

Natural Gas Meter Assessment and Auditing

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Abstract

Accurate measurement of natural gas flow is a foundational requirement for revenue assurance, operational planning, and safety. This paper converts the Meter Assessment Training slide deck into a formal technical paper suitable for distribution to auditors, operators, and engineering managers.

It expands slide bullets into explanatory text, provides practical examples and rationale, and offers actionable recommendations for station design, fabrication, calibration, diagnostics, and field practice.

The emphasis is on methods that reduce lost and unaccounted for gas (L&U), improve custody transfer accuracy, and enable condition-based maintenance.

1. Introduction and Scope

Accurate custody transfer and operational measurement of natural gas underpin commercial settlements, regulatory compliance, and pipeline integrity programs. Measurement errors arise from three broad causes: physical losses (leaks and theft), instrumentation and installation errors, and procedural or data-handling mistakes.

This paper addresses the latter two categories by describing measurement fundamentals, station design and fabrication best practices, calibration and test equipment requirements, diagnostic methods for orifice meters, pulsation effects and mitigation, gas sampling and chromatographic considerations, and practical field and safety practices.

Scope and audience. The intended audience includes field auditors, measurement engineers, station fabricators, and operations personnel responsible for custody transfer and fiscal metering. The paper assumes familiarity with basic fluid mechanics and gas measurement terminology but explains diagnostic methods and practical checks in sufficient detail for field application.

2. Measurement Fundamentals and Risk Management

Accurate measurement requires a clear statement of objectives, an understanding of error sources, and a risk-based prioritization of corrective actions.

Measurement objective and performance metrics. The core measurement objective is to ensure that measured inputs and outputs reconcile within acceptable uncertainty bounds so that L&U can be quantified and minimized. Practically, this means establishing station-level uncertainty budgets, documenting assumptions (base conditions, gas composition), and tracking trends in differential pressure, temperature, and flow that indicate drift or degradation.

2.1 Loss and Unaccounted For (L&U) - accounting basis and audit focus

The practical objective of a meter assessment is to reduce L&U while ensuring that each site has the best measurement achievable for the money spent in both capital equipment and maintenance. L&U is not only a bookkeeping number; it is a diagnostic signal that can indicate physical losses, poor equipment selection, calibration weakness, incorrect meter installation, or procedural failures.

At its simplest, the L&U balance is:

Inputs - Outputs = Loss or Gain.

Examples:

10 MMcf in - 10 MMcf out = 0 MMcf (perfect balance)

10 MMcf in - 8 MMcf out = 2 MMcf loss

10 MMcf in - 11 MMcf out = 1 MMcf apparent gain

In practice, L&U review must also consider contract terms, shrinkage, gas retained or consumed for operations, pressure and temperature base conditions, gas quality, and the completeness of sales and transportation reconciliation data. Total gas requirement is needed for forecasting, revenue calculations, and gas transportation reconciliation.

Common L&U drivers include physical leakage from corrosion or damaged pipelines, excavation damage or line hits, unauthorized consumption, and mismeasurement. For modern custody-transfer systems, mismeasurement is often the dominant controllable component. It can arise from flow device limitations, poor operating range, incorrect installation, poor skid build, unrepresentative gas sampling, incorrect EFM configuration, or maintenance practices that allow contamination and drift to accumulate.

An audit should therefore separate L&U into two broad categories: physical loss and measurement loss. Physical loss requires leak detection, integrity review, and operational investigation. Measurement loss requires a structured review of meter sizing, beta ratio, straight lengths, plate condition, meter tube roughness, transmitter span, EFM configuration, gas quality, sampling, and calibration records.

2.2 L&U audit workflow

A useful L&U workflow is to first establish the accounting boundary, then verify all input and output meters, then test whether the station data can support the reported balance. The audit should confirm that each meter has correct dimensional data, traceable calibration, proper operating range, and valid gas composition.

Where the L&U number is high or unstable, the auditor should review trends in flow, pressure, temperature, DP, gas quality, and maintenance history before recommending intrusive inspection.

The corrective action should be proportional to exposure. Low-cost checks include EFM parameter review, calibration certificate review, plate inspection, transmitter span review, and gas analysis validation.

Higher-cost actions may include tube replacement, flow conditioning, transmitter upgrades, sampling system redesign, chromatograph repair, or installation of diagnostic monitoring such as three-DP or pulsation testing.

