DETERMINATION OF LEAKAGE AND UNACCOUNTED FOR GAS
Class # 1070.1

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Introduction

Leakage and unaccounted for gas volumes are of the most significant costs of operation for natural gas producers, gatherers, processors, transporters and distribution system operators. These operational costs are so significant that such are directly addressed in tariffs, rate case filings and contractual agreements between parties in order that such may be itemized as a cost of operation, equitably managed and responsibly mitigated. Common acronyms denoting lost and unaccounted for gas volumes are **LAUF** (**L**ost **A**nd **U**naccounted **F**or), **LUG** (**L**ost and **U**naccounted for **G**as) and **UAF** (**U**n**A**ccounted **F**or). All of these designations refer to the same issue – *Product that you believe you should be able to account for but for some reason cannot*. For the sake of this discussion, LAUF shall be our acronym of reference.

So what is LAUF? It is the difference, or amount of imbalance, determined when performing physical system volumetric, energy or mass balancing analyses. The causes of LAUF are rooted in the inherent uncertainties associated with hydrocarbon measurement, as well as variances and errors that occur within the systems and processes employed to measure, record and calculate volumetric, energy and mass quantities.

LAUF issues are quantified within defined categories that comprise a typical pipeline system balancing analysis. Several of the most prevalent are System Receipts, Deliveries, Fuel and Use, Metering and Quantity Calculation Integrity, Line Pack and Variance, Pipeline Retrograde Condensation, Gas Quality, Contaminants and Impurities, and Leakage. While this categorical list captures most of the issues that will arise during system balancing analysis and LAUF mitigation, there are inevitably “outliers” that creep in from time to time to cause hair-pulling grief for the system operator and balancing analyst. So a bit of advice when it comes to LAUF determination and mitigation – *Remain open minded to any and all possibilities!*

System Receipts, Deliveries, Fuel and Use

We are asleep with compasses in our hands. ~ W.S. Merwin

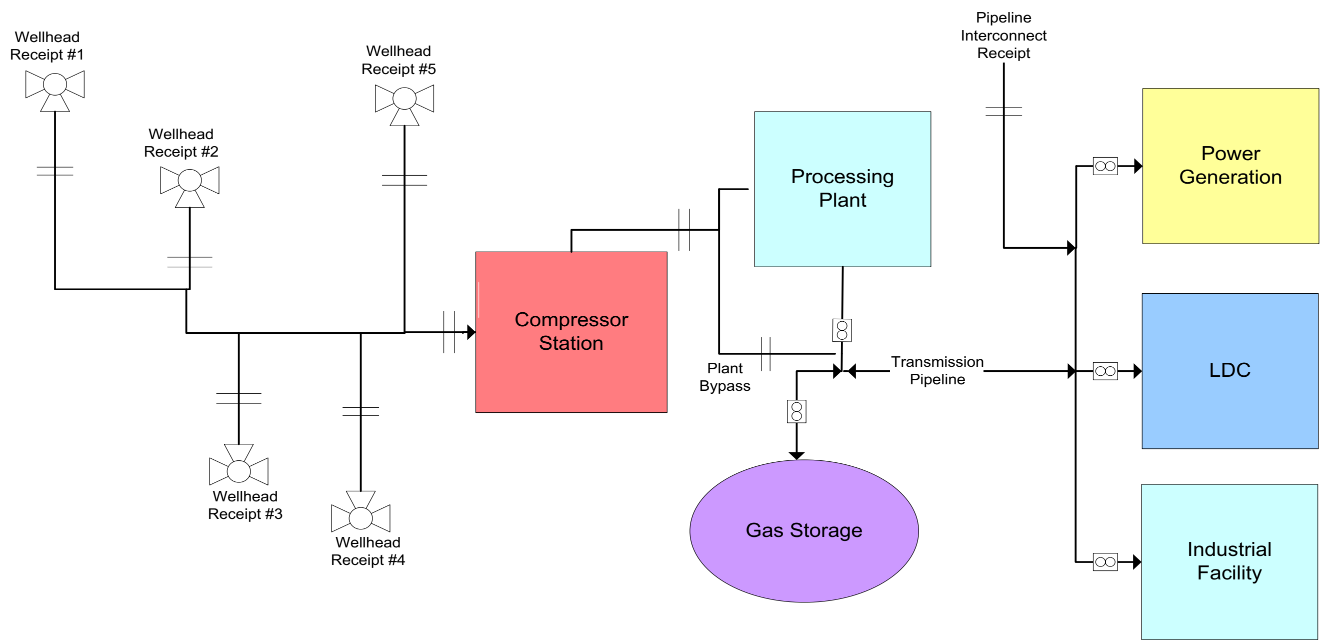

Figure 1

The most basic aspect of determining and managing LAUF is identifying and understanding all of the receipt and delivery points on the pipeline system. Additionally, all of the system fuel and auxiliary usage must be considered as well. One must know where product is intended to enter and exit the system before any subsequent analysis may be performed. This sounds simple enough, right? You would be surprised at the number of times a receipt or delivery point on a pipeline system is defined incorrectly. A typical gathering, processing and transmission scenario may be as shown in Figure 1.

Within the system depicted in Figure 1, multiple subsystems must be detailed in order to effectively perform a comprehensive system balance and determine LAUF.

