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Natural gas — Upstream area — Allocation of gas and condensate

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British Standards

National foreword

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Natural gas — Upstream area — Allocation of gas and condensate

Gaz naturel — Zone amont — Allocation du gaz et du condensat

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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

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Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights.

ISO/TR 26762 was prepared by Technical Committee ISO/TC 193, *Natural gas*.

Introduction

Hydrocarbon gas and condensate from onshore or offshore concessions is often transported by shared pipelines to shared main treatment facilities. The concessions are often owned by or licensed to a number of oil companies. At the main treatment facilities, the gas and condensate are processed to sales specifications. The gas is sold to shippers in terms of standard volume (standard cubic metres) or combustion energy (joules), and the condensate is sold in terms of standard volume (standard cubic metres) or mass (kilograms or tonnes). All the gas and condensate sold at the main treatment facility and the associated money should be allocated back to the individual concessions and, ultimately, to the individual reservoirs or wells, as illustrated in Figure 1.

When gas from two or more entry sources (e.g. two or more different companies) is commingled and processed in a common pipeline and terminal system and the sources have different ownership and/or operate under different tax regimes, then a gas allocation system is required. It is necessary that the allocation system provide a fair, equitable and auditable means of sharing out the products from the system to the entry sources and to the associated partners, recognizing the specific delivery requirements of each participant.

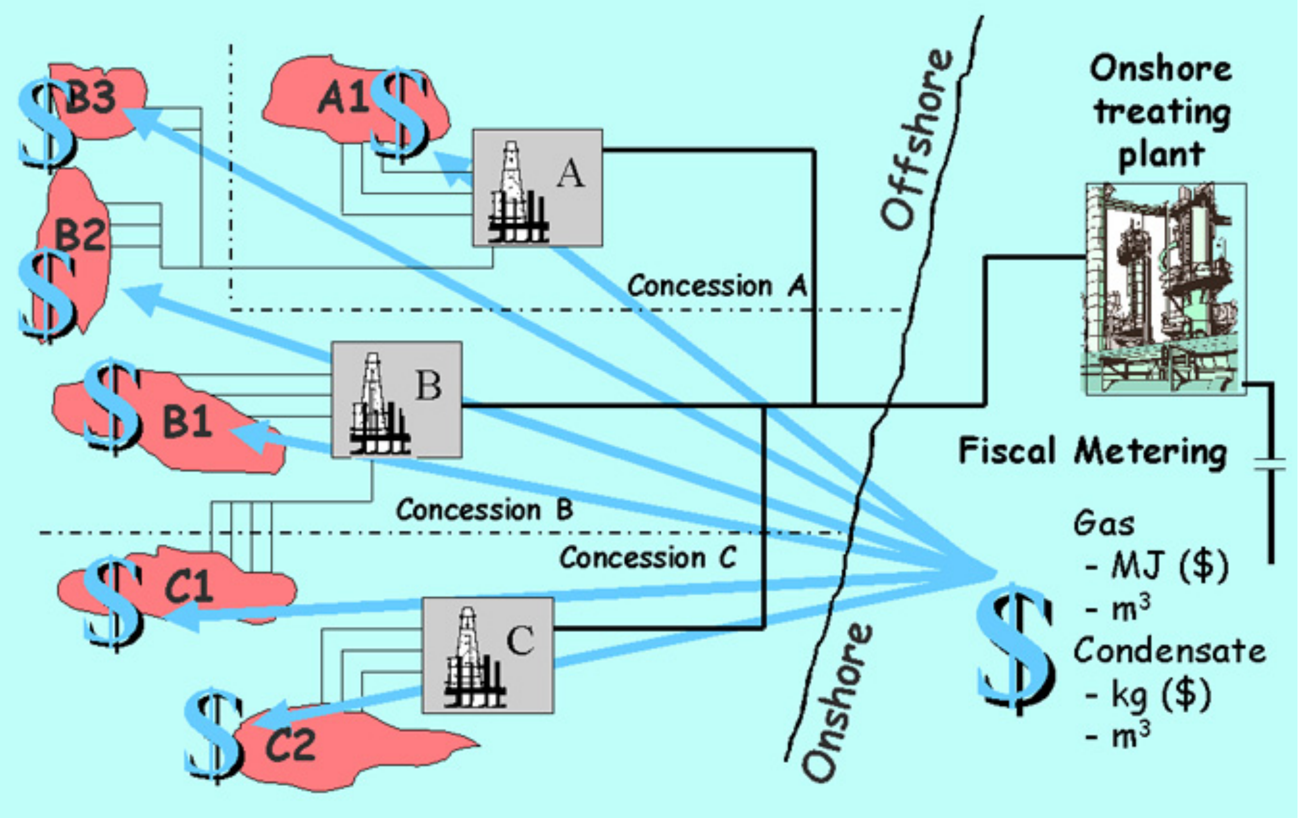


Figure 1 — Offshore gas distributions

Natural gas — Upstream area — Allocation of gas and condensate

1 Scope

This Technical Report describes the production measurements, in terms of both hardware and procedures, that can be used to allocate the gas and condensate back to the individual concessions, reservoirs and wells in a fair and equitable way. The objective is to give an approach that is recognized to be current best practice and that has a wide support in the oil and gas industry.

2 Normative references

ISO 5167-1, *Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full — Part 1: General principles and requirements*

ISO 5168, *Measurement of fluid flow — Procedures for the evaluation of uncertainties*

ISO 6974 (all parts), *Natural gas — Determination of composition with defined uncertainty by gas chromatography*

ISO 6975, *Natural gas — Extended analysis — Gas-chromatographic method*

ISO 6976:1995, *Natural gas — Calculation of calorific values, density, relative density and Wobbe index from composition*

ISO 9951, *Measurement of gas flow in closed conduits — Turbine meters*

ISO 10715, *Natural gas — Sampling guidelines*

3 Economic aspects

3.1 Overview

3.1.1 General

Production measurements in the upstream area, whether single-phase or multiphase, have an economic impact on the business. The implementation of production measurements costs money, but in return delivers data that can be used in decision-making processes and in measuring the economic returns. Generally, it is necessary to give the three issues described in 3.1.2 to 3.1.4 proper consideration to implement a cost-effective measurement and allocation system.

3.1.2 Value of information

The decision-making processes that use production measurement information are those associated with production optimization or reservoir modelling. Figure 2 indicates, schematically, the effect of measurement accuracy on the uncertainty band of the ultimate recovery from a concession (i.e. total production over field life). With poor accuracy in the measurements, the uncertainty band and associated risk exposure stay relatively large. With better and more accurate measurements, the uncertainty band and associated financial risk are reduced. The assessment of the value of information is the most difficult part of designing an allocation system and it is probably for that reason that it is rarely done properly, if at all. As an example, the difference between production allocation (i.e. allocation of fluids from a production facility to the individual wells) and sales allocation (i.e. allocation of products in a common pipeline) can be mentioned. In the sales allocation, it can be directly calculated what the relation is between uncertainties in fluid flow measurement and risk in money flow between the companies involved. In the production allocation, often within one single company, this is less obvious as complex reservoir modelling and petroleum economics are involved. This is often why, in general, the requirements for sales allocation are higher than the requirements for production allocation.

3.1.3 Hardware costs

Capital expenditures for production facilities, test separators, test lines, multiphase flow meters, etc. can all be assessed relatively easily. It should also be noted that the higher the accuracy requirement for a particular meter, the more expensive the meter hardware. This is the easiest part in the total cost estimate.

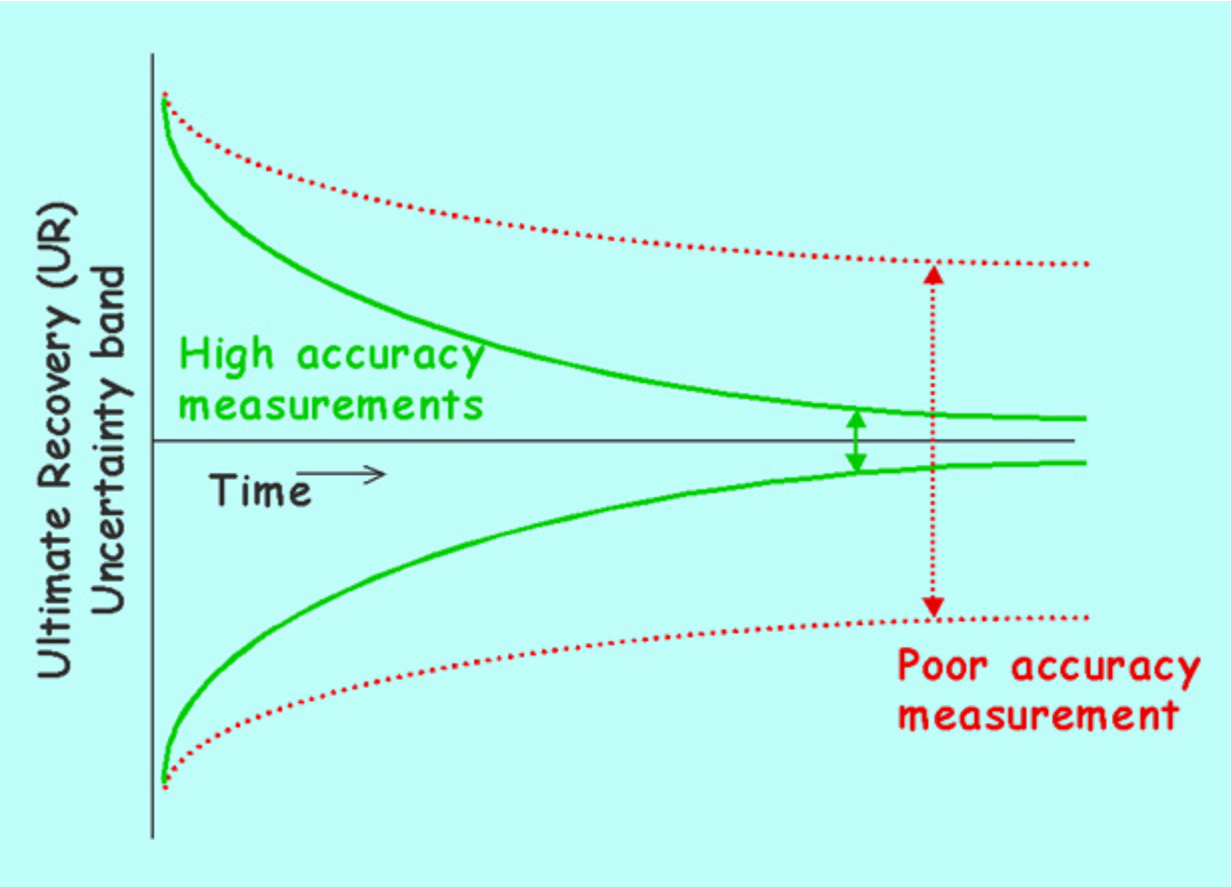


Figure 2 — Cost treatment of metering

3.1.4 Operating costs

Preparation and implementation of procedures and guidelines to keep the production measurement equipment in good shape (maintenance, verification and calibration) and to ensure that readings are reliable and within the original specifications require sufficient and consistent dedication during the operations phase. These costs are often underestimated, especially with new technologies such as multiphase or wet-gas flow metering.

3.2 Uncertainty and costs

With respect to uncertainty and costs, two extreme cases are considered.

- One extreme is a production system with very high accuracy in production measurements. Due to increased hardware costs and intensive operator involvement, the project and operating costs are higher, but with more and better information, better reservoir management and production optimization can be carried out. Consequently, the uncertainty band in the ultimate recovery decreases, giving a lower spread in project and operating risks (see Figure 2). Realizing that the value of the oil in the ground is limited, we can also conclude that at a certain cost level the development becomes economically unattractive.
- The other extreme is a poor accuracy in the production measurements or production is not measured at all. Poor reservoir management, sub-optimal production optimization and potential loss of revenue are the result. Consequently, the uncertainty band in the ultimate recovery stays large. The development can unwittingly become unattractive from an economic and risk point of view.

Somewhere between the above two extremes there is an optimum acceptable uncertainty, with the associated costs for the measurement and allocation processes. This is illustrated in Figure 3, in which costs (in arbitrary units) are plotted against acceptable uncertainty. This optimum can well be different for each individual hydrocarbon development. It can well be the case that, for a particular development, an accuracy of 10 % in gas flow rate is sufficient while in another development a 2 % accuracy is required.

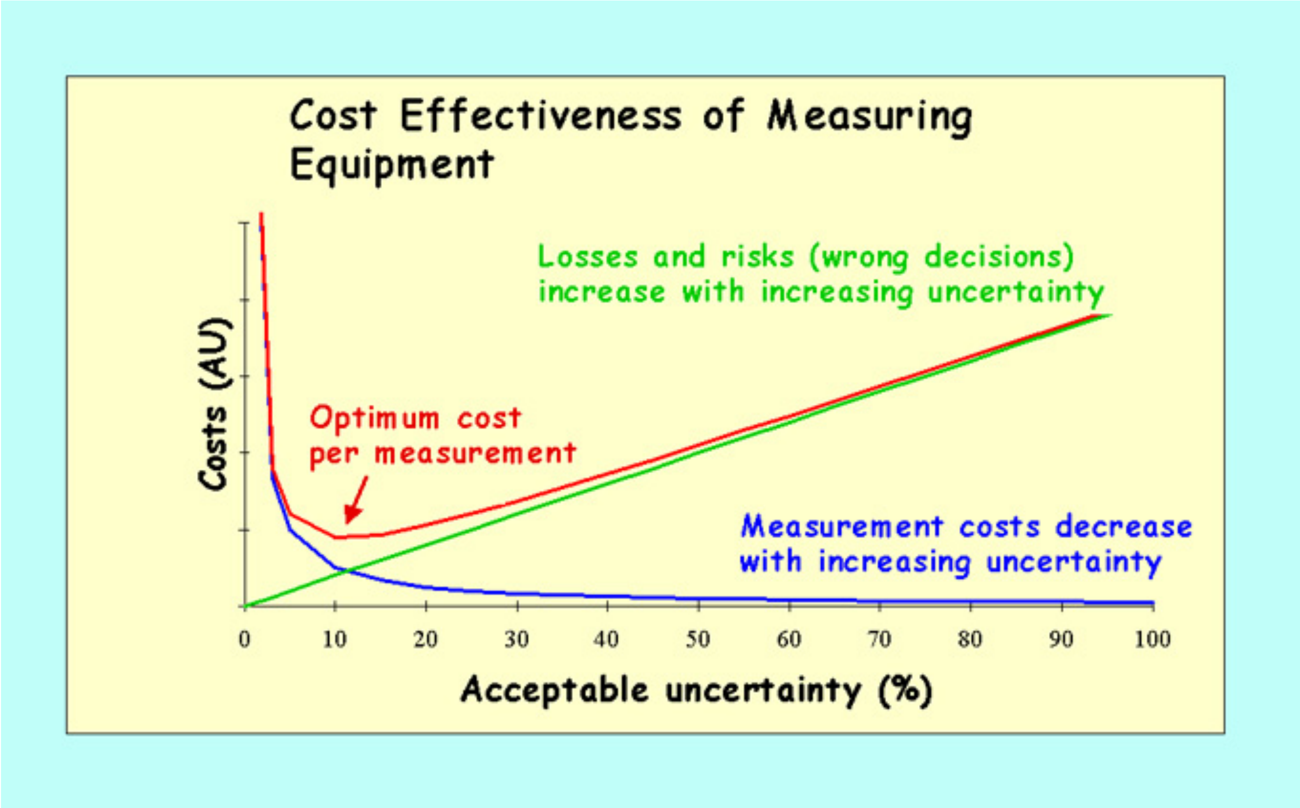


Figure 3 — Costs related to uncertainty

3.3 Allocation system overview

It is not unusual to take between one and two years to negotiate all the terms of a gas and condensate allocation agreement. A wide array of skills is required to understand the diverse topics in the development of an allocation system. To successfully conclude an agreement, it is good practice to form a team with expertise in the following:

- commercial negotiation;
- gas legislation;
- gas marketing;
- measurement and allocation;
- production operation;
- IT.

Besides the preparation of the commercial agreement, it is necessary to develop the business processes to manage the day-to-day operation of the agreement. It is imperative to establish responsibilities and ownership for the following:

- hydrocarbon stream meter data;
- hydrocarbon stream analysis;
- production forecast information;
- allocation system operation.

Development of the business processes requires a review of almost all departments within a gas production organization to ensure that the workload associated with the operation of the allocation system can be performed adequately and to identify whether additional personnel or external resources are required.

3.3.1 Overall scope of an allocation agreement

Figure 4 gives an overview of the major issues that feature in a gas and condensate allocation agreement. These issues are discussed separately in the following subclauses. One party or department should be charged with overall responsibility for producing the agreement, but the party or department may vary from company to company. It is of utmost importance that all parties or departments involved in the agreement ensure that the issues affecting them are properly and adequately dealt with in the agreement.

3.3.2 Reservoir performance

Reservoir performance data are required to assist in the forecasting of production to the operator of the gas treatment facilities. Long-term forecasts issued are likely based partly on the technical view of the reservoir potential and partly on the commercial view of possible future business. Shorter-term forecasts likely have a more technical focus and are likely developed in conjunction with operations staff to incorporate planned shutdowns, etc.

In addition, reservoir engineers provide an overview of the differences in composition of the fluids from the reservoirs covered by the allocation agreement. Reservoir engineering departments are normally responsible for the initial sampling and associated fluid analyses. Specific analytical requirements regarding gas quality should be discussed with the reservoir engineering departments to ensure provision of the appropriate data.

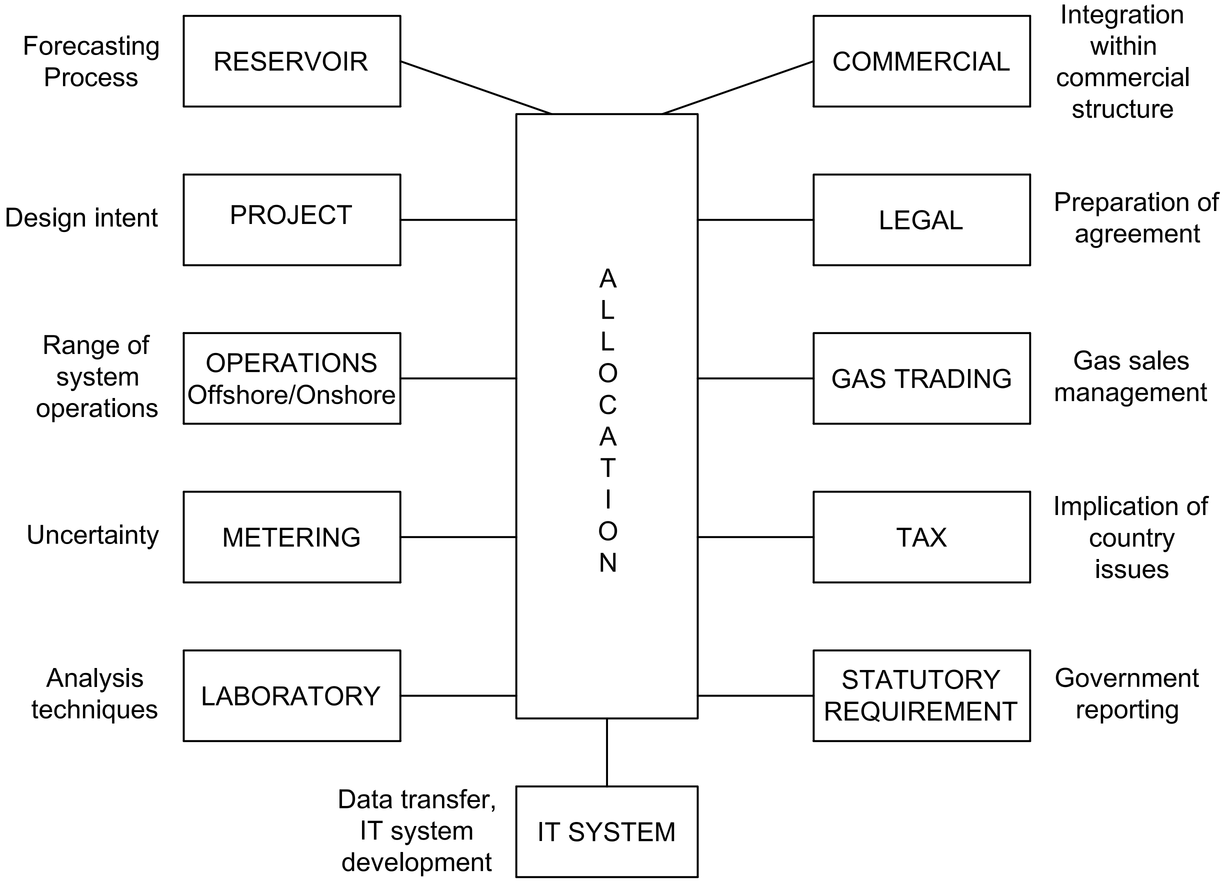


Figure 4 — Issues that feature in a gas and condensate allocation agreement

3.3.3 Project specifications

Discussions are required with the project team to ensure that

- the necessary metering devices are provided to the specified uncertainty levels,
- sampling systems are installed to obtain adequately representative gas and condensate samples,
- acceptable and appropriate analyses of the gas and condensate samples are performed,
- the required data are captured and transferred to a central IT system and an adequate production-measurement management system is in place (see ISO 10012).

Parties involved in these discussions include the metering and IT departments and, where appropriate, the operator of the gas treatment facilities.

3.3.4 Operations/gas-trading and coordinating group

A review of the allocation agreement should be made with the parties involved with the agreement to ensure that they understand and appreciate the implications of the agreement on their day-to-day duties and to ensure they have the opportunity to feed back potential problems or conflicts with existing agreements and associated operations.

The gas-trading group should ensure that the allocation agreement complies with gas marketing and reporting requirements for entry to the gas distribution network from the gas treatment facilities.

3.3.5 Metering requirements

Appropriately qualified and experienced metering engineers should be responsible for specifying and selecting the individual meters and associated equipment. When operations start, they should be responsible for the validation of metering data.

The validated meter data should be made available to the hydrocarbon accountants to run the allocation calculations and generate the allocation reports. It is necessary that the validation process for the metered data be performed independently of the allocation calculations. There is a tendency to use allocation processes as a check on the quality of the metering process. Balance factors or reconciliation factors can be used, with care, to highlight possible metering problems. Ideally, limits to these factors should be set based on sensitivity studies with the intrinsic uncertainties of the individual meters as input.

3.3.6 Laboratory requirements

Pressurized samples of gas and condensate are sent to a laboratory that has been selected for the shared pipeline system. The selected laboratory should have appropriate, acceptable accreditation.

Procedures should be developed for

- control and maintenance of the sample vessels,
- transportation of pressurized sample vessels between the production facilities and the laboratory,
- receipt and validation of the sample fluids,
- conducting and reporting of the analyses.

3.3.7 Commercial issues

The commercial group should review the allocation agreement for consistency with other agreements.

