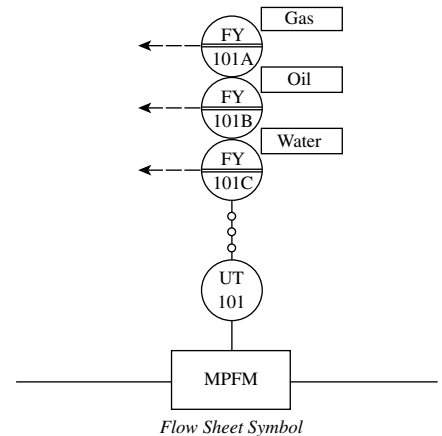


2.17 Polyphase (Oil/Water/Gas) Flowmeters

I. H. GIBSON (2003)



<i>Design Pressure</i>	Limited by piping design class
<i>Operating Temperature Range</i>	Limited by piping design class, 30 to 270°F (0 to 130°C)
<i>Fluids</i>	Mixtures of liquids, vapors, or gases; typically oil, water, and gas
<i>Cost</i>	Extremely variable, depending on line size, pressure rating, and installation requirements, starting at about \$100,000 Subsea equipment commonly twice the price of surface-design units of comparable capacity
<i>Accuracy</i>	Five to 10%, depending on relative proportions of phases
<i>Partial List of Suppliers</i>	3-Phase Measurements AS (VenturiX, PhaseTester) (www.framoeng.no) Agar Corp. (www.agarcorp.com) Aker-Kvaerner (DUET) (www.kvaerner.com/kop) FlowSys AS (Topflow) FMC Technologies (www.fmctechnologies.com) Framo Engineering AS, Schlumberger (www.framoeng.no) Jiskoot Autocontrol (Mixmeter) (www.jiskoot.com) McCrometer (www.mccrometer.com) Petroleum Software Ltd. (ESMER) (www.petroleumsoftware.co.uk) Roxar AS (Fluenta, MFI) (www.roxar.com) Solartron ISA (Dualstream) (www.solartronisa.com)

Whereas most flow measurements are carefully designed to operate in single phase (gas, vapor, liquid), there are many circumstances in which the ability to distinguish the components of a liquid/vapor/gas mixture (or, indeed, multiple immiscible liquids, vapor, and gas) in the presence of solids is highly desirable.

In the production of oil/gas from unpumped petroleum wells, the flow from several thousand meters underground to the surface brings up water (commonly saline), inert gases such as carbon dioxide and nitrogen, water-saturated hydrocarbon gas (methane, ethane), hydrocarbon condensates (propane, butane, and so on), and higher hydrocarbons.

The liquids and gases do not normally travel at the same velocity, as the liquids are being dragged to the surface by the expanding gas flow. A wide variety of flow regimes are

possible, depending on the mixture of phases and the geometry. A production facility may have tens of wells, and individual wells in a facility may have different mixes of ownership. This leads a requirement to be able to determine the flow of the economically interesting components from each well as accurately as possible.

The traditional method has been to use a small *test separator* that will separate the gas and the oil and water phases from a single well by gravity while production from the rest of the facility is flowing to production separators. The test separator is fitted with a full array of level and pressure controls and flowmeters (turbine, positive-displacement, orifice, and others) to enable a steady-state operation to be achieved. Commonly, the test separator is operated at a pressure slightly above the production separator to allow the

streams from the test separator to be mixed with the flows out of the production separator. This requires a large amount of room and a complex valving system to enable each well to be tested separately. As pressures are commonly 1000 to 4500 PSI (7000 to 30,000 kPa) or higher, and the temperature is 150 to 270°F (65 to 130°C) at the surface, the test separator is not an inexpensive device. Individual well tests rarely can be scheduled more frequently than monthly as a result of the time taken to stabilize operation at a set of operating conditions. Even with the best of intentions, test separator measurements are notorious for inaccuracies, because quite small amounts of vapor disengaging in the liquid meters can induce errors in the 5 to 10% region.

