

FOR PROJECT, METERING AND MATERIALS ENGINEERS

Raw Gas Is Not Sales Gas

What wet, CO₂-rich service does to an orifice meter run — and which decisions have to be made before the order is placed

A metering enquiry usually arrives complete. Size, rating, flange facing, beta ratio, tapping type, straight lengths, flow conditioner: all present, all correct, and between them they fix the geometry that the discharge coefficient depends on. Everything the measurement needs is there.

What is almost never there is the water dew point, the carbon dioxide and hydrogen sulphide partial pressures, the chloride content and the in-situ pH. That is nobody's oversight. Those numbers belong to the process engineer rather than the metering engineer, and on a sales-gas line they genuinely do not matter — the stream is dry, carbon steel is the right material, and a meter run built to the catalogue will hold its bore for decades. The habit is correct far more often than it is wrong.

It is wrong on raw gas, and it is wrong in a way that does not announce itself. This paper sets out what those missing numbers decide, what a sweet-service build loses in this duty and in what order it loses it, and which choices have to be made at enquiry stage because they cannot be made afterwards.

THE LINE THAT DECIDES WHICH DOCUMENT YOU ARE IN

ISO 15156 applies above an H₂S partial pressure of 0.3 kPa. On an 80 bar line that is about **38 ppm by volume** — under 0.004 mol%. A stream nobody at site would call sour, and which would pass many pipeline H₂S specifications, is inside the standard's scope. And an enquiry with no gas analysis attached is not a finding of sweet service. It is an absence of evidence, which is a different thing and has to be handled differently.

1. Two numbers the metering specification does not carry

Water is the switch. Carbon dioxide and hydrogen sulphide are both effectively inert towards steel with no liquid water present; corrosion needs an electrolyte on the metal. So the question is not how much CO₂ the gas contains but whether any surface in the assembly, at any operating or shutdown condition, sits below the water dew point. On a raw-gas meter run the answer is normally yes, for three independent reasons: the gas is usually water-saturated at the inlet, a metering skid has a high surface-area-to-volume ratio and loses heat, and any pressure drop cools the gas. The Joule–Thomson coefficient for natural gas is about 0.48 K/bar at 300 K, falling to roughly 0.44 K/bar at 40 bar, so a 40 bar drop is of the order of 18 K of cooling however hot the site is.

Partial pressure, not percentage. Once water is present, the severity of the CO₂ attack scales with its partial pressure. The familiar screening bands put corrosion as low below roughly 0.5 bar, possible to about 2 bar, and severe above that. The arithmetic that matters is how quickly an unremarkable composition clears the upper band once line pressure is applied.

CO ₂ IN THE GAS	P _{CO2} AT 20 bar	AT 50 bar	AT 80 bar	SCREENING BAND AT 80 bar
0.5 mol%	0.10 bar	0.25 bar	0.40 bar	low
2 mol%	0.40 bar	1.0 bar	1.6 bar	possible

CO ₂ IN THE GAS	p _{CO2} AT 20 bar	AT 50 bar	AT 80 bar	SCREENING BAND AT 80 bar
5 mol%	1.0 bar	2.5 bar	4.0 bar	severe
10 mol%	2.0 bar	5.0 bar	8.0 bar	severe
15 mol%	3.0 bar	7.5 bar	12.0 bar	severe

Table 1 — Ideal-gas partial pressures. A composition that is genuinely mild at 20 bar is in the severe band at 80 bar. This is the single most common reason a raw-gas meter run is under-specified: the percentage looks modest and the pressure is never applied to it.

2. What that costs, in millimetres per year

The de Waard–Lotz–Milliams correlation gives a film-free corrosion rate for carbon steel in wet CO₂. At 4 bar CO₂ and a metal temperature of 40 °C it returns 5.5 mm/y. Those inputs are illustrative and correspond to no particular installation, but the order of magnitude is not controversial: a field case on a short onshore gas line carrying only condensed water at 1.2 bar CO₂ and about 50 °C measured 4 mm/y.