3.3.8 Legal issues

In general, the allocation agreement is written by the responsible allocation personnel, with the metering section of the agreement produced by the metering engineer and the commercial issues dealt with by the commercial department. A review by the legal department is required to check for consistency with other agreements and that the liability clauses are appropriate and acceptable.

3.3.9 Tax issues

In some jurisdictions, the tax and royalty implications associated with a field and/or a party can have the most dominant impact on the revenue from an allocation system. A review is essential at the early stages of a development to ascertain any tax implications and incorporate the appropriate mechanisms within the allocation procedure.

Customs duties can be particularly relevant when gas and condensate from a development is produced into a shared pipeline in one country and entitlement to blended gas and condensate is received in another country.

3.3.10 Statutory requirements

It is essential at an early stage in a development to undertake a review of the statutory requirements and seek the necessary approvals from the appropriate governing bodies.

3.3.11 IT systems

The development of an IT system to perform the allocation procedure can take a significant period of time to implement, test and hand over to the responsible department. Because of tight development deadlines, it can be necessary to start the IT system design before the commercial agreement is finalized and strict project management is required to control the IT vendor and minimize change requests.

The software should be developed in a structure suitable to the application, with particular attention paid to the ability to modify/expand the system whilst maintaining the capability to revert to rerunning a pre-modification allocation.

3.3.12 Overall metering system

The entire process of metering and allocation (the metering hardware, the algorithms used, the data transmission and storage systems) should be covered by an adequate management process (see ISO 10012).

4 Allocation from different viewpoints and terminology

4.1 Physical system

This Technical Report is intended for use in the measurement and allocation of natural gas and condensate in multi-user pipeline transportation systems.

Such a system is typically comprised of production facilities, pipelines, reception facilities, processing facilities and sales points. Each of these elements can be represented in the allocation system described in 4.2 to 4.5 (see Figure 5 for an example of a typical system).

4.2 Gas/condensate system overview

4.2.1 System diagram

The physical system can be represented as a single-line nodal diagram, representing all the (production) sources, sinks (gas used for fuel, flare, vent, gas lift, injection gas, etc.), as well as flow paths of product. See Figure 5.

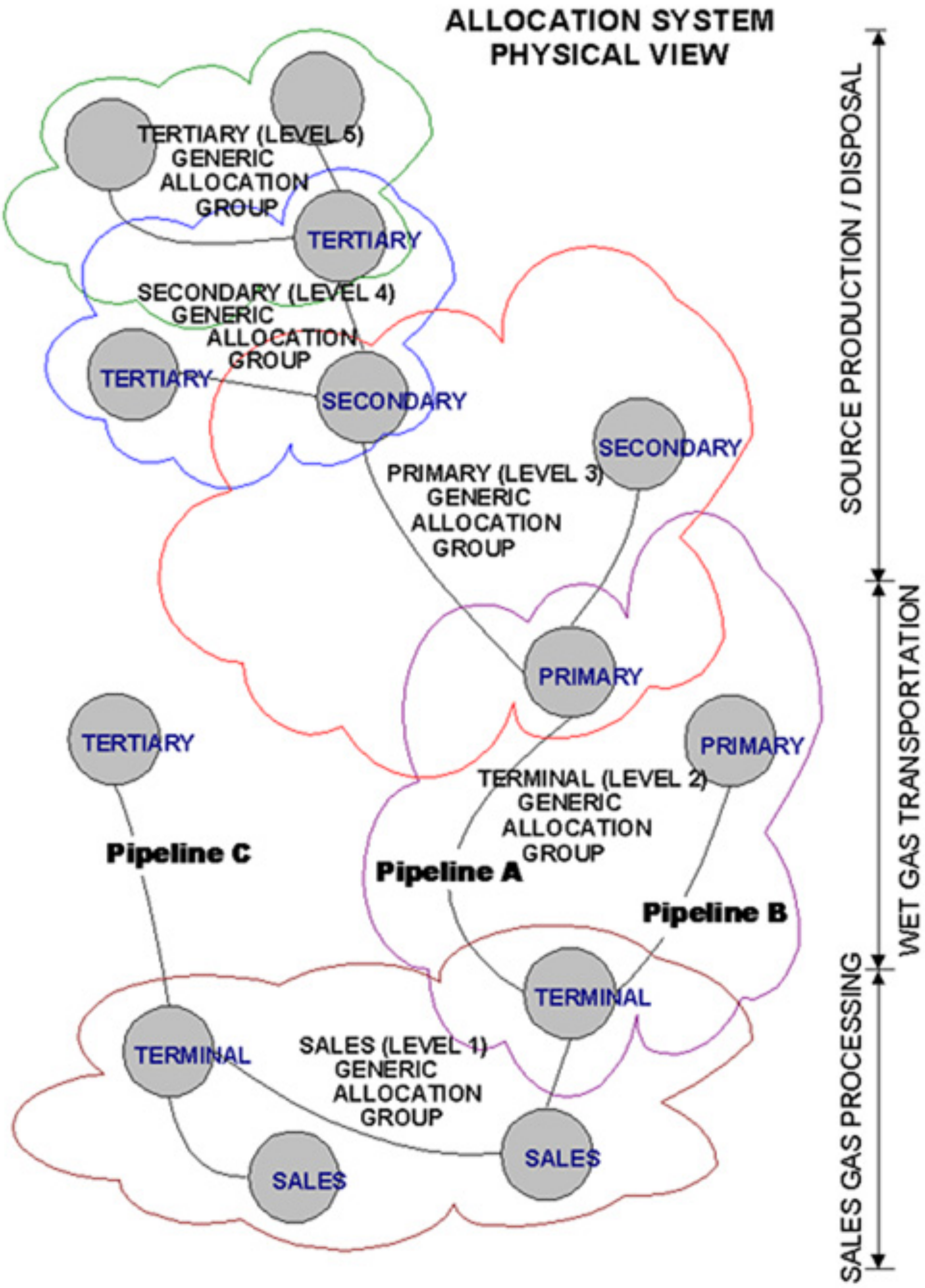


Figure 5 — Physical system

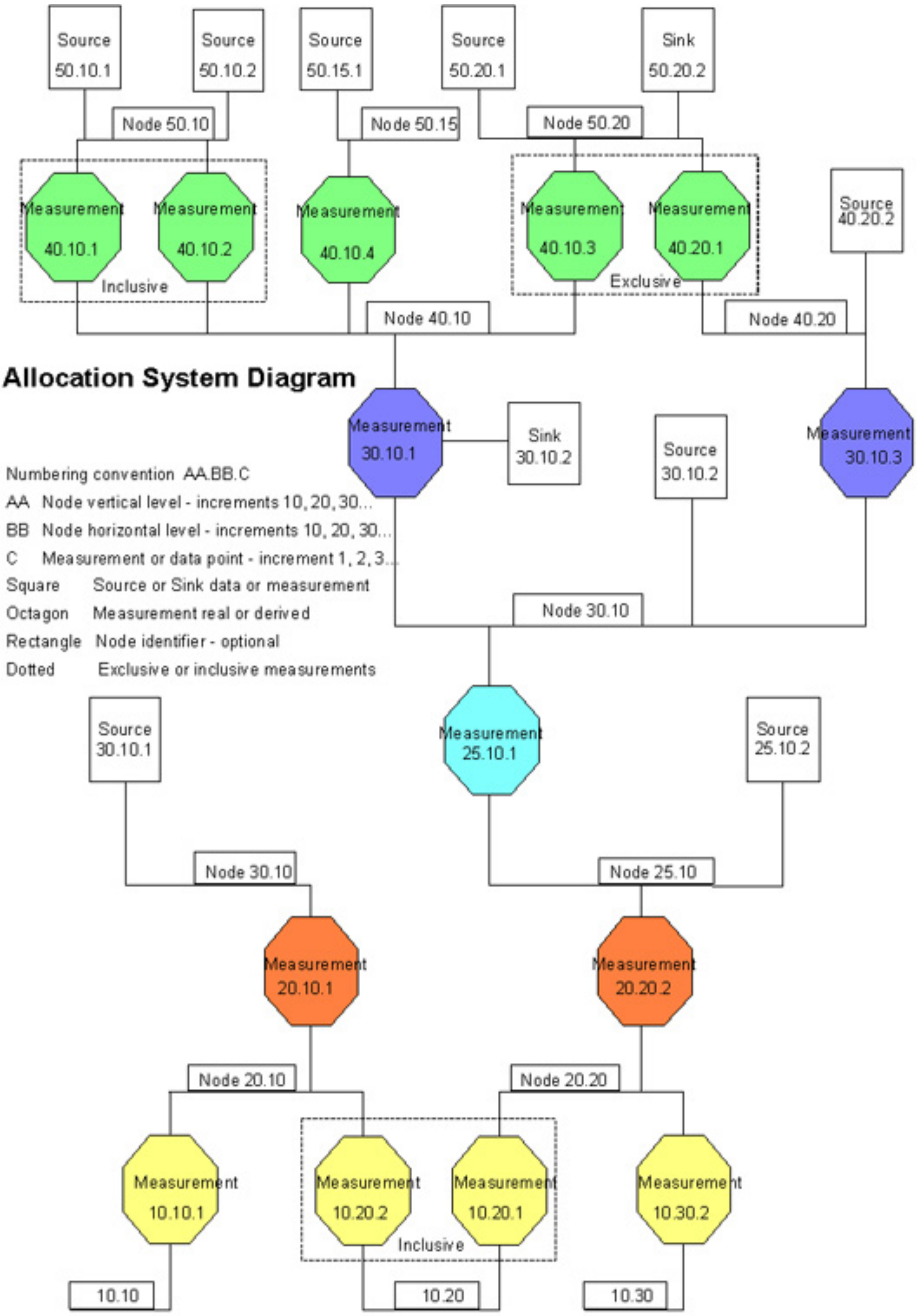


Figure 6 — Allocation system diagram

A supporting table (Table 1) developed from the system diagram (see Figure 6) describes what each node in the system represents, what the name of the producing field asset can be, the equity ownership interests, etc. It can further describe any product processing, calculations, simulations, yield factors, etc., as well as the allocation protocol for the node concerned.

The system description table (diagram) can look something like Table 1:

Table 1 — System description table

Node no.	Process function	Equity ownership	Allocation protocol/function	—	Comments

Other information can be provided, such as the following:

a) source: Any product feed entering a system node; this is generally a production stream coming from one or more wells or production facilities.

b) sink: Any product feed leaving a system node; this is generally gas and condensate sales streams but also water disposal streams, flare gas flows, blow-off gas, etc.

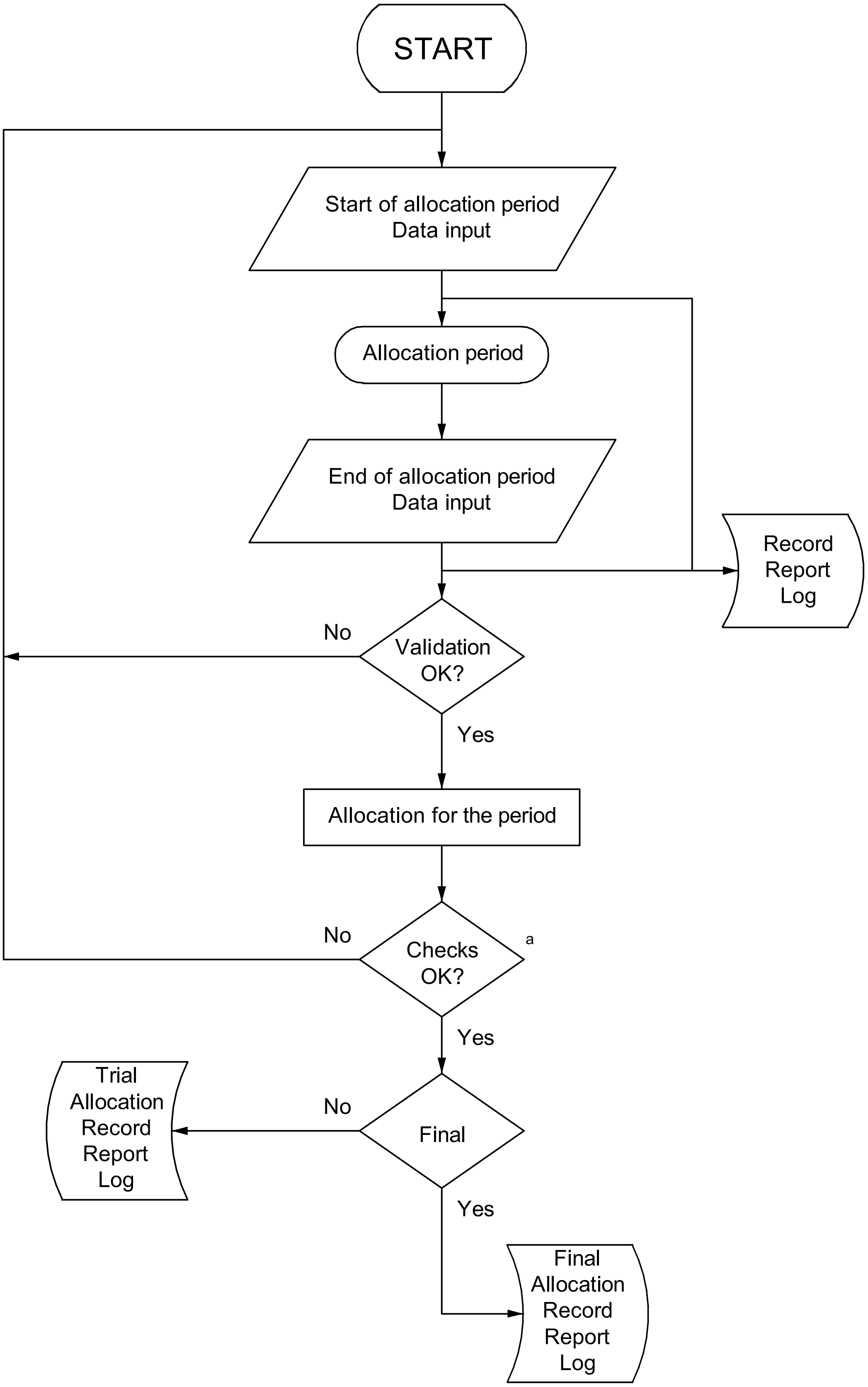
c) node: Any point in the system defined for the purpose of quantifying the quantity and quality of product passing through it.

d) commingling: Combination of product streams from two or more wells or production facilities into a common separator, pipeline or tank.

e) reconciliation: The process of dealing with any quantity imbalance between sources and sinks; possible phase changes between the gas and condensate phase can be taken into account as well. Reconciliation can take place at any node in the system and is usually done at agreed periodic intervals.

4.2.2 Allocation process

This is the process by which a quantity of hydrocarbon gas and hydrocarbon condensate, measured at a sink (e.g. sales point) is allocated to one or more contributing sources. (See Figure 7 for an example of a typical allocation process flow chart.)



[a] Checks here also include the sub-process of reconciliation, or system balance, i.e. what is reported as being delivered with what has actually been received. This is usually done periodically and at agreed-upon intervals.

Figure 7 — Typical allocation process flow chart

4.3 Physical system terms

4.3.1 Fluid definitions — General

Some definitions are given below for single-phase fluid streams (e.g. gas, water and liquid streams) and multiphase fluid streams (e.g. wet gas streams and multiphase streams). Unlike the downstream and transport and distribution businesses, for the upstream area it is not the case that all fluid streams are properly conditioned to a single phase or indeed stay in a single phase over a large range of pressure and temperature. In the upstream area, the fluids are often unstable, and any pressure and temperature change (even a Δp in a measurement device or over a valve) can cause a phase change and change a single-phase fluid into a multiphase fluid. Accordingly, all definitions below should be referred to the operation ranges of temperature and pressure that occur in the system under consideration.

4.3.2 Definitions for fluids

4.3.2.1
equation of state
EoS
mathematical expression that relates the composition, pressure and temperature of a fluid

NOTE For an ideal gas, the equation of state is the ideal gas law. More complicated equations of state have been developed to model the behaviour of actual gases over a range of pressures and temperatures, e.g. Benedict, Webb, Rubin (BWR equation) and Soave, who modified Redlich & Kwong's equation (SRK equation).

4.3.2.2
dry gas
treated gas
clean dry gas (not necessarily only hydrocarbons but may contain other components such as CO_2, N_2, etc.) where no liquid is present and no liquid condensation is expected over the expected normal operating temperatures and pressures at the metering point

EXAMPLE Gas with a dew point of – 5 °C that is measured under conditions between 5 °C and 10 °C.

4.3.2.3
equilibrium gas
⟨separated at dew point⟩ dry gas at its dew point but without the presence of liquid condensation (typically gas at the outlet of a properly functioning separator)

NOTE Any change in temperature or pressure can cause a change of state of the gas towards a dry gas or a wet gas.

4.3.2.4
wet gas
⟨two- or three-phase⟩ any mixture of gas and up to about 10 % by volume liquid hydrocarbon and/or water

NOTE The mass ratio of gas to liquid varies significantly with pressure for a constant gas volume fraction. A convenient parameter to indicate the wetness of the gas is the Lockhart-Martinelli parameter (see 4.3.2.15).

4.3.2.5
single-phase hydrocarbon liquid
liquid at a pressure above its equilibrium pressure (bubble point)

EXAMPLE Liquid below the level of the outlet of a separator where static head (or booster pumps) increase(s) the pressure above the equilibrium pressure.

NOTE The hydrocarbon liquid can contain traces of water.

4.3.2.6
single-phase water
water with a pressure above its equilibrium pressure (bubble point)

NOTE Some traces of liquid hydrocarbons may be present.

4.3.2.7
equilibrium liquid
separated liquid at bubble point
hydrocarbon liquid at its equilibrium pressure and temperature, which does not contain any gas

NOTE However, any further pressure or temperature change can cause gas to be released. True equilibrium liquid is very rare in gas-condensate processing as the dynamic nature of the processes does not allow sufficient time for liquids to reach equilibrium conditions.

4.3.2.8
gassy liquid
⟨two or three phases⟩ any mixture of hydrocarbon liquid and water at a pressure below its equilibrium pressure (bubble point) and where gas is present in the liquid mixture

NOTE This typically occurs inside a separator or where the liquid is exposed to a pressure reduction, e.g. cavitation.

4.3.2.9
gas-oil ratio
GOR
ratio of produced gas flow rate to the produced oil (condensate) flow rate

NOTE GOR is generally measured in standard units, e.g. cubic metres per cubic metre (standard cubic feet per barrel).

4.3.2.10
gas-condensate ratio
GCR
ratio of produced gas flow rate to the produced condensate flow rate

NOTE The GCR is generally measured in standard units, e.g. cubic metres per cubic metre (standard cubic feet per barrel).

4.3.2.11
gas-liquid ratio
GLR
ratio of produced gas flow rate to the produced total liquid flow rate

NOTE The GLR is generally measured in standard units, e.g. cubic metres per cubic metre (standard cubic feet per barrel).

4.3.2.12
watercut
water-liquid ratio
WLR
volumetric fraction of water in the total liquid stream (water plus liquid hydrocarbons), with both volumes determined at the same pressure and temperature

4.3.2.13
water fraction
volumetric fraction of water in the total fluid stream (water, liquid hydrocarbons and gas hydrocarbons), with both volumes determined at the same pressure and temperature

NOTE Water fraction is often used in wet-gas applications.

4.3.2.14
gas volume fraction
GVF
ratio of produced gas flow rate to the produced fluid (gas plus liquid) flow rate

NOTE The GVF is generally measured under actual conditions, e.g. cubic metres per cubic metre, and expressed as a fraction.

4.3.2.15
Lockhart-Martinelli parameter
X

dimensionless parameter, useful in the analysis of multiphase flow, that is expressed as given in Equation (1):

$$X = \frac{Q_\mathrm{l}}{Q_\mathrm{g}} . \sqrt{\frac{\rho_\mathrm{l}}{\rho_\mathrm{g}}} \qquad (1)$$

where

Q_l is the liquid volume flow rate at line conditions, expressed in cubic metres per day;

Q_g is the gas volume flow rate at line conditions, expressed in cubic metres per day;

ρ_l is the liquid density at line conditions, expressed in kilograms per cubic metre;

ρ_g is the gas density at line conditions, expressed in kilograms per cubic metre.

4.3.2.16
multiphase fluid
⟨oil and gas production⟩ mixture of the three phases: liquid hydrocarbon, water and gas

NOTE Almost all fluids encountered in oil and gas production are multiphase fluids. There are broad categories of multiphase fluid, e.g. wet gas (4.3.2.4) where the GVF is typically $>$ 90 %; fluids from a wide range of oil wells where 5 % $<$ GVF $<$ 90 %; and the low-GVF, “gassy’ oils”. It is important to realize that “multiphase fluid” is not a well defined substance.

4.4 Definitions for allocation systems

NOTE See Annex D for lists of letters for 3-letter abbreviations.

4.4.1 Allocation principles

4.4.1.1
mass component
total mass of a single chemical component within a stream, the total of all components being equal to the total mass delivered by that stream

4.4.1.2
energy
⟨gas/condensate allocation⟩ heat energy released when the gas or condensate is subject to combustion under specified conditions

NOTE Energy may be expressed per unit mass, per unit (standard or normal) volume or per mole, at various reference temperatures and pressures, with or without the condensation energy of the water vapour formed during combustion. Reference can be made to ISO 6976 for further information.

4.4.1.3
yield factor
expected returns of hydrocarbon liquids as a proportion of the potential liquids contained within a gas stream

4.4.1.4
delivery point
final measurement point(s) where hydrocarbons leave a single allocation stage

4.4.1.5
source point
entry of a product stream into a single allocation stage

NOTE Quantities associated with source points may be measured or derived.

4.4.1.6
allocation point
any node in an allocation system to which product is allocated

4.4.1.7
components
individual chemical compounds within a product stream

EXAMPLES CH_4, methane, also designated C_1; C_2H_6 , ethane, also designated C_2.

4.4.1.8
lift gas
gas that is pumped down a well to assist in that well’s production

NOTE For the purposes of allocation, all the gas pumped down the well is assumed to be recovered with the well production fluids. However, the lift gas can mix with the reservoir gas and can change its composition. This can affect a volume-based allocation.

4.4.1.9
injection gas
gas injected into the field’s reservoir to maintain reservoir pressure

NOTE The gas is not specific to any one producing well, as is the case with lift gas, and the gas might not appear from production wells until, perhaps, years after injection has begun. The allocation of injection gas is usually different from the allocation of lift gas.

4.4.1.10
utility gas
gas that is vented, flared or burnt as part of normal operations

NOTE Utility gas includes the following:

- vent/flare gas: It is necessary for all producing fields to have a means of maintaining a positive pressure in all vent lines from the processing facilities to atmosphere under normal operating conditions and also to have the capability to vent large amounts of gas in case of an emergency. At present, the method to do this is to continuously vent gas to atmosphere. Relatively small quantities of gas can be vented into the atmosphere un-ignited from some facilities. Usually, to make the gas safe, it is ignited on leaving the vent stack, when it is known as flare gas. This gas is waste product but it is necessary to account for it a) in normal operation, when there are usually small quantities and b) when large amounts are vented during an emergency. The allocation for these two scenarios is usually different.
- fuel gas: Fuel gas used by the plant is usually provided from the gas extracted from the incoming fluids. The allocation of fuel gas is usually driven by commercial or contractual considerations, so measurement applications can be very varied. New European environmental laws require operators to calculate the amount of CO_2 vented to the atmosphere; hence this requires the amount of CO_2 to be measured and allocated. (A component-based allocation system seems to be suitable for this.)