Sources of measurement error. Errors originate from:

- **Instrumentation:** transmitter nonlinearity, incorrect span, or drift.
- **Primary element issues:** plate misalignment, meter tube deformation, or surface contamination.
- **Installation effects:** insufficient straight-run, weld beads, or upstream fittings that induce swirl and turbulence.
- **Process conditions:** pulsation, two-phase flow, or composition changes that alter physical properties.
- **Human and procedural factors:** incorrect calibration records, poor sampling practice, or data transcription errors.

Risk management approach. A pragmatic audit program uses a risk-based triage:

1. **Exposure assessment:** estimate potential revenue impact using flow rates, contract prices, and historical variability.
2. **Diagnostic prioritization:** apply non-intrusive diagnostics (EFM logs, DP ratio checks, pulsation scans) to identify likely failure modes.
3. **Intervention selection:** choose monitoring, repair, or replacement based on cost-benefit and safety considerations.
4. **Verification:** after corrective action, re-test and document to close the audit loop.

Condition-based maintenance is emphasized: use diagnostics to trigger interventions rather than fixed schedules that may waste resources or miss emergent faults.

3. Station Design, Fabrication, and Calibration

Meter performance is strongly influenced by mechanical design, fabrication quality, and the calibration hierarchy used for verification.

3.1 Mechanical design and fabrication controls

Skid design and materials traceability. Metering skids should be engineered to recognized standards (ASME, ANSI) with full material traceability and documented stress calculations. Design reviews must confirm that flange classes, gasket materials, and bolting meet operating pressure and temperature requirements.

Manufacturing quality. Automated machining, laser cutting, and robotic welding reduce variability and improve repeatability of critical dimensions. Fabrication records should include weld procedure specifications, non-destructive test results where applicable, and dimensional inspection reports for meter tube geometry. Figure 1 indicates some of the main parameters for review.

Installation considerations. During installation, ensure:

- **Straight-run requirements** are met per the primary element standard; exclude pipe fittings or reducers from the straight length measurement.
- **Surface finish** inside the meter tube is free from weld spatter, corrosion, or scale.
- **Alignment** of flanges and plates to prevent eccentricity that alters the beta ratio.

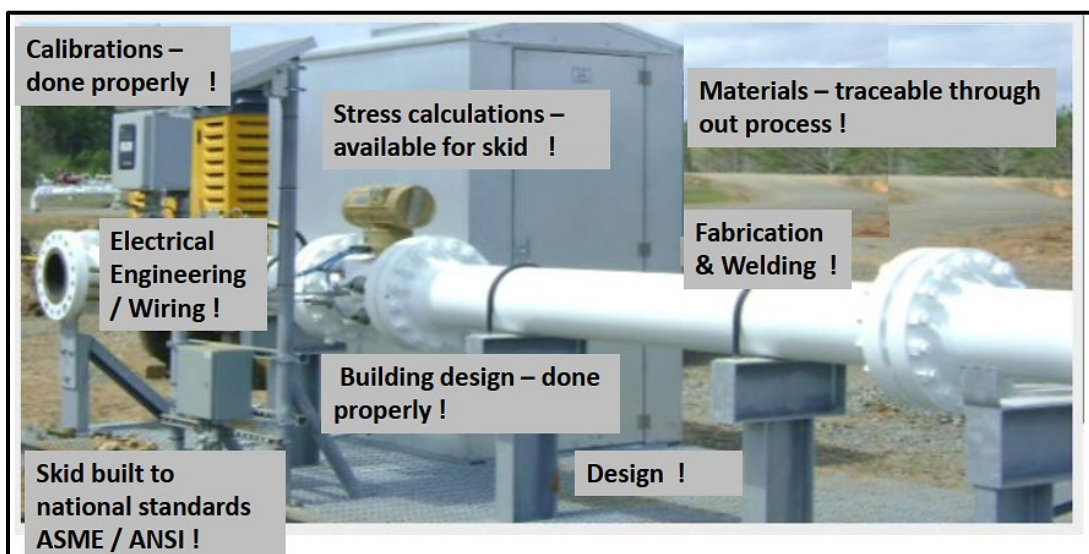


Figure 1. Metering Skid – fit for purpose?