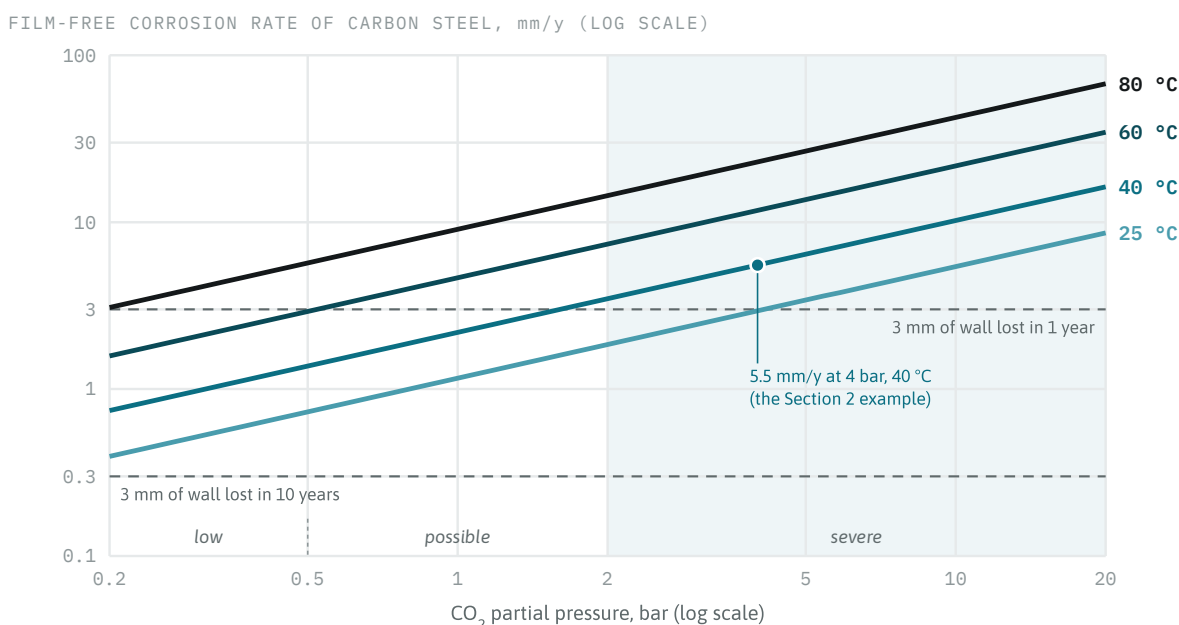


Figure 1 — Film-free rates from the published correlation, computed for this paper. These are a worst-case upper bound: with free water at the surface, no inhibitor and no credit for a protective iron carbonate film. Where a dense film establishes itself the rate can fall by an order of magnitude.

The honest reading of that chart is a range, and the range is the point. A 3 mm corrosion allowance — a normal figure, and the one carried on many meter runs — is consumed in about seven months at the film-free rate and in about five and a half years at one tenth of it. Neither is an economic life.

Nor is the middle of the range the safe place to be. Where an iron carbonate film forms and then locally fails, the exposed steel becomes a small anode facing a large filmed cathode and the attack concentrates. Published field data from one well record penetrating mesa attack at 5 mm/y near the top against about 0.5 mm/y measured further down: a factor of ten between the localised and the general rate. An average-wall-loss calculation can look entirely comfortable while the bore is being destroyed.

3. Above the threshold, the choice of steel narrows

Where hydrogen sulphide is present above 0.3 kPa, ISO 15156-2 divides the sour region into three severity bands on axes of H₂S partial pressure and in-situ pH. The boundaries rise one pH unit per decade of partial pressure.