— start-up gas:	Gas imported from other facilities to fill pipelines or equipment on facilities prior to start-up. Depending on size and pressure of the system, these quantities of gas can be large [e.g. for a 300 km, 91.5 cm (36 in) pipeline operating at 13 MPa (130 bar)] and should be taken into account in the allocation process.

4.4.1.11
condensate-gas ratio
CGR
ratio of condensate to gas

NOTE The condensate-gas ratio can be expressed on either a mass or a volume basis.

4.4.2
attribution
process of calculating a final quantity for each allocation point based on its assigned substitution and allocated quantities

4.4.3
substitution
process, in any system where nominations are used to target deliveries of products, whereby the difference between target production (nomination) and allocated deliveries are reduced through exchanges between allocation points

4.4.4
apportionment received at the allocation point
process of pro-rating an allocated/attributed quantity where the same ownership exists for all sources

4.4.5
system balance
performance indicator used to track the difference between the sum of all sources and all delivery points for an allocation system or single allocation stage

4.4.6
node
any originating point to an allocation system or a point with two or more streams attached

4.4.7
stream
⟨allocation modelling⟩ line depicting the flow of product from a source node to a delivery node

4.4.8
validation
process of performing data checks

4.4.9
mis-measurement
process resulting in an erroneous quantity or quality value being recorded and entered into an allocation system

NOTE The error in the value can be caused by faulty or incorrect equipment, incorrect configuration or correction factors.

4.5 Allocation from a commercial viewpoint

4.5.1 General

Prior to entering into gas allocation system negotiations, it is important to understand the underlying framework of commercial agreements (either existing or being negotiated) and the technical characteristics of the production system, pipeline and terminal. For example, each system user's perception of the local gas market influences the importance that party places on different aspects of the allocation agreement, such as the following:

a) security of gas supply with the aim to sell gas on a long-term contract:

- allocation and attribution period set at a day,
- limited re-nomination with relatively long lead times,
- priority system for the attribution process,
- mechanisms for notified and system substitution,
- pipeline stock controlled by the pipeline system operator;

b) flexibility of gas supply in a de-regulated system with the aim to sell gas on the spot market:

- allocation period set at less than a day,
- relatively short re-nomination lead times,
- no priority system with the allocation process,
- no gas substitution,
- all nominations and re-nominations treated as firm,
- linepack controlled by the system users,
- within a day production changes to supplement gas delivery.

The specific situations are never as clear-cut as outlined above and there are other issues that impact the gas buyers and/or the system users, e.g. independence and capacity rights. However, unless a high-level analysis is undertaken and the main issues evaluated prior to entering into negotiations, then there is the likelihood that the allocation system will not fulfil the system users' requirements and objectives. In the extreme situation, the poor quality of the allocation system can impinge on the operation of the offshore production facility and/or can limit the opportunity to sell gas in the open market.

Allocation agreements are commercial agreements with technical input and not the other way around. Attempting to develop a gas-allocation system in isolation has the potential to produce an allocation system that does not fit either commercial or technical purposes. It is necessary to give consideration to the following issues.

- Is the gas being sold to single or multiple buyers?
- Is there one or are there multiple gas sales points?
- Is the gas being sold on a short-term or long-term contract basis?
- Is there a spot market available for gas sales?
- Are there penalties for under-delivery or off-spec delivery?
- Are there any restrictions in use of system capacity by a system user?
- How is the gas from the production system being used within a system user's gas sales portfolio?
- What is the flexibility in the production system to respond to required changes in flow rate?

- Are there any local statutory regulations/considerations with respect to measurement devices, reporting and/or gas balancing?

4.5.2 Gas-allocation issues

To develop a gas-allocation system requires an understanding from a technical standpoint of all aspects of the overall process design and operation, including the implications on the terminal product of variations in processing conditions and gas compositions, and from a commercial standpoint of the gas sales agreements and the overall commercial structure that has been developed.

By its very nature, a gas-allocation system encompasses a wide range of topics including measurement methods and standards, laboratory techniques, data auditing, allocation principles and procedures, nomination, substitution and attribution procedures, statutory requirements, IT system development, audits, tax and related commercial transportation, operating and processing system agreements. The various issues are further explained in the remainder of this Technical Report.

4.5.3 Technical issues

4.5.3.1 Measurement

Measurement includes metering and sampling and is required to establish the quantity and associated quality of the gas exported from the production system into the pipeline and the product leaving the terminal. An understanding is required of the different types of metering systems, sampling installations and associated analytical techniques. This information is required to ensure that the meter specified is correct for the service and accuracy and that the sampling installation is installed in the appropriate location.

The specification of metering and sampling equipment at each measurement point should be designed in accordance with applicable standards and local regulations, although it should be noted that commercial considerations can have an impact on this specification. For example, it may be agreed that a marginal field may use a standard of metering with a higher uncertainty if the overall financial risk is mitigated. Measurement points include

- pipeline entry measurement point(s) for gas and liquid,
- terminal entry measurement point,
- terminal measurement exit point(s) for gas and liquid,
- terminal fuel gas,
- terminal flare gas,
- liquid storage.

In addition, the sampling systems are utilized to monitor the entry and exit streams to ensure that the composition specifications are achieved.

4.5.3.2 Terminal product slate

The terminal product slate relates to the onshore processing of the commingled gas stream in order to ensure that the sales gas and associated liquid product(s) meet the required specifications. In general, more liquid products requires a more complex allocation procedure. An understanding of the terminal process design is required to ensure that the developed procedures correctly reflect each field's allocated entitlement.

4.5.3.3 Pipeline capacity

Pipeline capacity relates to the steady-state and transient operation of the gas pipeline. It is important to ensure that the allocation mechanisms do not inhibit pipeline operation and *vice versa*.

4.5.3.4 System response time

System response time relates to the speed at which the offshore process, the pipeline and the onshore terminal can individually respond to a required change in system throughput. An understanding is required because of the necessity to ensure that the process reflects the dynamics of the system.

4.5.3.5 Gas sales agreement

The gas sales agreement specifies the gas specification at the re-delivery point, nomination procedures, forecasting and gas measurement required and, therefore, directly impacts the allocation process. An understanding is required to ensure that the allocation agreement enables the principles of the gas sales agreement to be applied or that the gas sales agreement can be negotiated to fit with the system's allocation agreement.

4.5.3.6 Commercial agreements

The commercial agreements relate to the transportation and processing agreements that specify, among other things, capacity rights, specifications and system-wide capacity constraint procedures.

4.5.3.7 Statutory obligations

The statutory obligations relate to specific reporting requirements, which can be technical (e.g. measurement), that are necessary to incorporate into the agreements.

4.5.3.8 Tax implications

Processes should be developed for the tax implications that recognize those fields that are liable for specific taxes and those that are not liable. Consideration should be given to the most tax-efficient option when developing the allocation procedures.

4.5.4 Commercial issues

4.5.4.1 Allocation

Allocation is the procedure for sharing out the terminal's gas and liquid production between the participating fields based on the measured data. Allocation relates to the physical movement of fluids through the system.

A series of mathematical equations has been developed to trace the physical flow of gas exported from a field through the pipeline to the terminal. The procedures are used to determine each field's and the associated system user's share of the terminal production (gas and liquids) based on the physical quantity of gas entering the pipeline.

4.5.4.2 Attribution

Attribution is the procedure for sharing out the terminal's gas production between the participating fields, primarily based on nomination data. Attribution relates to the commercial movement of gas through the system and can be independent of the measured input quantities.

A series of mathematical equations has been developed to establish each system user’s share of the gas exported from the terminal. The procedures are based on the user's gas allocation, nomination and specific substitution rights.

4.5.4.3 Nomination

Nomination relates to the quantity of gas requested by a buyer from a system user for delivery from the terminal. The aggregate nominations of all system users (from a field) are used to establish the field's contribution of production into the pipeline system.

4.5.4.4 Substitution

Substitution is the mechanism that enables one user to lend or borrow gas (exported from the terminal) to/from another system user to meet either system user's nominations.

The difference between a field's allocated and attributed quantities is substitution. Substitution is basically a mutual self-help process that is controlled at the terminal by the terminal operator. The terminal operator is aware if a producing area is having difficulties meeting the production targets and can find another operating area that can contribute; and *vice versa* if a producing area has the ability to produce excess gas. Limitations may be imposed on the level of lending, borrowing and the payback period.

4.5.5 Allocation issues

4.5.5.1 Units

Units relate to the base unit of the allocation and attribution processes, for example component mass and/or energy.

4.5.5.2 Time period

The time period relates to the allocation and attribution calculations. Consideration is given to daily, hourly or another allocation period. The allocation period might not be linked to the nomination period, e.g. quite often there exists an hourly allocation period but a daily nomination period. In addition, there often exists downstream gas transporters "balancing" periods. This balancing period is the time frame within which the downstream gas transporter can levy penalties for imbalances between inflow and outflow, e.g. an hourly allocation period but a balancing period of four to six hours. (This gives the gas time to travel from the input point to the output point). The allocation period is shorter as this enables the shippers to manage their imbalance positions within the balancing period.

4.5.5.3 Forecasting

Forecasting is necessary to ensure that the lead times for provision of the data required by the gas sales agreements and the production and planning targets for the terminal and platform operators are incorporated.

4.5.5.4 Pipeline stock

Pipeline stock relates to the use of pipeline stock to help achieve gas delivery. It is necessary to give consideration to which commercial party controls the level of stock in the pipeline, e.g. the pipeline/terminal operator or the system users.

4.5.5.5 Existing systems

It is necessary to ensure that the system seamlessly integrates with existing gas-allocation systems and with the existing procedure associated with existing downstream systems.

4.5.5.6 Data timing

Data timing is necessary to ensure that nominations and any potential re-nominations within the allocation agreement coincide with the requirement of the gas sale agreements and operational requirements.

4.5.5.7 Data flow and reporting

It is necessary to evaluate data flow and reporting to ensure that sufficient information is provided to check the allocation and attribution reports prepared by the system operator. Where individual parties receive data, it is necessary to check that all parties receive the same information at the same time. Business processes are required for the terminal operator to advise the field operators to increase/decrease flow of production into the pipeline system.

4.5.5.8 Auditing

Auditing is critical to provide a means of checking the overall operation of the system operator in the event that errors are found within the allocation statement. It is necessary that this issue be a priority item within any allocation-agreement negotiations.

4.5.5.9 Fallback

A detailed fallback plan is required to establish how nominations and data flow are provided in the event that the normal communication processes fail or meter data do not exist.

4.5.6 Summary

The results from allocation calculations establish each participant's revenue from the system and it is necessary to stress that a gas-allocation agreement is not a technical agreement. During the negotiation of an allocation, system users should be wary of statements that imply that the allocation agreement is purely a technical arrangement and, hence, should be developed by the technical departments.

In conclusion, when gas from two or more entry sources are commingled and processed in a common pipeline and terminal system and the sources have different ownership and/or operate under different tax regimes, then a gas-allocation system is required. It is necessary that the allocation system provide a fair, equitable and auditable means of sharing out the products from the system to the entry sources and to the associated partners recognizing the specific delivery requirements of each participant.

The following should be stressed.

a) All allocation procedures are unique and are specifically designed for a given system driven by commercial considerations.

b) For an allocation system, technical solutions are developed to meet the specific commercial requirements.

c) There is no such thing as a standard allocation procedure but there are standard elements/approaches that combine to produce the overall allocation system.

d) As with any other commercial agreement, allocation agreements are finalized as a result of negotiation and compromise; therefore, it is not good practice to take an existing agreement and attempt to modify it without discussing the terms of the agreement with the personnel that negotiated it.

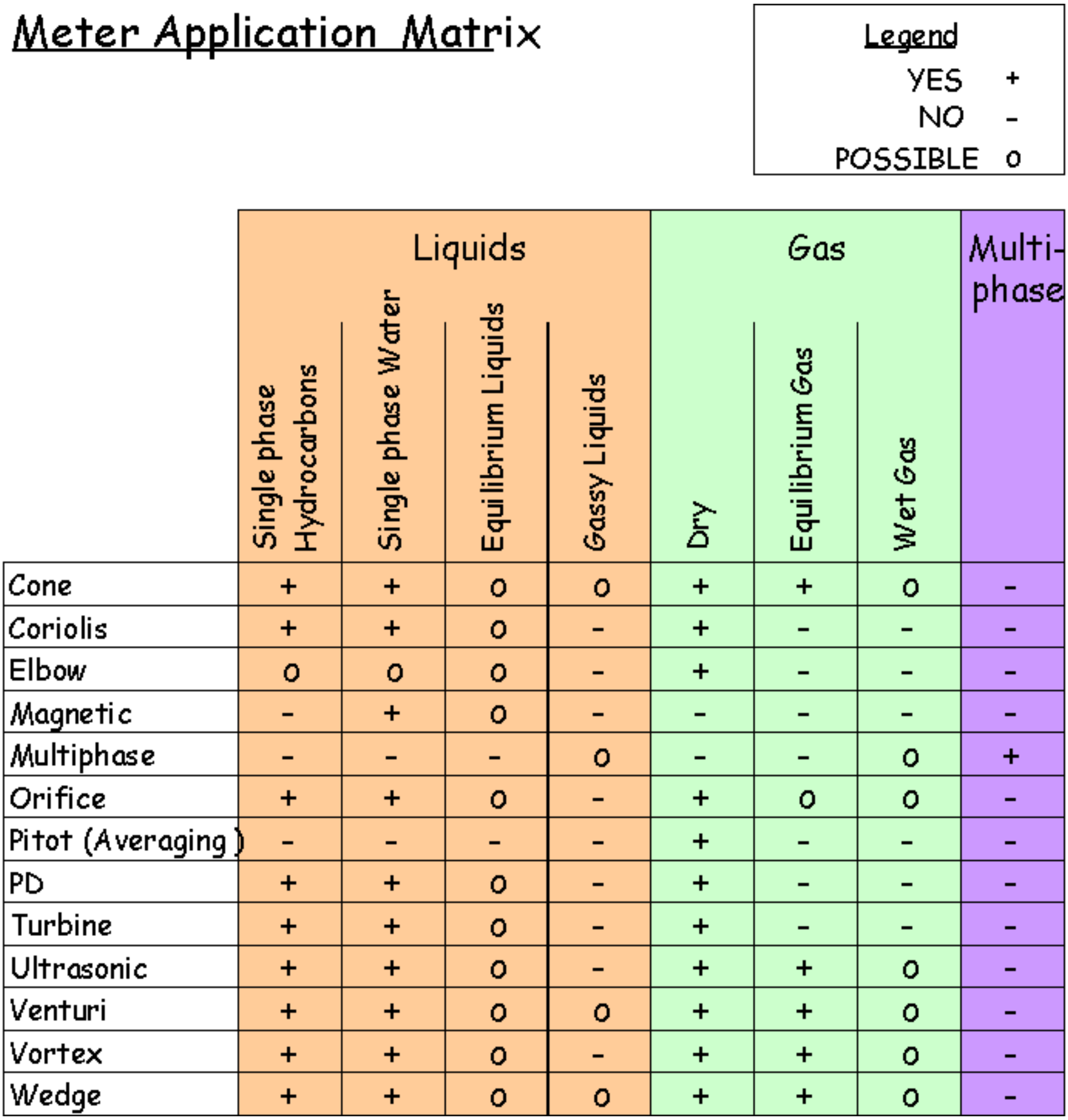
e) It is necessary that an allocation/attribution system not be developed in isolation from the other commercial agreements, e.g. transportation and operating agreements.

5 Quantity measurement for gas and condensate

5.1 Introduction

Quantities of gas and condensate may be expressed, allocated or sold in units of mass, energy of combustion or volume at specified conditions of temperature and pressure. However, direct measurements are only possible for mass (using a Coriolis meter) or volume at operating conditions, and then only for single-phase fluids. For most measurements of mass, all measurements of combustion energy and all measurements of volume at reference conditions of temperature and pressure other than line conditions, direct measurement is not possible and it is necessary that volume measurements at line conditions be combined with measurements of other parameters depending on the composition or quality of the gas/condensate fluids. Measurement of quality for gas and condensate is dealt with in Clause 6. Clause 5 deals with the measurement of volume at line conditions and the direct measurement of mass, including quantity measurement in terms of the different fluids encountered in gas/condensate applications, quantity measurement in terms of the meter types available and the validation of the different types of meter.

Figure 8, the flow meter application matrix, summarizes the types of meters used in allocation metering systems for gas and condensate. It should be noted that for multiphase and wet-gas measurement, the technology is developing fast and it is necessary to consult appropriate information. Some manufacturers are combining different metering concepts (with different over-reading characteristics) to enable a direct gas and liquid flow rate measurement. More detailed guidance is given in 5.2.



Meter Application Matrix

Legend
YES +
NO -
POSSIBLE o

	Liquids				Gas			Multi-phase
	Single phase Hydrocarbons	Single phase Water	Equilibrium Liquids	Gassy Liquids	Dry	Equilibrium Gas	Wet Gas	
Cone	+	+	o	o	+	+	o	-
Coriolis	+	+	o	-	+	-	-	-
Elbow	o	o	o	-	+	-	-	-
Magnetic	-	+	o	-	-	-	-	-
Multiphase	-	-	-	o	-	-	o	+
Orifice	+	+	o	-	+	o	o	-
Pitot (Averaging)	-	-	-	-	+	-	-	-
PD	+	+	o	-	+	-	-	-
Turbine	+	+	o	-	+	-	-	-
Ultrasonic	+	+	o	-	+	+	o	-
Venturi	+	+	o	o	+	+	o	-
Vortex	+	+	o	-	+	+	o	-
Wedge	+	+	o	o	+	+	o	-

Figure 8 — Flow meter application matrix

5.2 Quantity measurement by type of fluid streams

5.2.1 Dry gas (treated gas)

Dry gas is defined as a gaseous fluid for which there is no liquid dropout over the expected temperature and pressure operating ranges at the metering point. Various devices are available to measure dry gas and some methods are covered by International Standards or documents giving best practice. Gas from a three- or a two-phase separator is usually liquid-saturated gas, just above its hydrocarbon dew point. When applying dry-gas metering principles, care should be taken to prevent liquid drop-out due to pressure and temperature fluctuations at the measurement point, resulting in two-phase conditions and corresponding difficulties in measuring the flow.

Other parameters that are necessary to consider are correct meter sizing and installation to prevent unnecessary pressure drop and line insulation to maintain temperature in the system at the metering point. Gas-conditioning devices installed between the measurement point and the separator can change the measurement conditions at the measuring point and possible effects from their installation should be addressed.

Dry-gas flow measurement shall be performed using methods and standards that are generally accepted by the oil and gas industry and which shall be mutually agreed upon by the parties having interests in the gas-transportation system (for example, gas shippers, partners in the field development, field operators and relevant authorities). The selection of the measurement method shall be on the basis of demonstrated reliability and accuracy. The design of new installations or revision of existing installations shall also be subject to the agreement of the above parties.

The following gas flow metering methods are used most often for single-phase gas flow rate measurement, but other methods are not excluded:

a) orifice plates;

b) turbine meter;

c) multi-path ultrasonic meter;

d) Coriolis meters.

The gas quantities shall be displayed in the following units:

— kilograms (tonnes) per day,	mass flow rate for allocation and hydrocarbon accounting purposes;
— standard cubic metres per day,	volume flow rate for capacity planning and hydrocarbon accounting purposes;
— gigajoules or terajoules per day,	energy flow rate for allocation and hydrocarbon accounting purposes.

5.2.1.1 Orifice plate for gas flow measurement

Gas flow measurement for custody transfer (also referred to as fiscal metering) by means of differential pressure devices shall be according to the relevant edition of ISO 5167-1 using a square-edge orifice plate with flange tapings installed in a meter run. These documents give detailed guidance on design, installation and flow computation.

5.2.1.2 Turbine meter for gas flow measurement

Gas-flow measurement for custody transfer by means of turbine meters shall be in accordance with ISO 9951. Turbine meters should not be used where frequently interrupted and/or strongly fluctuating flow or pressure pulsations are present. The turbine meter shall be of demonstrated reliability and accuracy. For each turbine meter, a certificate of the calibration at a high pressure shall be available. The calibration data provided in the certificate shall include the error of the meter for at least six points over the whole range of the meter in accordance with ISO 9951.

5.2.1.3 Ultrasonic meter for gas flow measurement

Multi-path ultrasonic flow meters offer extensive technical and economical advantages as compared to other type of flow meters with respect to, among others, high accuracy, low pressure losses, rangeability (turndown), bi-directional flow, low sensitivity to dirt, trouble-free operation, reduced maintenance and calibration costs.

The application of ultrasonic flow meters should, therefore, be seriously considered for new applications. Application of these meters shall be in accordance with field-proven installation practices. The ultrasonic flow meter shall be of demonstrated reliability and accuracy. The influence of chemicals on the epoxy transducers should be reviewed. The ultrasonic flow meter shall be calibrated in accordance with the manufacturer's procedures. A certificate of the calibration of the ultrasonic flow meter at a high pressure shall be available only if required by parties involved. The calibration data provided in the certificate shall include the error of the meter for at least six points over the whole range of the meter in accordance with ISO 9951.

5.2.2 Equilibrium gas (separated gas at dew point)

Equilibrium gas is defined as separated gas that basically has no free liquids but can develop a small liquid content by changes in process conditions or meter/pipe-work interaction. Any process changes of the gas can cause a shift in the definition of the gas as wet or dry. These changes can affect the GOR, GCR, the Lockhart-Martinelli parameter and the gas and liquid properties. Near critical conditions, small changes can cause large variations in the liquid and gas fractions and in the fluid properties. Care should be taken in the meter selection so as not to cause additional impact on the line process conditions.

The measurement devices that can be used for equilibrium gas are similar to the devices mentioned for dry gas application. However, in the design, care should be taken that as soon as liquids start to form (e.g. due to pressure drop in the meter), the effect on the reading should be established.

Ultrasonic meters are increasingly being used for this service and the following comments are relevant.

- At present ultrasonic meters are not suitable for measuring gas above 0,5 % LVF as the units produce unstable readings.
- Care should be taken in systems subject to carry-over or liquid entrainment when the ultrasonic meter is poorly located. If the meter is too close to bends, valves or other obstructions, the resulting swirl/turbulence can seriously affect the accuracy of the mathematical techniques used to find the velocity profile and, therefore, the flow rate.
- If the operating temperature is too high, there is a question mark over the strength of the bonding material used in the manufacture of some ultrasonic transducers. Testing has shown the transducers can fail at temperatures in excess of 150 °C or when there is a sudden pressure fluctuation (a common occurrence in production pipelines).
- Other installation parameters or concerns that are necessary to consider are that signals read by the meter are very susceptible to background noise from other components in or close to the line on some designs.
- Work is underway to develop ultrasonic meters for wet gas above current norms.