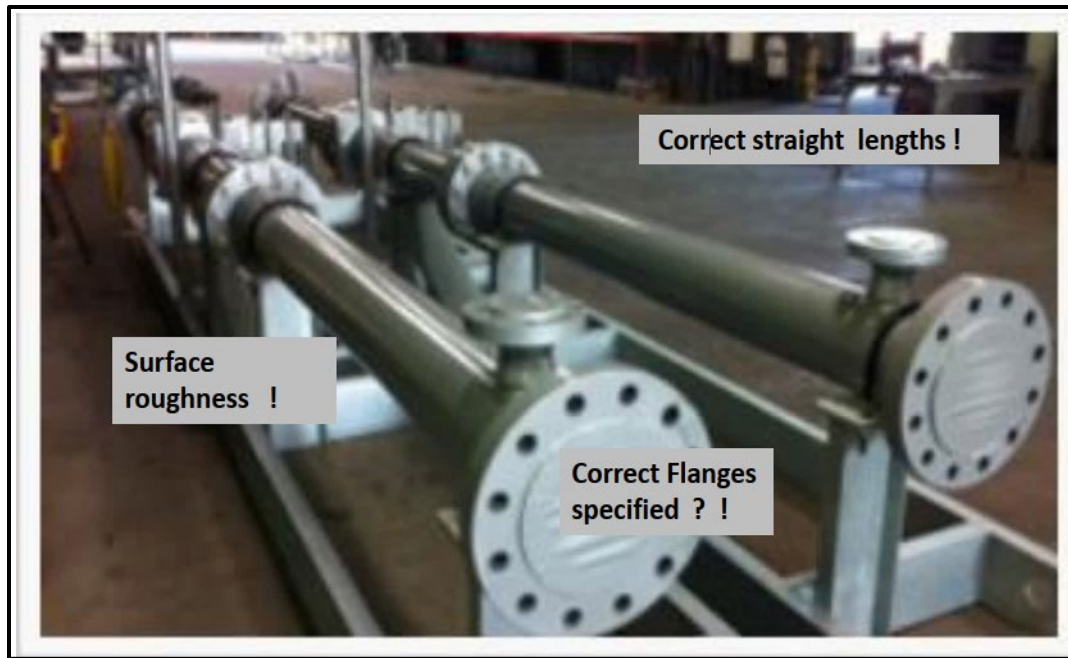


Figure 2. Metering Skid – fit for purpose straight-run, surface roughness etc.?

3.2 Calibration and test equipment hierarchy

Standards hierarchy. Calibration must be traceable to primary standards. Primary standards (e.g., gravimetric or volumetric provers) define the highest accuracy; secondary standards (transfer provers, calibrated flow rigs) inherit uncertainty from the primary.

Electronic instruments are not primary standards and must be calibrated against certified mechanical or volumetric references.

Uncertainty management. Document the uncertainty of each calibration step and propagate uncertainties to produce a station-level measurement uncertainty. For custody transfer, ensure that the combined uncertainty meets contractual and regulatory requirements.

Station data control sheets. (Mic sheets) Maintain a station data control sheet that records geometry, plate serial numbers, transmitter spans, regulator setpoints, and historical calibration dates. Attach regulator reports and overpressure protection (OPP) documentation to the station file to support audit traceability.

4. Orifice Meter Theory, Diagnostics, and Pulsation Effects

Orifice meters remain widely used for custody transfer; however, their accuracy is sensitive to geometry, flow regime, and dynamic disturbances.

4.1 Orifice meter fundamentals and installation effects

Key parameters. Orifice flow calculation depends on the beta ratio, discharge coefficient C_d , differential pressure ΔP , and fluid properties (density, compressibility). Installation deviations—such as reduced straight-run, eccentric plates, or rough meter tube surfaces—alter the effective C_d and introduce bias.

Meter tube geometry and measurement. The meter tube internal diameter should be measured at multiple circumferential and axial locations; the arithmetic mean of these measurements defines the effective diameter used in calculations. Record plate thickness, bore diameter, and plate concentricity. Surface roughness and deposits reduce effective flow area and can cause negative bias.

Orifice plate and meter tube inspection. Field assessment should include plate bore measurement, plate thickness, edge sharpness, bevel direction, flatness, seal condition, plate centering, and verification that the bore size entered in the EFM matches the actual plate.