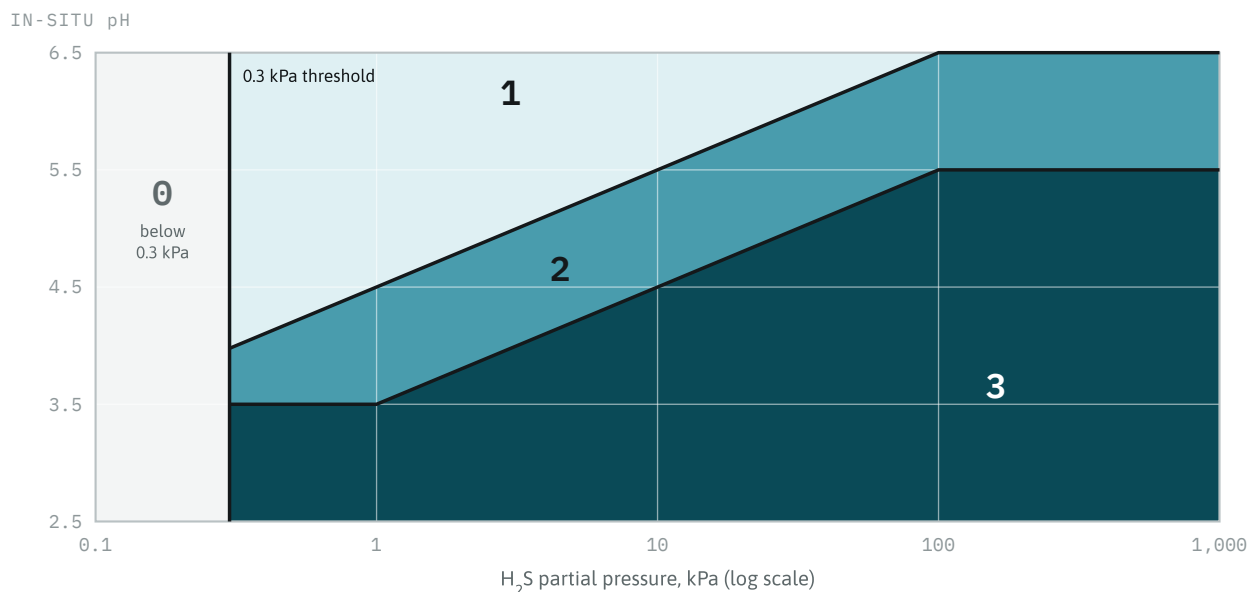


Figure 2 — Sulphide stress cracking (SSC) severity regions, redrawn from ISO 15156-2:2020 Figure 1. Steels for region 1 may be selected using Annex A.2, A.3 or A.4; for region 2 using A.2 or A.3; for region 3 using A.2 only. The framework is discontinuous below 0.3 kPa and above 1 MPa.

The axis that is hardest to pin down is in-situ pH, and it is the one that moves a service towards the severe end. In an unbuffered condensate — precisely what forms on a cold meter run — pH is low, typically between 3.5 and 4.5. The standard makes the point itself: clause 7.2.1.2 says the possibility of exposure to unbuffered, condensed aqueous phases of low pH during upset operating conditions or downtime should be considered. A run that is benign while flowing hot can sit in a more severe region while it stands cold and full.

4. What a sweet-service build loses, and in what order

Equipment assembled from competent sales-gas materials does not fail all at once here. It degrades along two paths at the same time, and only one of them is visible.

The measurement goes first

ISO 5167-2 accepts an upstream plate edge as sharp if its radius does not exceed $0.0004 d$. On a 6 in run of 146.36 mm bore at $\beta = 0.5$ that is **0.029 mm**. Flow-laboratory work established that rounding the edge to $0.002 d$ raises the discharge coefficient by about 1 % — a radius of about **0.15 mm**, roughly the thickness of a sheet of paper, five times the limit and entirely invisible to the eye. Corrosion attacks that edge preferentially, because an edge is a high-energy surface and because the local velocity there is the highest in the assembly.

