

AUDITING LIQUID MEASUREMENT STATIONS

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Abstract

Accurate liquid measurement is fundamental to custody transfer, operational control, and financial integrity across the hydrocarbons value chain. Even minor deficiencies in meter design, configuration, calibration, or operation can result in significant volumetric or mass bias and corresponding financial exposure. This paper outlines a structured approach to auditing liquid measurement stations, with a focus on pipeline, terminal, plant involved in the measurement of natural gas liquids (NGLs), liquified petroleum gases (LPGs), and refined products and also touches on the differences found with crude oil LACY measurement. Emphasis is placed on metering theory, compliance with industry standards. Practical guidance is provided to assist measurement professionals in identifying risk, validating measurement integrity, and minimizing loss and developing their own check lists to audit liquid measurement stations.

1. Introduction

An audit, defined as a methodical examination and review, is a critical tool in ensuring that liquid measurement systems perform as intended. In the hydrocarbon energy business, the purpose of auditing extends beyond regulatory compliance as it is essential for minimizing measurement uncertainty, resolving imbalances, and protecting asset value.

Audits are conducted for several core reasons:

- Risk mitigation: Identifying sources of bias before they result in financial loss.
- Verification of check measurement: Confirming that secondary or comparison measurements are suitable for custody or accounting purposes.
- Investigation of known or perceived issues: Addressing unexplained losses, gains, or plant imbalances.
- Reconciliation support: Resolving discrepancies identified in downstream balances.
- Policy and regulatory compliance: Satisfying internal company standards or government requirements.

Because measurement errors tend to persist until corrected, even small issues discovered during an audit can justify the effort through avoided gains and losses.

For example, a gas plant processing 250 MMSCFD can easily produce 30,000 barrels of NGLs per day. A bias or error as small as a tenth of a percent can have huge financial impacts over the course of a year (see Figure 1). As a result, systematic auditing of measurement stations is a necessary component of an effective measurement management program.

Product	BPD	\$/BBL (09/2025)	Value (\$) per Day	Value of 0.10% per Day	Annual value of 0.10% per Day
Crude Oil	30000	98.07	2,942,100	2,942	1,073,867
NGLs	30000	31.02	930,565	931	339,656
Ethane	13110	8.40	110,124	110	40,195
Propane	9270	34.37	318,610	319	116,293
IsoButane	1230	50.51	62,127	62	22,676
Normal Butane	3456	49.69	171,714	172	62,676
Natural Gasoline	2934	91.33	267,990	268	97,816

FIGURE 1 - The impact of a 0.10% loss on various products (pricing bases on May 2026)

2. Types of Measurement Points

There are several different types of measurement points each with its own unique characteristics and challenges, I identify these points as:

- Meter stations – there would be stand-alone metering skids found at the outlet of an asset or facility, such as at the outlet of a gas processing plant.
- Pipelines – this would include balancing the injections and withdrawals of a pipeline.
- Terminals – terminals consist in general of multiple inlets on outlets and possibly multiple products.
- Plants – in this category, I include fractionators, refineries, etc., so essentially a facility that takes a feedstock and separates or converts it to another.

Measurement of a single molecule can occur in one or several of these types of points. In Figure 2, the NGLs into the pipeline might be measured both by Company A who produces the product, and Company B who gathers the product. Company C might then receive the product into a terminal where it either stores the product temporarily and then delivers it to a fractionator co-owned by Company D. Products produced by the fractionator are then either stored and/or shipped to other companies. In some cases, all this measurement may be done by a single company.