For offshore platforms, where the cost of test separator equipment can exceed on-shore costs by many times (and especially for subsea operations, where operators cannot easily access equipment), the potential savings from an on-line method of measurement have driven the development of a variety of devices over the past 15 years. These employ a wide variety of operating principles, some of which are outlined below.

The techniques used differ depending on the ratio of liquid to gas (known as LGR or the inverse, GLR). The extreme end of the LGR (say <10% by mass) is classified as *wet gas*.

WET-GAS METERING

The standard approach for wet-gas metering treats the fluid as a gas. This uses differential-pressure devices (venturi or orifice) or vortex or ultrasonic meters. Turbine meters are unsatisfactory because even small quantities of high-velocity liquid can damage the meter. The venturi has a considerable advantage over the orifice in that it does not dam liquid behind the device, altering the flow profile. The McCrometer V-cone™ meters (Section 2.28) are also suitable for this service and have also been used for flow conditioners.

Normal ISO 5167 flow conditioners are *not* recommended for wet-gas service; not only can they dam liquids, they can induce hydrocarbon hydrate formation.

Where practical, insulation of the metering run is recommended. In some environments, trace heating may be indicated to prevent hydrate formation in the tapping connections.

Pressure tappings should be short and inclined vertically upward to avoid trapping condensate in the connections and to avoid hydrate formation.

Process gas chromatographs are not recommended for wet-gas services unless the liquid content is below 0.1%.

Venturi Meters

The venturi (Section 2.29) is much more rugged than the orifice in wet-gas service and allows for higher differential-pressure operation. With modern transmitters, turndown up

to 10:1 is possible and may be necessary, given that wet-gas behavior is far more variable than that of a pure gas.

Design is generally in accordance with ISO 5761–1, although recent work by Reader-Harris et al¹ has shown that the ISO coefficients are not as well defined as claimed. The coefficients are quite sensitive to minor machining variations and, at high Reynolds number operation, the flow may break away from the throat. The coefficient can also be sensitive to the diameter-to-length ratio of the tappings; use of the “triple-T” piezometer connections advocated by ISO 5167 is impractical for wet-gas service, because the downward-facing tappings would fill with liquid.

A downstream tapping after the full pressure recovery is achieved is recommended to allow the calculation of liquid content and temperature correction to upstream conditions.

Algorithms for Wet-Gas Measurement

Differential devices used on wet-gas service will generally *overestimate* the dry-gas flow rate, and various algorithms have been developed to compensate. The Chisholm and Murdock² correlations were developed for orifice plates; the de Leeuw correlation has been developed for venturi meters and is an extension of the Chisholm equations.

In addition to the dry-gas flow rate, it is normally required to determine the liquid flow rate, and particularly the condensate flow rate. All three correlations (de Leeuw, Chisholm, Murdock) are based on the Lockhart–Martinelli parameter, which is a function of both liquid flow rate and density. The liquid flow rate can be determined by

- Routing the flow to a test separator
- The use of tracer techniques
- Sampling

or a combination of these. Since these are all spot-test techniques, modification to the Lockhart–Martinelli equation can be made to work in terms of the dry-gas mass fraction, which is relatively constant, provided the wetness of the gas is constant. None of these techniques is easily useful in subsea conditions, and adaptations have been made to apply dual measurements in series with devices of different geometry that allow the Lockhart–Martinelli relationship to be solved for equal values of liquid/gas. These still require considerable input of process data derived from composition.

Theory of Operation of Wet-Gas Metering

It has long been known that a gas stream carrying a well-dispersed liquid content through a differential flow element (orifice, nozzle, venturi, or V-cone) will develop a higher differential than that due to the corresponding gas flow. If the properties of the gas and liquid are known, it is possible to calculate the relative content of liquid in the gas.