Meter tube inspection should include internal diameter measurement, upstream and downstream straight length verification per Figure 4., tap condition, evidence of liquid or dirt, roughness, and whether flow conditioning is installed and cleaned. Figure 3 shows AGA 3 meter-run installation requirements versus beta ratio

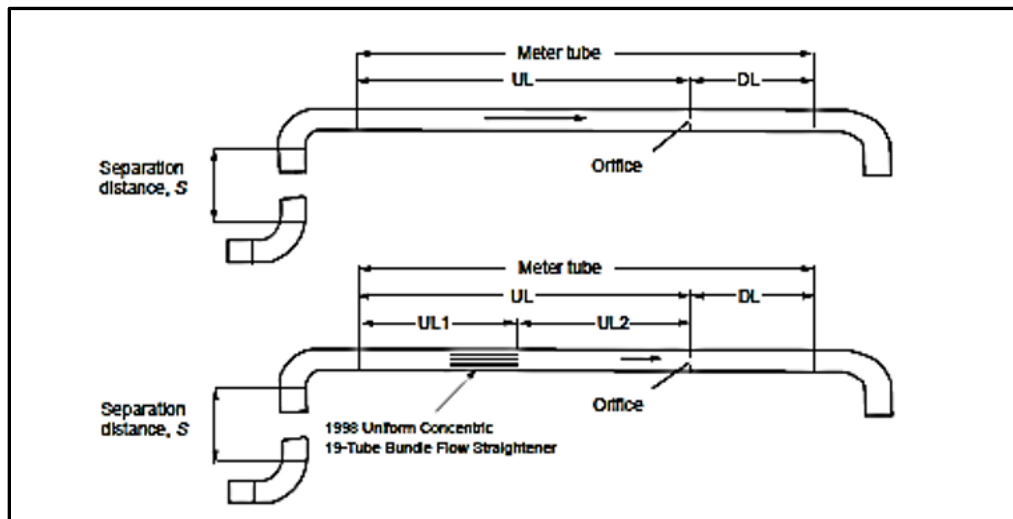


Figure 3. Requirements for meter run installations versus Beta ratio values

Roughness and contamination are important because standards are based on reference flow conditions. Exceptional pipe roughness, grease, dirt, damaged edges, mis-seated plates, or blocked flow conditioners can move the meter away from the reference condition and introduce significant negative bias.

Inspection records should include photographs where possible, because photographs are often the fastest way to communicate the condition to operations and management.

Table 1. AGA - Straight length versus Beta ratio table

Diameter ratio β	Minimum Straight Unobstructed Meter Tube Length from the Upstream Side of the Orifice Plate (in multiples of published internal pipe diameter, D_1)										Downstream meter tube length
	a. Single 90° elbow b. Two 90° elbows in the same plane with $S \geq 30D_1$ c. Two 90° elbows in perpendicular planes with $S \geq 15D_1$	Two 90° elbows in the same plane "S" configuration spacer $S \leq 10D_1$	Two 90° elbows in the same plane "S" configuration $10D_1 < S \leq 30D_1$	Two 90° elbows in perpendicular planes. $S \leq 5D_1$ *	Two 90° elbows in perpendicular planes. $5D_1 < S \leq 15D_1$	Single 90° Tee used as an elbow but not as a header element	a. Single 45° elbow b. Two 45° elbows in the same plane "S" configuration $S \geq 22D_1$	Gate valve at least 50% open	Concentric reducer	Any other configuration (catch all category)*	
≤ 0.20	UL	UL	UL	UL	UL	UL	UL	UL	UL	UL	DL
0.20	6	10	10	50	19	9	30	17	6	70	2.8
0.30	11	10	12	50	32	9	30	19	6	108	3.0
0.40	16	10	13	50	44	9	30	21	6	145	3.2
0.50	30	30	18	95	44	19	30	35	7	145	3.5
0.60	44	44	30	95	44	29	30	30	9	145	3.9
0.67	44	44	44	95	44	36	44	35	11	145	4.2
0.75	44	44	44	95	44	44	44	44	13	145	4.5
Recommended length for maximum range $\beta \leq 0.75$	44	44	44	95	44	44	44	44	13	145	4.5

UL = Minimum meter tube length upstream of the orifice plate in internal pipe diameter (D_1)(see Figure 2-6). Straight length shall be measured from the downstream end of the curved portion of the nearest (or only) elbow or of the tee or the downstream end of the conical portion of reducer or expander.
 DL = Minimum downstream meter tube length in internal pipe diameters (D_1)(see Figure 2-6).
 S = Separation distance between piping elements in internal pipe diameter (D_1) measured from the downstream end of the curved portion of the upstream elbow to the upstream end of the curved portion of the downstream elbow.
 * These installations exhibit the strong effect of Reynolds number and pipe roughness on the recommended length due to the rate of swirl decay. The present recommendations have been developed for high Reynolds numbers and smooth pipes to capture the worst case.