The bore goes the same way. Both governing standards specify a roughness *window*, not a ceiling: AGA Report No. 3 clause 5.1.1.1 sets 300 μin Ra maximum below $\beta = 0.6$ and 250 μin at or above it for NPS 12 and smaller, with a floor of 34 μin ; ISO 5167-2 clause 5.3.1 varies both bounds with β and Reynolds number. A honed bore leaves the shop at 0.8–1.6 μm Ra. General corrosion raises that steadily and mesa attack destroys it — and NIST work found that errors of approximately 1 % can arise from meter tubes that are too rough *but still inside* the standards' limits.

These errors do not cancel. Edge rounding and bore roughening both tend to raise the discharge coefficient, so the meter reads low, keeps reading low, and passes every visual inspection. On a stream worth USD 20,000 a day, 1 % is USD 73,000 a year, in one party's favour, from an instrument nobody has any reason to suspect.

Then the equipment stops doing its job

Sulphide stress cracking attacks exactly the parts a designer wants hard: stems, pinion shafts, the vent needle, springs, retaining rings, the seal bar. Chloride-bearing condensate pits austenitic internals. Elastomers cured with sulphur harden in H_2S . And any seal saturated with high-pressure CO_2 can blister when the pressure is released — which, in a dual chamber fitting, happens every time the upper chamber is vented to change the plate.

WHERE THE REAL LOSS SITS

The carrier binds on corrosion product, the rotary valve seat pits and no longer seals, the seal bar O-ring has taken a set, one of the stems is cracked. At that point the plate cannot be withdrawn under pressure. A dual chamber fitting is bought at a premium over an orifice flange union for exactly one reason — to change the plate without a shutdown. When that capability is lost, typically within a few years in this service, the premium has bought nothing, the meter is reading low by an unknown and growing amount, and the assembly is a pressure vessel with an unquantified wall.

5. The remedy is condition, not alloy

The instinct on reading the above is to raise every material: duplex bodies, nickel internals, perfluoro seals. It works, it multiplies the price and the lead time, and it is not what the standards ask for.

ISO 15156 is not a specification for expensive materials. It is a set of qualified envelopes — for each material, in each heat-treatment condition, up to each hardness, for each equipment category, it states the conditions under which that material has been shown to resist cracking. The engineering task is to find, for each part, the lowest-cost material and condition whose envelope contains the service. The result is that most parts keep the same material and change only their **condition**, their **hardness limit** and the **evidence** supplied with them.

COMPONENT GROUP	SALES-GAS BUILD	WET CO ₂ / SOUR BUILD	WHAT ACTUALLY CHANGED
Body castings, spools	A216 WCB, A106 Gr.B	same grades, listed heat-treatment condition, ≤ 22 HRC, heat traceable	condition + certificate
Flanges, branch outlets	A105	A105 at ≤ 187 HBW per ISO 15156-2 A.2.1.3 a) — or A350 LF2	a tighter, specific limit
Wetted carbon steel surfaces	uncoated, external paint only	high-phosphorus electroless nickel, 75 µm, on all wetted surfaces	the largest single addition
Valve, seat, carrier, bushings	316, any condition, often cold-drawn bar	316/316L solution annealed, ≤ 22 HRC, not from cold-drawn bar	condition of the bar stock
Stems, shafts, gears	17-4PH H900 (≈ 44 HRC)	17-4PH double aged at 621 ± 14 °C, ≤ 33 HRC, furnace record	heat treatment + hardness
Springs, retaining rings	music wire, 17-7PH, carbon steel circlips	Alloy X-750 (UNS N07750) ≤ 50 HRC, or Co-Cr-Ni alloy (UNS R30003) ≤ 60 HRC, cold worked + aged	genuine material upgrade
Seals	NBR, cure unspecified	HNBR, peroxide cured , qualified for rapid gas decompression at the service conditions	compound + qualification
Non-wetted hardware	4140 Q&T, zinc plated	unchanged	nothing, deliberately

Table 2 — The difference between the two specifications, component group by component group. The material itself changes in a minority of rows.

