individual samples is subsequently subjected to laboratory analysis for determination of product composition and quality. This method of sampling involves the additional cost of the composite sampling mechanism, as well as often employed sample containment systems of more complex designs and capabilities. However, the composite sample reveals information that is more representative relative to the composition and quality of the flowing fluid stream over an extended period of time. This application is advantageous in fluid streams that are subject to compositional and quality variances.

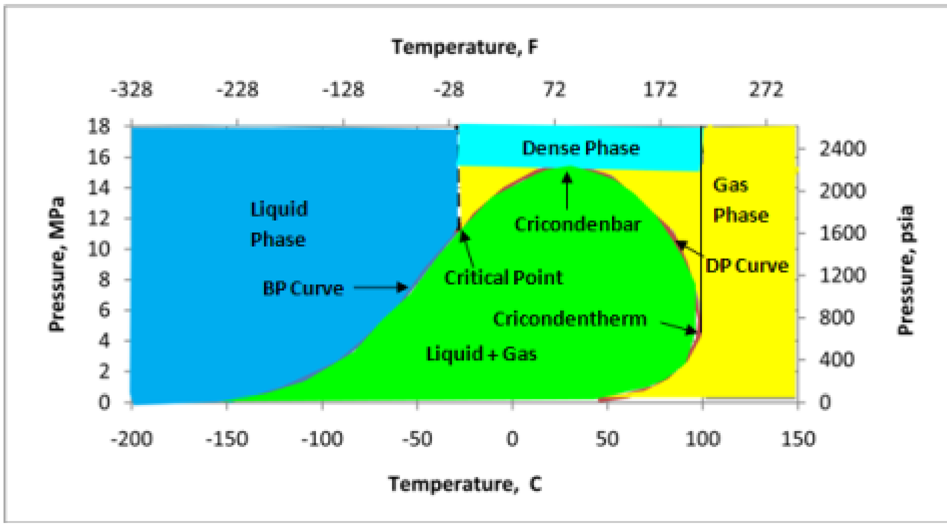
On-Line Sampling and Analysis

The most comprehensive means of determining fluid composition and quality is the employment of on-line analytical systems that frequently acquire samples of the flowing fluid and transports such to a sample conditioning and analytical system that determines the composition and quality of such. These analytical systems are generally interfaced with other on-site measurement systems to provide a comprehensive quantification of fluid volumetric and quality information. This information can then be immediately available to supervisory control and business systems for the purposes of operational and commercial management in virtual real time. This method involves the additional costs of the on-line analytical systems and associated peripheral equipment. However, sample containment and shipping equipment, as well as subsequent laboratory analytical services are only necessary as test or confirmation samples and analyses are desired by the operator.

On-Line systems may also be employed to measure specific components within the flowing fluid stream, such as water vapor, hydrogen sulfide, or determine hydrocarbon dewpoint. These systems add costs to facilities, but provide important information that enables the protection of downstream facilities that may be adversely affected by these constituents or parameters.

Sample Conditioning Systems

Regardless of the hydrocarbon sampling method, sample conditioning is of critical importance and consideration in ensuring that the sample collected is representative of the product under consideration. Why is sample conditioning important? Hydrocarbons components will experience changes of state when subjected to conditionings that will force the compound to reach critical parameters of pressure and temperature. This critical parameter is the hydrocarbon dewpoint, which is the temperature, at a given pressure, at which hydrocarbons will begin to condense from the gaseous phase to the liquid phase. Critical parameters within hydrocarbon dewpoint determination are the *cricondenbar* and the *cricondentherm*. The *cricondenbar* is the maximum pressure above which no gas can be formed regardless of the temperature. The *cricondentherm* is the maximum temperature above which no liquid can be formed regardless of the pressure. A simple graphical depiction of these critical parameters, the "Phase Envelope", indicates these thermodynamic relationships.[i]



The purpose of employing sample conditioning systems is to maintain the fluid sample within parameters that will render a representative sample of the fluid within the system. For gas systems, this means identifying those pressure and temperature relationships that will ensure that the collected sample is single-phase gaseous, and for liquid samples, single-phase liquid. When samples of fluids are collected within the retrograde (liquid + gas) region, the composition of the sample can be misrepresentative of the actual flowing product within the system. This leads to errors in the determination of gas, liquid and recoverable NGL quantities, and directly impacts the associated economics of production, gathering and processing.