Note: The tolerance on specified lengths for UL and DL is $\pm 0.25D_1$.



Figure 4. Upstream and downstream straight length verification.

4.2 Three differential pressure diagnostic method

Method overview. Installing three differential pressure (DP) taps and three DP transmitters on a single orifice run produces three independent DP measurements and three DP ratios.

Under correct installation and steady flow, these ratios follow predictable relationships derived from the orifice flow equation and the geometry of the tap locations. (See Figure 5.)

Diagnostic use. Deviations from expected DP ratio patterns indicate:

- **Plate mis-seating or eccentricity** (one DP pair out of pattern).
- **Recirculation or separation** (nonlinear ratio changes with flow).
- **Tap blockage or transmitter drift** (one transmitter inconsistent across flows).

Practical implementation. Use a diagnostic matrix: plot DP ratios versus flow or versus each other to reveal clustering and outliers.

Combine with visual inspection and plate removal when indicated. This type of diagnostic method is applicable to differential-pressure meters, and commercial systems have been developed that apply this methodology for orifice meter verification and condition-based monitoring.

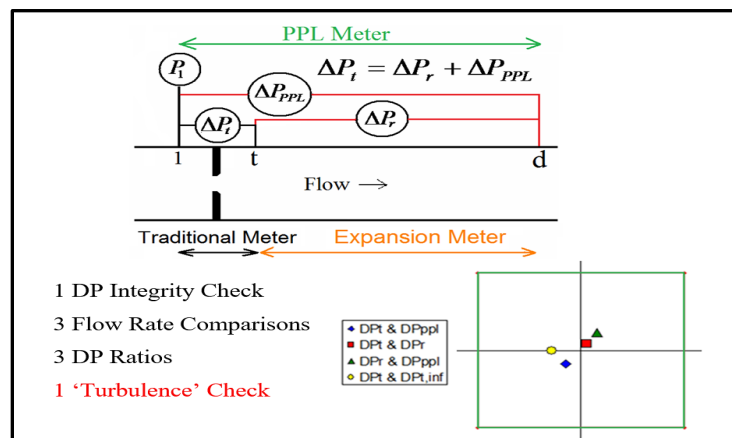


Figure 5. Three differential pressures, tap diagnostic methodology.

4.3 Pulsation and square-root averaging error

Pulsation characteristics. Pulsation is a time-varying pressure and flow fluctuation often originating from reciprocating compressors, control valve chattering, or upstream pulsation sources. Pulsation frequency and amplitude determine its impact on DP measurement and the effective C_d .

Square-root, averaging error (SRE). Because orifice flow is proportional to the square root of differential pressure, averaging ΔP and then taking the square root is not equivalent to averaging the instantaneous square roots of ΔP . SRE is therefore used as a practical indicator of pulsation severity. It is calculated by comparing the square root of the average differential pressure with the average of the square roots of the individual differential-pressure samples, as shown in Equation 1 and Table 2.

$$\% \text{ SRE} = \frac{\sqrt{\text{Avg. } \Delta P} - \text{Avg. } \sqrt{\Delta P}}{\text{Avg. } \sqrt{\Delta P}} \times 100 \quad \dots \text{Eq 1.}$$

Table 2: Indicates errors possible based on sampled differential pressures

Primary and secondary pulsation effects. Pulsation produces two distinct measurement problems. The primary-element problem includes square-root averaging error, discharge coefficient shifts, and inertial effects caused by gas velocity lagging behind differential pressure changes.

The secondary-element problem includes gauge-line and transmitter response errors. Both can create material measurement uncertainty if they are not identified and controlled.

The associated presentation material with this paper uses SRE as a practical severity indicator. As a screening guide, SRE values above about 0.1% on flows greater than 2 MMcf/day, about 0.25% on flows below 2 MMcf/day, and about 0.5% on flows below 5 MMcf/day should trigger further review. Even a small SRE can be commercially important: an SRE of 0.25% represents approximately 200 Mcf/day at 80 MMcf/day.