THE TWO LINES THAT ARE INVISIBLE ON A DELIVERED PART

Cold-drawn 316 bar is the cheap, straight, readily available stock, and in the as-drawn condition it can sit well above 22 HRC — cold work is itself a cracking risk factor. And a seal described only as “HNBR 80 Shore A” says nothing about its cure system; sulphur-cured HNBR is the cheaper and more widely available product. Neither can be told from the finished part, both are free to specify, and neither can be corrected afterwards.

One honest limitation belongs with the coating. Electroless nickel is not named, listed or endorsed as a qualified sour-service material by ISO 15156 or by the API equipment standards. It is a corrosion barrier selected on engineering judgement — which is why it is applied over a pressure envelope that meets ISO 15156-2 on its own merits. The compliance argument rests on the steel; the coating extends its life.

Coating a meter run is also a dimensional design problem before it is a coating problem. The deposit is conformal, so the bore is honed *before* plating, to the final diameter plus twice the coating thickness. Honing afterwards cuts through the deposit and exposes bare steel in the one place where that is least acceptable. Threads grow by about four times the deposit thickness, not twice. And every masked surface is a deliberate corrosion initiation site, so the masking plan is a decision to be minimised rather than a detail to be delegated.

6. What belongs in the enquiry

None of this is an argument for asking for more. It is an argument for asking, at enquiry stage, for the handful of things that decide the answer — and for recognising which of them cannot be added later.

ITEM	WHAT IT ESTABLISHES
Design basis for the wetted parts, stated explicitly	Either a gas analysis — CO ₂ , H ₂ S, water dew point, chloride, in-situ pH — or a written decision that sour service to ISO 15156 is the design basis. Silence is the one answer that cannot be priced.
Minimum design metal temperature	Whether Joule–Thomson cooling and winter ambient have been carried into the material choice.
Impact testing, decided at order	A105, A106 and A216 carry no Charpy requirement at all — not as standard, not as a supplementary requirement. A test specimen must come from the same heat as the product, so this is a purchase-order decision or it is unavailable. The standards-compliant route is A350 LF2, A333 Gr.6 or A352 LCC.
Hardness limit and heat-treatment condition, per part group	The requirement that does the work. A limit without a batch hardness record is a drawing note, not a fact.
Internal coating: specification, not just thickness	Type, service-condition class and post-plate class, plus the embrittlement-relief bake — and the dimensional allowances that follow from them.
Elastomer compound and cure system	Named on the order and on the storage label. A reorder placed against a part number alone will eventually return a sulphur-cured seal.
Post-coating dimensional and bore verification	That the measuring geometry is correct in its final, coated state — which is the state it will run in.

Table 3 — Seven items. Three of them (the design basis, the impact test and the coating allowances) cannot be recovered after the order is placed.

RAW GAS METER RUN — MATERIALS

“Wetted materials shall conform to ISO 15156 / NACE MR0175 for the stated service, or, where the gas analysis is not available at the time of order, sour service shall be adopted as the design basis for all wetted parts. Carbon and low-alloy steel pressure-containing parts shall be supplied in one of the heat-treatment conditions of ISO 15156-2 A.2.1.2 at 22 HRC maximum, with ASTM A105 forgings not exceeding 187 HBW, and shall be impact tested at the specified minimum design metal temperature with specimens from the same heat. Austenitic internals shall be solution annealed and not machined from cold-drawn bar. Precipitation-hardened internals shall be double aged, with a furnace record and a batch hardness test. Elastomers shall be peroxide cured and qualified for rapid gas decompression at the service conditions. All wetted carbon steel surfaces shall be coated as specified, with the measuring bore, roundness and roughness verified after coating.”