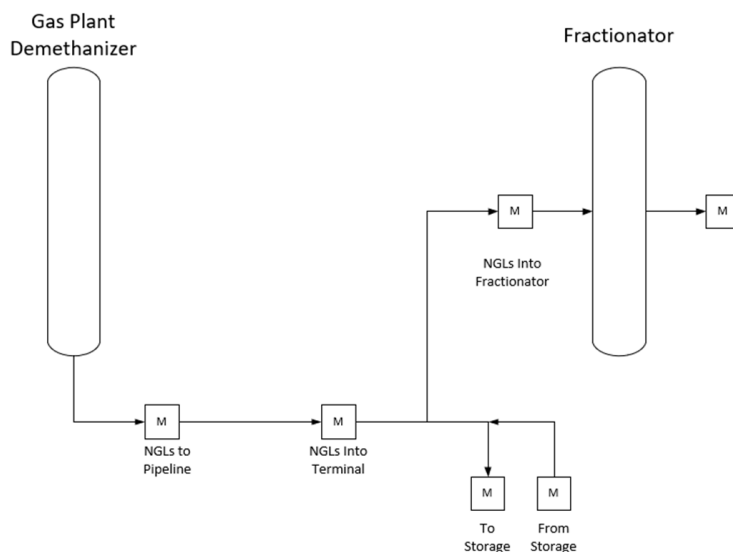


Figure 2 - Value chain of an NGL stream

As noted above, each measurement point presents unique risks based on operating conditions, product properties, and contractual requirements. Effective audits consider not only individual meters but their role within the broader system.

3. Types of Liquid Metering Systems

Liquid measurement systems used in plants, pipelines, and terminals generally fall into two main categories:

- Volumetric Measurement Systems – these systems are used for LPG, finished products, crude oil, condensate, and other products measured using correction tables.
 - LACT/ACT systems are generally used for crude oil and condensate.
- Mass Measurement Systems – these systems either measure and report mass only, in cases such as polymer grade ethylene and propylene, or measure mass and report volume for product such as NGLs, refinery grade propylene, and other mixes.

Understanding whether the accounting basis is volumetric or mass measurement is a critical first step in any audit, as it drives the calculation methodology and required instrumentation.

4. Elements of a Liquid Meter (non-crude oil)

When developing an audit plan and check list, it is important to understand all the standards involved with the metering system being audited. Figure 3 shows a typical light liquid metering skid and all the API MPMS and GPA Midstream standards involved with the design, installation, and operation of the skid.

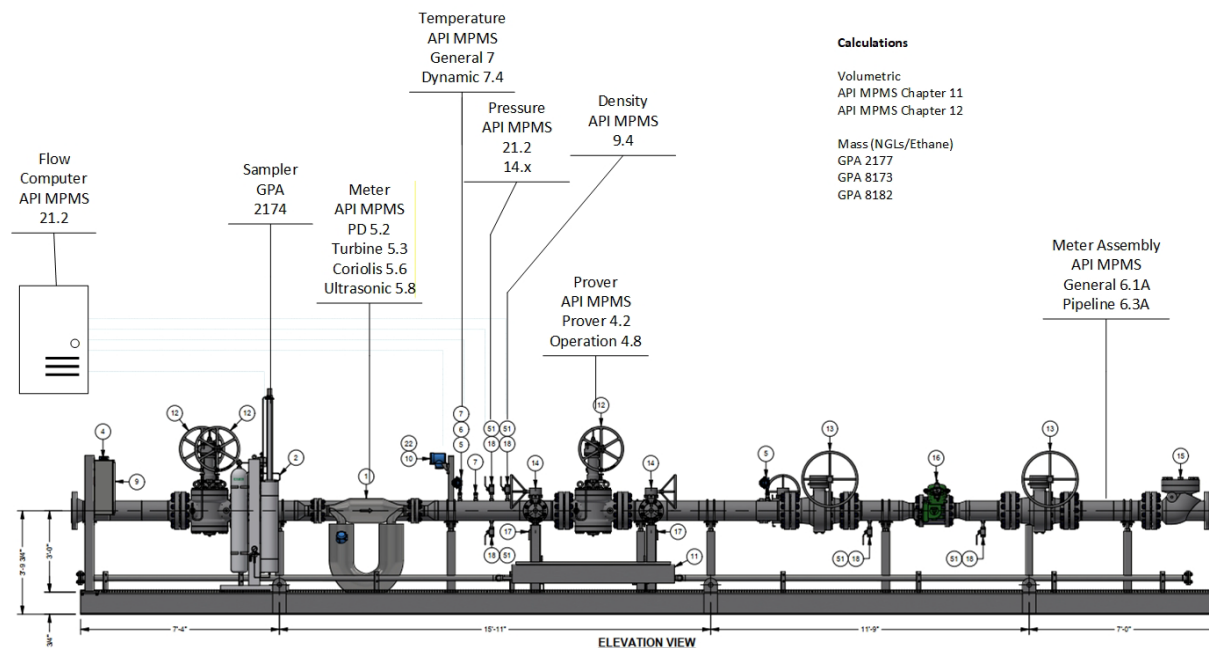


Figure 3 - Elements of a Liquid Meter (non-crude)