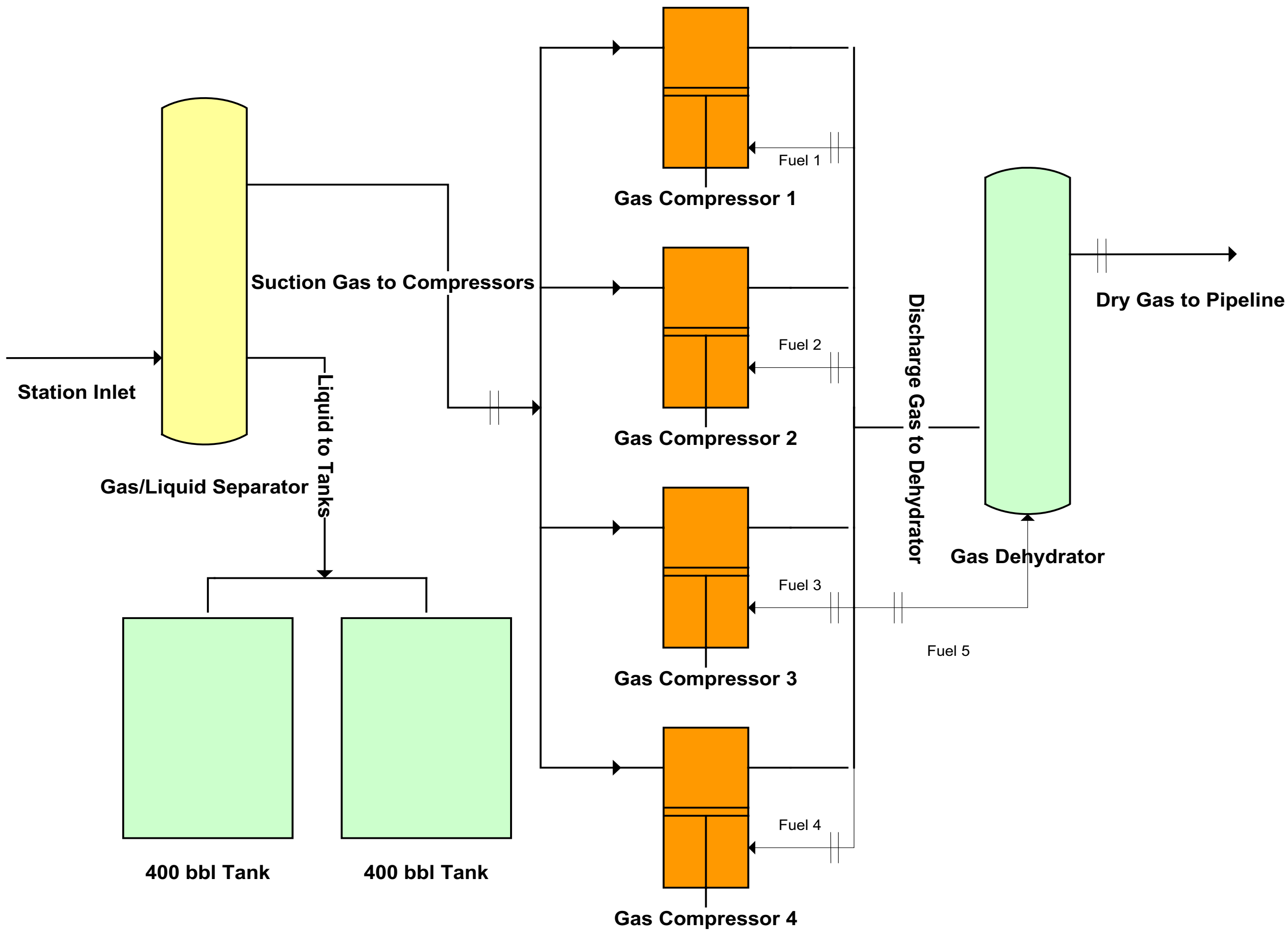

Figure 2

Figure 2 depicts a typical natural gas compressor station equipped with inlet gas/liquid separation, liquid storage, natural gas fueled engines and compressors, and gas dehydration.

As can be seen, there are many points within the gas compression facility that need to be included in a balance. Not only are there several gas points that must be included, there is liquid removal that must be considered when balancing as well.