5.2.3 Wet gas (high-GVF, multiphase fluids)

This term is used to denote a natural gas flow containing a relatively small amount (up to about 10 % by volume) of free liquid. There are presently few techniques available that can measure this type of fluid regime to a high degree of accuracy. The phenomenon occurs in several ways, for example the following.

- Over time as dry natural gas wells age, changes in flow conditions, including a reduction in line pressure, can result in the heavier hydrocarbon gases condensing in flow lines and transportation pipelines.
- Production wells for gas condensate fields usually have wet gas flow.
- The quantity of lift gas injected to increase production from many oil wells brings them to flow conditions that can be termed wet gas.

Many gas wells worldwide are now approaching these latter stages of their production life and wet gas metering is becoming common. Current trends indicate approximate ranges of liquid/gas ratios found in most producing gas fields as having GVF > 90 % or Lockhart Martinelli parameters to a maximum of approximately 0,3. Meter performance requirements in this area are not covered in current standards but API RP 85 describes the use of wet-gas meters in an allocation system. Representation of the fluid velocities, measured volumes and mass have not been defined exactly and various regions of the world use different terminology to obtain a measurement result. Accordingly, wet-gas measurement methods are discussed in more detail in this Technical Report to give the current best guidance.

A major challenge in the upstream oil and gas area is the measurement of the non-single-phase flow streams. These streams are the so-called multiphase and wet-gas streams, either coming directly from the wells or partially processed in offshore production facilities. Often, these partially processed streams are such that the gas and condensate are not fully stabilized and often any pressure or temperature change results in the release of gas from the liquid or the dropping-out of liquids from the gas phase. Hence, the “wet-gas streams” and/or “gassy liquid streams” are formed. Figure 9 gives a generic schematic of a so-called two-phase flow map where liquid superficial velocity is on the vertical axis and gas superficial velocity on the horizontal axis, both logarithmic scales. Superficial velocity is a parameter that has been found useful in multiphase metering. It is calculated for each phase of the multiphase fluid by taking the flow rate of that phase and assuming that that phase alone is traveling in the pipeline. The flow regimes depend on the individual superficial gas and superficial liquid velocity. Lines showing GVF have also been plotted. For gas/condensate systems, the wet-gas flow regimes are most relevant, and these are found in the bottom right-hand half of the diagram, below the 90 % GVF line.

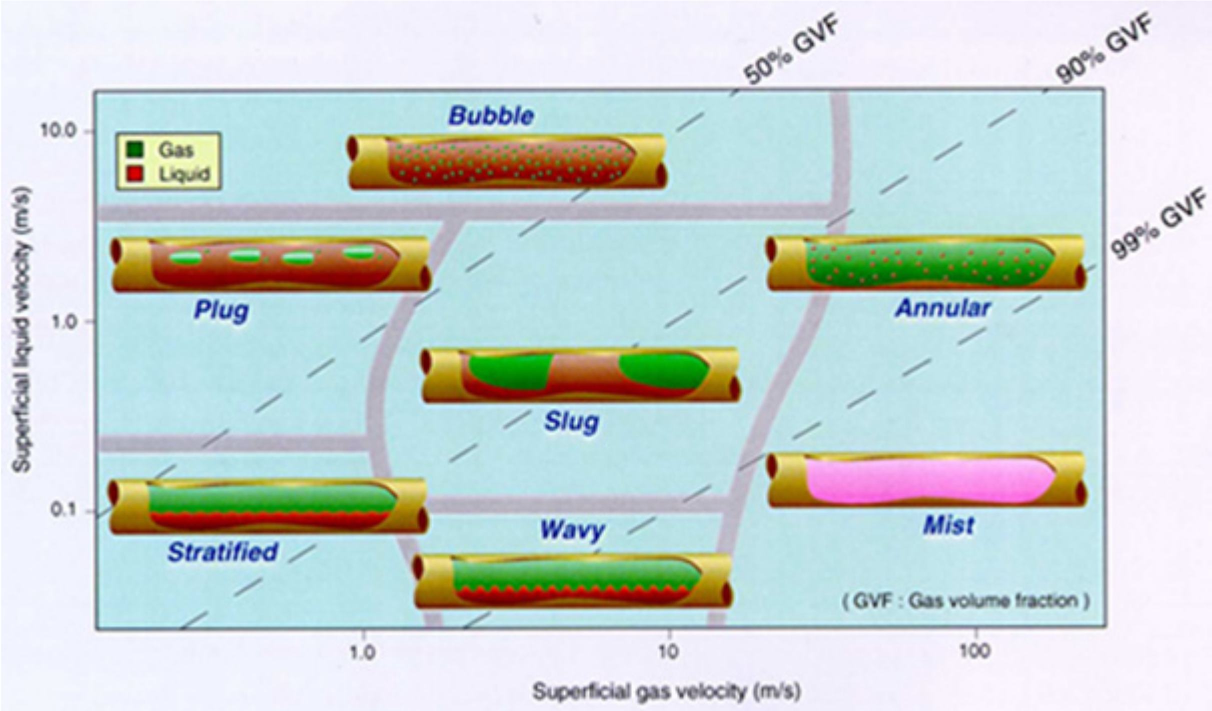


Figure 9 — Generic horizontal two-phase flowmap

There is a tendency to assume that gas is the dominant component in wet gas. This can be true in volume terms, but it is not the case in mass terms. If the multiphase compositions are displayed as mass fractions, rather than as volume fractions, a very different picture emerges. Figure 10 shows mass fractions for gas densities at the measuring point of 10 kg/m^3, 50 kg/m^3 and 200 kg/m^3 [corresponding very roughly to 1 MPa (10 bar), 5 MPa (50 bar) and 20 MPa (200 bar)], oil density of 600 kg/m^3, (corresponding to a very light condensate) and water density of 1 050 kg/m^3 (corresponding to very saline produced water). At a low gas density of 10 kg/m^3, a 10 % oil volume fraction corresponds to about an 85 % oil mass fraction. At medium pressures, with a gas density of 50 kg/m^3, it corresponds to about a 55 % oil mass fraction and at high pressures, with gas density of 200 kg/m^3, it corresponds to some 25 %.

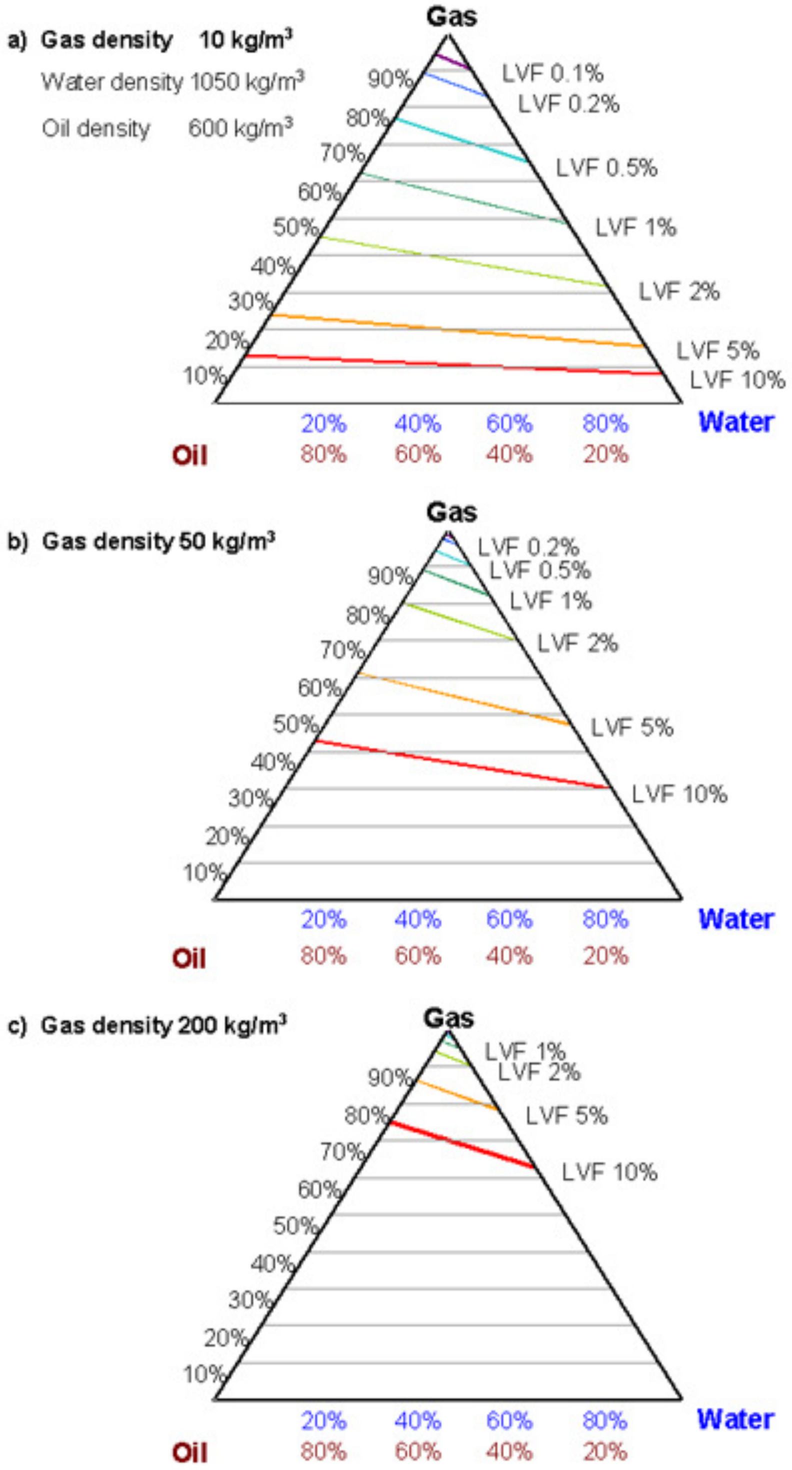


Figure 10 — Multiphase fraction triangles showing liquid volume fraction lines at three gas densities pressures

Since the measurement of wet-gas has a greater uncertainty than that of treated (dry) gas, those parties that have an interest, e.g. joint operators and government authorities, shall approve the design and construction of a wet-gas measurement station.

In the ultimately reallocated production figures resulting from the transportation system allocation procedure, the maximum allowable uncertainty shall amount to approximately 1 %.

The maximum allowable uncertainty of the wet-gas measurement installation shall always be determined in consultation with the metering expert(s) and the hydrocarbon accounting department responsible for the development and execution of the transportation system allocation procedure.

In practice, the allowable total uncertainty of the wet-gas measurement installation, including the uncertainty in the liquid-gas ratio (LGR) factor, is between approximately 2 % and 3 %. An assessment of the suitability of available gas-flow metering methods is as follows.

a) Currently, the following gas-flow metering methods are used most often for wet-gas flow rate measurement:

   1) differential pressure devices:

      — Venturi meter,

      — cone meter;

   2) dedicated wet gas meters:

      — combination of Δp devices with different sensitivities to liquid content. These are not discussed further in this report;

   3) Multiphase flow meters:

      — some have an extended range into the wet-gas flow region.

b) Currently the following gas flow methods are not considered suitable for wet gas flow rate measurement:

   1) orifice meter:

      — Although still the most-used devices for measuring single-phase gas (e.g. from a separator), orifice meters are not recommended for measurement of wet gas. The main reason is that liquids can build up on the upstream side of the plate causing the meter to over-measure. Drain holes are often drilled through the plate, but this is not recommended as it increases the measurement uncertainty and the hole can be blocked by debris in the line.

   2) ultrasonic meter:

      — At present, ultrasonic meters are not suitable for measuring gas above 0,5 % LVF as the units produce unstable readings. Work is, however, underway to develop ultrasonic meters for wet gas above current norms.

Flow conditioners, devices that alter the flow to a desired flow profile for metering, are often used in single-phase gas metering and may be considered in wet gas metering. However, careful consideration is required if flow conditioning is applied to two-phase flow conditions. Such devices are discussed in ISO 5167-1. It is generally true that what is good for single-phase flow measurement is good for two-phase flow or multiphase flow measurement. In practice, it is necessary to take care that these devices do not induce sufficient pressure drop across the unit to cause any water in the flow to sublimate and for the water crystals (or “hydrates”) to block the conditioning passages, making the velocity profile worse rather than better.

It should also be noted that the effectiveness of these devices is reduced by placing them too close to the nearest upstream obstruction as the swirl and local velocities of the flow are often too much for the conditioner to cope with.

5.2.3.1 Differential pressure devices

5.2.3.1.1 General

As primary measurement elements, both the Venturi and cone are used with differential pressure, pressure and temperature transmitters for the determination of mass and standard volume, expressed in standard cubic metres, produced.

5.2.3.1.2 Manufacture and installation

The manufacture and installation of Venturi meters and their associated transducers should generally follow the requirements of ISO 5167 (all parts), but as ISO 5167 (all parts) is intended for measurement of dry gas, some deviations from the requirements of ISO 5167 (all parts) are necessary. In particular, it is necessary to take care to prevent liquid retention in the impulse lines. Piezometer rings are not recommended and, for horizontal Venturis, it is necessary that the tapping points be on the top half of the Venturi. The diameter of the tapping points shall be at least 10 mm. Furthermore, all parts of the impulse lines and the transmitters that come into contact with the process gas shall be kept at least at the temperature of the process gas by adequate insulation and/or trace heating to prevent condensation in the impulse lines. The temperature measurement shall be made in such a manner that it does not influence the straight lengths before and after the Venturi. If a surface-mounted temperature measurement device is used, the whole Venturi shall be suitably insulated to ensure that the indicated temperature represents the fluid temperature. This is particularly relevant for subsea wet-gas meters. The Venturi can measure gas with a liquid content up to 5 % to 10 % by volume using modified Venturi algorithms, e.g. Murdock, Chisholm and de Leeuw.

It is recommended that further advice be sought from a vendor or consultant experienced in wet-gas metering.

Currently, cone meters are not as widely used as Venturis for wet-gas metering and, consequently, experience in their use is not so widespread in the metering community. Accordingly, installation of cone meters should follow the manufacturer's guidelines. Currently, the cone can measure gas with a liquid volume content up to 5 % by volume using algorithms developed by the manufacturer. Generally, shorter installation footprints are possible with this technology.

5.2.3.1.3 Gas and liquid properties

The gas and liquid properties used in calculations shall be based on the best estimates of the composition of the gaseous and liquid fractions at the measurement point at the operating temperature and pressure. In practice, this means taking samples of equilibrium gas and equilibrium liquid from points close to the measurement point. To obtain the best estimate of full-stream composition, it is necessary to determine the flow rates of gas and liquid at the measurement point. These may be measured at intervals elsewhere in the system, e.g. at a separator, probably at pressures and temperatures different from those at the wet-gas measurement point. This requires making corrections for changes in composition to adjust the liquid and gas flow rates to those at the wet-gas measurement point.

5.2.3.1.4 Wet-gas correction

The liquid-gas ratio (LGR) strongly influences the apparent reading of a differential pressure meter. During the calculation of the gas flow rate, the flow computer shall take account of the deviation introduced by the LGR. A correction shall be made for this deviation with an approved correction algorithm, preferably in the flow computer, based on the raw data from the installation. This correction procedure may be implemented in the hydrocarbon accounting computer system.

Wet-gas tests performed by Shell on Venturis have been reported on in the open literature. These tests showed that the deviation as determined by Chisholm or Murdock on orifice plates are also applicable for Venturi meters.

The dry-gas flow rate, Q_g, can be determined from the wet-gas measurements according to Murdock as given in Equation (2) or according to Chisholm as given in Equation (3):

$$Q_\mathrm{g} = \frac{Q_\mathrm{tp}}{1 + 1{,}26X} \tag{2}$$

where Q_tp is the gas flow rate calculated using the two-phase pressure drop.

$$Q_\mathrm{g} = \frac{Q_\mathrm{tp}}{\sqrt{1 + CX + CX^2}} \tag{3}$$

where

$$C = \left(\frac{\rho_\mathrm{l}}{\rho_\mathrm{g}}\right)^{0{,}25} + \left(\frac{\rho_\mathrm{g}}{\rho_\mathrm{l}}\right)^{0{,}25} \qquad \text{(for } X < 1\text{)} \tag{4}$$

X is the Lockhart Martinelli parameter, as given in Equation (5):

$$X = \frac{Q_\mathrm{l}}{Q_\mathrm{g}} . \sqrt{\frac{\rho_\mathrm{l}}{\rho_\mathrm{g}}} \tag{5}$$

where

ρ_g is the density of the gas;

ρ_l is the density of the liquid.

A simpler expression, as given in Equation (6), is sometimes used:

$$Q_\mathrm{g} = Q_\mathrm{tp} \times \frac{2\,000}{2\,000 + R_\mathrm{LG}} \tag{6}$$

where R_LG is the liquid-gas ratio, expressed in cubic metres of liquid per 10^6 normal cubic metres of gas, as given in Equation (7):

$$R_\mathrm{LG} = \frac{Q_\mathrm{l}}{Q_\mathrm{g}} \times 10^6 \quad (\mathrm{m}^3 \text{ liquid per } 10^6 \text{ normal } \mathrm{m}^3 \text{ gas}) \tag{7}$$

Note that these expressions are accurate and useful only for small liquid/gas ratios. They may be implemented on older wet gas installations, but their use is not recommended for new installations. In particular, the Murdock formula does not incorporate a pressure dependence and, at larger liquid/gas ratios, the pressure dependence of the Chisholm formula does not match the experimental data.

A more recent equation for the determination of the dry gas volume has been developed by Shell (De Leeuw), as given in Equation (8), which was published at the Multiphase '97 Conference in Cannes. This equation has been verified against an extensive database of experimental data to establish its validity. Further work carried out at NEL (Steven et al.) has shown a dependence on the β-ratio of the Venturi.

$$Q_{\mathrm{g}} = \frac{Q_{\mathrm{tp}}}{\sqrt{1 + CX + CX^2}} \tag{8}$$

where

$$C = \left(\frac{\rho_{\mathrm{l}}}{\rho_{\mathrm{g}}}\right)^n + \left(\frac{\rho_{\mathrm{g}}}{\rho_{\mathrm{l}}}\right)^n \tag{9}$$

$$n = 0{,}606(1 - e^{-0{,}746 F_{\mathrm{rg}}}) \qquad \text{(for } F_{\mathrm{rg}} \geqslant 1{,}5\text{)} \tag{10}$$

$$F_{\mathrm{rg}} = \frac{v_{\mathrm{sg}}}{\sqrt{gD}} . \sqrt{\frac{\rho_{\mathrm{g}}}{\rho_{\mathrm{l}} - \rho_{\mathrm{g}}}} \tag{11}$$

g is the gravitational constant;

D is the internal pipe diameter;

V_{sg} is the superficial gas velocity.

A cone-meter manufacturer has established similar correction equations, which were published at the North Sea Flow Measurement Workshop in 2004.

5.2.3.1.5 Limitations

It is recommended that the rangeability of the measurement installation in terms of dry gas be determined as for dry-gas flow measurement. Preferably, a smart digital differential-pressure sensor should be applied, allowing a turn-down of 10:1 in gas measurement, or a maximum of two differential pressure transmitters ranged high and low.

The maximum value for the LGR corresponds to a Lockhart-Martinelli parameter of 0,3, or approximately 10 % free liquid by volume. The uncertainty of the LGR value shall be less than 10 %.

5.2.3.1.6 Uncertainty calculation

The uncertainty calculation of the measurement installation shall be based on the method described in ISO 5167-1 and ISO 5168.

An extra factor shall be introduced for the uncertainty in the LGR and the uncertainty of the known systematic measurement error according to the correction formula applied. This is illustrated below using a Venturi meter and the Chisholm formula.

The uncertainty, $\frac{\delta Q_{\mathrm{v}}}{Q_{\mathrm{v}}}$, for a wet-gas measurement by Venturi (according to Chisholm, including LGR and increased by 0,5 % if the minimum straight lengths are in accordance with ISO 5167-1) is calculated as given in Equation (12):

$$\frac{\delta Q_{\mathrm{v}}}{Q_{\mathrm{v}}} = \sqrt{\left(\frac{\delta Q_{\mathrm{venturi}}}{Q_{\mathrm{venturi}}}\right)^2 + \left[\frac{3}{2Y} \times \frac{\delta (Q_{\mathrm{l}}/Q_{\mathrm{g}})}{(Q_{\mathrm{l}}/Q_{\mathrm{g}})}\right]^2} \tag{12}$$

where

$\frac{\delta Q_{\text{venturi}}}{Q_{\text{venturi}}}$ is the uncertainty of a Venturi measurement calculated in accordance with ISO 5167-1 and ISO 5168;

$\frac{\delta\left(Q_{\text{l}}/Q_{\text{g}}\right)}{\left(Q_{\text{l}}/Q_{\text{g}}\right)}$ is the uncertainty of the LGR, set at 10 %.

Reference can be made to 4.2.1 for other factors not mentioned.

A similar approach should be used for the cone meters. The manufacturer should be consulted if further advice is required.

5.2.3.1.7 Sample collection points

For the collection of gas samples, a sample point including a probe shall be installed outside the straight lengths of the wet-gas meter.

Where the LGR is determined by means of a tracer technique, sample injection and collection points shall be made available.

The injection point shall be located in the bottom of the flow line at a sufficient distance upstream of the primary element to allow adequate mixing of the tracer with the liquid phase.

The collection point shall be located in the bottom of the flow line downstream of the primary element.

Where the wet-gas meter can be put in series with a test separator, gas and liquid flow rates may be measured and samples may be taken at the test separator.

Gas and liquid properties may be derived by means of a flash calculation; from these data, it is possible to check whether the wet gas meter is functioning correctly.

5.2.3.1.8 Calibration and maintenance

For effective maintenance of wet-gas metering facilities, it is essential to provide suitable calibration facilities such as

- test connections for the supply and/or measuring of pressure and differential pressure, e.g. from a deadweight tester;
- read-out of the analogue signals of pressure, differential pressure and temperature transmitters in milliamperes or millivolts;
- protection against climatic influences (e.g. rain) for the measurement and test equipment;
- measurement/test connections in auxiliary cabinets for monitoring data transmission to the flow computers.

5.2.4 Single-phase liquid

The relevant liquids for this subclause are condensate and water. These can be measured by various recognized devices (see Figure 8) and for some devices International Standards or recommended practices documents are available. Condensate from separators can contain some water due to the separation process, but normally condensate and water separate very easily. As the condensate at the exit of the separator is at gas equilibrium pressure (bubble point), any subsequent reduction in pressure causes gas breakout. This gas breakout can degrade the performance of single-phase measurement devices. To minimize this affect, the condensate should be measured with as much head as is physically practical. This requires adequate height between the measurement point and the minimum expected separator gas-liquid level. Note that for a condensate with density 600 kg/m^3, a 5 m head corresponds to a pressure above bubble point of only about 30 kPa (0,3 bar).