Table 2: Possible errors based on sampled differential pressures

Reading	Individual ΔP s	Square Root ΔP s
1.	75.0"	8.660"
2.	30.0"	5.477"
3.	47.5"	6.892"
4.	52.2"	7.225"
5.	26.1"	5.109"
6.	<u>71.6"</u>	<u>8.462"</u>
Total	302.4	41.825"
AVG	50.4"	6.71"
Square Root AVG	7.099"	Sum 6.971"
<i>Square Root of the Sums (7.099) – Sum of the Squares (6.971)</i> <i>$\times 100 = \% \text{ of Square Root Error which is } 12.8\%$</i>		

The audit should record whether there is any reason to suspect pulsation, whether a pulsation test was performed, the test date, the results, and whether a gauge-line error test was also performed.

Compressor proximity, regulator chatter, control valve action, low DP operation, and unstable EFM trends are practical triggers for additional pulsation review.

Mitigation strategies.

Mitigation includes:

- Source control: reduce pulsation at the compressor or install pulsation dampeners.
- Instrumentation: use high-speed DP sampling and compute flow from instantaneous square roots or apply correction factors.
- Mechanical: install pulsation absorbers or change piping to alter resonance characteristics.

5 Gas Quality, Electronic Flow Computers, and Secondary Elements

Measurement accuracy depends not only on primary elements but also on correct handling of gas composition, sampling, and secondary instrumentation.

5.1 Gas sampling and chromatographic analysis

Importance of composition. Gas composition determines density, compressibility, and heating value—parameters essential for converting volumetric flow to energy and for custody transfer.

Sampling best practices. To avoid sample bias:

- Locate sample points in well-mixed, representative flow streams away from dead legs.
- Heat sample lines when heavy hydrocarbons or high hydrocarbon dew points are possible to prevent condensation.
- Use appropriate sample conditioning (filters, heated probes) and document sample chain of custody.
- BTU error due to incorrect sampling methods can be expensive- See Table 3.
- Hydrocarbon Dewpoint determination is important particularly when selecting Cal Gas and GC equipment See Figure 6.

Table 3. BTU Error due to incorrect sampling methods

			Error	Units
Flow Rate	75,000.00	MCFD	0	%
Energy Content	1050	BTU/cf	10	BTU/cf
Gas Cost	\$3.00	\$/MMBTU		
Value of Gas	\$236,250	\$/day		
Cost of Error	\$2,250	\$/day		

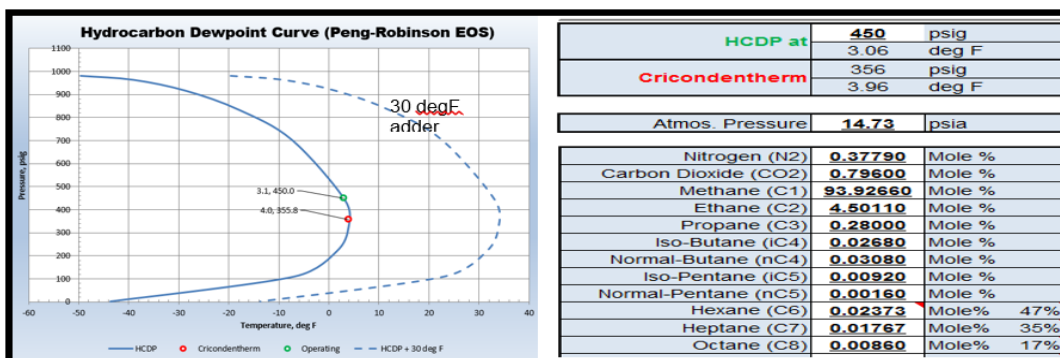


Figure 6. Hydrocarbon Dewpoint determination

Chromatography and QA/QC.

Maintain chromatograph calibration using certified calibration gas standards selected to match the expected gas composition and hydrocarbon dew-point conditions.

5.2 Electronic flow computers (EFMs) and transmitter span

Transmitter span and operating point. Transmitters specified as a percentage of span produce the stated accuracy only when the operating point is near mid-span. Operating at a small fraction of span magnifies percentage error. Re-span transmitters to match typical station operating ranges to reduce measurement uncertainty.

EFM validation. Validate EFM calculations by:

- **Cross-checking** EFM outputs with independent manual calculations for a sample of operating points.
- **Verifying** that base pressure and temperature standards used by the EFM match contractual and regulatory definitions.
- **Logging** EFM raw data and alarms for trend analysis and post-audit verification.