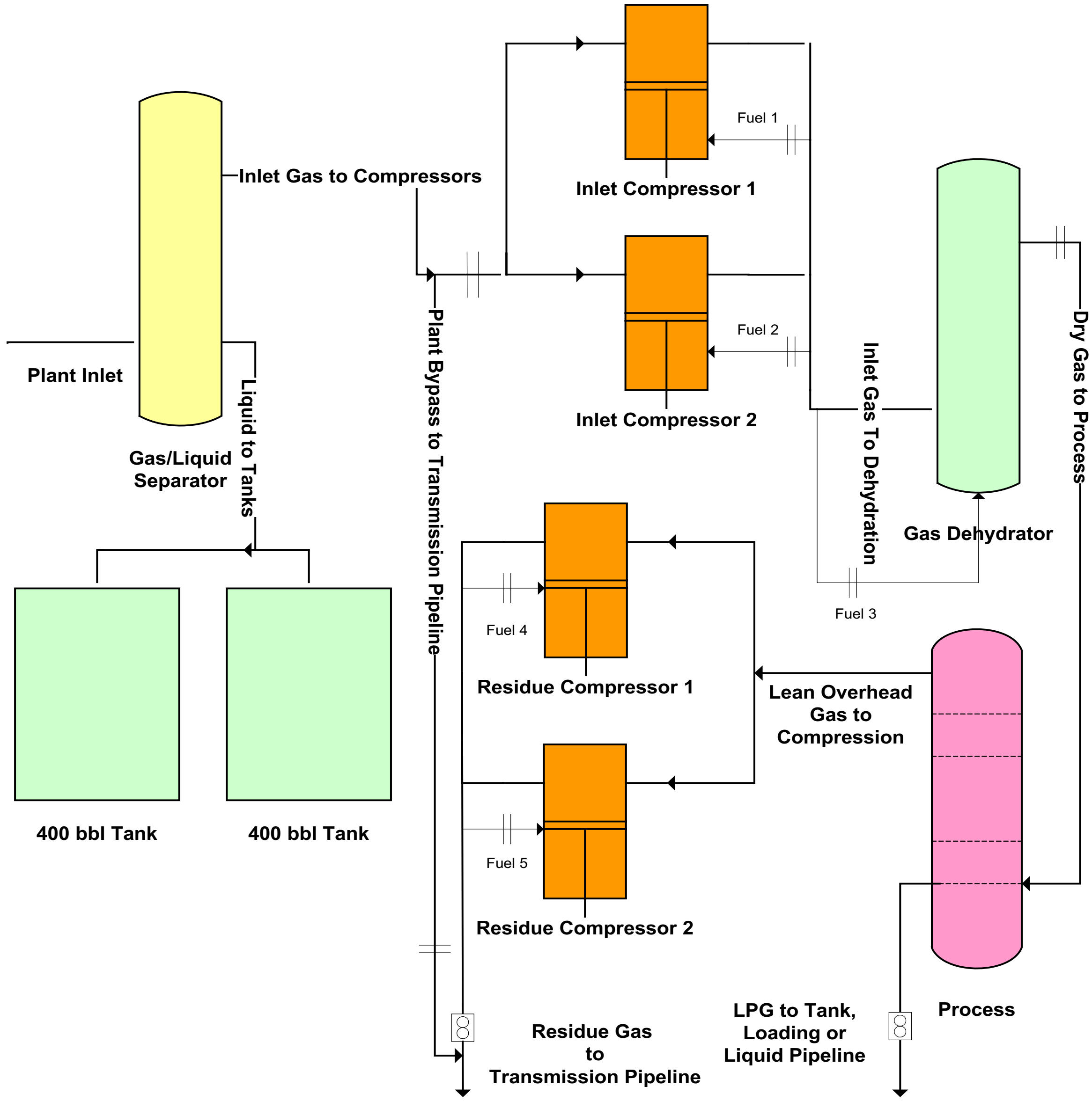

Figure 3

Figure 3 depicts a typical natural gas processing facility scenario as represented as part of the system in Figure 1. The plant is equipped with inlet gas/liquid separation, inlet liquid storage, inlet natural gas fueled engines and compression, gas dehydration, LPG extraction process equipment, and residue natural gas fueled engines and compression.

Notable within this scenario is the bypass of the plant that can deliver rich, unprocessed natural gas to the downstream residue/transmission pipeline. This introduces issues of varying gas quality that can affect the system balancing analysis and LAUF.

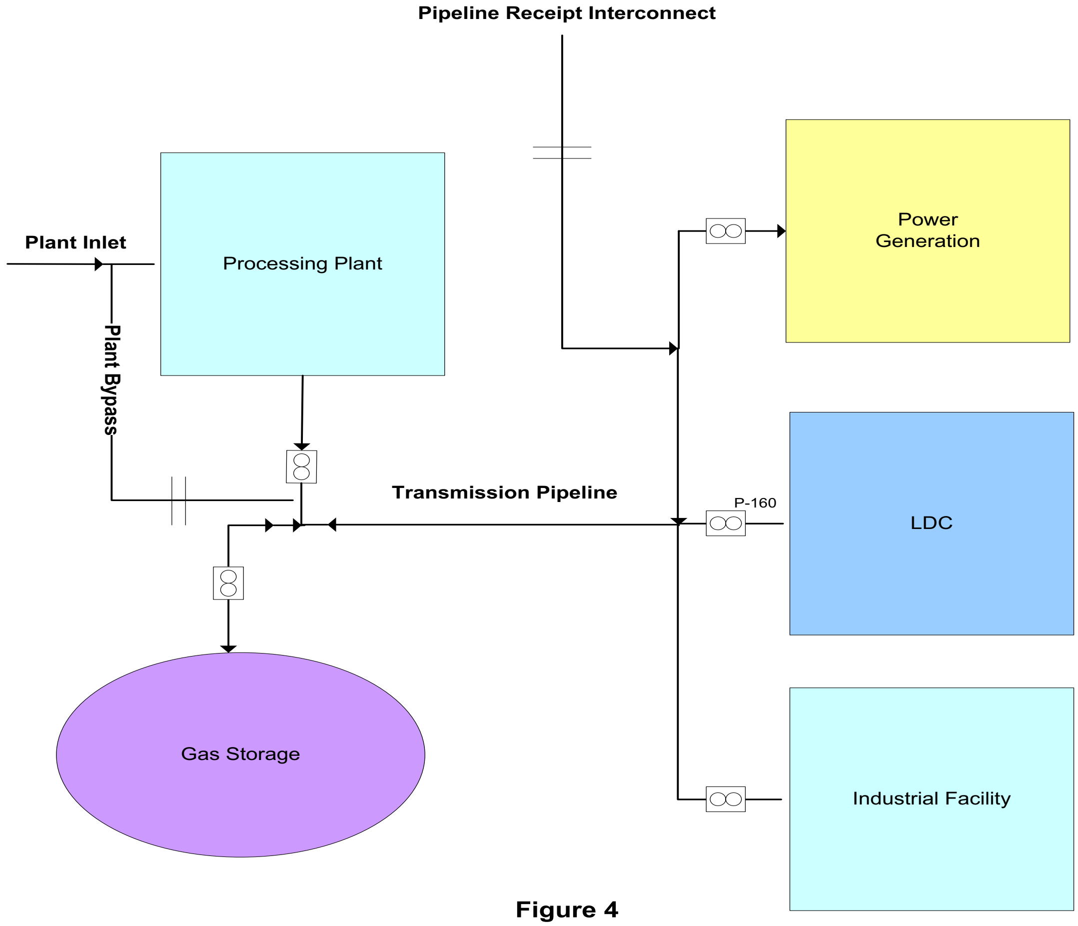

Figure 4

Figure 4 depicts the transmission pipeline into which the processed and unprocessed natural gas is received from the processing plant, a gas storage facility and a pipeline interconnect receipt point from an external party. The gas may be delivered into and received from gas storage, and ultimately delivered to the end users.