Capital Investment and Operations

Capital investment and continuing operations costs of facilities are critical components of economic consideration. Capital investment is necessary for project initiation and implementation. Operations requirements result in continuous costs and must be evaluated within the context of cost/benefit. Costs of operations are attributable to the systems and processes employed as noted previously. For example, the implementation of online analytical and sample conditioning systems will require more capital investment than spot sampling or composite sampling systems, but will facilitate more frequent measurement of fluid composition and calculation of critical parameters. Generally, some of the primary categories within which these investments and continuing costs are considered are:

1. Capital Investment
    a. Exploration (Finding & Development)
    b. Land and Right-of-Way
    c. Permitting
    d. Equipment
    e. Construction and Installation
    f. Commissioning
2. Operations and Maintenance
    a. Personnel
        i. Facilities
        ii. Office (Information Processing, Data Storage, etc.)
    b. Equipment and Supplies
        i. Consumables
        ii. Spare Parts
    c. Compliance
        i. Regulatory
        ii. Safety
        iii. Environmental
    d. Outside Services
    e. Inspection, Calibration & Repair
    f. Administrative Overhead
    g. Equipment Salvage Value

Ultimately, a good means of identifying and controlling operational costs is establishing such in terms of cost per volume unit of measured product ($/MMBTU, $/BBL or $/MCFE). This enables the operator to determine the impact such has on the comprehensive economics associated with the measured product, and realize how such contributes to or diminishes value.

ACCURACY AND UNCERTAINTY

Needless to say, accuracy and uncertainty are of paramount importance to the effectiveness and economic viability of measurement, sampling and conditioning, and analytical systems. Systems that cannot achieve satisfactory levels of accuracy or minimize uncertainties will result in a costly proposition in the long run. Too often, minimization of initial capital costs are given undue precedence over sustained accuracy and continued cost of operations.

Conversely, disregard for capital investment employed for the sake of attempting to achieve levels of accuracy and uncertainty that are inconsequential or without applicable merit can be ruinous to the overall viability of a project. Acceptable levels of accuracy and uncertainty are established for many measurement parameters and systems. These are defined within industry publications and standards by which prudent operators design, implement and operate measurement systems and facilities. These standards should be the guide basis by which operators formulate decisions regarding measurement and analytical system applications. To either disregard these guiding resources, or seek to surpass such in excess, can lead to measurement systems and associated economics that are indefensible and/or unsustainable.

A simple example may help clarify. Let's assume that we are considering the purchase and installation of an on-line analytical system for a facility. The facility is projected to experience average flow rates of natural gas of 10,000 MMBTUD. The "out-of-the-box" uncertainty specification for the system is +/- 0.5%. This implies that, when properly installed, operated and maintained, we should realize accurate measurement of parameters to within +/- 0.5% of true accuracy. Alternatively, we may be able to enhance the system per the employment of characterization or peripheral mechanisms that will improve the system's performance and reduce the uncertainty to +/- 0.2%. This will have a cost that will be additive to the initial capital investment required to install the facility, as well as increase O&M costs, and will subsequently effect the project economics. We need to determine if this additional investment is a prudent expenditure and the addition to capital is economically justified.