The following development has been adapted from the UK DTI Oil and Gas Division’s Guidance Notes for

Petroleum Measurement under the Petroleum (Production) Regulations.²

de Leeuw Wet-Gas Venturi Correlation

de Leeuw³ has shown that the real gas mass flow rate can be derived from the following equations (all equations are based on SI units):

$$Q_{\text{real gas}} = \frac{Q_{\text{uncorrected gas}}}{\sqrt{(1 + CX + X^2)}} \quad 2.17(1)$$

where $Q_{\text{uncorrected gas}}$ = uncorrected gas mass flow rate as indicated by the venturi meter using the following equation:

$$Q_{\text{uncorrected gas}} = C_{\text{gas}} \varepsilon \pi d^2 \frac{\sqrt{(2\rho_{\text{gas}} \Delta P)}}{4\sqrt{1 - \beta^4}} \quad 2.17(2)$$

where

C_{gas} = discharge coefficient of the venturi flowmeter in dry gas as determined through calibration

ε = expansibility of gas in venturi as defined by ISO 5167-1

d = throat diameter of the venturi flowmeter (corrected for temperature)

ρ_{gas} = gas density at upstream conditions

ΔP = raw differential pressure as measured by the transmitter

β = ratio of d to D , the pipe diameter

and X is the *Lockhart–Martinelli* parameter, which is derived as follows:

$$X = \frac{Q_{\text{liquid}}}{Q_{\text{real gas}}} * \sqrt{\frac{\rho_{\text{liquid}}}{\rho_{\text{gas}}}} \quad 2.17(3)$$

where

Q_{liquid} = combined liquid flow rate through the venturi flowmeter

ρ_{liquid} = combined liquid density

The coefficient C is given by the following equation:

$$C = \left(\frac{\rho_{\text{liquid}}}{\rho_{\text{gas}}} \right)^n + \left(\frac{\rho_{\text{gas}}}{\rho_{\text{liquid}}} \right)^n \quad 2.17(4)$$

where the exponent n is given by

$$n = 0.606(1 - e^{-0.746 Fr_g}) \quad \text{for } Fr_g \geq 1.5 \quad 2.17(5)$$

$$n = 0.41 \quad \text{for } 0.5 \leq Fr_g \leq 1.5 \quad 2.17(6)$$

and Fr_g is the gas Froude number given by

$$Fr_g = \left[\frac{V_{\text{gas}}}{\sqrt{(gD)}} \right] * \left[\frac{\sqrt{\rho_{\text{gas}}}}{\sqrt{(\rho_{\text{liquid}} - \rho_{\text{gas}})}} \right] \quad 2.17(7)$$

where

V_{gas} = superficial gas pipe velocity

g = local acceleration due to gravity

V_{gas} can be derived using an iterative method and “seeding” a velocity based on the uncorrected mass flow rate. The first pass equation is

$$V_{\text{gas}} = \frac{4 * Q_{\text{uncorrected gas}}}{\rho_{\text{gas}} \pi D^2} \quad 2.17(8)$$

For further iterations $Q_{\text{uncorrected gas}}$ is replaced by consecutive $Q_{\text{real gas}}$ values until the equation converges to a solution.

Liquid Mass Flow Rate Correction Algorithm

The resultant liquid mass flow rates can be derived from the following equations:

$$Q_{\text{total}} = Q_{\text{real gas}} + Q_{\text{liquid}} \quad 2.17(9)$$

Condensate mass flow rate

$$Q_{\text{condensate}} = Q_{\text{total}} * \zeta_{\text{condensate}} \quad 2.17(10)$$