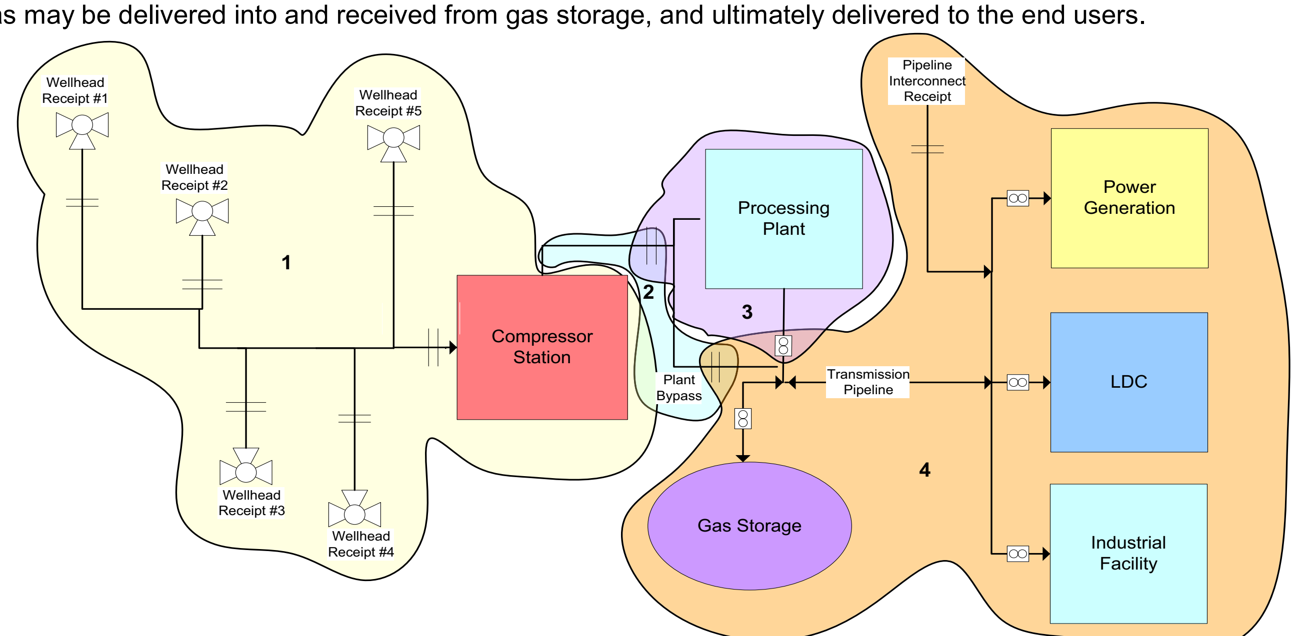

Figure 5

For this discussion, we will use the example balancing scenarios shown in Figure 5; Gathering and Compressor (1), Compressor to Processing Plant (2), Processing Plant (3), and Processing to Transmission (4).

The **Gathering and Compressor** balancing scenario will be as follows.

Gathering & Compressor Station	Receipt		Delivery		Receipt Check		Delivery Check	
	MCF	MMBTU	MCF	MMBTU	MCF	MMBTU	MCF	MMBTU
WH 1	145,000	166,750						
WH 2	148,654	180,615						
WH 3	125,369	148,688						
WH 4	124,896	150,000						
WH 5	100,668	111,238						
Fuel 1			3,150	3,701				
Fuel 2			3,006	3,532				
Fuel 3			2,863	3,364				
Fuel 4			2,744	3,224				
Fuel 5			1,500	1,763				
Condensate Removal			2,047	9,724				
Water Removal (Tanks)			3,696	0				
Water Removal (Dehy)			2,030					
CS Discharge 1							618,244	724,582
	644,587	**757,290**	**21,036**	**25,308**	**0**	**0**	**618,244**	**724,582**

LAUF			
MCF	MMBTU	MCF%	MMBTU%
(5,307)	**(7,400)**	**(0.82%)**	**(0.98%)**

Table 1

Note that condensate and water removal quantities must be converted to gas equivalencies. Water removal from the dehydration unit is the net volume reduction per the water vapor content of the gas entering the unit versus the water vapor content of the gas exiting the unit[1]. Also, note that the compressor station discharge volumes are noted as "Delivery Check" volumes, implying that such are exiting this internal balancing segment and entering another internal balancing segment. Another segment must have the same reciprocating "Receipt Check" volume in order to ensure that the composite system balancing analysis properly reflects these internally measured volumes as "net zero" quantities.

Next, we must analyze the connecting system from the **Compressor Station to the Processing Plant**.

Compressor Station to Processing Plant	Receipt		Delivery		Receipt Check		Delivery Check	
	MCF	MMBTU	MCF	MMBTU	MCF	MMBTU	MCF	MMBTU
CS Discharge 1					618,244	724,582		
Plant Inlet							498,665	583,189
Plant Bypass to Transmission Line							118,542	138,635
Condensate Removal			512	2,431				
Water Removal (Tanks)			222	0				
	0	**0**	**734**	**2,431**	**618,244**	**724,582**	**617,207**	**721,824**

LAUF			
MCF	MMBTU	MCF%	MMBTU%
(303)	**(327)**	**(0.05%)**	**(0.05%)**

Table 2

[1] In this example, an assumption of 20 lbs/mmcf entering the unit and 5 lbs/mmcf exiting the unit was used

Note that, once again, there were some small liquid volumes removed that must be included. In addition, significant volumes bypassed the plant and were delivered directly to the transmission pipeline.