Uncertainties place an "At Risk" component onto project economic evaluations. These "At Risk" components may be considered as follows:

Flow Rate of Natural Gas 10,000 MMBTU/Day

(1) Measurement System Uncertainty (Out-of-the-Box) 0.5%

(2) Measurement System Uncertainty (Enhanced) 0.2%

Natural Gas Value $3.50/MMBTU

Quantity (1) "At Risk" = 10,000 MMBTU x 0.5% x $3.50 = $175/Day …. $5,250/Month …. $63,000/Year

Quantity (2) "At Risk" = 10,000 MMBTU x 0.2% x $3.50 = $70/Day …. $2,100/Month …. $25,200/Year

As can be seen, these "At Risk" values are of significance at this projected flow rate. One may conclude that the additional capital expenditure would be justified in this case. What must also be considered in this evaluation are the additional operations and maintenance costs. If the additional costs offset the potential in value, serious considerations must be given to viability.

Measurement system accuracy and uncertainty are critical parameters that must be considered and managed. As with any other parameter, such should be considered within the relevant context of the specific application in which the system will be employed.

MEASURED PRODUCT VALUATION

<u>Commodity Value</u>

Another categorical aspect of hydrocarbon measurement economics is an extremely dynamic one – product value. The impact of measurement systems on the determination, and potential misrepresentation, of the fluids and subsequent products that such measure is of great significance. For instance, the commodity value of natural gas itself is generally given consideration when contemplating measurement system uncertainties. However, what about the liquefiable products resident within those quantities of gas? And, what about the natural gas condensate liquids that may be realized within pipeline systems through retro-grade condensation? What of the produced condensate at the wellhead? What of the produced oil? And, what about all of the things that can, do and will happen to these products at various stages of production, gathering, processing, refinement, storage, transportation and consumption? Suddenly, what seemed to be a simple concept of price per MMBTU is now a multi-faceted economic review of product life cycle.

Natural Gas

The commodity value of natural gas itself is generally given consideration when reviewing measurement system uncertainties. For instance, let's assume the following conditions:

Flow Rate of Natural Gas 10,000 MMBTU/Day

Measurement System Uncertainty 0.5%
Natural Gas Value $3.50/MMBTU

Quantity "At Risk" = 10,000 MMBTU x 0.5% x $3.50 = $175/Day …. $5,250/Month …. $63,000/Year

As is evident, measurement system uncertainty is of significance in managing comprehensive economics and value.

This issue of product valuation is of great importance when considering means and systems for the determination of composition and quality by sampling and analytical processes. Unrepresentative samples that result in errors in product quality determinations impact measured product economies. As an example, let's assume that a sample is taken of a natural gas stream, and such is contaminated with air as indicated by an abnormally high Nitrogen content.

	Correct Sample Analysis		Incorrect Sample Analysis	
Component	**Mol %**	**GPM**	**Mol %**	**GPM**
Methane	85.000	------	83.501	------
Ethane	5.500	1.476	5.403	1.449
Propane	3.000	0.829	2.947	0.814
Iso-Butane	1.500	0.492	1.474	0.484
Normal Butane	1.500	0.474	1.474	0.466
Iso-Pentane	1.000	0.367	.982	0.360
Normal Pentane	1.000	0.364	.982	0.357
Hexanes +	0.450	0.196	.442	0.192
Nitrogen	0.750	------	2.500	------
Carbon Dioxide	0.300	------	.295	------
Total	100.00	4.198	100.00	4.124
DBTU/ft^3	1239.3	------	1217.3	------
Relative Density	0.712	------	0.717	------

The effects of these differences in indicated composition and quality are:

Calculated volumes with correct analysis:
8,070 MCF 10,000 MMBTU
Calculated volumes with incorrect analysis:
8,012 MCF 9,753 MMBTU

At $3.50/MMBTU, this renders a valuation difference of $865. Furthermore, the economic effects on recoverable NGL's can be determined per methods and examples that follow.