Water mass flow rate

$$Q_{\text{water}} = Q_{\text{total}} * \zeta_{\text{water}} \quad 2.17(11)$$

Methanol (or glycol) mass flow rate

$$Q_{\text{methanol}} = Q_{\text{total}} * \zeta_{\text{methanol}} \quad 2.17(12)$$

where

$\zeta_{\text{condensate}}$ = condensate mass fraction

ζ_{water} = water mass fraction

ζ_{methanol} = methanol mass fraction

In turn,

$$\zeta_{\text{condensate}} = X * \psi_{\text{condensate}} \quad 2.17(13)$$

$$\zeta_{\text{water}} = X * \psi_{\text{water}} \quad 2.17(14)$$

$$\zeta_{\text{methanol}} = X * \psi_{\text{methanol}} \quad 2.17(15)$$

where

- $\psi_{\text{condensate}}$ = condensate-to-gas mass fraction
- ψ_{water} = water-to-gas mass fraction
- ψ_{methanol} = methanol-to-gas mass fraction (methanol injection is commonly used to suppress hydrocarbon hydrate formation)

Liquid Density Calculation Algorithm

The liquid density can be calculated as follows:

$$\rho_{\text{liquid}} = \frac{\psi_{\text{liquid}}}{\left(\frac{\psi_{\text{condensate}}}{\rho_{\text{condensate}}} \right) + \left(\frac{\psi_{\text{water}}}{\rho_{\text{water}}} \right) + \left(\frac{\psi_{\text{methanol}}}{\rho_{\text{methanol}}} \right)} \quad 2.17(16)$$

where

- ψ_{liquid} = total liquid to gas mass ratio
- ρ_{liquid} = density of liquid
- $\rho_{\text{condensate}}$ = density of hydrocarbon condensate
- ρ_{water} = density of water
- ρ_{methanol} = density of methanol
- $\rho_{\text{condensate}}$ = is derived from the condensate base density and corrected for temperature and pressure (Ctl and Cpl)

Corrections from the standard API MPMS11.2.1M may be applied. However, for improved accuracy, it is recommended that samples of the condensate be obtained and analyzed to derive specific correction factors. The values of K_0 and K_1 for crude oil (613.9723 and 0, respectively) are not ideal for condensate, and the alternatives from the standards referred to above may be no better.

Water and methanol densities can be derived as follows:

$$t = (t_m + 273.15) * \left(\frac{P_3}{P_1} \right) K_3 - 273.15 \quad 2.17(17)$$

where

- t = temperature at the inlet of the venturi
- A, B, C = water constants (e.g., -0.0001732, -0.1307, 1040)
- D, E, F = methanol constants (e.g., 0.0000713, -0.3344, 540)

The correct values of these methanol and water constants may vary due to salinity or product type. It is therefore advisable to have the liquids analyzed to determine appropriate values.

Upstream Temperature Correction and Pressure Recovery

The correction for downstream measured temperature to upstream temperature (in degrees centigrade) at the inlet is given by

$$t = (t_m + 273.15) * \left(\frac{P_3}{P_1} \right) K_3 - 273.15 \quad 2.17(18)$$

where

- t_m = measured temperature
- P_3 = fully recovered downstream pressure
- P_1 = pressure measured at the upstream tapping
- K_3 = downstream to upstream temperature correction exponent

P_3 can be measured using a third pressure tapping or calculated (in bar) from the following empirical equation from Miller:⁴

$$P_3 = P_1 - 10^{-3} * \Delta\omega \quad 2.17(19)$$

where

$$\Delta\omega = (A\beta^2 + B\beta + C) * \Delta P \quad 2.17(20)$$

and the constants A , B , and C , for venturies with 7 and 15° exit cone angles, are as follows:

7° cone angle	$A = 0.38$	$B = 0.42$	$C = 0.218$
15° cone angle	$A = 0.59$	$B = 0.86$	$C = 0.436$

Gas Mass Fraction Estimation Using Tracer Techniques

The gas mass fraction can be estimated as follows:

1. Perform the tracer flow technique to determine condensate and water flow rates and mass ratios. This uses concentrated oil-soluble and water-soluble fluorescent chemicals, injected upstream and partially recovered by sampling downstream of the flowmeter.
2. Analyze the condensate to determine base density.
3. Sample the gas to determine gas density.
4. Record the total uncorrected gas flow from venturi during the tracer flow technique.
5. Determine the dry "first pass" gas mass fraction and liquid-to-gas ratio based on the recorded uncorrected gas flow and tracer flow results (corrections for methanol injection after completion of tracer technique may be required).
6. Seed values from the last stage into the wet-gas venturi flow calculation to determine a "first pass" corrected gas flow rate.
7. Re-seed this value into the calculation, correcting gas mass ratio and liquid-to-gas ratio.
8. Iterate the process until the corrected gas flow rate converges.