Now, the **Processing Plant**:

Processing Plant

	Receipt		Delivery		Receipt Check		Delivery Check	
	MCF	MMBTU	MCF	MMBTU	MCF	MMBTU	MCF	MMBTU
Plant Inlet					498,665	583,189		
Fuel 1			15,002	15,002				
Fuel 2			13,659	13,659				
Fuel 3			758	758				
Fuel 4			16,223	16,223				
Fuel 5			18,954	18,954				
Water Removal (Dehy)			524					
Process Liquid Removal			65,263	151,475				
Plant Discharge 1							367,855	367,855
	0	**0**	**130,383**	**216,071**	**498,665**	**583,189**	**367,855**	**367,855**

LAUF

MCF	MMBTU	MCF%	MMBTU%
(427)	738	(0.09%)	0.13%

Table 3

Next, the **Processing to Transmission** segment is our final system segment to analyze:

Processing to Transmission

	Receipt		Delivery		Receipt Check		Delivery Check	
	MCF	MMBTU	MCF	MMBTU	MCF	MMBTU	MCF	MMBTU
Plant Bypass to Transmission Line					118,542	138,635		
Plant Discharge 1					367,855	367,855		
Pipeline Receipt Interconnect	900,237	919,142						
Gas Storage to Transmission	124,998	127,123						
Line Pack Variance			2,994	3,037				
Transmission to Gas Storage			51,699	53,043				
Pow er Generation Delivery			836,921	858,681				
LDC Delivery			365,269	374,766				
Industrial Facility Delivery			251,335	257,870				
	1,025,235	**1,046,265**	**1,508,218**	**1,547,397**	**486,397**	**506,490**	**0**	**0**

LAUF

MCF	MMBTU	MCF%	MMBTU%
(3,414)	(5,358)	(0.23%)	(0.35%)

Table 4

Note that because the plant was bypassed during the balancing period, the gas quality values became skewed. This results in the MCF and MMBTU LAUF values reflecting the skew of the gas quality variances and is an indicator that there are gas quality errors within the measurements and calculations.

Finally, all of the system balancing segments may be combined to reflect the **Composite Balance** and LAUF:

Composite System Balance

	Receipt		Delivery		Receipt Check		Delivery Check	
	MCF	**MMBTU**	**MCF**	**MMBTU**	**MCF**	**MMBTU**	**MCF**	**MMBTU**
WH 1	145,000	166,750						
WH 2	148,654	180,615						
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Pow er Generation Delivery			836,921	858,681				
LDC Delivery			365,269	374,766				
Industrial Facility Delivery			251,335	257,870				
	1,669,822	**1,803,555**	**1,660,371**	**1,791,208**	**1,603,306**	**1,814,261**	**1,603,306**	**1,814,261**

LAUF

MCF	MMBTU	MCF%	MMBTU%
(9,451)	**(12,348)**	**(0.57%)**	**(0.68%)**

Table 5

As can be seen, when all balancing points are properly defined within each segment, such will roll up into the composite balancing analysis and correctly reflect the total system balance and LAUF.

Now that we have ensured that our balancing points and definitions are correct, we need to discuss several of the detailed aspects that are contained within the analysis.

Metering and Quantity Calculation Integrity

Two and two the mathematician continues to make four, in spite of the whine of the amateur for three, or the cry of the critic for five. ~ James McNeill Whistler, Whistler Versus Ruskin, 1878

The operator must ensure and trust that the metering, recording and quantity calculation systems employed meet the minimum levels of integrity as established by industry standards. These standards minimally define the construction, installation and operational requirements for various primary metering systems[2], and the minimum design, calibration, verification and performance requirements for secondary and tertiary (EGM) systems[3].

A primary dependency in ensuring that the results derived from the measurements, recordings and calculations of the applied standards and instruments are valid and accurate is verifying and continuously ensuring, at a minimum, the following:

Meter Internal Diameter	Orifice Bore Diameter	Meter Material	Orifice Plate Material
Reference Temperatures	Temperature Base	Atmospheric Pressure	Pressure Base
Meter Factors	K Factors	Specific Heat Ratio	Fluid Viscosity
Ultrasonic Transmitter Path Lengths	Transmitter Spans	No Flow Cutoff Values	Sampling Intervals
Calculation Intervals	Data Logging Intervals	Gas Quality Values	Pressure Tap Location
Meter Tolerances and Dimensions	Heating Value Basis		

Calibration and accuracy verification activities that ensure the precision of the instruments that are used to measure and record critical fluid flow variables are vital. The verification of configuration data, as indicated above, is just as critical. These processes are absolutely necessary in performing LAUF analyses and ultimately achieving mitigation of lost and unaccountable quantities.

Line Pack and Variance

We become aware of the void as we fill it. ~ Antonio Porchia

Line pack is the static volume of gas contained within a pipeline system. This volume can be very significant, especially in large diameter transmission systems. Many operators may actually use large diameter pipelines as a storage medium by which significant gas volumes may be packed, or stored, for an intermittent time and then delivered later to a downstream facility to meet a peak demand. This is often experienced when a pipeline system is delivering to an end use facility that will experience wide variances in intraday demand. An electric power generation plant is a common example of a facility that can experience intraday variances in fuel requirements due to peak demand times. A common method for determining line pack and line variance is as follows.