5. What is the Accounting Basis of the Product Being Measured?

Before preparing to do an audit, one important thing to know is, what is the accounting basis of the product or products being measured? LPGs, refined products, crude oil, and condensate are generally measured by volumetric methods, i.e. using temperature and pressure correction algorithms. NGLs, mixed products such as refinery grade propylene or refinery grade butanes, are generally measured using mass techniques and using analysis and densities defined by GPA 2145 or other sources, to convert to equivalent liquid volumes. Products such as polymer grade ethylene or propylene are simply measured by mass.

5.1. Volumetric Measurement Principles

Volumetric measurement relies on the determination of Gross Standard Volume (GSV), which corrects the indicated metered volume for fluid temperature, fluid pressure, and manufacturing effects (see Equation 1).

$$GSV = IV \times \text{Meter Factor} \times CTL \times CPL \quad (\text{Equation 1})$$

Where:

IV (Indicated Volume) is derived from meter pulses and the K factor per API MPMS Chapters 5 and 12.

The Meter Factor is established by proving in accordance with API MPMS Chapters 4 and 12.

CTL (Correction for Temperature of Liquid) corrects to standard temperature using API MPMS Chapter 11.

CPL (Correction for Pressure of Liquid) corrects to equilibrium vapor pressure using API MPMS Chapter 11.

Auditing each input to this equation is essential, as errors compound multiplicatively.

For crude oil and condensate, the equation expands further to:

$$\text{NSV} = \text{GSV} * (1 - \text{SW}) \quad (\text{Equation 2})$$

Where:

NSV (Net Standard Volume) is the GSV adjusted for sediment and water and calculated per API MPMS Chapter 12.

SW is the percentage of sediment and water in the product divided by 100 and determined per API MPMS Chapter 10.

In the case of LPGs, and finished products, NSV is the same as GSV since these products are generally assumed to have no sediment and water.

5.2. Mass Measurement Principles

Mass is measured by either direct or indirect measurement methods. When measuring mass directly, Equation 3 is simply the mass measured at the meter times the meter factor:

$$\text{Mass} = \text{Indicated Mass} * \text{Meter Factor} \quad (\text{Equation 3})$$

Where:

Indicated Mass is the uncorrected mass from the mass meter itself.

Meter Factor for a mass meter is derived from a volumetric proving using a densitometer at the prover to determine the mass of the prover.

Indirect mass measurement involves determining the indicated volume, meter factor, and the density of the fluid at the meter. So Equation 4 becomes:

$$\text{Mass} = (\text{IV} * \text{Meter Factor}) * (\text{Density at T \&P} * \text{Density Correction Factor}) \quad (\text{Equation 4})$$

It is important to note that the two methods use different proving techniques and also require the determination and calibration of density. Conversion of mass to volume involves determining the composition of the stream and following GPA 8173 to determine the equivalent volume.

6. Flow Meter Technologies and Audit Considerations

Each metering technology has its specific installation and operation requirements. When performing an audit, it is important to know what these requirements are to properly evaluate the technology.

6.1. Positive Displacement Meters

Positive displacement (PD) meters are defined by API MPMS Chapter 5.2. Key audit points include:

- Confirm that a strainer is installed to protect the meter internals.
- Confirm that the meter K factor matches the flow computer configuration and/or proving report.
- Is the temperature measured on the body or within five pipe diameters from the outlet flange?
- Verification that meter factors are derived correctly from proving data

PD meters do not require flow conditioning, but they are sensitive to mechanical wear and debris.