Solartron-ISA Dualstream II™ Theory

The Solartron-ISA Dualstream™ II, originally developed by British Gas, extends the theory noted above by fitting two dissimilar pressure differential devices in series. These have differing Lockhart–Martinelli characteristics, and the

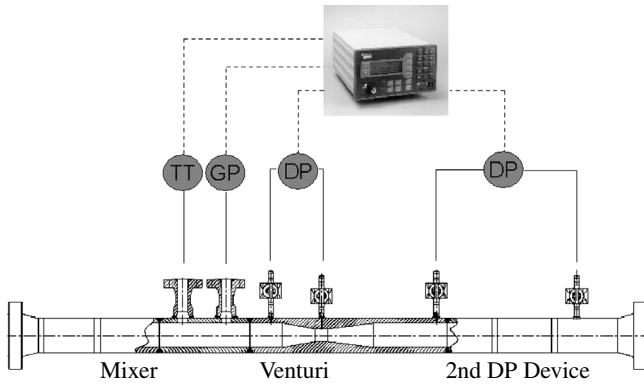


FIG. 2.17a

Solartron—ISA Dualstream II™ wet gas flowmeter.

combination can determine changes in the gas-to-liquid ratio. The venturi will generate an indicated flow rate. This can be corrected to generate a “true” gas flow rate using the equations in previous sections.

The second “DP device” will generate a second indicated flow rate. This flow rate can be corrected to give a “true” gas flow rate using similar relations.

A simultaneous equation can be formed from these flow rates:

$$Q_g = \frac{Q_{gi(\text{venturi})}}{1 + M_{(\text{venturi})} \frac{(1-x) C_g}{x C_l} \epsilon_g \sqrt{\frac{\rho_g}{\rho_l}}}$$

$$= \frac{Q_{gi(2nd\ Dp)}}{1 + M_{(2nd\ Dp)} \frac{(1-x) C_g}{x C_l} \epsilon_g \sqrt{\frac{\rho_g}{\rho_l}}} \quad 2.17(21)$$

$$x = \frac{\sqrt{\frac{\rho_g}{\rho_l}} \left(\frac{Q_{gi(2nd\ Dp)}}{Q_{gi(\text{venturi})}} M_{(\text{venturi})} - M_{(2nd\ Dp)} \right)}{\left(1 - M_{(2nd\ Dp)} \sqrt{\frac{\rho_g}{\rho_l}} \right) - \frac{Q_{gi(2nd\ Dp)}}{Q_{gi(\text{venturi})}} \left(1 - M_{(\text{venturi})} \sqrt{\frac{\rho_g}{\rho_l}} \right)} \quad 2.17(22)$$

This enables a continuous estimation of the liquid-to-gas ratio without the necessity for tracer measurements, and it is particularly useful sub-sea, where tracer measurements are impractical with current technology.

MULTIPHASE FLOWMETERS

The various true multiphase flowmeters can be effective from straight liquid through to 95 or 97% gas. Some meters, such as the Agar MPFM400 and Jiskoot, attain the extreme gas end by using an in-line separator to send the wet gas through a wet-gas meter and the remaining gas, with oil and water,

through a separate multiphase flowmeter section. No standards exist as yet to assist engineers in designing multiphase metering systems, and there are wide variations in the methods used to define *accuracy* and performance. When considering a manufacturer’s performance and accuracy statements, it is essential to understand the implications of accuracies quoted in different ways. There are three common ways in which multiphase meter accuracies are presented:

1. Percent phase volume flow rate
2. Percent total multiphase flow rate
3. Percent gas and liquid flow rate plus absolute uncertainty of water cut in liquid phase

Method 1 is favored by metrologists and clearly represents performance as stated. This method may not be the most practical for extreme cases of phase fractionation.