5.3 Linear and inferential meters

Although this paper emphasizes orifice measurement, an assessment program should also include turbine, rotary, diaphragm, positive displacement, and ultrasonic meters where they exist in the system. These meters require verification that the application is suitable, the operating range is appropriate, and the meter has current proof, test, or calibration documentation.

For turbine and other inferential meters, the auditor should verify line size, meter make and model, body and module serial numbers, maximum daily rate, normal flow range, minimum daily flow, pressure rating, proof-test date, time since test, test method, and whether the test was within the required tolerance.

The assessment should also note whether the meter has a circular, digital, standard, fixed-factor, or compensated index, and whether the index is appropriate for the site.

The guiding principle is simple: meters are only as good as their calibration and their application. A properly calibrated meter installed outside its intended operating range can still create significant commercial error. For custody transfer, calibration records, operating range, and site conditions must be reviewed together rather than in isolation.

5.4 Gas analysis, chromatographs, and contaminants

Gas analysis should be treated as a measurement input, not as an administrative attachment. The audit should confirm the source of the gas composition, chromatograph calibration records, sample handling, hydrocarbon dew-point risk, contaminants, and whether the composition used by the EFM is current and representative. Incorrect composition affects density, compressibility, heating value, and therefore both volume and energy measurement.

Contaminants and liquids can also affect primary and secondary elements. Liquids or heavy hydrocarbon condensation in a meter tube, sample line, or gauge line can bias DP measurement, distort gas analysis, and contribute to L&U. Where wet gas, hydrocarbon carryover, or high H₂S/CO₂ streams exist, the sampling and analyzer system should be reviewed with the same discipline applied to the meter run.

6 Safety, Field Practices, Recommendations, and Conclusion

Field safety and disciplined procedures are prerequisites for reliable measurement and successful audits.

6.1 Safety and operational checks

Personal safety. Always follow site OPP, use appropriate PPE, and ground equipment before contact. Treat all field work as potentially hazardous and ensure permit-to-work and isolation procedures are in place for intrusive inspections.

Operational verification. During audits, verify:

- **Regulator reports** and relief device settings.
- **Run switching logic** and that bypass valves block and bleed as designed.
- **Leak checks** around flanges, valves, and fittings using calibrated leak detection equipment.

6.2 Practical recommendations for auditors and operators

1. **Prioritize sites by exposure.** Use flow history and contract prices to rank sites for audit frequency.
2. **Adopt three-DP diagnostics** on orifice runs where feasible to detect installation and plate issues early.
3. **Implement condition-based maintenance** driven by diagnostics rather than fixed intervals.
4. **Enforce fabrication traceability** for new skids and require documentation of material certificates and weld records.
5. **Span transmitters to operating ranges** and re-calibrate after any significant process change.
6. **Heat and condition sample lines** where hydrocarbon dew point or heavy ends are present.
7. **Maintain station data control sheets** with geometry, serial numbers, calibration dates, and regulator/OPP reports attached.

Conclusions

Natural gas measurement auditing is more than a paperwork exercise. It is a disciplined engineering review of the complete measurement system, beginning with the physical installation and ending with the final reported volume, energy value, and accounting balance.

Transforming the Meter Assessment Training slides into a technical paper clarifies the rationale behind the diagnostic techniques and provides the narrative and procedural detail that auditors, operators, technicians, and engineering managers need in order to act effectively.

The central objective of any meter assessment program is to ensure that the measurement at each site is the best achievable for the equipment installed, the operating conditions present, and the money spent on capital equipment and maintenance.

This directly affects Lost and Unaccounted-for gas, or L&U. Although true physical losses can occur from leaks, corrosion, line damage, or unauthorized use, a significant portion of apparent L&U can also result from mismeasurement.

Incorrect meter tube geometry, poor installation practice, damaged or contaminated orifice plates, incorrect transmitter ranges, pulsation, poor gas sampling, and EFM configuration errors can all create bias in the final reported gas volume or energy quantity.

For this reason, a successful audit must treat the metering station as a complete system rather than as a collection of separate components. The orifice plate, meter tube, flow conditioner, pressure and differential pressure transmitters, temperature measurement, gas analysis, EFM configuration, calibration records, and station operating history must all be reviewed together.

A technically correct primary element can still produce poor measurement if the meter tube is rough, the straight length is inadequate, the sample system is unrepresentative, or the electronic flow computer is using incorrect data.