Pipeline segment volume may be determined using the average pressure and temperature per the equation[4]:

$$V_b = (36.6667)\frac{\pi}{4}D^2 L \frac{P_{avga}}{T_f}\frac{T_b}{P_b}\frac{Z_b}{Z_{avg}}$$

Where: D =Pipe inside diameter (inches)
L = Line length (miles)
P_{avga} = Average pipeline pressure (psia)
$T_{f} =$ Flowing gas temperature ^{o}R (^{o}F+460)

[2] Primary metering standards of reference include; *American Gas Association (AGA) Report #3 and American Petroleum Institute (API) Chapter 14, Section 3 (Orifice Meters), American Gas Association (AGA) Report #7 (Turbine Meters), American Gas Association (AGA) Report #9 (Ultrasonic Meters), American Gas Association (AGA) Report #10 (Speed of Sound Calculations), American Gas Association (AGA) Report #11 (Coriolis Meters), American National Standards Institute (ANSI) B109 (Positive Displacement Meters)*

[3] Secondary and tertiary metering standard of reference; *American Petroleum Institute (API) Chapter 21, Section 1 (Electronic Gas Measurement – EGM)*

[4] *Piping Calculations Manual*, E. Sashi Menon, McGraw-Hill, 2004, Pgs. 433-435

T_b = Temperature base ^oR (^oF+460)
P_b = Pressure base (psia)
Z_b = Gas compressibility at base conditions (generally assumed to = 1)
Z_{avg} = Gas compressibility at average pressure and flowing temperature

With the average pressure of the pipeline segment being calculated using:

$$P_{avga} = \frac{2}{3}\left(P_1 + P_2 - \frac{P_1 P_2}{P_1 + P_2}\right)$$

Where: P_1 = Upstream pipeline pressure (psia)
P_2 = Downstream pipeline pressure (psia)
P_{avga} = Average pipeline pressure (psia)

And the gas compressibility calculated[5] at the conditions of average pressure and temperature using:

$$Z_{avg} = \frac{1}{1 + P_{avgg}(344{,}400)(10)^{1.785G} \Big/ T_f^{\,3.825}}$$

Where: P_{avgg} = Average pipeline pressure (psig)
G = Gas relative density (air = 1.000)
$T_{f\,=}$ Flowing gas temperature ^oR (^oF+460)

Line pack should be determined frequently in order to include the ongoing variance of such in the system balance analysis. Additionally, line pack must always be considered and included when commissioning newly constructed or repaired pipelines with initial purge and pack volumes.

Pipeline Retrograde Condensation

We never know the worth of water till the well is dry. ~ Thomas Fuller

The presence of significant amounts of liquefiable hydrocarbons and water vapor within the composition of the gas can lead to constraining operational issues and difficulty in properly accounting for volumes. When subjected to variances in temperature and pressure, heavier hydrocarbons (generally propane (C_3H_8) and heavier) can begin to experience retrograde condensation, or changes of state from vapor to liquid. The critical temperature and pressure at which this change of state from vapor to liquid will occur is the **Hydrocarbon Dew Point** or **HCDP**[6]. The maximum temperature and pressure at which this phase change takes place is the **cricondentherm** and the maximum pressure at which the vapor and liquid phases of the compound may coexist is the **cricondenbar**. The occurrence of this physical change of state in the fluid properties results in the fluid entering the system in a gaseous phase and exiting the system in both gaseous and liquid phases.

Water vapor received into pipelines also experiences frequent changes of state due to changes in temperature and pressure. The critical temperature at a given pressure at which water will experience a change of state from vapor to liquid is the **Water Vapor Dew Point**[7]. Not only will the water that condenses into liquid within the

[5] *Piping Calculations Manual*, E. Sashi Menon, McGraw-Hill, 2004, Pgs. 408, California Natural Gas Association (CGNA) method

[6] Hydrocarbon Dewpoint is directly measured via the use of a chilled mirror dew scope. Other technologies also exist to determine HCDP. Equations of State (EOS) are also employed to calculate HCDP, cricondentherm and cricondenbar from a known gas composition. *American Petroleum Institute (API) Chapter 14, Section 1* addresses natural gas sampling and related activities associated with the ultimate determination of HCDP.

[7] Water Vapor Dewpoint is directly measured via the use of a chilled mirror dewscope. Other technologies also exist to determine water vapor dew point including chemical titration methods, electrochemical cells and laser based spectroscopy. The value may also be precisely determined and inferred from the use of Equations of State (EOS) models. The effects of water vapor on gas measurement and volumetric calculations are detailed in *Gas Processors Association (GPA) Standard 2172* and *American Gas Association (AGA) Report #3, Part 3*.

pipeline create operational problems in and of itself, it can also create major problems through the formation of hydrates within the gas stream. Hydrates occur when water combines with hydrocarbons and forms an inclusive compound, resulting in a solid that can restrict or totally block the flow path within the pipeline.

The condensed hydrocarbon and water liquids removed from pipelines must obviously be included within the system balancing and LAUF analysis. Because flows are received into the system as vapor[8] and measured as such, they must also be accounted for as deliveries, even though a change of state was experienced in transit. It is simply a matter of accounting. What must be observed is the proper conversion of liquid volumes to gas equivalent volumes[9].

Gas Quality, Contaminants and Impurities

The problem with the gene pool is that there's no lifeguard. ~ David Gerrold

Pipeline Quality Gas – now there is a contradiction in terms. A common misconception is that pipelines, namely transmission lines, have only clean, high quality gas that is well within specifications for thermal value, inerts, impurities, contaminants or diluents. This is definitely the goal of transmission pipeline operators in order that they may control the quality of the product that they are delivering to their customers and effectively protect the mechanical and operational integrity of their pipeline systems. However, upstream issues in the production, gathering and processing areas can quickly affect the quality of gas received into the transmission pipeline, and subsequently have a significant effect on the determination of quantities within the system.

The issue of gas composition and quality measurement is one of the most critical and frequently occurring problem issues related to the effective determination of a pipeline system balance and LAUF. Volumetric and energy calculations are dependent upon the precise definition of fluid composition in order that the quantities derived from such are representative. Arguably, more fluid measurement quantity calculation errors, and ultimately LAUF issues, are the result of inaccuracies in the measurement of natural gas composition[10] and the resulting errors in determining the fluid density, thermal value and compressibility properties.