Methods 2 and 3, whereas quoting relatively small numbers on the order of 5 to 10% for gas/liquid phase uncertainties and 2 or 3% for percentage water cut, may nevertheless exhibit very large individual phase errors of 100% or more, depending on the absolute value of the percentage water.

The first requirement for a mixed liquid phase is to distinguish hydrocarbon from water. If the liquid phase is oil-continuous, typically water less than 40% liquid hydrocarbon, then dielectric constant measurement at microwave frequencies can determine the water fraction. The dielectric constant of dry hydrocarbon is in the order of 2 to 4, depending on composition, while water is 82, giving a sensitive means of measurement.

For higher water content, the measuring element will short out in a water-continuous phase, but density measurement can distinguish water from oil. This requires stream-specific characterization, as the composition and density of the liquid is pressure and temperature dependent.

The next requirement is to distinguish the flow of liquid from the flow of gas in a system where the two will try to separate and travel at different velocities. Flow conditioning in these systems is commonly provided by a horizontal branch-in, vertical-out tee, which acts as a mixer. Cross-correlation flowmeters (see Section 2.5) used by some suppliers apply nuclear techniques to measure the density of the stream twice, a short vertical distance apart, and correlate the fluctuations in density with time; others use electrical characteristics in a similar manner.

As it is difficult to distinguish the differing velocities of liquid and gas, it is common to measure the velocity of one phase and use flow-modeling techniques to estimate the velocity of the other phase.

Most of the techniques are limited by the liquid/gas ratio (LGR). Lean gas streams, with less than 5% liquid, are difficult to measure given that the density of the gas stream can be comparable with that of the liquid phase; at 3000 PSI (21,000 kPa), the gas phase can be on the order of 200 kg/m³ with the liquid phase perhaps 600 kg/m³. So, a change from 5% liquid to 4% liquid is a 20% variation in liquid, but it will

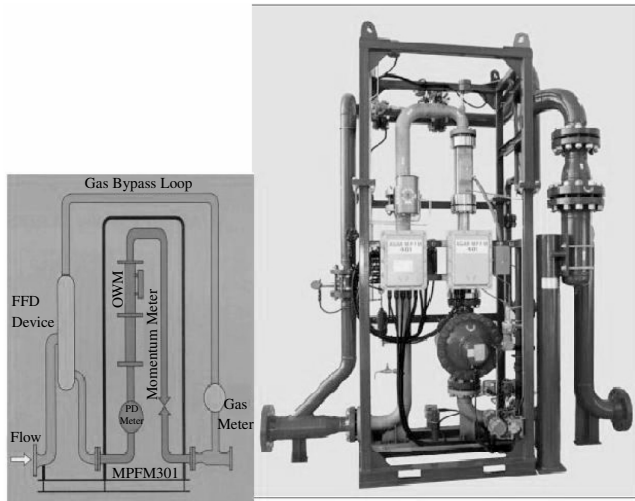


FIG. 2.17b
Agar MPFM 400 high void fraction meter.

only change the density by less than 2%. To avoid this, one supplier (AGAR) uses a centrifugal separator to separate much of the gas from a remaining three-phase mixture, measure this separately, and then mixes it back after the other stream has been measured. Removing 80% of the gas enables the multiphase meter section to be much smaller and more sensitive to the valuable liquid hydrocarbon. The true volumetric flow of the multiphase mixture is measured by a positive-

displacement Oval™ gear meter, and venturi techniques and microwave water content distinguish the different phases.

The orientation of a multiphase flowmeter can strongly influence the multiphase flow regime. In systems with medium to high gas content and low velocity, vertical upflow can find the gas phase unable to continuously sweep the liquid phase forward, and the liquid may recycle backward, leading to metering errors and to slug flow. This offers a significant low-end constraint on flow through devices of fixed geometry, which will differ between devices of similar size.