The combination of robust fabrication practices, careful installation, traceable calibration, diagnostic monitoring, disciplined sampling, and EFM validation provides measurable improvements in custody transfer accuracy and reduces L&U. In particular, three-DP diagnostic methods, pulsation analysis, square-root error checks, and condition-based monitoring allow operators to identify developing problems before they become major commercial issues. These methods also reduce unnecessary intrusive maintenance, which can improve safety and make better use of technician time.

A key message from this paper is that measurement uncertainty is not controlled by calculation alone. Field conditions matter. Surface roughness, grease, liquids, damaged plates, poor probe location, upstream disturbances, blocked taps, and transmitter range selection can all shift the actual measurement away from the assumptions built into the standard calculation. The audit process therefore provides a bridge between standards-based calculation and real-world station performance.

Good measurement also depends heavily on documentation. Station data sheets, inspection records, calibration certificates, gas analysis reports, chromatograph records, plate inspection results, and EFM verification records form the evidence trail needed to defend custody transfer measurement.

Without this documentation, it becomes difficult to determine whether a measurement discrepancy is caused by a true system loss, a field installation problem, an operational change, or a data-handling error.

The practical outcome of a well-executed assessment program is improved confidence. Operators gain confidence that their systems are measuring correctly. Commercial groups gain confidence that custody transfer quantities are defensible.

Auditors gain a structured basis for identifying and prioritizing corrective action. Most importantly, the organization gains a method for reducing L&U through engineering evidence rather than assumption.

In summary, effective natural gas meter assessment requires a balance of standards knowledge, field experience, diagnostic testing, and practical judgment. When these elements are applied together, measurement systems become safer, more reliable, more transparent, and more commercially accurate.

This technical paper is intended to support that objective by providing a practical reference for audits, training, corrective action planning, and continued improvement of natural gas custody transfer measurement.

References

1. **American Gas Association (AGA), Report No. 3 / API MPMS Chapter 14.3, *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids*.**
Used as the primary reference for orifice meter design, installation, beta ratio limits, meter tube requirements, orifice plate geometry, and pulsating-flow concerns.
2. **American Gas Association (AGA), Report No. 8 / API MPMS Chapter 14.2, *Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases*.**
Used for gas compressibility calculations applied in electronic flow computers and gas volume correction.
3. **API Manual of Petroleum Measurement Standards, Chapter 21.1, *Flow Measurement Using Electronic Metering Systems — Electronic Gas Measurement*.**
Used for EFM data handling, electronic measurement records, audit trails, and validation of electronically calculated gas quantities.
4. **API Manual of Petroleum Measurement Standards, Chapter 14.1, *Collecting and Handling of Natural Gas Samples for Custody Transfer*.**
Used for representative gas sampling, sample probe installation, sample conditioning, and handling of gas samples for custody transfer analysis.
5. **GPA Midstream Standard 2145, *Table of Physical Constants for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry*.**
Used as a supporting reference for component properties used in gas analysis and heating value calculations.
6. **GPA Midstream Standard 2261, *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*.**
Used as a supporting reference for chromatographic gas analysis and gas quality determination.
7. **GPA Midstream Standard 2172, *Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer*.**
Used for heating value, relative density, and hydrocarbon liquid content calculations from gas composition.
8. **ASME B31.8, *Gas Transmission and Distribution Piping Systems*.**
Used as a general engineering reference for gas piping design, pressure integrity, and station mechanical safety considerations.
9. **ASME Boiler and Pressure Vessel Code**, applicable sections.
Used where pressure-containing components, fabrication, welding, and pressure integrity documentation are reviewed.
10. **ANSI / ASME flange and piping standards**, applicable editions.
Used for flange ratings, bolting, gasket selection, and pressure class verification during meter station assessment.
11. **Dr Richard Steven / DP Diagnostics technical publications and training material** relating to orifice meter verification using additional downstream pressure taps and differential-pressure ratio diagnostics. Used as supporting technical background for the three-DP diagnostic method and condition-based monitoring of orifice meters.
12. **PAL Technical Services LLC, *Meter Assessment Training — Natural Gas Meter Assessment / Auditing*, 2024. KOC Training Meeting, Kuwait Middle East. Philip A Lawrence P.E. C.Eng.**
Internal training material used as the basis for this technical paper, including the L&U discussion, station data control sheets, orifice meter inspection checklists, pulsation/SRE examples, and practical audit methodology.