Natural gas is primarily composed of hydrocarbons, such being Methane (C_1H_4), Ethane (C_2H_6), Propane (C_3H_8), Butanes (C_4H_{10}), Pentanes (C_5H_{12}) and Hexanes (C_6H_{14}), with ever diminishing smaller amounts of heavier hydrocarbons within the compound. In addition, smaller concentrations of non-hydrocarbons are also in natural gas. The most common non-hydrocarbons contained in natural gas in pipelines are Nitrogen (N_2), Carbon Dioxide (CO_2), Oxygen ($O_{2)}$), Hydrogen Sulfide (H_2S) and Water (H_2O).

Nitrogen (N_2) is a diluent that is of no heating value and thereby diminishes the thermal value of the natural gas compound by its increasing presence. Nitrogen poses no threat of corrosion.

Carbon Dioxide (CO_2) is a diluent that is of no heating value and thereby diminishes the thermal value of the natural gas compound by its increasing presence. CO_2 does pose a threat of corrosion. When combined with water (H_2O), carbonic acid (H_2CO_3) can form which acts as a corrosive to steel pipe. Corrosion specialists generally consider the presence of CO_2 to be at a critical level of concern when such reaches seven pounds of partial pressure. The partial pressure is determined when the percentage of the constituent by volume, in this case CO_2, is multiplied by the flowing pressure.

Hydrogen Sulfide (H_2S) is a contaminant in natural gas that is both highly corrosive and toxic. The presence of H_2S in natural gas is of great concern to operators because of its highly corrosive effect on steel and the tremendous safety risks inherent to exposure to gas containing the compound.

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[8] Theoretically anyway! Receipts into gas pipeline systems are **supposed** to be vaporous, but it doesn't always work out that way. For the sake of our discussion (hopefully not our argument), we assume that all receipts are in a gaseous phase.

[9] Methods and factors for conversion of liquid volumes to gas equivalent volumes may be found in *Gas Processors Association (GPA) Standard 2145* and the *Gas Processors Suppliers Association (GPSA) Engineering Data Manual*.

[10] Methods for the accurate sampling of natural gas are found in *American Petroleum Institute (API) Chapter 14, Section 1*. Methods for the accurate analysis of natural gas by gas chromatography and determination of thermal and physical properties of the compound are found in *Gas Processors Association (GPA) Standard s 2145, 2172, 2261 and 2286*.

Oxygen (O_2) is a contaminant in natural gas that is not a naturally occurring component of the compound. In other words, O_2 is a foreign constituent introduced into the natural gas from an external source. Generally, oxygen enters the gas stream via mechanical equipment or from very low pressure (vacuum) pipeline gathering laterals that are leaking and actually drawing air into the system. Oxygen also poses a corrosion threat to steel pipelines, as well as posing a threat of combustion if the ratio of air to natural gas reaches the lower explosion limit (LEL).

Leakage

Beware of little expenses; a small leak will sink a great ship. ~ Benjamin Franklin

Leakage (gas truly lost from the system) can be substantial or very subtle. In any case, leakage comprises a significant portion of LAUF. Gas volumes lost through pipeline breaks and ruptures are significant, but may generally be accounted for by some means, whether inferential determination per measured receipts and deliveries and the known duration of the leak, or through engineering calculations per the known size of the leak, pressure loss and leak duration. It is generally the subtle system leaks that are unaccountable and cause the greatest source of frustration. A frequent example of subtle leaks that result in difficult to determine LAUF issues are system deliveries that frequently experience intermittent periods of flow.

On transmission pipeline systems, volumes entering and exiting the system are usually scheduled and nominated on a daily or even an hourly basis. This means that flowing volumes entering and exiting the system are not necessarily steady state flows, but subject to the supply and demand operations criteria placed upon the pipeline system. Therefore, flows are turned on and off at multiple points on the system throughout the day.

Here is where the subtle problems can occur. Many times, control valves are remotely actuated by control centers via SCADA to start, stop and control the flows entering and exiting the system. These valves are often the only source of isolation between systems that are utilized. Due to the frequent use and seat erosion experienced by even the best of these valves, positive shutoff continually becomes more difficult to achieve. Therefore, small leaks can, and often do begin to occur.

Ironically contributing to the issue is the use of the better recording technologies (EGM) employed today. EGM's and some primary devices use a mechanism known as "No Flow Cutoff" to filter out very low level gradients and anomalies that falsely represent flow. This software mechanism is a necessity in ensuring that only legitimate flows are recorded and used in volume calculations. The "No Flow Cutoff" is often set at a very low flow indication (0.25" H_2O, 0.5 ft/sec, etc.). These very low filter points are intended to be below any point of expected operational flow rate in which operators reasonably expect to function. However, when the seat of a valve subtly leaks, the unexpected flow rate experienced can, and very often does stay below the "No Flow Cutoff" filter point in which flow is recognized as legitimate and recordable. Suddenly, unmeasured flows are occurring.

One argument may be "The volumes just aren't enough to matter". The following examples indicate that when considering and managing leakage and LAUF, all leakage volumes can matter very significantly.