The pipe-work internal diameter should also be kept as large as possible and the number of bends kept as low as possible to minimize the pressure drop. The calculated pressure head at the measuring device shall be enough to prevent gas breakout at the measurement point due to a pressure drop across the device at maximum flow.

Condensate density, temperature and pressure should be measured as close to the primary measuring device as possible.

Gas breakout is not as critical for measurement of the water stream as for the condensate stream, but again it is recommended that the measurement device be placed sufficiently below the minimum expected separator liquid level and that a full-bore measurement device, such as an electromagnetic or ultrasonic flow meter, should be used. The water flow measurement from a single separator can have a very large turn-down ratio and multiple meter runs may be required under these conditions. The effect of temperature and pressure on the water measurements is about half that for condensate and it is normally not considered necessary to provide a separate stream temperature or pressure measurement.

The following liquid flow metering methods are suitable for metering condensate or water:

- turbine meters;
- vortex meters;
- Coriolis meters;
- tank-level measurement.

These methods are well described in industry standards and so are not discussed in detail in this Technical Report. It is necessary to take care to comply with the requirements for low-viscosity liquids given in these standards.

Positive-displacement meters should not be used for metering either condensate or water as the viscosity of both fluids at operating temperatures is well below the 5 cSt usually considered as an acceptable minimum viscosity.

5.2.5 Equilibrium liquid (separated liquid at bubble point)

Equilibrium liquid, i.e. liquid from a separator at its bubble point, in principle contains only liquid. However, small amounts of gas can break out in situations where a pressure drop is encountered (e.g. valves or metering equipment). This condition occurs when the head pressure has been sufficiently reduced or the temperature increased to cause gassing-off or boiling of the fluid. This gas breakout usually gives rise to measurement errors if single-phase liquid meters are used. Measurements of these fluids require care and attention in view of the pipe geometry and line sizes to ensure that the liquid is below its bubble point at the measurement point. Meter choice is of prime importance and pressure drop should be minimized to prevent meter performance degradation.

5.2.6 Gassy liquids (low-GVF, multiphase fluids)

Gassy liquids are liquids that contain small amounts of gas. Generally, the GVF of these fluids is in the range of 0 % to approximately 25 %. Single-phase meter behaviour is not predictable and damage to certain meter types can occur.

6 Quality measurement

6.1 Sampling and analysis

Sampling and analyses of process fluids is essential for the allocation process. Samples are taken for the following analyses in the allocation process:

- quality analyses, to obtain the energy content of the hydrocarbons for sales purposes and properties for volume or mass measurements;
- evaluation analyses, to obtain the economic value of the hydrocarbons;
- PVT analyses, to establish and monitor the behaviour of the producing reservoirs.

The analytical results depend strongly on the method of sampling and on the process conditions at which the sample is taken. Furthermore, one should always be aware that a (spot) sample is only a snapshot and that samples might not always be representative for a continuous process.

For specific requirements related to gas sampling, reference is made to ISO 10715.

6.1.1 Dry gas (treated gas)

The sampling of dry gas, as it is a single phase, allows a highly representative sample to be obtained. To ensure that the sample is representative, it is necessary to take some precautions as part of the sampling exercise.

Before a sample is obtained, it is necessary to flush the sampling system with process gas from the pipeline under process operating conditions in order to remove contamination and equalize the temperature of the sampling system. It is necessary to take care to ensure that no condensation of the sample gas occurs due to the length of the sampling lines or from a drop in pressure or temperature. An adequate flushing time is at least ten times the residence time of the process gas in the sampling system.

For spot sampling of dry gas, the sample can be collected by the following methods:

- flow through method;
- pressurize-depressurize method;
- vacuum method.

The vacuum method gives better results when the gas is not guaranteed dry and is, therefore, the method recommended.

The use of a sample probe in accordance with ISO 10715 is recommended.

Because heavy components are, in general, not present in dry gas, an analysis of the sample in accordance with ISO 6974 (all parts) is sufficient.

6.1.2 Equilibrium gas (separated gas at dew point)

The sampling of equilibrium gas that is on the verge of condensing is a much more critical exercise. Minor temperature or pressure fluctuations can cause condensation and invalidate the representativeness of the sample. To enhance the representativeness of the sample, some precautions shall be taken during the sampling exercise.

For spot sampling, the vacuum method shall be the preferred method as this method is the least sensitive to the undesired accumulation of condensate in flow lines and the sample bottle. An analysis in accordance with ISO 6975 is recommended because of the possible presence of heavy components.

6.1.3 Wet gas (two- or three-phase)

Flow profiles in a pipeline can be laminar or turbulent. Sampling of wet gas in a laminar, multiphase flow shall be avoided as there is little chance of sampling the phases proportionally. Even samples taken from a turbulent flow normally do not yield representative proportions of the phases in the pipeline.

Samples from wet-gas flows can be used only to detect the presence of a particular component in one or more phases (e.g. H_2S). It is not recommended to use this sample to determine mole fractions of the full range of components.

Only those components that are guaranteed to be in either the gaseous phase or the liquid phase under the sampling conditions can be determined with some accuracy.

The recombined result, using the liquid-gas ratio, normally represents a compositional analysis with a low accuracy, especially for those components that are in equilibrium between the gas and liquid phases under the sampling conditions. For many cases, this is the component range C_5 to C_{10}. As a consequence, manual or continuous sampling can be reliably performed only for a limited range of the composition or one particular component in one phase.

A representative range of all components of the full fluid flow can be determined only by sampling the individual phases after separation and recombining the analyses in proportion to the respective flows. The recombination can be based on the individual flows from separator measurements.

When a separator is not available, a recombination analysis can be made on the basis of a flow determination by means of the tracer-dilution technique.

The use of a sample probe is strongly recommended; for sample recovery, the probe shall be positioned as isokinetically as possible relative to the required phase in the flow. This improves the representativeness of the sample.

Nevertheless, to keep costs down, some allocation procedures may make use of wet-gas sampling. The consequence is a higher uncertainty of the overall allocation process, mainly caused by the samples not properly representing the entire flow. This can only be accepted if contracting parties are fully aware of the implications.

6.1.4 Single-phase liquids

The method used for sampling condensate is highly dependent on its purpose. If the full compositional data of the condensate is required for PVT analysis, reallocation purposes or LPG composition, it is necessary that the sample always be taken at process operating conditions. This requires, in most cases, a pressurized sample. The preferred method of taking a pressurized sample is with a bottle with an expansion compartment.

To obtain a sample, it is necessary that the sampling system first be flushed with condensate from the pipeline under process operating conditions, in order to remove contaminants, and then be filled with the representative fluid. It is necessary that the flushing and/or filling of the bottle or bombe be executed slowly and with great care to prevent evaporation of the sample in the sample system, which can influence the composition of the condensate sample.

In some cases, condensate samples can also be taken at atmospheric pressure. This means that the sample is brought to atmospheric conditions from whatever the process operating conditions were. Consequently, if the process temperature and/or pressure are elevated, the composition of the condensate can change due to evaporation of the lighter components.

Accordingly, the sample may be used for a full compositional analysis only if the process operating conditions are at atmospheric conditions.

This method, however, is applicable if there is no requirement for full compositional data for the condensate at elevated operating conditions (e.g. for cloud point or pour point determination).

6.1.5 Equilibrium liquids (separated liquid at bubble point)

For equilibrium liquids, the sampling techniques for single-phase liquids are applicable. It is necessary to take care to flush and fill bottles slowly so that free gas is not generated.

6.1.6 Gassy liquids (two or three phases)

For gassy liquids, the sampling technique mentioned under single-phase liquids is applicable. However, the use of a properly positioned sample probe is of great importance. In addition, the representativeness of the sample can easily be affected by small amounts of gas. This causes a higher uncertainty in the analytical results.

6.1.7 Multiphase fluid

Samples from multiphase flow lines suffer from the same non-representativeness as wet-gas samples. All aspects mentioned under wet-gas sampling are largely valid for multiphase sampling. Only those components that are guaranteed in either the gaseous phase or the liquid phase under the sampling conditions can be determined with reasonable accuracy.

Because of the lack of representativeness of the sample, the accuracy of the analytical results can be poor; it is, therefore, not recommended to use the results of multiphase sampling in the allocation process.

6.2 Analysis

Sample analysis can take place only on one phase at a time; therefore, the phases shall be fully separated. For continuous sampling, this requires a sampling conditioning system designed to pass only the required phase or phases.

When dealing with spot samples, the phases (liquid and gas) shall be carefully pre-conditioned, separated (in the sample bottle) and analysed separately. Then the two phases can be combined on a mass-weighted basis to create a complete analysis of the sample.

The range of components for analysis shall be determined in advance and depends on the purpose of the analysis. In general, an analysis in accordance with ISO 6974 is intended for the range of dry gas components suitable for Heating Value calculations. An analysis in accordance with ISO 6975 provides a much wider range of components and is normally required for process simulations or compressibility calculations.

6.3 Uncertainties

Many aspects, both in the sampling and the analysis, affect the uncertainty of a fluid component analysis. The most significant aspects that contribute to the uncertainty of the sampling are

a) non-representative sampling (caused by non-stable process conditions, sample-probe position and sampling method),

b) phase changes in the sample bottle (condensation, evaporation),

   NOTE It is necessary to note that gas chromatographs operate at atmospheric pressure and, thus, it is necessary to heat the sample prior to pressure reduction. Also, it is necessary that the gas remain above the dew point at the operating temperature of the gas chromatograph oven. (This limits its use to wet-gas systems.)

c) the stability and linearity of the chromatograph,

d) the quality of calibration gases,

e) pre-treatment of the sample.

Of these five major effects on the overall uncertainty, the last four are reasonably controllable. By taking appropriate care, the sum of the effects of b), c), d) and e) should make a very small contribution to the uncertainty of the final analysis. On the other hand, the effect of non-representative sampling, a), is difficult to control. To limit the overall uncertainty, attention should focus on the representativeness of the sample and the contribution to the uncertainty by individual components.

Attention should be paid to the uncertainty calculation as described in the ISO 6976. The uncertainty is normally calculated for the heating value or molecular mass of the analysis. Individual components can have a much higher uncertainty.

6.4 Other

6.4.1 Geochemical fingerprinting

Geochemical fingerprinting is a technique that may be used for product allocation between two or more contributing fields whose product can be commingled for production and transportation. It has been used on a UK continental shelf development in the northern North Sea. It was developed mainly for oil fields but is, in principle, also applicable to gas condensate fields

This technique uses a multi-dimensional gas chromatographic analysis to determine quantitatively the concentration of the aromatic compounds within the C_8 to C_{10} range of a sample of the hydrocarbon reservoir fluid. The relative proportions of the aromatic components in this range are usually unique to a reservoir, giving the reservoir fluid a unique signature.

The technique determines the relative amounts of these components in commingled production from different fields by analysing a representative sample. The results of this analysis are compared with a previously prepared mixing model that is generated from the analysis of samples from the individual contributing fields. The resultant component ratios, plus a flow-quantity measurement of the combined product stream, allow the determination of the quantity contributed from each field by prorating the total flow according to the geochemical component ratios.

For the method to be viable, it is necessary that aromatic compounds in the C_8 to C_{10} range be contained in the composition of the product from each of the contributing fields. It is also necessary that there be sufficient difference in the relative amounts of some of the components of the contributing fields to enable the field product ratios to be established, i.e. if the geochemical signatures for two contributing fields are very similar then the method does not work.

Figure 11 describes the process of geochemical fingerprinting, from initial method application validation, through to operational implementation and to periodic verification plus calibration. Although it refers to oilfields, the method applies to wet gas fields providing the qualifying criteria are satisfied.

6.4.2 Near-infrared methods

Determination of water in gas/condensate streams is often important to prevent corrosion or hydrate formation in pipelines. Increasingly, near-infra-red methods are being used or developed for these applications. Water determination by infra-red absorption is difficult because the absorption peaks of water and major hydrocarbon components overlap. Photo-acoustics, in which the relative absorption by water compared to hydrocarbons is greatly enhanced, and the absorbed infra-red radiation is converted to ultrasound for detection, can potentially provide better instruments for this application.

6.4.3 PVT packages

A variety of PVT packages are available for determining the properties of gas condensate streams from a compositional analysis. These packages are discussed in greater depth in Clause 7.

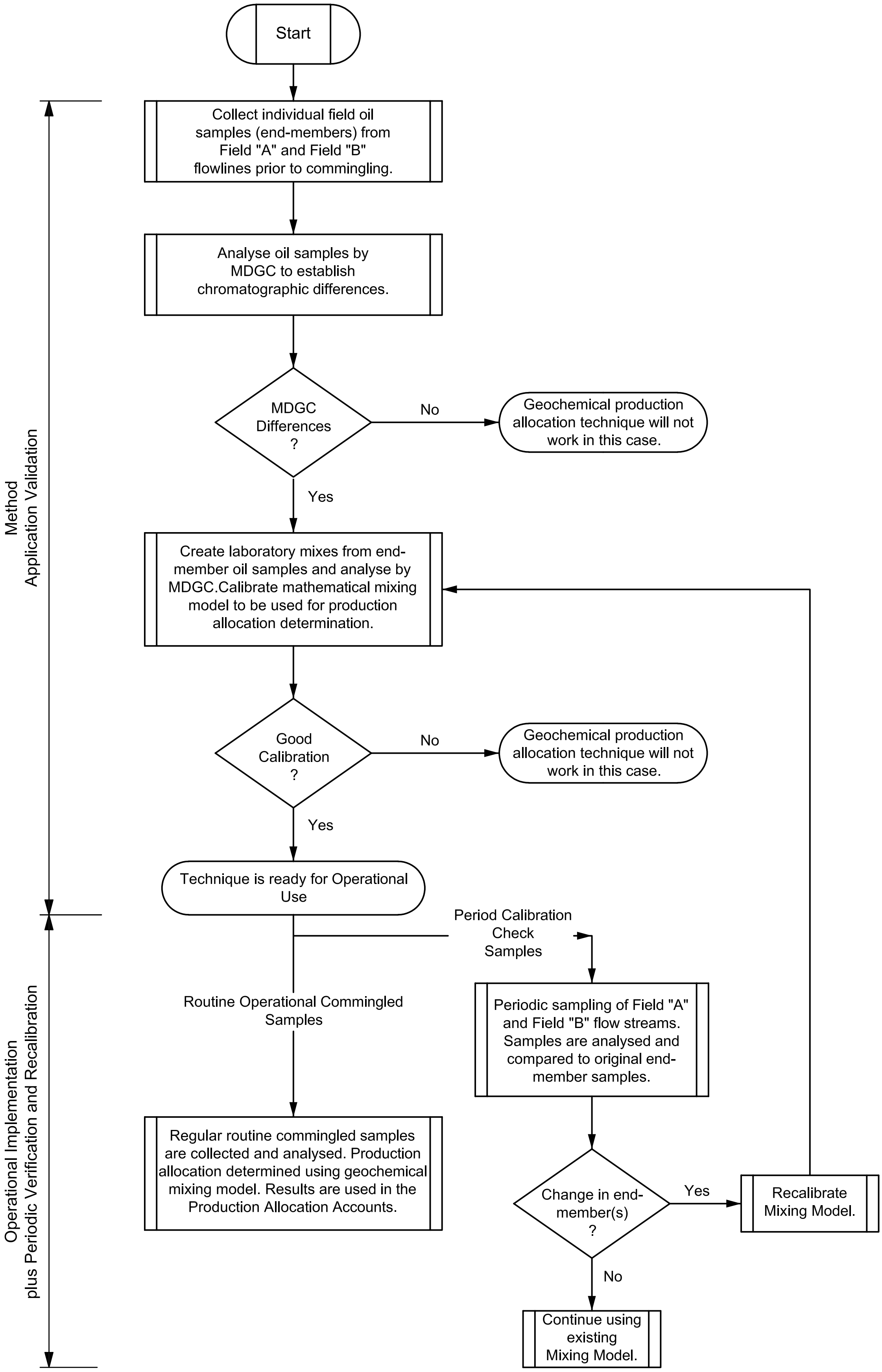


Figure 11 — Process flow chart for geochemical production allocation

6.4.4 Tracers

Tracer techniques for determining the flow rates of condensate and water in wet gas streams were developed by Shell and have been licensed to two service companies. In principle, a tracer can be used to determine the gas flow, but practical gas tracers have not yet been found and implemented.

Measurement of liquid by tracers is straightforward in principle, but requires much attention to detail. Suitable tracers have been found that dissolve almost entirely either in condensate or in water, with little cross contamination. The condensate and water tracers of known concentration are injected under pressure upstream of a suitable mixing element, say a partially closed valve or a long length of flow line. Samples of condensate and water are withdrawn at a suitable point downstream, ensuring that liquid cannot settle around the sampling point. The tracers are injected at a known flow rate, chosen to match the expected flow rate of the water or condensate and give a suitable concentration for analysis in the sample. Because the tracers are conservative, the product of concentration and flow rate is constant. The injection concentration and flow rate are known; the sample gives the tracer concentration in the water or in the condensate in the flow line, so that the flow rate of water or condensate in the flow line can be determined easily.

It is necessary to take care when sampling such that the time to take the sample is much shorter than the period of variation in the liquid flow rate. High concentrations of tracer in the sample correspond to low liquid flow rates and low concentrations of tracer to high flow rates. A sample taken over a period with large variation in liquid flow rates underestimates the liquid flow rate.

7 Data processing

Allocation of gas and condensate consists in determining the quantities of commingled output products for attribution to different users of the common gas/condensate treatment and transportation system. To obtain the final allocated data from primary measurements, it is necessary to implement different data-processing steps. This clause describes some data-processing routines applicable to gas and condensate allocation. It includes

- calculations at the measurement point;
- process simulation;
- balancing and reconciliation;
- inventory calculations.

7.1 Calculation at the measurement point

7.1.1 Gas and liquid properties

7.1.1.1 General

The knowledge of thermodynamic properties (e.g. composition, density, phase fractions), flow characteristics (e.g. viscosity, phase velocity) and flow patterns (e.g. mist, annular, annular–mist, mist/film) are required to determine flow rates from primary measurements (e.g. velocity, pressure drop, attenuation, frequency, absorption).

In 7.1, The calculation method is addressed for use when fluid properties and/or composition

- change with pressure and temperature,
- are not measured or cannot be measured directly.

At the conditions prevailing at the measurement point, streams can be stabilized (gas phase or liquid phase) or non-stabilized either as one phase (gas or liquid) or as two phases (gas and liquid).

7.1.1.2 Stabilized fluids

For stabilized gases, calculation routines to derive density and compressibility factors are based on existing standards such as ISO 6976 using composition, pressure and temperature to derive density compressibility factors.

For liquid, similar standards from API or ISO are used.

7.1.1.3 Flash calculations for non-stabilized and wet gas flows

For non-stabilized fluids including two-phase flows, such as wet gas, it is necessary that gas and liquid composition and properties be determined indirectly by flash calculations.

Flash calculations can be performed on-line or off-line using specific PVT software or a process simulator. If flash calculations are performed off-line and are complex, flash interpolation tables or equations can be generated and downloaded in flow computers or in any digital control system.

As an example, such tables can be two-dimensional tables containing values of density, liquid fractions for a specific well or field composition at specific values of temperature and pressure. For each composition, a flash table or equation can be generated.

The flash-calculation specification requires flow composition based on components and pseudo-components previously defined with their respective properties (molecular weight, specific gravity and boiling point, for instance) based on laboratory analysis and properties tuning.

These calculations also require selection of an appropriate equation of state and the appropriate flashing conditions.

7.1.1.4 Flow rates calculations

If required in the allocation, gas and liquid flow rates measured at line conditions can be converted to standard conditions (e.g. 15 °C; 101,325 kPa) by using similar flash calculation and simulating a single flash or a multistage flash.

7.2 Balancing and reconciliation

7.2.1 General

On each system (e.g. production, pipeline, terminal) where inputs, $\sum x_{\mathrm{IN}}$, and outputs are measured, adjustments and calculations are made to balance the inputs, $\sum x_{\mathrm{IN}}$, with the outputs, $\sum x_{\mathrm{OUT}}$, and/or to calculate outputs from inputs mainly to satisfy material conservation, as given in Equation (13):

$$\sum x_{\mathrm{IN}} = \sum x_{\mathrm{OUT}} + \Delta s \qquad (13)$$

where Δs is the change in stock, as given by Equation (14):

$$\Delta s = s_{\mathrm{t2}} - s_{\mathrm{t1}} \qquad (14)$$

where

s_{t2} is the stock at time, t_2;

s_{t1} is the stock at time, t_1;

$t_2 > t_1$.

It is strongly recommended that the material balance be carried out on a mass basis or a component mass basis over a representative period of time. Attempts to carry out the material balance on a volume basis generally lead to divergence over time.

7.2.2 Balancing by proration

Simple balancing can be achieved by apportioning outputs among inputs on a proportional basis (pro rata). This is done in cases where output measurements are more accurate than inputs. Application of this method assumes similar uncertainty on all inputs.

The material balance and conservation of mass are verified by simple application of the method.

EXAMPLE

Field A	100 000
Field B	140 000
Fuel gas	− 1 000
Net gas	239 000
Export gas	250 000
Reconciliation factor	250/239
Adjusted field A	100 000 × 250/239
Adjusted field A	140 000 × 250/239
Adjusted fuel	− 1 000 × 250/239

7.2.3 Reconciliation

It is possible to assign imbalances of systems to each meter based on its accuracy or uncertainty.

Reconciliation calculations based on statistical methods can be applied to adjust measurements to satisfy the mass balance equations in complete systems.

7.3 Process simulation

Allocation can be based on the true thermodynamics of the process (component-by-component allocation) or on the use of a mathematical model of the process to calculate the production from wells and fields when they are processed separately or all together.

EXAMPLE The simulation of a production system can give the component mass flow in the export gas for each input hydrocarbon, i, for a given field, j.

The mass, $\left(m_{\mathrm{E}}^{j}\right)_{i}^{\mathrm{a}}$, of component i in the export gas allocated to field j is proportional to the mass, $\left(m_{\mathrm{E}}^{j}\right)_{i}^{\mathrm{sim}}$, of component i in the export gas, and can be calculated with a simulator such as that given in Equation (15):

$$\left(m_{\mathrm{E}}^{j}\right)_{i}^{\mathrm{a}} = \frac{\left(m_{\mathrm{E}}^{j}\right)_{i}^{\mathrm{sim}}}{\sum\limits_{j}\left(m_{\mathrm{E}}^{j}\right)_{i}^{\mathrm{sim}}} \times \left(m_{\mathrm{E}}\right)_{i} \qquad (15)$$

The total mass, $\left(m_{\mathrm{E}}^{j}\right)^{\mathrm{a}}$, of export gas allocated to field j is as given in Equation (16):

$$\left(m_{\mathrm{E}}^{j}\right)^{\mathrm{a}} = \sum_{i} \left(m_{\mathrm{E}}^{j}\right)_{i}^{\mathrm{a}} \tag{16}$$

When there are many producing fields, it is possible to simulate the production from one of the fields by simulating the treatment of the mixture from all fields followed by that of the mixture from all the fields, less the field in question. The resulting difference gives the theoretical quantities of the products that can be allocated to the field in question.