6.2. Turbine Meters

Turbine meters are defined by API MPMS Chapter 5.3 and require careful attention to installation:

- Is there upstream flow conditioning or adequate straight-run length (typically $\geq 20D$)?
- If a flow conditioner is used, has it been installed according to the manufacturer's requirements?
- It should be noted that the K-factor might not match the meter body, so confirm if the K-factor is based on a proving or based on some other value.
- The temperature device shall be no closer than five pipe diameters to the outlet flange.
- While not required, proper insulation can help temperature stability during proving.

Audits frequently identify installation-related biases in turbine applications.

6.3. Coriolis Meters

Coriolis meters are defined by API MPMS Chapter 5.6 and are widely used for both mass and volumetric measurement but require more detailed verification to ensure they are being operated correctly.

- Confirm the meter is properly supported and stress-free.
- Do the calibration coefficients of the sensor match the values shown in the transmitter?
- Is damping disabled for both flow and density measurement? This can affect the meter factor and repeatability.
- If the meter is operating above 100 psig, is pressure compensation enabled?
- Document any density or flow cutoffs as they could impact measurement.
- How is flowing temperature being determined? The RTD on the meter body does not measure temperature of the fluid.

Any meter misconfiguration could result in errors in the meter factor, measurement, or both.

6.4. K Factor and Frequency Limitations

Manufactured pulse meters depend on proper K factor selection. Audits should verify that:

- Expected flow rates do not exceed flow computer frequency limits
- K factors are selected to balance resolution and maximum frequency

Failure to consider frequency limitations can lead to pulse saturation and under measurement.

7. Pressure and Temperature Measurement

Pressure and temperature measurement accuracy is critical due to their influence on CTL, CPL, meter factors, and prover corrections.

7.1. Temperature

Temperature measurement requirements include:

- Test thermowells located per API MPMS Chapter 7 and shall be the lesser of 3 pipe diameters or 18 inches away from the transmitter.
- The Test thermometer resolution should be at least 0.1 °F.
- Monthly verification within ± 0.2 °F and annual calibration for meter ticketing and proving.
- Thermowells should have conductive materials in them.

For LPG products, temperature differences as small as 0.05 °F can cause measurable bias.

7.2. Pressure

Pressure measurement audits should confirm:

- Compliance with API MPMS pressure uncertainty requirements (± 3 psig)
- Pressure tap elevation matches meter elevation
- Quarterly transmitter verification and annual calibration

While pressure sensitivity is typically lower than temperature sensitivity, it remains significant for volatile liquids.

8. Density Measurement

Dynamic density measurement defined by API MPMS Chapter 9.4 supports both volumetric and mass measurement. Volumetrically, it can be used to determine CTL and CPL. In mass measurement, it is either used in determining density in indirect mass measurement or determining the mass in a prover for indirect mass provings.

Key audit steps include:

- Verify the temperature and pressure tube stiffness compensation coefficients in the flow computer.
- If using a time-period signal from the densitometer, verify the flow computer can handle the time-period signal and is not interpreting it as frequency.
- When an analog output is used from the densitometer, verify the analog loop prior to calibration.
- Does the calibration software require observed or corrected density, and is the proper value being used.

Density errors directly affect CTL, CPL, and inferred mass calculations.

9. Proving Systems and Prover Valves

Meter proving is only as accurate as the integrity of the proving system and has a direct effect on the meter factor.

9.1. Prover Block Valves

Prover isolation valves can be a significant source of measurement bias. In a single-meter setup, leakage through the prover isolation valve will affect the meter factor. In a meter header arrangement, such as the one shown in Figure 4, the valves leading to the prover are just as critical. Leakage through any of these valves can allow product to flow into or out of the prover system, resulting in incorrect meter factors and potentially contaminating the product. Any leaking isolation valve will introduce measurement bias.



Figure 4 - Meters in Series with a Stationary Prover

Audits must verify double block and bleed configurations and confirm no hidden bypasses exist, including GC speed loops.