Natural Gas Liquids

Natural gas liquids are extracted from natural gas at gas processing facilities, generally by processes of absorption, adsorption, refrigeration/cryogenics and/or fractionation distillation. Each of these technical processes has applicability to targeted product and component recoveries. As products are extracted, such will retain a value as a recovered liquid. These values are additive economically in comprising the composite value of the produced gas stream. The following exemplifies these comprehensive economics:

Component	Mol %	GPM	NGL Price ($/Gal)	NGL Recovery Efficiency (%)	Recovered NGL GPM	Recovered NGL Value $/MCF
Methane	85.000	---------	------------	------------	------------	------------
Ethane	5.500	1.476	0.60	75.0	1.107	0.6642
Propane	3.000	0.829	0.90	95.0	0.789	0.7101
Iso-Butane	1.500	0.492	2.00	100.0	0.492	0.9840
Normal Butane	1.500	0.474	1.95	100.0	0.474	0.9243
Iso-Pentane	1.000	0.367	2.30	100.0	0.367	0.8441
Normal Pentane	1.000	0.364	2.30	100.0	0.364	0.8372
Hexanes +	0.450	0.196	2.30	100.0	0.196	0.4508
Nitrogen	0.750	----------	------------	------------	------------	------------
Carbon Dioxide	0.300	----------	------------	------------	------------	------------
Total	100.000	4.198			3.789	

If the flow rate is 8,070 MCF & 10,000 MMBTU, the associated economics are:

Value of Natural Gas (Initial) 10,000 MMBTU x $3.50/MMBTU = <u>$35,000</u>

Value of Natural Gas (Post-Extraction) 7,225 MMBTU x $3.50/MMBTU = $25,287

Value of Recovered Ethane = 1.107 Gallons x 8,070 MCF x $0.60/Gallon = $5,360

Value of Recovered Propane = 0.789 Gallons x 8,070 MCF x $0.90/Gallon = $5,730

Value of Recovered Iso-Butane = 0.492 Gallons x 8,070 MCF x $2.00/Gallon = $7,940

Value of Recovered Normal Butane = 0.474 Gallons x 8,070 MCF x $1.95/Gallon = $7,459

Value of Recovered Pentanes + = 0.927 Gallons x 8,070 MCF x $2.30/Gallon = $17,206

Total Stream Value = <u>$69,982</u>

Difference in Value = Total Stream Value - Value of Natural Gas (Initial) = $69,982 – $35,000 = $<u>34,982</u>

As indicated in the example, the total value of the measured gas stream is much greater than just the price of gas per unit of volume. The extracted value of the NGL's greatly enhances the overall value of the measured stream.

Now, if we apply the previously used measurement system uncertainty to this new Total Stream Value:

Value "At Risk" = $69,982 x 0.5%= $350/Day …. $10,500/Month …. $126,000/Year

We realize that the "At Risk" value of the measured product stream due to measurement system uncertainty is virtually double that of which was originally contemplated as only a valued gas stream.

<u>Natural Gas Condensate and Oil</u>

The value of condensate is dynamic, but often closely emulates the price of oil when stable and meeting certain quality specifications. The economic issues related to the handling, storage and measurement of condensate are somewhat complex, and deserve discussion in order to understand and quantify such.

As noted previously, condensate is a liquid composed of natural gas components. Most of these components are Pentanes and heavier. However, the liquid will also contain some amounts of lighter hydrocarbons. At the point of production, products (gas, condensate & water) are separated by mechanical means. These products are then individually transported to points of delivery or disposal. For condensate, this often means that a dump-valve incorporated into the condensate phase of the mechanical separation unit will open, thereby transporting (dumping) the condensate to a tank. When this occurs, a process commonly known as "weathering" takes place. As the condensate experiences the sudden change in pressure when dumped from the pressurized separation vessel into an atmospheric tank, the fluid will begin to "roil". This means that lighter components within the mixture are experiencing a change of phase from liquid to gas via the change in conditions and associated turbulence of the occurrence. As these components weather, the gases exit the tanks from the top and are either lost to the atmosphere, or may be captured and re-injected into the gas pipeline per the use of a vapor recovery unit (VRU).