Orifice Meter		Ultrasonic Meter	
Meter Size ("ID)	12.0	Meter Size ("ID)	12.0
Orifice Bore Size ("ID)	6.0	Static Pressure (PSIG)	750.0
Static Pressure (PSIG)	750.0	Fluid Velocity (ft/sec)	0.4
Differential Pressure ("H_2O)	0.1	Fluid Temperature (^oF)	60.0
Fluid Temperature (^oF)	60.0	Flow Rate (MCFH)[11]	**58.7**
Flow Rate (MCFH)[11]	**90.9**		

In this example, the pipeline operator could lose 2,182 MCF in a day and 65,460 MCF in a month that went unrecorded by the EGM on the orifice meter, or 1,409 MCF in a day and 42,270 MCF in a month that went unrecorded by the EGM on the ultrasonic meter. At \$5.00/MMBTU, that comes to \$327,300 and \$211,350

[11] Flow rate calculations are based on 14.73 psia pressure base, 60^0F temperature base,0.600 relative density, 0.5% CO_2, 1.0% N_2, 95.0% C_1H_4, and 1025 dbtu/cf.

respectively that may be lost in one month. And the solution? A small investment in equipment and applications that will close the block valve upon cessation of flow though the facility. That looks like a pretty good investment!

Steps taken to minimize the possibility of leakage through a control valve at un-recordable low flow levels would include the closure of a block valve in conjunction with the closure of the control valve. Block valves employed in series with control valves are designed for higher probability of positive shut off. This is an easy operational step to take that can save many dollars and tons of grief through the mitigation of leak potential.

Leaking valves at interconnect points only represent one definable aspect of leak potential that can occur and contribute to LAUF. Several other relevant sources of leak consideration that should be closely managed include flanges connections, hand valves, meter fittings and bodies, tubing and pipe fitting connections, pressure relief valves, and liquid dump valves attached to gas/liquid separators and vessels, to name a few.

Other general steps that may be taken include leak detection activities. Typical leak detection methods include the use of shut-in pressure tests, Flame Ionization Detection (FID) leak detection devices, aerial and ground surveys of pipeline right-of-ways to visually check for signs of leaking product (dead vegetation, bubbling surface and ground water, etc.), aerial based infrared leak detection, thermography, liquid leak detection solutions, mathematical (hydraulic) models and other effective leak detection methods.

<u>Lingering Questions</u> (Our Own Little Collection of LAUF FAQ's)

No question is so difficult to answer as that to which the answer is obvious ~ George Bernard Shaw

Q. Since MMBTU's are the same regardless of pressure base, does P_b really matter?

A. MMBTU's are the same regardless of pressure base contingent upon the volume (scf) and energy per unit of volume (btu/cf) being determined on the <u>SAME</u> pressure base. Remember that MMBTU is a calculated quantity that is dependent upon other calculated quantities that are dependent upon the inference of physical measurements taken of the flowing fluid. The physical bases upon which these measurements are recorded, applied, and quantities ultimately calculated is of critical importance in ensuring that those final calculated quantities are legitimate.

Q. Do we need to concern ourselves with water since our contracts stipulate that we measure on a dry basis?

A. The main thing to remember is that NATURAL GAS CAN'T READ! That being said, one of the most conflicting issues that occurs in reviewing and mitigating LAUF is the resolution of the <u>Administrative Terms</u> versus the <u>Physical Realities</u> of the reported quantities. Although the contract or tariff may stipulate that the gas will be dry and free of contaminants, there will always be the occasion (infrequently, we hope) that the product measured contains components that are not expected. To disregard those contaminants due to "expectation" would be to misstate the overall quantity and quality of the product measured, thereby further contributing to the uncertainty and LAUF. To effectively perform a legitimate LAUF evaluation, the quantities must be fully considerate of the <u>Physical Realities</u> and subsequently reconciled to the <u>Administrative Terms</u>.

Q. How can we continue to have any measurement problems since we replaced our chart recorders with electronic measurement?

A. In and of itself, electronic measurement (EGM) is simply a more capable technology enabling the operator to resolutely record bad measurements, quickly calculate inaccurate quantities and communicate the faulty information to corporate business systems with a speed and efficiency that could not have been comprehended only a few years ago. Electronic measurement is a secondary (recording) and tertiary (calculating) application, not the primary measurement device. The accuracy and legitimacy of the recorded and calculated quantities are totally dependent upon the measurements rendered by the primary metering device, whether such is an orifice, turbine, ultrasonic, positive displacement, or other type of primary meter.

Q. How can our measurement be in error when our meters are constructed and installed per industry specifications?

A. *Metering uncertainty is dependent upon specified conditions as noted within applicable industry standards. For example, orifice metering uncertainty as stated is dependent upon steady, laminar, non-pulsating fluid flows at the points of measurement of the critical flowing variables. Additionally, the fluid is assumed to be single phase only, free of aerosols, liquids or particulates. As we know from experience, the product that is often measured by the primary metering device may be of less than ideal quality. By assuming only optimum conditions for accurately measuring the fluid flow, we may overlook significant problems that may continually contribute to LAUF.*

Conclusion

There are very few human beings who receive the truth, complete and staggering, by instant illumination. Most of them acquire it fragment by fragment, on a small scale, by successive developments, cellularly, like a laborious mosaic. ~ Anaïs Nin

Thus is the process of managing system balance and minimizing LAUF. Very rarely do we find the "smoking gun" that brazenly shows itself and is the illuminating answer to our missing volume quandary. More often, our analysis involves a pain staking, comprehensive search of detailed aspects that are inherently uncertain[12].

Determination of leakage and unaccounted for gas volume and energy quantities is one of the most important operational and administrative processes that pipeline operators must perform. The financial implications of volumes that are lost or unaccountable can be significant. And, there is no such thing as "It just doesn't matter" when it comes to performing detailed system balancing analyses.

When LAUF reaches unacceptable levels, all of the aspects of a comprehensive pipeline system balancing analysis that have been discussed must be reviewed, verified and substantiated. The costs of ignoring any of them are too high.

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[12] Moreover, there are undoubtedly aspects of system balancing analysis and LAUF mitigation that have not been addressed here. There is always more to learn and new rocks to turn over. Beware of the one who claims to know it all – he has probably never ventured very far!