9.2. Provers

For pipe and compact prover operation, see API MPMS Chapter 4.8:

- Prover sizing must be appropriate for the meter
- Temperature should be measured near the inlet/outlet
- Water draws must be current and compliant
- All transmitters must be verified prior to proving

In inferred mass proving, using density at the prover not at the meter is essential. Also as shown in Figures 5, achieving temperature between the prover and outlet of the pycnometer to within 0.2°F or less is crucial, as the more deviation in temperature, the more bias that will result in the proving.

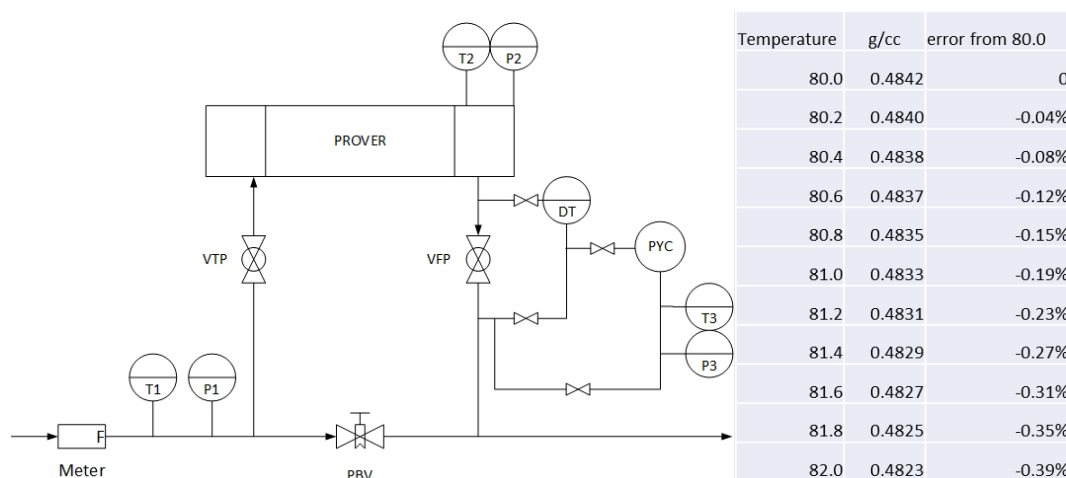


Figure 5 – T2 and T3 Need to Agree to Within 0.2°F or Better

10. Sampling Systems

Sampling systems support both volumetric correction and product valuation. In volumetric measurement, the product density can be used to determine CTL and CPL. For mass measurement, analysis is used to convert the mass and to component pounds and subsequently component volume as shown in Figure 6.

Gross 10000 Barrels		Notes: 1) From GPA 2145 - 09	
Meter Factor	0.9907	2) Calculations done per GPA 8173	
Flowing Density	0.48780 g/cc		
Mass	1693873 Lbs		

	(A)	(B)	(C)	(D)	(E)	(F)
Component	WT%	Weight Fraction C/Sum(C)	Mass	Lbs/Gallon (1)	Component Mass B * C	Barrels @ 60°F and EVP E / D /42
N2	0.000%	0.00000	1693873	6.7271	0	0
CO2	0.029%	0.00029	1693873	6.8129	491	2
C1	0.474%	0.00474	1693873	2.5	8029	76
C2	34.272%	0.34272	1693873	2.9704	580524	4653
C3	28.498%	0.28498	1693873	4.2285	482720	2718
IC4	5.830%	0.05830	1693873	4.6925	98753	501
NC4	14.291%	0.14291	1693873	4.8706	242071	1183
IC5	4.214%	0.04214	1693873	5.212	71380	326
NC5	4.106%	0.04106	1693873	5.2584	69550	315
C6+	8.286%	0.08286	1693873	5.9061	140354	566
	100.000%	1.00000			1693873	10341

Note: C6+ Properties determined from extended analysis

Figure 6 - Conversion from Mass to Component Volume using GPA 8173

Audit focus areas include:

- Sample probe location and orientation. It should never be between the meter and prover block valve.
- The sample bevel should point into the flow.
- The sample should be taken proportional to flow, or time based.
- Ensure the sample pump is paced at a rate no faster than manufacturer specifications which in some cases is every 30 seconds.
- Confirm the sampler and receiver are adequately sizing based on grab size, recover time, and time between sample pulls.