Additionally, significant amounts of the heavier components that would normally be retained within the liquid condensate are lost as well. This occurs because of the rapid roiling of the fluid during the change in pressure, as well as effects of ambient temperatures. All of these occurrences result in compositional and quality changes to the fluid, and thereby affect the value of such. Mechanical stabilization processes enable many of the heavier hydrocarbons to be retained within the liquid product rather than being flashed as vapor. The process of controlling pressure, temperature and rate allows for the gradual extraction of the lighter hydrocarbons to occur while retaining the heavier components as liquid product, thereby enhancing recovered volume and product value.

Of additional economic significance regarding natural gas condensate and oil is the issue of quality specifications associated with transportation. Most liquid pipeline tariffs will specify quality parameters and shrinkage penalties that impact delivered volumes and valuation. Commonly, initial shrinkage of up to 2% may be applied to delivered volumes, with additional shrinkage factors applied for deviations from certain quality thresholds. Very common shrinkage deductions will occur at API Gravities exceeding 45^{o}. Volumes will usually be deducted in 0.5% increments for every 10^{o} of excess API Gravity up to a limit, usually 2%. Trucking and rail transportation methods will also impose quality limitations and penalties.

LOST AND UNACCOUNTED FOR QUANTITIES

Lost **A**nd **U**naccounted **F**or (LAUF) volumes of product result in significant economic impact to operating revenues on a continuing basis. It is, therefore, no surprise that LAUF receives so much attention from operators, industry organizations, and industry schools and seminars. The Energy Information Administration reports that in 2011, *290,000,000,000 ft^3* (that's 290 BCF for the acronym aficionado) of natural gas was lost and unaccounted for in the United States from all sources, a *1.19% LAUF* with regard to all sources of receipt and consumption. At the average 2011 Nominal Price of $3.95 per MCF, that equates to *$1,145,500,000* in lost commodity value. Of this quantity, 200 BCF is categorized as known quantities that were vented and flared. That leaves a whopping *90 BCF* of imbalance …. Unknown … Vamoose …. Whoosh …. Gone! That is *0.37%* of total 2011 U.S natural gas consumption and *$355,500,000* in commodity value. [i]

From the perspective of the individual point of measurement, LAUF is of relevance from many perspectives. In gathering systems (midstream operations) LAUF is often allocated back to each point of receipt into the system on a periodic basis, usually monthly. The amount of allocable LAUF is often capped at a maximum allowable percentage of total system receipts. If the maximum allowable LAUF that may be allocated is 2% of system receipts, such directly impacts the economic metrics of the producing facility. As example:

Measured quantity	10,000 MMBTU
System LAUF%	2.0%

Allocable LAUF quantity adjustment:
10,000 x 2.0% = 200 MMBTU

Allocated "Lost" Value at $3.50/MMBTU:
200 MMBTU x $3.50 = $700

Allocated "Lost" Natural Gas (Post Extraction) Gas & NGL Values:

Value of "Lost" Natural Gas (Post-Extraction) 145 MMBTU x $3.50/MCF = $508

Value of "Lost" Ethane = 1.107 Gallons x 161 MCF x $0.60/Gallon = $107

Value of "Lost" Propane = 0.789 Gallons x 161 MCF x $0.90/Gallon = $114

Value of "Lost" Iso-Butane = 0.492 Gallons x 161 MCF x $2.00/Gallon = $158

Value of "Lost" Normal Butane = 0.474 Gallons x 161 MCF x $1.95/Gallon = $149

Value of "Lost" Pentanes + = 0.927 Gallons x 161 MCF x $2.30/Gallon = $343

Total "Lost" Gas & NGL Value = <u>$1,379</u>

COMPREHENSIVE ECONOMIC EVALUATIONS

Now that we have touched on many of the economic facets related to the measurement, sample conditioning and analysis of hydrocarbon products, let's look at a more comprehensive evaluation of the life cycle of hydrocarbons from a revenue/cost perspective. This evaluation will consider a well that is drilled and completed, and is producing natural gas and condensate.