Horizontal-flow installations can show internal segregation, with gas, oil, and water layers traveling at different velocities. Again, maintaining a high velocity helps to mix the phases, but the upstream piping layout may contribute to slugging, which the meter system can do little to correct.

Measurement in multiphase flow is notable by widely varying conditions under nominally constant flow. In slug flow, the liquid fraction can vary between almost zero in the region after a liquid slug to almost 100% inside the slug. Significant fluctuations will also be present in annular and churn flow patterns.

The pressure drop of a liquid slug passing through a venturi meter can be five times higher than the average pressure drop for the flow; the minimum pressure drop in the same flow, corresponding to the *film* region, can be 20% of the average. Therefore, a venturi meter would experience pressure drop varying by 25:1 at a nominally steady multiphase production condition. This is one reason for the

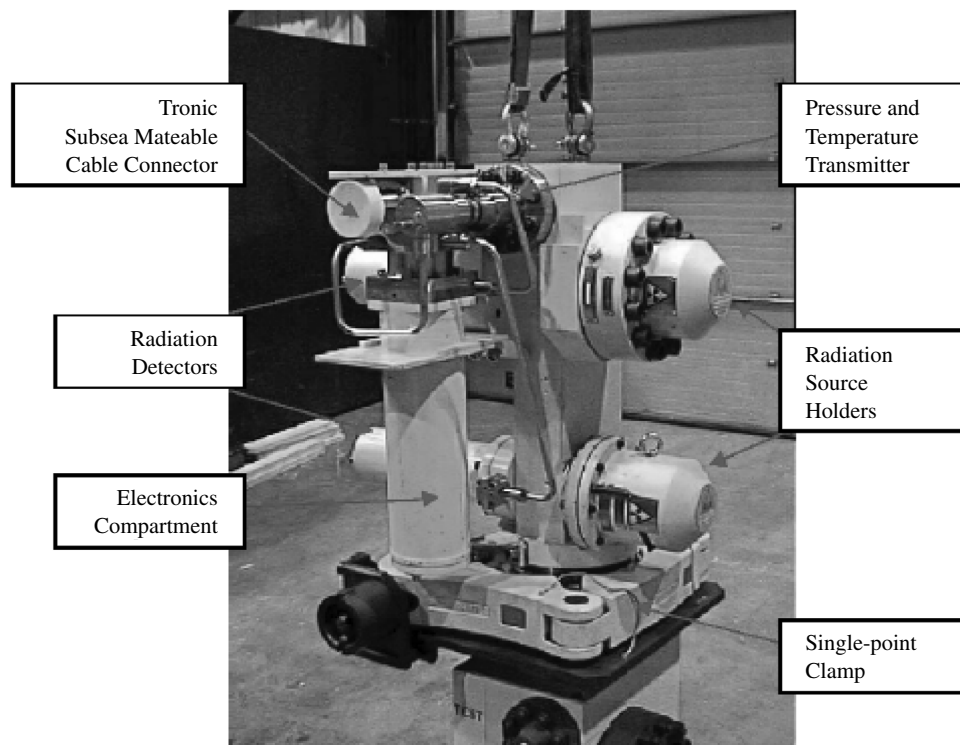


FIG. 2.17c
Aker-Kvaerner "DUET" subsea multiphase flowmeter.

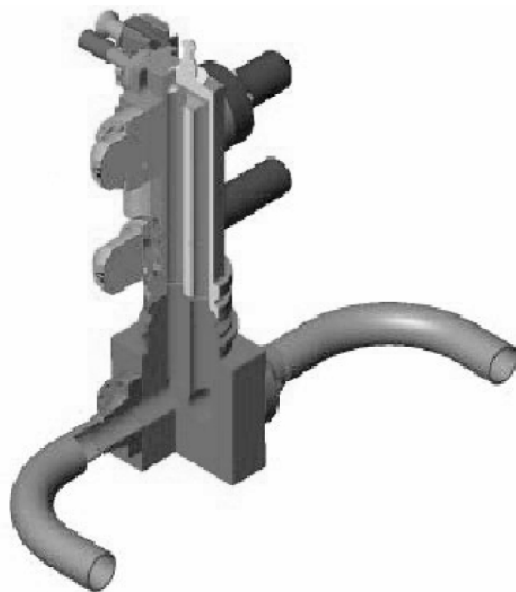


FIG. 2.17d

Aker-Kvaerner “DUET” subsea multiphase flowmeter sectional drawing.