11. LACT Systems

LACT units share many characteristics with pipeline and light liquid metering but introduce additional considerations:

- Net Standard Volume calculation accounting for sediment and water is common and require testing for sediment and water.
- Back pressure regulators are generally installed and locked to hold a fixed back pressure.
- Certified hydrometers are used for gravity determination for both the proving and meter ticketing.

Although the S&W monitor is not used in accounting calculations, it must be functional and calibrated to prevent contaminated deliveries.

12. Meter Ticket Adjustments

Most commercial contracts specify thresholds for meter factor or density factor changes. Typical limits are shown below, but contracts should be referred to when auditing to ensure ticket corrections are being issued and properly calculated.

- Adjustments are often required when the meter or density correction factor exceeds $\pm 0.25\%$ as compared to the prior factor.
- Deviations beyond $\pm 0.50\%$ typically require action to be performed such as cleaning a meter or densitometer.

Audits should verify that any applied corrections conform to contractual requirements, including correct use of half, full, or other partial adjustments.

13. Conclusions

Auditing liquid measurement stations is a critical safeguard against financial loss and operational disputes. This paper demonstrates that:

- Small measurement errors can produce large economic consequences
- Many biases originate from configuration, installation, or maintenance not meter technology
- Adherence to API MPMS, GPA Midstream, and other industry standards is essential but not always sufficient.
- Structured checklists significantly improve audit effectiveness and should be developed prior to performing an audit.

By understanding how each component contributes to overall measurement uncertainty, organizations can implement robust auditing programs that protect value and ensure confidence in reported volumes and masses.

References:

API MPMS

API MPMS Chapter 4.1 Proving Systems Introduction

API MPMS Chapter 4.2 Displacement Provers

API MPMS Chapter 4.8 Operation of Proving Systems

API MPMS Chapter 5.1 General Consideration for Measurement by Meters

API MPMS Chapter 5.2 Measurement of Liquid Hydrocarbons by Displacement Meters

API MPMS Chapter 5.3 Measurement of Liquid Hydrocarbons by Turbine Meters

API MPMS Chapter 5.6 Measurement of Liquid Hydrocarbons by Coriolis Meters

API MPMS Chapter 5.8 Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters

API MPMS Chapter 6.1A Metering Assemblies – General Considerations

API MPMS Chapter 6.3A Pipeline and Marine Loading/Unloading Measurement Systems

API MPMS Chapter 6.4A Lease Automatic Custody Transfer (LACT) Systems

API MPMS Chapter 7 Temperature Determination

API MPMS Chapter 7.4 Temperature Determination – Dynamic Temperature Measurement

API MPMS Chapter 9.1 Standard Test Method for Density, Relative Density (Specific Gravity) or API Gravity of Crude & Liquid Petroleum Products by Hydrometer Method (ASTM D1298)

API MPMS Chapter 9.4 Continuous Density Measurement Under Dynamic (Flowing) Conditions

API MPMS Chapter 10.4 Determination of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure)

API MPMS Chapter 11.1 Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils

API MPMS Chapter 11.2.2 Compressibility Factors for Hydrocarbons: 0.350-0.637 Relative Density (60°F/60°F) and –50°F to 140°F Metering Temperature

API MPMS Chapter 11.2.4 Temperature Correction for NGL & LPG – Tables 23E, 24E, 53E, 54E, 59E, 60E (GPA 8217)

API MPMS Chapter 11.2.5 A Simplified Vapor Pressure Correlation for Commercial NGLs (GPA 8277)

API MPMS Chapter 12.2 Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors

GPA Midstream

GPA Standard 2145 – Table of Physical Properties for Hydrocarbons and Other components of Interest to the Natural Gas and Natural Gas Liquids Industries

GPA Standard 8173 - Standard for Converting Mass of Natural Gas Liquids and Vapors to Equivalent Liquid Volumes

GPA Standard 8182 - Mass Measurement of Natural Gas Liquids and Other Hydrocarbons