There are many data points (and assumptions) that must be considered in formulating this evaluation. For the sake of this example, let's assume the following operating and economic conditions with two distinct gas compositions (one "representative" and one "unrepresentative" due to air contamination in the sample):

Operating Conditions		
Flow Rates	Gas (MCFD)	5,000
	Condensate (BBLD)	500
	Water (BBLD)	50
Operating Pressure (psia)		900
Operating Temperature (^{o}F)		75
Pressure Base (psia)		14.73
Temperature Base (^{o}F)		60
Project Life		10 Yrs
Production Decline Rates/Year	1	50%
	2	20%
	3	15%
	4	10%
	5-10	5%
Gas Processing Liquid Recovery Efficiency	C_2	75%
	C_3	95%
	IC_4	100%
	NC_4	100%
	IC_5	100%
	NC_5	100%
	C_6+	100%
Unit Pricing (Revenues)		
Oil/Condensate $/BBL		$90.00
Gas $/MMBTU		$3.50
NGL's $/Gallon	C_2	$0.60
	C_3	$0.90
	IC_4	$2.00
	NC_4	$1.95
	IC_5	$2.30
	NC_5	$2.30
	C_6+	$2.30

Unit Cost Drivers		
Finding & Development (F&D)		$11,000,000
Production Cost $/MCFE		$1.30
Gathering & Treating Cost $/MCF		$0.15
Transportation & Fractionation Cost $/Gallon		$0.07
Condensate Transportation Cost $/BBL		$3.00
Water Hauling & Disposal Cost $/BBL		$2.00
LAUF %		1%
Consumer Price Index (CPI)		3%
Discount Rate		10%

Gas Composition & Quality			
Representative Sample		Unrepresentative Sample	
C_1	84.000%	C_1	80.502%
C_2	5.000%	C_2	4.792%
C_3	3.000%	C_3	2.875%
IC_4	1.400%	IC_4	1.342%
NC_4	1.400%	NC_4	1.342%
IC_5	1.000%	IC_5	0.958%
NC_5	1.000%	NC_5	0.958%
C_6+	0.450%	C_6+	0.401%
CO_2	0.700%	CO_2	0.288%
N_2	0.300%	N_2	4.792%
H_2O	1.75%	H_2O	1.750%
BTU/CF	1,214	BTU/CF	1,162
Relative Density	0.708	Relative Density	0.718

The financial metrics that will most commonly be considered for project viability will be Earnings Before Interest, Depreciation and Amortization (EBITDA), Internal Rate of Return (IRR) and Net Present Value (NPV) with consideration of discounted cash flows. As has been discussed previously, consideration should be given to the entire product value chain, as well as all of the capital investment and recurring operations and maintenance costs that will be incurred. Obviously, the commodity value of the individual products is of vital importance, but assumptions must be made as to the changes in these values over time. These changes can be extremely dynamic and difficult to predict as such are subject to many sensitivities. For the sake of this evaluation, all of the commodity values and recurring unit cost drivers were adjusted annually by the Consumer Price Index (CPI) at an assumed annual rate of three percent (3%).

While it is obvious that erroneous sample characterizations would be reconciled on a timelier basis, this example is meant to demonstrate how unrepresentative sample composition determinations can significantly impact the economic viability of the hydrocarbon value chain. The following model depicts how these two sample compositions would affect the comprehensive economics of this project over a ten year period.