7. What this is really about

A raw-gas meter run built to a sales-gas specification does not fail in a way that produces a report. It produces a slow, one-directional shift in the quantity of gas two parties believe has changed hands, and — some years later — a fitting that can no longer do the one thing it was bought to do. Both outcomes are settled at enquiry stage, by information that was not asked for and a decision that was never consciously taken.

It is worth saying plainly that none of this is anybody's error. The metering specification is written by the people who own the measurement, and it is complete on its own terms. The materials question belongs to a different document that, on most enquiries, correctly does not exist. The remedy is not more rigour. It is one added line — what the wetted parts are being designed for — and the willingness to answer it with a decision when the analysis is not available.

AN OPEN OFFER

If you are preparing an enquiry for a meter run in wet, CO₂-bearing or potentially sour service, we are glad to read the draft technical requirements and mark up which items genuinely decide the outcome, which are already settled by the governing standards, and which cannot be added after the order. There is no charge and no obligation to buy anything.

SOURCES AND STANDARDS REFERENCED

ISO 15156-1, -2 and -3:2020, *Petroleum and natural gas industries — Materials for use in H₂S-containing environments in oil and gas production* (ANSI/NACE MR0175-2021) · ISO 5167-1 and ISO 5167-2:2022, *Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full* · ISO/TR 9464:2023 · API MPMS Chapter 14.3, Parts 1 and 2 / AGA Report No. 3 · ASTM B733, B850 and B849; ISO 9588 · ISO 23936-2; NORSOK M-710 · NORSOK M-506 · ASTM A105, A106, A216, A350, A333, A352; ASME B31.3 · C. de Waard, U. Lotz and D. E. Milliams, *Predictive Model for CO₂ Corrosion Engineering in Wet Natural Gas Pipelines*, Corrosion 47(12), 1991 · R. Nyborg and A. Dugstad, *Reliability and Limitations of Corrosion Prediction Tools for Oil and Gas Pipelines, and Understanding and Prediction of Mesa Corrosion Attack*, CORROSION/2003 · T. J. S. Brain and J. Reid, *Measurement of Orifice Plate Edge Sharpness*, Measurement and Control 6, 1973 · J. A. Brennan et al., *Effect of Pipe Roughness on Orifice Flow Measurement*, NIST, 1989 · Danish Gas Technology Centre, Joule–Thomson coefficients for natural gas.

ABOUT İNKOTEK ENERJİ

İnkotek Enerji is an Ankara-based engineering and manufacturing company specialising in differential-pressure flow elements and integrated metering systems: orifice plates, Venturi tubes, flow and Venturi nozzles, cone and wedge meters, averaging, grid-type and retractable Pitot assemblies, dual chamber orifice fittings, flow conditioners, meter runs, custody-transfer and fiscal metering skids, and SWAS sampling stations. Engineering is supported by CFD analysis, high-precision machining, precision welding, post-weld heat treatment, ultrasonic and radiographic examination and corrosion-protection coatings, including material selection and qualification for sour and corrosive service. Designs are prepared to ISO 5167, AGA Report No. 3 / API MPMS 14.3 and OIML R 140, under a management system certified to ISO 9001:2015, ISO 14001:2015 and ISO 45001:2018. Served sectors: natural gas transmission and distribution, power generation, petrochemicals, refining and general process industry.

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Figures are worked examples based on published standards and openly available industry data; they are illustrative and do not replace a service-specific materials selection. The corrosion rates in Figure 1 were computed for this paper from the published correlation, from inputs stated as assumptions; they correspond to no particular installation. Clause wording is a drafting aid, not legal or contractual advice; adapt it to the governing standard, edition and jurisdiction of your project. Read the current edition of every standard cited. © 2026 İnkotek Enerji Sanayi ve Ticaret Ltd. Şti. · WP-05 Rev 03 · 3 October 2026