The following should be noted.

a) The mass of the product obtained by the treatment scheme can be very different from the sum of the masses obtained by the treatment of the production of each field individually.

b) The simulator includes process parameters (pressure, temperature) that do not necessarily remain constant over the entire allocation period.

c) The results are highly dependent on the compositions of simulated streams.

d) To be applicable, it is necessary that the simulation model give results consistent with measured data.

7.4 Line packing and stock change

When the allocation period is quite long, the inventory of the terminal at the end of the allocation period represents only a small quantity relative to the total mass shipped during that period. Consequently, the quantity received by the terminal during the allocation period is very close to the quantity exported. The inventory can, therefore, be neglected and the properties of the various products formed at the terminal can be calculated by simple proportionality equations between production at the terminal and that at the production centre over the same period.

However, when the allocation periods are very short (for example, one day for gas allocation), the production at the terminal can be representative of only part of the inventory quantity. If the quality of the export mixture varies significantly (as when the relative production of the fields varies), the quality of the blend delivered to the terminal during the allocation period can be significantly different from that of the blend exported during the same period. Consequently, the terminal product yields no longer correspond to the productions measured at the production centre. It is necessary that the calculation of the quantities of products allocated to each field include a provision for this inventory variation.

This is discussed further for gas in the remainder of this subclause. A similar discussion holds for condensate.

Each field produces an “initial inventory” (at field production start-up), which is the sum of the “dead stock” and the “capacity buffer”.

The “dead stock” is defined under mutual agreement but it usually corresponds to the gas mass contained in the gas pipeline at a mean pressure equal to the minimum terminal operating pressure. This mass is allocated to all the fields using the system, generally proportionally to the anticipated yearly production, of annual contracted quantity (ACQ).

The “capacity buffer” is the amount of stock above the “dead stock” to get a differential pressure across the pipeline adequate to achieve the total flow rate. This quantity varies with the daily nomination.

The “line pack” is the mass of gas that is in excess of the dead stock and capacity buffer when the gas pipeline flow rate is equal to the overall nomination and the gas pipeline output pressure is equal to the market gas network inlet pressure plus the pressure loss in the terminal. Provided it is permitted by the pipeline operator, the system users may be allowed to build up a line pack buffer to secure the supply in the event of a platform trip. Line pack can be allocated in a number of ways, i.e. “who put it in gets it”, by reserved capacity or on a first-come first-served basis.

Each field’s inventory (now the sum of dead stock, capacity buffer and line pack) is recalculated at the end of every allocation period to give the closing stock. The inventory imbalance between the beginning and the end of the allocation period is the difference between the closing stock of the current period and the closing stock of the previous period. This variation is calculated in terms of quantity and quality for each field to give the stock ownership.

Each field’s inventory is recalculated at the end of every allocation period to give the closing stock. The inventory imbalance between the beginning and the end of the allocation period is the difference between the closing stock of the current period and the closing stock of the previous period. This variation is calculated in terms of quantity and quality for each field to give the stock ownership.

The inventory mass, m_I, expressed in kilograms, in the transportation pipeline can be calculated according to Equation (17):

$$m_\text{I} = V \times \rho_\text{m} \tag{17}$$

where

V is the geometric volume of the pipeline, expressed in cubic metres;

ρ_m is the mean density of the product in inventory at the end of the period, which can be calculated from the equation of state at mean pipeline temperatures and pressures over the allocation period, expressed in kilograms per cubic metre.

If a field is connected to the gas transportation network at an entry point different from that of other fields, then its production is transported only through part of the gas pipeline. It is necessary that the part of the inventory upstream of this entry point be differentiated from the downstream part. The gas inventory masses in each of the pipeline sections are calculated as before; but care is taken that the calculations include only those fields that contribute to the calculated inventory. For a subsea connection, the pressure at this point can be calculated using the conventional pressure-loss formula for pipelines. The total inventory of the fields furthest upstream in this transportation system is obviously the sum of the inventories of these fields calculated in the two sections of the gas pipeline.

8 Lift, injection and utility gas

8.1 General

Lift gas, injection gas and utility gas can be a large fraction of the gas exported from a production system. Accordingly, these gas streams should be measured to an appropriate accuracy in terms of the economic aspects discussed in Clause 3. Historically, the practice has been that these streams were measured poorly, or not at all; but this is no longer acceptable in systems where there are large transfers of gas from one party in the system to another. The practice has also been to measure and attempt to allocate these streams in terms of a standard or normal volume. As stated in 7.2, this generally leads to divergence over time in the reconciliation. With the availability of low-cost composition determining instrumentation, there is little excuse for not operating a mass component allocation on these gas streams. However, a proper analysis should always be done to compare the installed and operational costs versus the ultimate uncertainty.

8.2 Lift gas

Lift gas is used to increase the production of hydrocarbon liquids from wells and, consequently, it is important that it be metered to ensure its optimal use. Allocation of lift gas is straightforward if carried out on a mass component basis. Differential pressure devices are usually installed at the lift-gas metering points. It is necessary that pressure and temperature also be measured at these points and to measure only the gas composition, together with pressure and temperature, at a convenient point on the common supply line for the lift gas. All the information is then available for calculating the mass component flow rates at the lift-gas metering points, which can then be fed into the allocation system calculations. It should be noted that often the amount of lift gas that is circulated on a daily basis is significantly more than the daily gas production. Since the latter is calculated by subtraction, proper uncertainty analyses should be carried out to determine the uncertainty in the final gas production.

If the meters at the lift-gas metering points are volume meters, it is necessary that pressure and temperature be measured again at the lift-gas metering points, which, together with the composition from the common lift gas supply line, provide all the information necessary to calculate the mass component flow rates.

If the meters at the lift-gas metering points are mass meters, then it is not necessary to measure the pressure and temperature for allocation purposes at the lift-gas metering points. It is sufficient to combine the mass flow rates from the lift-gas metering points with the composition data from the common lift gas supply line to calculate the mass component flow rates.

It is essential to ensure that there is no liquid drop-out in the lift-gas lines through changes in pressure and temperature. Clearly, it is inefficient to produce liquid hydrocarbons and not remove them sufficiently from the lift-gas streams.

8.3 Injection gas

The allocation of injection gas is almost identical to that of lift gas. The major difference is that injection gas is usually at a higher pressure than lift gas. Gas is injected into reservoirs for several purposes (e.g. gas storage, pressure maintenance, long-term enhancement of liquid production, reduction of flaring).

Allocation of injection gas is straightforward if it is carried out on a mass component basis. If differential-pressure devices are installed at the injection-gas metering points, it is necessary that pressure and temperature also be measured at these points. It is necessary only to measure gas composition, together with pressure and temperature, at a convenient point on the common supply line for the injection gas to have all information necessary for calculating the mass component flow rates at the injection-gas metering points. These data can then be fed into the allocation system calculations. It should be noted that it can take several years before injected gas is recovered again from the reservoir.

If the meters at the injection-gas metering points are volume meters, it is necessary that pressure and temperature be measured again at the injection-gas metering points, which, together with the composition from the common injection gas supply line, provides all the information to calculate the mass component flow rates.

If the meters at the injection-gas metering points are mass meters, then it is not necessary that pressure and temperature be measured for allocation purposes at the injection gas metering points. It is sufficient to combine the mass flow rates from the injection-gas metering points with the composition data from the common injection gas supply line to calculate the mass component flow rates.

It is essential to ensure that there is no liquid drop-out in the gas injection lines through changes in pressure and temperature. Clearly, it is inefficient to produce liquid hydrocarbons and not remove them sufficiently from the injection gas streams.

8.4 Utility gas

The major difference between the utility gas and the lift or injection gas is that the latter streams are usually much smaller and it might not be deemed cost effective to meter these streams accurately. Historically, utility streams have been measured in a standard or normal volume. However, in many production systems, utility gas often comes from several sources of significantly different composition and, consequently, the composition of the utility gas can vary sufficiently to impact the overall allocation. A cost-effective allocation system is best based on mass component flow rates; utility gas measured in a standard or normal volume can lead to considerable and expensive confusion over the lifetime of the production system. With the availability of low-cost instrumentation to determine the composition, there is little excuse for not operating a mass component allocation on utility gas streams.

8.4.1 Fuel and own-use gas

Fuel gas and own-use gas streams are usually relatively small so that their measurement falls well within the range of Coriolis meters, allowing a compact, and therefore relatively inexpensive, metering system giving mass flow directly. It is then necessary only to combine these data with composition measurements from a low-cost gas-composition measuring device to obtain mass component flow rates. It can be practical to use the composition from an instrument installed primarily for other purposes.

If other meter types are installed (i.e. differential pressure or volume types), it is necessary to have adequate pipe lengths upstream and downstream of the meter and to measure the pressure and temperature to obtain the necessary information for the allocation system.

8.4.2 Flare gas

Flare gas has been considered historically as a very challenging measurement, mainly because users want a meter that can measure both the relatively small flow of gas under normal operating conditions and the very large flows of gas when the facility is blowing down part or all of the inventory of the process vessels and their associated pipelines. In the latter case, the fluid temperatures can drop far below normal operating temperatures. It is considered impossible to make such measurements with a single type of existing meter. It is also impractical to meaningfully allocate measurements made in this way in an allocation system. However, the more stringent environmental and trading requirements can well lead to new developments in this area.

Flare-gas metering and allocation becomes quite straightforward if the process conditions are treated separately.

The relatively low flare flow rate for normal production is readily metered by ultrasonic flare-gas meters to give a volume flow rate. This, combined with measurements of pressure, temperature and composition mass component, can be readily used to determine the flow rate.

For blowdown conditions, the process equipment is segregated into blocks for emergency shut-down (ESD) purposes and defined in the facility safety case. From the measured volumes of the vessels and pipelines, position of level, pressure and temperature sensors and the estimated composition of the fluids in the vessels, it is relatively straightforward to calculate the mass of each component flared when each process equipment block is blown down. The initiation of the blowdown of each process block can be fed to the allocation system, together with the masses of the components involved.

It is evident that the total flare is the sum of the metered flare-gas under normal conditions, plus the inventories of the process blocks blown down under emergency conditions.

It is necessary to take care that the equipment used to meter the normal, relatively low flow rates and the gas composition under normal conditions can withstand and recover fully from the blowdown conditions.

8.5 Uncertainty considerations for lift, injection and utility gas

As several of the streams considered in 8.2 to 8.4 are small compared with the export streams, it is important to consider how to deal with the uncertainties associated with these streams. The uncertainty of a minor disposal stream consists of two aspects.

a) The uncertainty of the direct measurement, which, for the disposal stream, can be determined in the usual manner, as defined in the ISO 5168. The impact of the common assumption that a minor gas stream has a constant composition falls under this category and can be estimated in a similar manner.

b) The uncertainty in the allocation to the various parties that have, or have not, contributed to the disposal stream. In most cases the small volumes of the disposal stream mean that a higher uncertainty of the measurement values or the allocation mechanism is acceptable.

   Often the disposal stream is a collective disposal and allocation to individual parties can be determined in various ways, e.g.

- fixed ratio, for which parties have a fixed share,
- proportional with production volumes, equal to a factor times production volume,
- more complex calculations, e.g. CGR times production.

Calculation of the overall uncertainty can become complex because of the assumptions made, particularly if the allocation is based on volumes. From that point of view it is generally adequate to calculate practical, maximum deviations to demonstrate the potential impact on the allocated proceeds to the stakeholders. In a mass-component-based allocation, the assumptions (if any) are usually more transparent and the uncertainty analysis is greatly simplified.

Uncertainty in measurement is defined as the range of values of a measurement with a 95 % confidence level. It is assumed that the range of measurement values can be represented by a normal distribution, for which 95 % of the measurement values lie within ± 2 standard deviations from the centre of the distribution, ranging between the 2,5 % and 97,5 % percentile. This means that 2,5 % of the measurement values lie in each of the high and low tails of the normal distribution. Other confidence levels are occasionally used in some applications.

9 Uncertainty — General considerations

NOTE Some aspects of uncertainty for a specific topic are discussed in the subclauses dealing with that topic. This clause gives an overview of uncertainty as it relates to the major elements of the allocation process.

9.1 Economic consequences

9.1.1 General

The impact of uncertainty of measurement on allocation is to create a financial exposure that can be either random or biased (related to systematic errors). The exposure due to random uncertainty approaches zero in the long term. Random error is of less concern than bias, which always results in a difference, generally in the same direction, from the actual value and in time can result in a large cumulative financial exposure (gain or loss). Biases should be corrected and minimized wherever possible. A large random uncertainty is generally of less concern than a small bias, due to the lower long-term financial exposure risk. However, large random uncertainties should be addressed, as they can conceal smaller, but significant, systematic uncertainties.

The measurement uncertainty and the method of allocation determine the financial exposure in the allocated share of the total production for each party; it can have a significant impact on the economics of a measurement and allocation system. The acceptable level of financial exposure should be established at an early stage to determine the appropriate method of measurement. There is a trade-off between the cost of implementing a measurement system and the resulting financial exposure of the allocation. Several iterations of the high-level design can be required to find the optimum cost and financial exposure solution.

9.1.2 Metering

Measurement uncertainty for metering is generally in the range of 0,25 % to 0,5 % for high-accuracy liquid systems (sales, custody transfer, or fiscal metering). The uncertainty for high-accuracy gas-metering systems is somewhat higher, with that for orifice metering systems typically 0,7 % to 1 % and that for systems using calibrated turbine or ultrasonic meters slightly better, possibly 0,5 % to 0,8 %. These uncertainties are only general indications. There can be reasons (mostly economic) to relax the uncertainty requirements and if approval is obtained from the other parties involved (e.g. government authorities, partners, sellers, buyers, etc.), other means of flow rate determination can be selected.

Measurement uncertainty in allocation systems is generally on the order of 1 % to 3 %, usually because meters are often positioned in poorer measurement conditions much further upstream in the production process, where the fluids are generally not fully processed. For example, gas measurements downstream of a separator are likely to have liquids present and, similarly, liquid measurements downstream of a separator can have relatively high water cuts, be contaminated with sand and well chemicals or possibly be subject to gas breakout upstream of the meter. The choice of measurement devices is constrained by these conditions. Measurement uncertainty is increased and biases (systematic errors) are introduced when conditions change (e.g. when liquids are present in the gas, water-in-oil or oil-in-water emulsions are present, or when gas breakout occurs). There is often little way of knowing that these conditions are present, and the biases are unlikely to cancel out over the long term. However, it is important that these uncertainties should be minimized and correction made for the biases.

Again, a proper consideration should be made whether a relaxation in the uncertainty for allocation systems can be accepted. It is a common fallacy that it is not necessary for allocation meters to have a low uncertainty because the allocation metering is “corrected” by the higher-accuracy meters at the final export point(s) from the production system. This is almost always not the case. The final meters determine how much production is shared but the financial exposure over the long term for an individual party’s share is determined mostly by the systematic biases in that party’s meters. In some cases, it can be a waste of resources to measure a very small gas stream to high accuracy in a large gas production system but, on the other hand, it can be well worthwhile for a small producer in a large production system to ensure that its small production stream is measured without significant bias.

9.1.3 Sampling and analysis

Sampling and analysis is required to determine properties of the fluid and may be categorized into online or offline and into gas and liquid systems. Determining the uncertainty for sampling and analysis systems is probably the hardest task in determining the overall uncertainty in a metering system. This is because it is often difficult to assess how representative is the sample ; the analysis is non-linear and there is often human intervention that is difficult to include meaningfully in an uncertainty analysis. The types of systems commonly installed in gas/condensate operations are discussed in 9.1.3.1 and the instruments or measurements required for gas or liquid allocation reporting and the approaches in assessing the uncertainties in 9.1.3.2 and 9.1.3.3.

9.1.3.1 Sampling systems

9.1.3.1.1 Online method

These systems continuously or intermittently measure the fluid properties within a relatively short time interval, for example by on-line gas chromatograph. The advantage of online measurement is that there is no delay in determining the fluid properties and measurement and, consequently, the allocation quantities and qualities can be calculated in a short time frame. This reduces the overall uncertainty, as short-term variations in the fluid properties are included in the final results. The disadvantage of online systems is the relatively high cost of maintenance and the low confidence in some measurements.

9.1.3.1.2 Offline method

Offline system samples are taken at intervals, and, consequently cannot take account of short-term variations in the fluid properties; this increases the overall uncertainty in the analysis. The cost of sample extraction is low but onsite analysis requires specialist personnel and laboratory facilities. Offsite analysis usually leads to long delays in transit and production of the analytical results. The quality of sampling and analysis is dependant on the operator, for which it is difficult to assign an uncertainty. With periodic sampling, the probability of sampling at the extremes of variation is low; therefore, the analysis tends to underestimate the extremes.

9.1.3.1.3 Proportional method

In proportional sampling, samples are taken at regular time intervals (time-weighted) or proportional to the rate of production (flow-weighted). Representative time-weighted samples require steady production rates. Flow-weighted samples, which represent the actual production over the sampling periods, are usually more representative. The proportional sample is then analysed, usually offsite, and applied, retrospectively, to the production for the sample period. The main disadvantage is the time lag between measurement, sampling and analysis and the processing of the allocation results. In addition, the ongoing maintenance cost of the sampling equipment is relatively high.

9.1.3.2 Gas sampling and analysis

It is necessary to assess the impact of the following instruments and measured properties on the overall uncertainty of the gas allocation system:

- gas conditioning, pressure reduction and fast loops;
- online gas chromatograph (C_{5+}, C_{6+}, C_{7+}, etc.);
- gas densitometer;
- RD analyser;
- H_2S analyser;
- dewpoint/moisture (both hydrocarbon and water);
- condensate-gas ratio (CGR);
- water-gas ratio (WGR);
- proportional sampler (flow-weighted, time-weighted);
- spot sample point.

9.1.3.3 Liquid sampling and analysis

It is necessary to assess the impact of these instruments and measured properties on the overall uncertainty of the liquid allocation system:

- sample, fast loop, pump, mixing and representative sample;
- liquid densitometer;
- basic, sediments and water (BS&W) meter;
- proportional sampler (flow-weighted, time-weighted);
- spot sample point;
- static mixer;
- dynamic mixer.

9.2 Sensitivity

Sensitivity, S, expressed as cubic metres per cubic metres, is the change in the output, $\Delta\chi_{\text{OUT}}$, of a system due to a change in the input, $\Delta\chi_{\text{IN}}$, to the system as represented by Equation (18):

$$S = \frac{\Delta\chi_{\text{OUT}}}{\Delta\chi_{\text{IN}}} \tag{18}$$

Sensitivity is of interest in assessing the stability of allocation system results relative to changes in the input and has two effects:

a) a large change in the measurement uncertainty, which has a similar impact on some allocation results, such as a small change in the CGR (condensate gas ratio) in a wet gas measurement that can significantly change the measurement uncertainty above a certain threshold;

b) a small change in the input parameter, which has a big impact on measurement and the final allocation result, such as a small change in the C_3 gas component that can have a large impact on the allocated mass and energy.

9.3 Allocation principle

The method of allocation can have a significant impact on the allocation uncertainty. For example, at some ratios of production from two fields, allocation by difference has a lower uncertainty than proportional allocation methods. However, the proportional allocation has limited maximum uncertainties, regardless of the production ratio and is, therefore, more stable over wide production ranges for the two fields. Nevertheless, the financial exposure for a difference allocation can be substantially lower than for a proportional allocation over a limited production range. Furthermore, this might be the only viable option due to the cost of the measurement system or due to the difficulty of making measurements. Always, the costs of the metering and data processing should be balanced with the benefits accruing from the reduction of the uncertainty in the data; i.e., it is not necessary to measure a 10 bbl/d production with a 1 % uncertainty, however a 100 000 bbl/d sales stream probably requires the lowest uncertainty that can be achieved. Also, in allocation processes, the absolute value of the allocated volumes should determine the individual measurement uncertainty.

9.4 Uncertainty determination

9.4.1 General

Measurement uncertainty is contributed from many sources, including manufacturer's data, calibration history, measurement and lab-analysis statistical data, plus uncertainty from the measurement device method and the dataset.

9.4.2 Analytical uncertainty

Root sum square (RSS) or least squares approximation (LSA) uncertainty methods, as described in ISO 5168 and ISO/IEC Guide 98 (formerly GUM), are suitable for most end measurement devices. These methods are preferred as the calculations are sufficiently well understood and the complexity is limited. Typical examples are ISO 5167-2 orifice plate uncertainty, two-input proportional allocation system and a pressure transmitter.

9.4.3 Stochastic uncertainty

Allocation systems, particularly mass-component-weighted allocation systems, usually involve a linear combination of product streams for which the mathematical analysis of the uncertainties in the systems is relatively straightforward. However, where complexity increases or the allocation system involves non-linear elements, it is recommended that the alternative Monte Carlo simulation (MCS) uncertainty method be used, as described in ISO 5168 and ISO/IEC Guide 98 (formerly GUM). A typical example where MCS is extremely useful is in the analysis of the uncertainty of gas properties derived from the composition as determined by gas chromatograph (e.g. for the gas compressibility, as described in AGA8 or the calorific value as described in ISO 6976). Complex mass component allocation systems can be best tackled using MCS as the formal structure required in setting up a Monte Carlo simulation allows the structure to be modified and corrected more easily than for a conventional uncertainty analysis.

10 Validation

10.1 General

Validation is a critical part in the process of establishing confidence in any allocation system. The actual method depends on the techniques used to determine product quantity and quality.

In 10.2 to 10.7, validation in the following areas is considered:

- meters;
- analysers;
- samplers/systems;
- reported quantities (data);
- calculations and modelling;
- allocation process.

Each area has different requirements for validation. However, the process of validation invariably consists of an initial validation before use and subsequent periodic validations while in use to demonstrate that the systems are performing as intended. The interval between periodic validations in each area may be set by specifications in the relevant agreements between partners, but often it depends on the performance of the area of the system during the validation activity. Successful performance can allow the interval between validations to be extended. This is particularly the case where new technology is involved and periodic verification can be carried out more frequently to establish the quality of the measurements over time. On the other hand, when there are marked changes in the produced fluids over time, it can be necessary to increase the frequency of periodic validations.

10.2 Meter validation

10.2.1 Initial validation

Initial validation may include

- metrology checks;
- conformance with relevant standards [i.e. ISO 5167 (all parts), etc.];
- flow calibration reflecting the expected in-service flowing conditions.

10.2.2 Periodic validation

Validity of a meter at the actual flowing conditions is the most critical consideration for its influence on the integrity of the overall measurement system.

The objective of periodic validation of the meter is to ensure that changes to the meter and its operating environment throughout the lifetime of the production facility do not result in unacceptable degradation of the measurements. This may include

- physical inspection;
- calibration checks and calculation checks of primary and secondary elements of the system;
- removal of equipment for comparison against a recognized reference standard;

- using diagnostic checks available with certain types of equipment;
- validation by difference, e.g., by shutting a flowing product stream to check its influence.