attraction of correlation flowmetering techniques, which do not experience such extremes yet require (and see) appreciable fluctuations in physical properties in the short term.

To reduce the uncertainty associated with measurement of a parameter that fluctuates over such a wide range, many samples are required over a relatively long measuring period.

When a multiphase meter is located at the receiving end of a pipeline, the resulting measurement is influenced by the flow into the line (which may be combined from several wells); the flow patterns developing along the line; the elevation changes along the line, which can trap liquid at low points; the outlet pressure changes; and other fluctuations. As can be imagined, the flow out of such a pipeline varies considerably, and the measuring equipment must be specified to cover the full range of the variation, usually based on inadequate data.

References

1. Reader-Harris, M. J., Brunton, W. C., Gibson, J. J., Hodges, D. and Nicholson, I. G., Discharge coefficients of venturi tubes with standard and nonstandard convergent angles, *Flow Meas. Instrum.*, 12, 135–145, 2001.
2. U.K. Department of Trade and Industry (DTI) Oil and Gas Division Guidance Notes For Petroleum Measurement Under The Petroleum (Production) Regulations Issue 6, October 2001.
3. de Leeuw, H., Liquid correction of venturi meter readings in wet gas flow, North Sea Flow Measurement Workshop, Kristiansand, Norway, Paper 21, 1997.
4. Miller, R. W., *Flow Measurement Engineering Handbook*, Table 6.4, 3rd ed., McGraw-Hill, New York, 1996.

Bibliography

- Chisholm, D., Two phase flow through sharp-edged orifices, research note, *J. Mech. Eng. Sci.*, 1977.
- Couput, J. P., Wet Gas Metering in the Upstream Area: Needs, Applications & Developments, North Sea Flow Measurement Workshop, Gleneagles, Scotland, Paper 6.1, 2000.
- Jamison, A. W., Johnson, P. A., Spearman, E. P. and Sattary, J. A., Unpredicted behaviour of venturi flow meter in gas at high Reynolds numbers, North Sea Flow Measurement Workshop, Peebles, Scotland, 1996.
- Murdock, J. W., Two phase flow measurement with orifices, *J. Basic Eng.*, December 1962.
- Steven, R., An Overview of the Current State of Wet Gas Metering in the Natural Gas Production Industry and Proposals for Future Research, 2nd Annual Course on Practical Developments in Gas Flow Metering—Focus on Cost Reduction, NEL, East Kilbride, Glasgow, 1999.
- Stobie, G., Wet gas flow measurement in the real world, One Day Seminar on Practical Developments in Gas Flow Metering, National Engineering Laboratory, East Kilbride, Glasgow, 1998.
- Stobie, G. J., Wet gas metering in the real world—part II, Wet Gas Metering Seminar, Paris, 2001.
- Van Maanen, H. R. E., Cost Reduction for Wet Gas Measurement Using the Tracer-Venturi Combination, Practical Developments in Gas Flow Metering, Paper 2, NEL, East Kilbride, Glasgow, 1999.
- Wilson, M. B., The Development and Testing of an Ultrasonic Flow Meter for Wet Gas Applications, Seminar on the Measurement of Wet Gas, East Kilbride, Scotland, 1996.
- Zanker, K. J., The Performance of a Multi-path Ultrasonic Meter with Wet Gas, North Sea Flow Measurement Workshop, Paper 6.2, Gleneagles, Scotland, 2000.