Microsoft Excel - Econ Model Presentation Compare

Initial Production Flow Rates (IP)

Gas (MCFD)	5,000
Condensate (BBLD)	500
Water (BBLD)	50
Operating Pressure (psia)	900
Operating Temp (°F)	75

Production Decline Rate/Year

1	50%
2	20%
3	15%
4	10%
5	5%
6	5%
7	5%
8	5%
9	5%
10	5%

Pressure Base (psia)	14.73
Temperature Base °F	60

Unit Pricing

Oil $/bbl	$90.00
$/MMBTU	$3.50
$/Gal C_2	$0.60
$/Gal C_3	$0.90
$/Gal IC_4	$2.00
$/Gal NC_4	$1.95
$/Gal IC_5	$2.30
$/Gal NC_5	$2.30
$/Gal C_6+	$2.30

Unit Cost Drivers

Finding & Development (F&D) Cost	$11,000,000
Production Cost $/MCFE	$1.30
Gathering & Treating Cost $/MCF	$0.15
Transporation & Fractionation Cost $/Gallon	$0.07
Condensate/Oil Transportation Cost $/BBL	$3.00
Waste Water Hauling/Disposal Cost $/BBL	$2.00
LAUF	1.00%
CPI	3.00%
Discount Rate	10.0%

	Gas Composition (mol%) 1	Gas Composition (mol%) 2
C_1	84.000%	80.502%
C_2	5.000%	4.792%
C_3	3.000%	2.875%
IC_4	1.400%	1.342%
NC_4	1.400%	1.342%
IC_5	1.000%	0.958%
NC_5	1.000%	0.958%
C_6+	0.450%	0.401%
N_2	0.700%	4.792%
CO_2	0.300%	0.288%
H_2O	1.750%	1.750%
Total	100.000%	100.000%
Gas (BTU/CF)	1,214	1,162

GP Liquid Recovery Efficiency (%)

C_2	75%
C_3	95%
IC_4	100%
NC_4	100%
IC_5	100%
NC_5	100%
C_6+	100%

Financial Indices

	Case 1 EBITDA/Year	Case 2 EBITDA/Year	Difference EBITDA/Year
0	($11,000,000)	($11,000,000)	$0
1	$10,874,221	$10,252,186	($622,035)
2	$13,884,320	$13,486,259	($398,061)
3	$11,790,637	$11,452,623	($338,014)
4	$10,628,773	$10,324,086	($304,687)
5	$10,136,315	$9,845,763	($290,553)
6	$9,919,486	$9,635,165	($284,321)
7	$9,707,271	$9,429,049	($278,223)
8	$9,499,575	$9,227,320	($272,255)
9	$8,520,388	$8,276,209	($244,179)
10	$7,022,274	$6,821,039	($201,235)
Total	$101,983,261	$98,749,700	($3,233,562)
NPV	$65,988,019	$63,788,589	($2,199,430)
IRR	17.05%	16.45%	(0.60%)

Input | $$$ | $$$ 2

In the first month alone, the economic impact is a decrease in revenue of $69,853 and a decrease in the first year's EBITDA of $622,035. If this trend is extrapolated over the entire project life of ten years, it results in a total decrease in realized EBITDA of $3,233,562, a reduction in NPV of $2,199,430 and a reduction in IRR by 0.6%. While this example represents a very simplistic variance in product compositional determination, it is readily apparent that the economic impact of ensuring that hydrocarbon fluids are measured, conditioned, sampled and analyzed correctly to ensure the determination of representative quantities, compositions and quality values is of tremendous significance.

SUMMARY

So, does measurement play a significant role in the current energy business environment? Do the efforts and investments into measurement, communications, analytical and control systems really make any difference regarding the financial performance and health of the organization?

It is obvious that the unequivocal answer is "YES"! The accurate determination of hydrocarbon quantities and qualities is the FIRST point of influence on the primary basis upon which the energy producer, gatherer, processor, transporter or distributor business model is based. Without accurate, reliable and efficient measurement and communication systems, the energy organization's financial performance is in jeopardy.

[i] Image acquired from www.jmcambell.com, John M. Cambell & Co., "*Variation of properties in the dense phase region; Part 2 – Natural Gas*", by Dr. Mahmood Moshfeghian, Posted January 1, 2010.

[ii] United States Department of Energy, Energy Information Administration, DOE/EIA -0384(2011) | September 2012, "*Annual Energy Review 2011*", Page 177-194.

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