10.3 Allocation procedures and process validation

10.3.1 Initial validation

It is essential to establish clear descriptions of the allocation system and the calculations employed in each of the calculation areas. Calculations for allocation purposes may be carried out in the field using onsite flow computers, in facility-control systems, in company offices and, in very large allocation systems, at centralized locations. It is evident that it is necessary to pay special attention to how one part of the system interfaces to the next. Validation of the subsystems is usually by agreed acceptance testing, involving testing by use of "signature" checks where known data inputs have expected or pre-calculated outcomes. System models that replicate key areas of the system, e.g. important calculations, timeliness of results (i.e. processing time), balance checks, factor checks, etc., may be used. Full "end-to-end" checks from the measurement equipment on each production facility to the reports (results) should be carried out.

10.3.2 Periodic validation

Under normal circumstances, periodic validation of the allocation system is done only when any change is made to the system. The allocation system should be designed with inbuilt checks to warn of faults, precluding the requirement for extensive, difficult-to-implement, periodic validations.

10.4 Data validation

At the various nodes within an allocation system, checks are made to ensure the validity of the data reported, calculated, etc., to reduce the possibility of product misallocation due to data corruption by whatever means. Refer to the allocation process diagram in Figure 6.

10.5 Process-model validation

Process-model validation may be done by varying the process-plant operating conditions and then checking if the results compare with those predicted by the model. If necessary, the model parameters may be updated to reflect operational experience from such a validation methodology.

10.6 Allocation-process results validation

10.6.1 Allocation-process trial results

Trial results are usually run before final allocation results (reports) are produced. This can be, for instance, because sample analysis data are not yet available and an assumed composition is used. The trial results are checked to ensure they lie within predetermined limits to assure their validity.

10.6.2 Allocation-process final results

Once all the final data are available, the allocation system is run to determine the final results. Before the final results are accepted and issued, they are checked to ensure that they lie within predetermined limits to assure their validity.

10.7 Software validation

10.7.1 Initial software validation

The software for an allocation system is comprised of several program packages written by different suppliers. These program packages interface to provide the complete allocation system. Each of these packages should be well specified, especially with regard to the interfaces with other packages. It is necessary to validate each package, when produced, against its specification and then, when incorporated into the overall allocation system, relative to the interfaces with other packages.

10.7.2 Periodic software validation

The allocation system should be structured so that there are built-in checks to give confidence that the software is working correctly. Periodic validation is required when a software package is modified or upgraded and it is necessary to check out thoroughly both the package itself and its interfaces with the rest of the allocation system.

11 Classification of allocation processes

11.1 General descriptions and calculations

11.1.1 Mass component allocation

11.1.1.1 General

In 11.1.1 are described principles of mass-component volume-component and other types of allocation systems and in 11.1.2 are presented layouts for several allocation systems common in gas/condensate production.

Mass-component allocation is the preferred allocation system when used on systems that deliver both gas and hydrocarbon liquids through the same pipeline. This process accommodates the exchange of components between the gaseous and liquid phases that takes place in the shared treatment and transportation facilities. This method also enables streams with differing hydrocarbon qualities to be more equitability allocated than by other non-component-quantity allocation methods.

11.1.1.2 Allocation by mass

The mass allocation process involves the following steps (see Figure 12).

a) At each nodal point (see 4.4.1), meter all components by mass. The number of components used within the analysis is determined by the composition of the gas. Gas that entrains a high proportion of hydrocarbon liquids requires a more detailed analysis.

b) Correct the masses for any contaminants (e.g. hydrogen sulfide, water); generic equations can be found in Annex A.

Determine the mass component flow for of all gas streams as given by Equation (19):

$$M_{\mathrm{G},f,n} = M_{\mathrm{GC},f} \times \frac{(X_{\mathrm{G},f,n} \times M_{\mathrm{r},n})}{\sum_{n=1}^{c}(X_{\mathrm{G},f,n} \times M_{\mathrm{r},n})} \qquad (19)$$

where

$M_{\mathrm{G},f,n}$ is the mass of gas for each field per component;

$M_{\mathrm{GC},f}$ is the mass of gas for each field after correction for fuel gas and water;

$X_{\mathrm{G},f,n}$ is the mole fraction of each component for each field;

$M_{\text{r},n}$ is the relative molecular mass for each component;

c is the number of components.

As a minimum, the components C_1, C_2, C_3, *n*-C_4, *iso*-C_4, *iso*-C_5, *neo*-C_5, C_6, C_7, C_8, C_9, N_2 and CO_2 should be used (lumping the higher hydrocarbons together). However, sometimes the uncertainty requirements are such that all 58 components listed in ISO 6976 should be used.

c) Correct for any fuel/utility/vent/flare gas. See Annex B for generic equations.

d) Determine the mass component flow of all condensate streams as given by Equation (20):

$$M_{\text{CC},f,n} = M_{\text{C},f} \times \frac{(X_{\text{C},f,n} \times M_{\text{r},n})}{\sum_{n=1}^{c}(X_{\text{C},f,n} \times M_{\text{r},n})} \tag{20}$$

where

$M_{\text{CC},f,n}$ is the mass of condensate for each field per component;

$M_{\text{C},f}$ is the mass of condensate for each field;

$X_{\text{C},f,n}$ is the mole fraction of each component for each field;

$M_{\text{r},n}$ is the relative molecular mass for each component.

e) Combine the gas and condensate mass components to give the total for each entry and delivery point. Each component of the fluid flowing through a delivery point is pro-rated against the entry point component quantities, as given by Equation (21):

$$A_{\text{MG},f,n} = M_{\text{TOT},n} \times \frac{(M_{\text{G},f,n} + M_{\text{CC},f,n})}{\sum_{n=1}^{n_{\text{TOT}}}(M_{\text{G},f,n} + M_{\text{CC},f,n})} \tag{21}$$

where

$M_{\text{TOT},n}$ is the mass total of component n in the delivered gas mass at the custody transfer exit node;

n_{TOT} is the total number of input nodes;

$A_{\text{MG},f,n}$ is the allocated mass of gas per field for each component.

f) Sum the individual components for each entry point to derive the total nodal point allocated mass, $A_{\text{MG},f}$, as given in Equation (22):

$$A_{\text{MG},f} = \sum_{n=1}^{c} A_{\text{MG},f,n} \tag{22}$$

where $A_{\text{MG},f,n}$ is the total allocated mass of gas per field.

11.1.1.3 Allocation by volume

It can be necessary to calculate an associated volume for attribution, accounting and reporting purposes. The allocated mass figures can be readily converted to volume by dividing by the density of the stream in question. The method illustrated in the Figure 13 may be utilized.

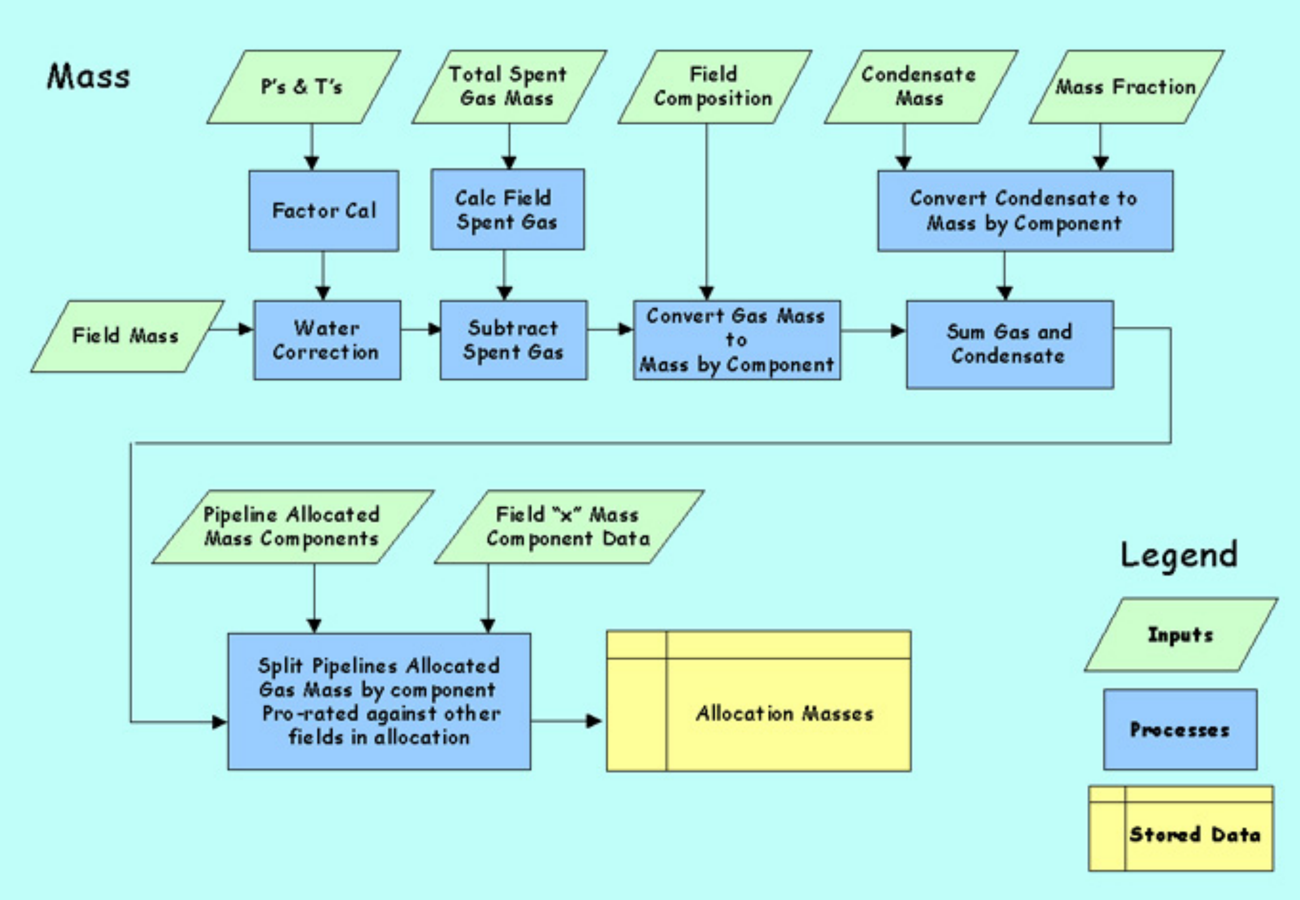


Figure 12 — Mass-allocation process

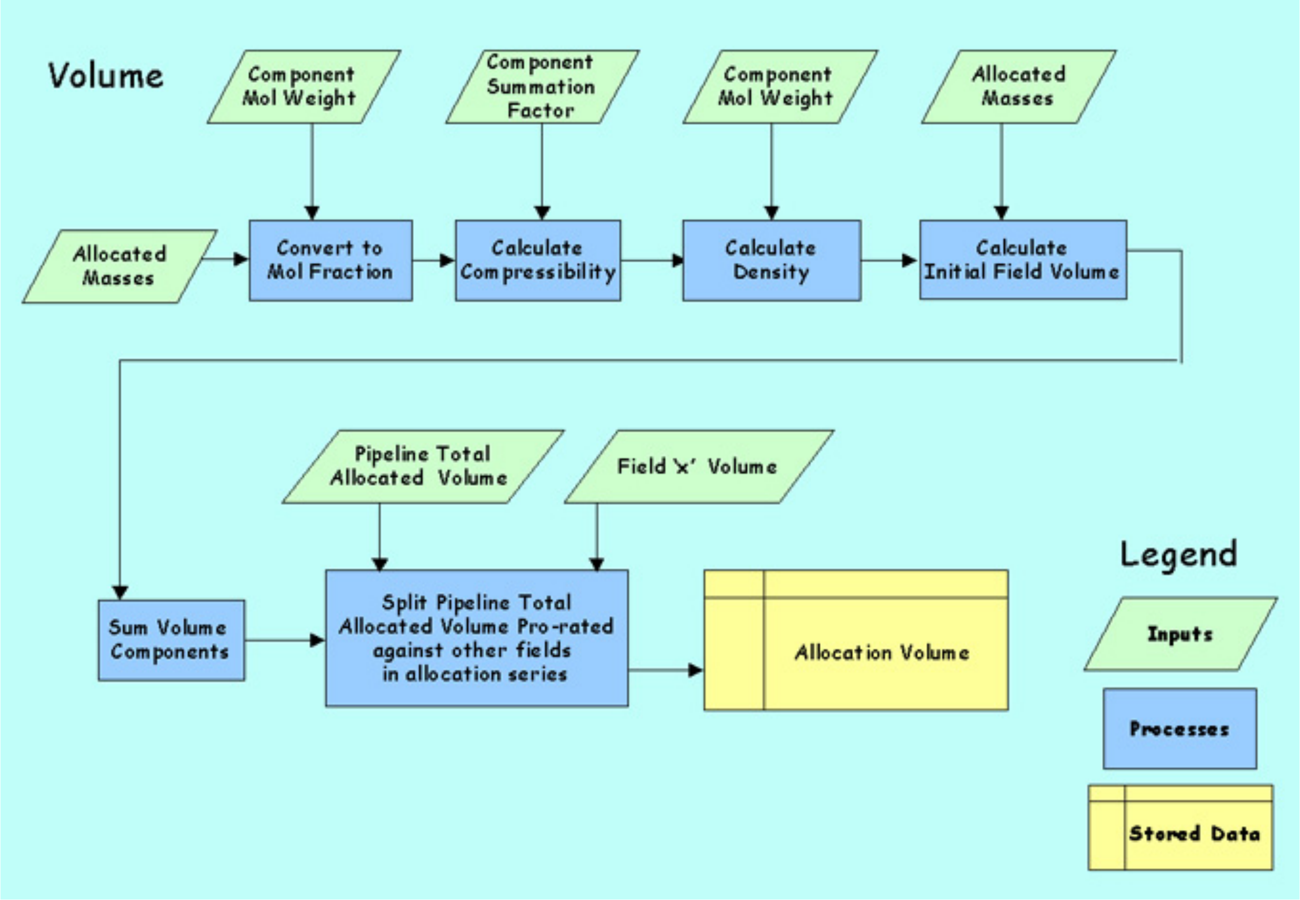


Figure 13 — Volume-allocation process

After the mass component allocation has been performed the volume flow is calculated using factors from the latest industry standards in the following steps:

a) Determine the composition of the allocated stream, expressed as a mole fraction, $X_{f,n}$, using the component relative molecular mass, as given in Equation (23):

$$X_{f,n} = \frac{(A_{\mathrm{MG},f,n} / M_{\mathrm{r},n})}{\sum_{n=1}^{c} (A_{\mathrm{MG},f,n} / M_{\mathrm{r},n})} \tag{23}$$

b) Calculate component compressibility using summation factors, as given in Equation (24):

$$Z_f = 1 - [\sum_{n=1}^{c} (X_{f,n} \times \sqrt{b_n})]^2 \tag{24}$$

where $\sqrt{b_n}$ is the summation factor for component n from ISO 6976.

c) Calculate the component density using component relative molecular mass, as given in Equation (25):

$$D_{f,n} = F_{\mathrm{den}} \times 10^{-6} \times \frac{M_{\mathrm{r},n}}{Z_f} \tag{25}$$

where

$$F_{\text{den}} = \frac{P_{\text{ref}}}{R \times T_{\text{ref}} \times 10};$$

P_{ref} is equal to 101,325 kPa (1,013 25 bar);

R is in accordance with ISO 6976 and expressed in $\text{J} \cdot \text{mol}^{-1} \cdot \text{K}^{-1}$;

T_{ref} is equal to 288,15 K.

d) Calculate the component volume, as given in Equation (26):

$$Q_{f,n} = \frac{A_{\text{MG},f,n}}{D_{f,n}} \tag{26}$$

e) Calculate the total volume per field, as given in Equation (27):

$$Q_{\text{TOT},f} = \sum_{n=1}^{c} Q_{f,n} \tag{27}$$

f) Calculate the allocation quantity per field, as given in Equation (28):

$$A_{\text{Q},f} = Q_{\text{TOT}} \times \frac{Q_{\text{T},f}}{\sum_{f=1}^{f_{\text{TOT}}} Q_{\text{T},f}} \tag{28}$$

where

f_{TOT} is the total number of input nodes;

Q_{TOT} is the total volume at the export nodal point.

11.1.1.4 Energy

Generally, the ultimate aim of using a mass-based allocation is to calculate the energy for allocation to a source. After the mass-component allocation has been performed, the energy is calculated as illustrated in Figure 14 using the following steps.

a) Using factors from the latest industry standards, calculate the heating energy per component, as given in Equation (29):

$$U_{f,c} = A_{\text{MG},f,c} \times H_{\text{H},c} \tag{29}$$

where $H_{\text{H},c}$ is the hydrocarbon heating value for each component, c.

1) Calculate the sum of the components for each field, as given in Equation (30):

$$U_{\text{T},f} = \sum_{n=1}^{c} U_{f,n} \tag{30}$$

2) Calculate final allocated energy per field, as given in Equation (31):

$$A_{\mathrm{U},f} = U_{\mathrm{TOT}} \times \frac{U_{\mathrm{T},f}}{\sum_{f=1}^{f_{\mathrm{TOT}}} U_{\mathrm{T},f}} \qquad (31)$$

where

f_{TOT} is the total number of input nodes;

U_{TOT} is the total energy at the export nodal point.

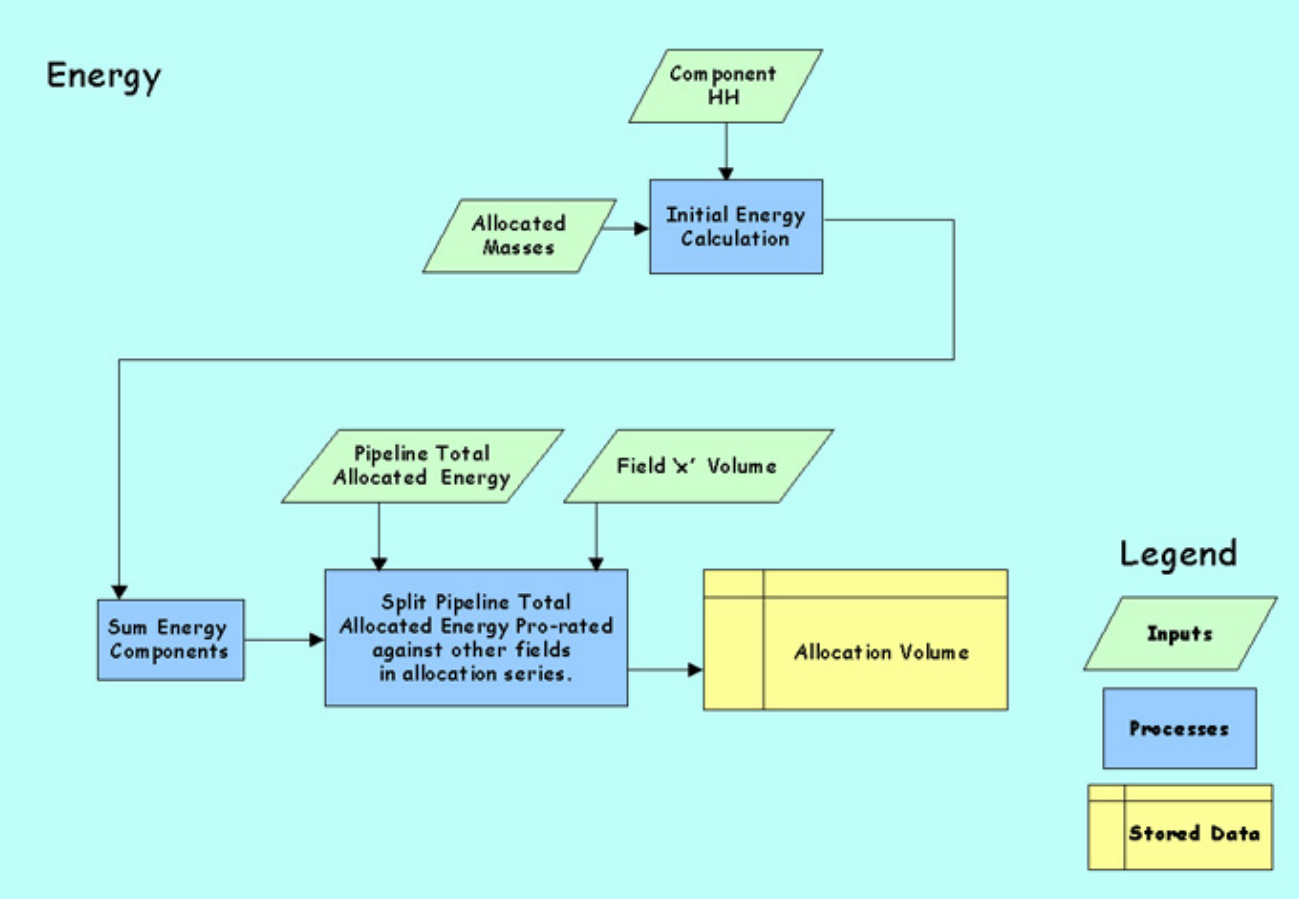


Figure 14 — Energy-allocation process

11.1.2 Quantity allocation

11.1.2.1 General

Quantity allocation (either in mass, volume, or energy) is more simplistic than mass-component allocation. Suggested situations where this method may be considered are as follows:

a) where there are no hydrocarbon liquids for allocation. Such a system can result from the use of an alternative pipeline system to export the hydrocarbon liquids, separate from the allocation and metering system in question, or it can be assumed and agreed for commercial purposes that there are no hydrocarbon liquids; (Agreements should consider how to handle hydrocarbon liquids if they are received.)

b) where hydrocarbon liquid quality is agreed for commercial purposes to be consistent across the sources, i.e. produced quantities of liquids are negligible or of similar quality.

The input-metered quantities are prorated to the metered total at the custody transfer exit node, as given in Equation (31):

$$A_{\text{QG},f} = Q \times \frac{Q_{\text{G},f}}{\sum_{f=1}^{f_{\text{TOT}}} Q_{\text{G},f}} \tag{31}$$

where

Q is the quantity of the delivered gas at the custody transfer exit node;

f_{TOT} refers to the number of input nodes;

$A_{\text{QG},f}$ is the allocated quantity of gas per field;

$Q_{\text{G},f}$ is the quantity of gas for each field.

11.1.2.2 Mass-quantity allocation

Where the gas is metered in units of mass, it is possible to calculate the volume, moles, and energy providing that a representative composition is recorded within the allocation system.

11.1.2.3 Volume quantity allocation

As volume is used within many older agreements for nominating, targeting and substitution, any new system that is dependent on the older systems can be required to use the same principles. However, as discussed above, mass streams can be readily converted to volume streams by dividing by the density. It is practical, therefore, where it is necessary for a new system to comply with old agreements, to gain the simplicity and flexibility of mass-allocation systems.

The volume quantities are calculated within the flow computers; final allocation calculations are performed as shown above.

11.1.2.4 Energy-quantity allocation

As energy is used within many new agreements for nominating, targeting and substitution, many national transmission systems use energy as the unit for trade. In such cases, energy is the preferred method of quantity allocation.

The quantities are calculated within the flow computer; final allocation calculations performed as shown in 11.1.1.

11.1.3 Process simulation

Process simulation may be used in place of measurement equipment or, in particular circumstances, where it is deemed acceptable due to low financial risk or marginal field viability.

The following are examples where process simulation may be used:

- pipeline stock and/or “packet allocation”;
- liquid determination, where there are no liquid-measurement stations;

- liquid correction for wet gas measurement;
- pipeline stock calculation for mass balancing or stock apportionment;
- prediction of flow totals;
- yield factors (component/full stream);
- shrinkage due to liquid drop-out;
- glycol;
- field decay;
- interaction/back-out;
- rich and lean gas: simulation may be used when streams are mixed to ensure a stream is an acceptable quality.

11.1.4 Thermodynamics in allocation processes

As hydrocarbon streams travel through a pipeline or processing plant, they are subjected to changes in temperature and pressure that can result in an exchange of components between the phases in multiphase pipelines, or in liquid drop-out due to cooling and/or to changes in pressure in a gas pipeline.

Chillers or “dew point units” remove excess hydrocarbons from a gas system in order to dry gas so that it can meet the specification for entry into the national gas network.

The hydrocarbon liquids removed by such units may be allocated using the methods suggested below:

- cost/value/yield($)/recovery/process adjustment factors applied to allocated/metered gas;
- factors based on agreed values or routine samples/well tests, the value of the product and the quantity exported (sold);
- when used in a mass component system, hydrocarbon liquids metered in mass and split to a component level to combine with allocated gas quantities;
- hydrocarbon liquid/gas ratio used based on the mass of the metered gas and calculated to a component level to adjust for the hydrocarbon liquids during the gas allocation process;
- a commercially agreed assumption that no hydrocarbon liquids are produced or transported through the system modelled by the allocation agreement.

11.1.5 Reconciliation

The reconciliation process is one which may be performed on a routine basis and may be a requirement under the terms of the allocation agreement.

It may be used in the following circumstances:

- as a predetermined method to correct for mis-measurements in a regular and controlled manner;
- to correct for fluid factors or compositional data from that of an assumed data set to that of a final data set;
- prior to issuing the finalized allocation statements for the accounting period.

11.1.6 CGR determination

11.1.6.1 General

In some situations, it is important to know the condensate-to-gas ratio (CGR). The methods given in 11.1.6.2 to 11.1.6.4 may be used.

11.1.6.2 Test separator

A field or well may be routed to a dedicated separator (test or production) that measures the gas downstream of the separator vessel, separates the hydrocarbon liquids from any water and then meters the associated hydrocarbon liquids. The following guidelines should be followed.

- The test should be performed for the maximum time possible to achieve the best possible accuracy, preferably in excess of 24 h. The well flow-line length should also be taken into account.
- The frequency of the tests should be specified within the agreement and should be based on the expected stability of hydrocarbon liquid production from the field(s).
- The well or field should be flowing prior to the beginning of the test to ensure stability and, therefore, a more accurate result.
- The meters should be of a good standard and the separator vessel of suitable capacity.

11.1.6.3 Tracer

Tracer methods can be used to determine CGR in a wet-gas stream. In principle, all that is required is a suitable gas tracer and a suitable condensate tracer. In practice, no suitable gas tracer has been found. This means that it is necessary to measure the gas flow on the stream in question. This discussion assumes there is a wet-gas meter of the differential-pressure type.

The following steps give the CGR.

a) Measure the flow rate of the condensate using a condensate tracer.

b) Measure the flow rate of the water using a water tracer.

c) Determine the total liquid flow rate.

d) Note the uncorrected wet-gas flow rate.

e) Determine the over-reading of the wet gas meter due to the liquid.

f) Correct the wet-gas flow rate to a dry-gas flow rate.

g) Determine the condensate-to-gas ratio.

11.1.6.4 Well test

For a well or field where there is no access to a permanently installed separator, the CGR can be obtained from a well test performed when the well is initially drilled or the subject of a work over. The gas is flowed to flare through a standard process of separation and metering the gas and liquids.

Essentially, this approach uses a test separation to acquire the required data; see 11.1.6.2 for further details.

11.2 Allocation systems layout

11.2.1 Gas only

11.2.1.1 Description

It is necessary to characterize the gas flowing through a “gas only” system as “dry.” Such a system can possibly use an alternative means, apart from the allocation and metering system in question, to export the hydrocarbon liquids.

If it is assumed that no hydrocarbon liquids are produced from the field or are transported through the measurement node, it is necessary that this be stated in the allocation agreement, together with the actions that it is necessary to take if hydrocarbon liquid products are received at the measurement node. Such liquids should be defined as either a valued or a waste product, and there should be a method specifying how to determine ownership.

For the measurement requirements, refer to Figure 8.

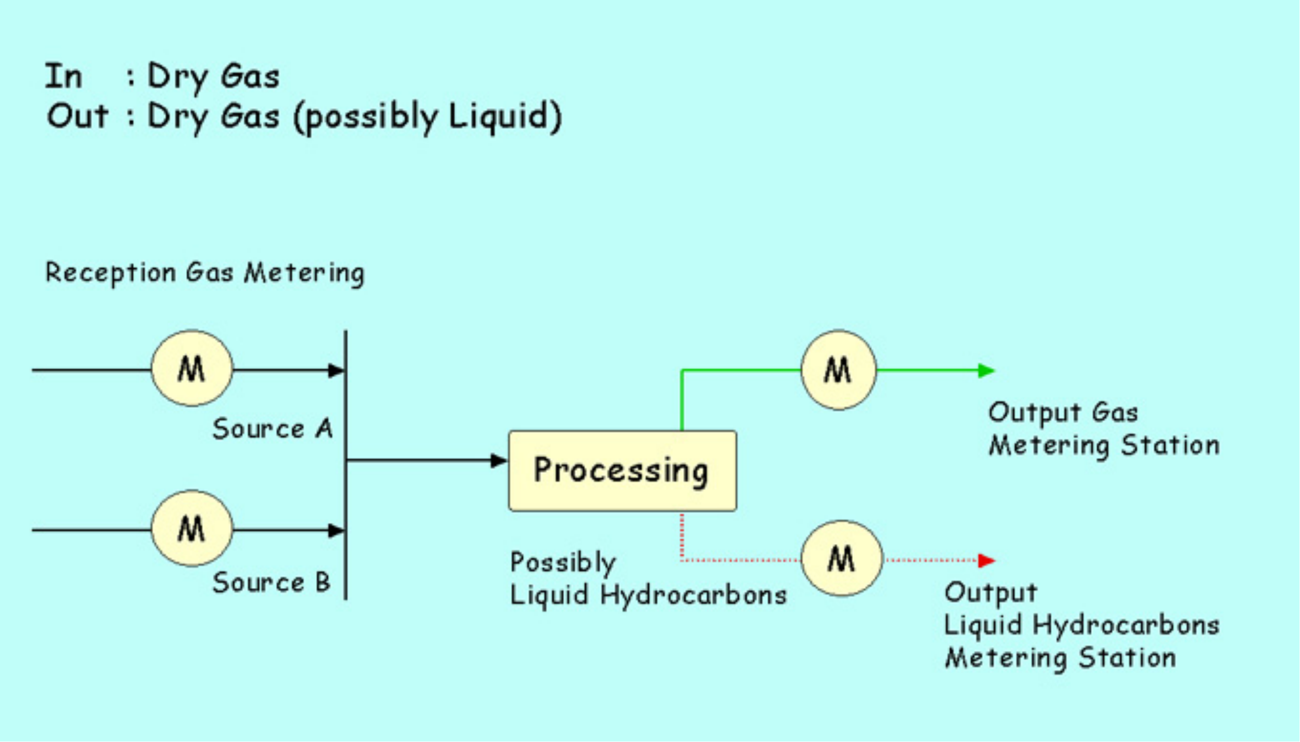


Figure 15 — Gas-only system

11.2.2 Dry gas in; dry gas and liquid out

11.2.2.1 Description

The layout in the diagram is used where liquids drop out during processing or where two-phase flow is present. It removes the need for wet-gas metering. Further processing can be required to enable the gas to meet the entry standards to a distribution network.

An additional meter may be used to measure the quantities removed through the final processing stage. This can be necessary if the source streams have significantly different qualities.

For the measurement requirements, refer to Figure 8.

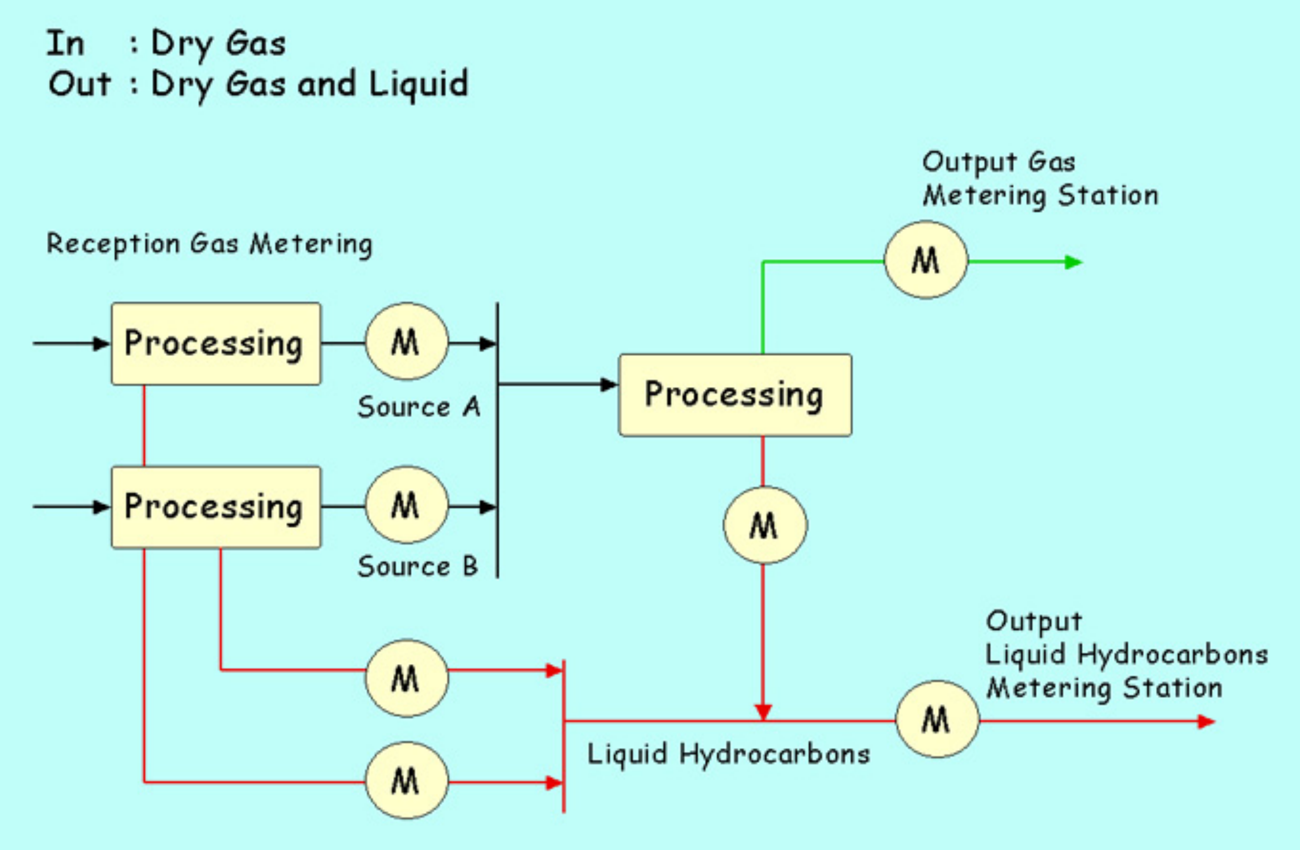


Figure 16 — System with dry gas and liquid in, dry gas and liquids out

11.2.3 Wet-gas combined in; dry gas and liquid out

11.2.3.1 Description

An input measurement node is required to meter a two-phase flow, possibly sub-sea.

Separators or slug-catches may be used to remove liquids prior to processing.

An additional liquid-hydrocarbon meter may be used to measure the hydrocarbon liquid quantities removed through the final processing stage. This can be necessary if the source streams have significantly different qualities.

For the measurement requirements, refer to Figure 8.

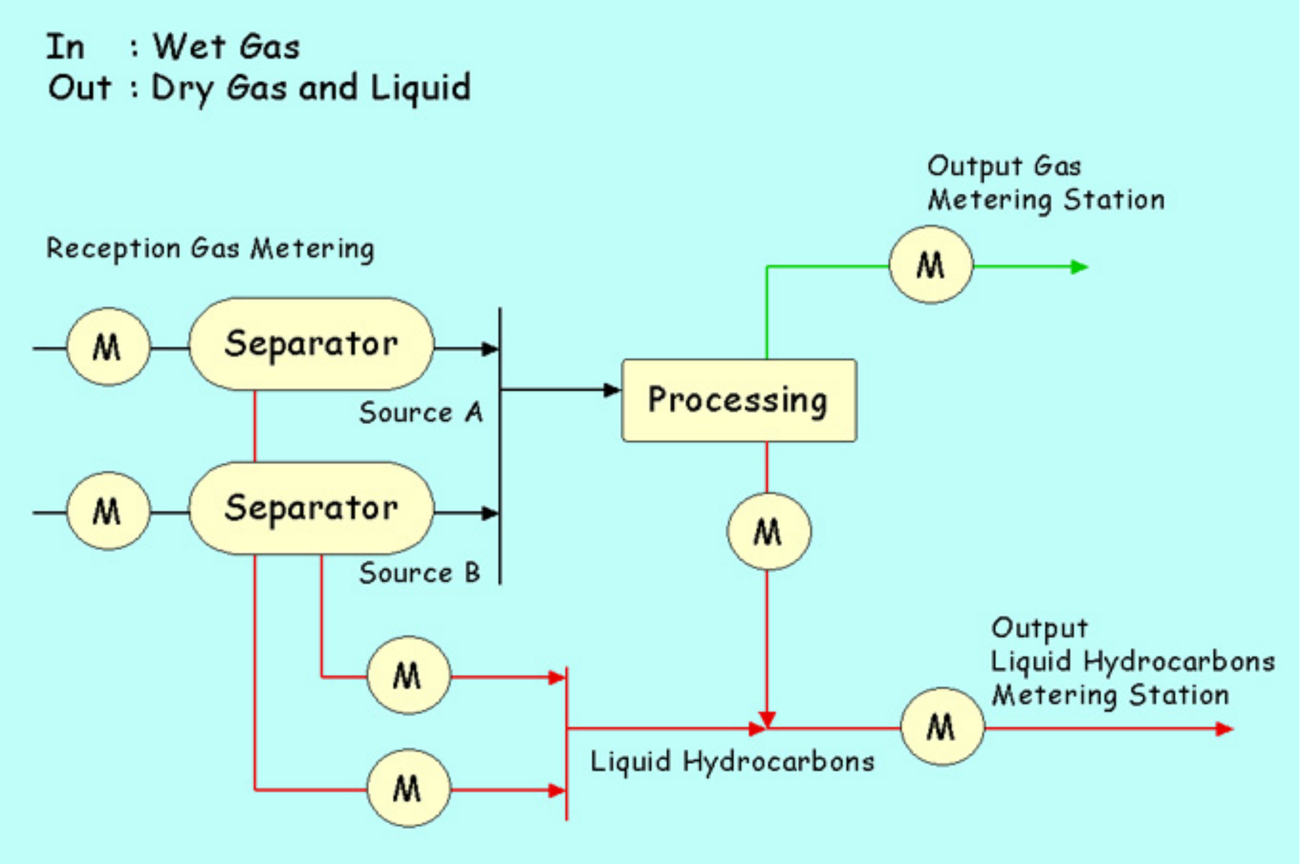


Figure 17 — System with wet gas in and dry gas and liquid out

11.2.4 Dry gas and liquid in; dry gas and liquid out

11.2.4.1 Description

This process applies where hydrocarbon liquids are transported separately from the gas stream. Liquids from sources A and B may be combined at the hydrocarbon-liquid inlet, source A, and split using process simulation or CGR's, or the phases may be transported and metered separately.

An additional meter may be used to measure the quantities removed through the processing stage. This can be necessary if the source streams have significantly different qualities.

For the measurement requirements, refer to Figure 8.

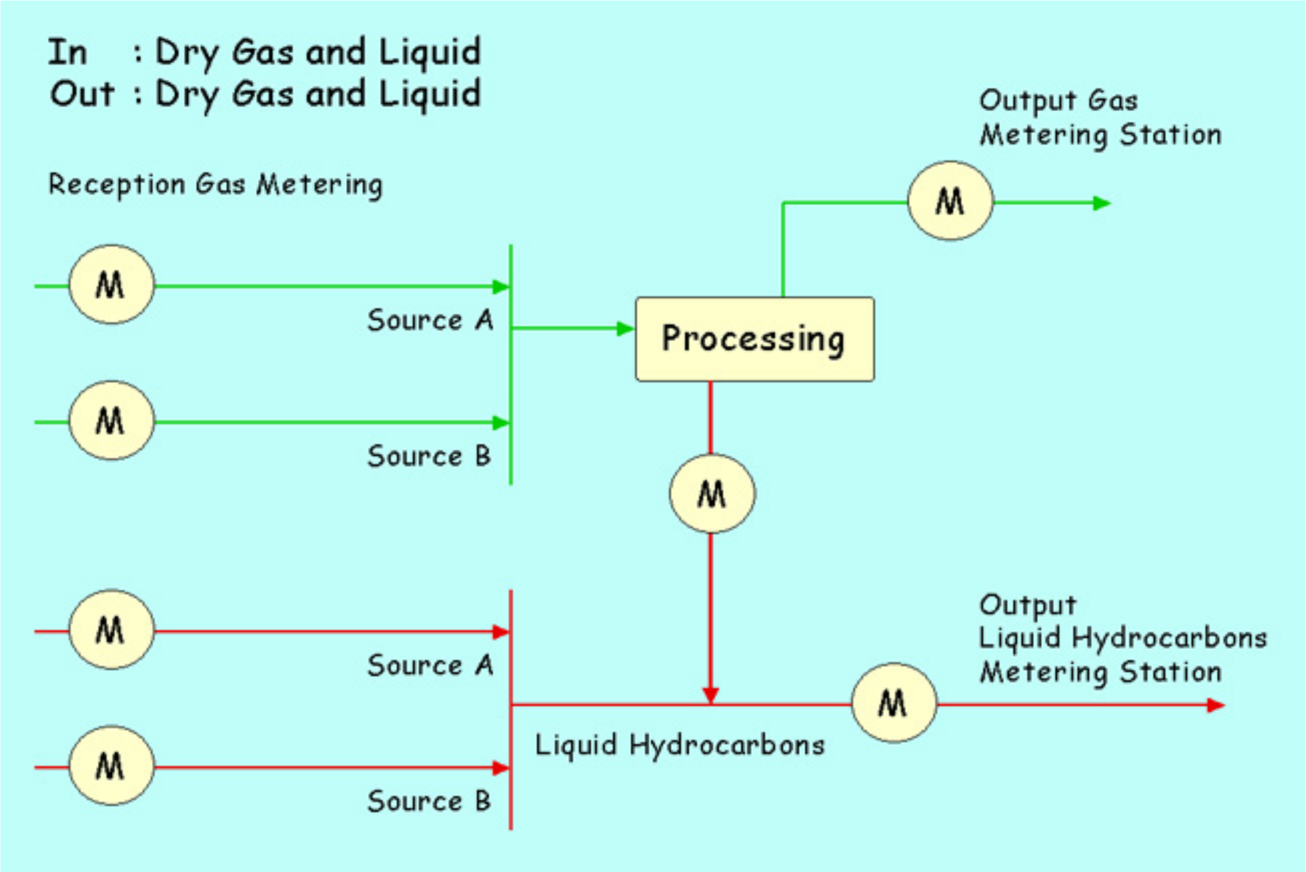


Figure 18 — System with dry gas and liquid in, dry gas and liquid out

11.2.5 Allocation by difference

11.2.5.1 General

Allocation by difference usually arises when an existing gas/condensate production and transportation system is extended by allowing access to the production from new fields. Two situations are discussed in 11.2.5.2 and 11.2.5.3 that differ only in that the one in 11.2.5.2 affects a sub-allocation, whereas the one in 11.2.5.3 affects the main allocation and, in fact, is the driver for requiring an allocation agreement.

11.2.5.2 New development tied into an existing one

Many pipeline systems have strict entry regulations on the quality of metering and on the quality of the products exported from fields into the pipeline. It can simply be impractical commercially to negotiate a new entry point to a pipeline owned by many partners, as this can mean renegotiating complex agreements. It is often more attractive for a new development to be tied into an existing one, making use of the existing entry point to the transportation system. A sub-allocation agreement is required to deal with the sub-allocation of products allocated to the entry point under the main transportation agreement. Usually, the new field is required to meter its products to a reasonably high standard. The high-quality metering at the export point into the transportation system now meters the commingled flow of the existing and new fields. It is usually not deemed economic to install high-quality metering for the products from the existing field, and the process metering is usually of a significantly lower standard. In these circumstances, the production from the existing field is determined by subtracting the production of the new field from the total production exported into the transportation system.

Clearly, allocation by difference can operate equally well on a mass-component-based allocation system as on a quantity-based allocation system.

Additional new fields may be added, provided that they are metered to a reasonable, agreed accuracy. The sub-allocation can be made from the shared export point into the transportation system with one, and only one field, not metered.

It is necessary to take care when using this approach for the following reasons.

- The uncertainty in the measurements from the existing field increases significantly and can affect the partner's shares, or government taxes if the different fields are taxed at different rates.
- The allocation schemes described in 11.2.2 to 11.2.4 have a in-built check for errors in that the sum of the input production equals the output production within the uncertainty of the meters. With allocation by difference, this check is lost and errors are less obvious.
- The un-metered field is the "balance" for the sub-allocation, and it bears the consequences of any errors in the metering of the other fields.

11.2.5.3 New development tied into an existing transportation system

A gas producer may feed the production from one or more fields into its own transportation system. At the end of the transportation system, there may be further processing before the gases and liquids are exported through high-accuracy export meters. As long as the equity in the fields is the same, and they fall under the same taxation schemes, it might not be necessary to have an accurate allocation system; it can be sufficient to base the company internal allocation system on the process standard measurements.

For various reasons, the gas producer may allow another gas producer to transport gas/condensate in the transportation system. Immediately, the issue of high-accuracy allocation arises. The obvious solution is to install high-accuracy allocation metering on each field inlet into the transportation system. This is often considered too expensive for the original gas producer, who can be required to install a number of metering stations. Similarly, the new gas producer might not be willing to pay for the installation of the metering stations for the installations of the original gas producer. The compromise is for the new producer to install high-accuracy metering at the inlet into the transportation system, and for the total production of the original producer to be determined by difference between the export meter at the end of the transportation system and the metering of the new field. It is necessary to draw up an allocation-by-difference agreement.

It is evident that this situation is almost identical to the sub-allocation system described in 11.2.5.2, and that it is necessary to take the same care in using this approach.

11.2.6 Uncertainty-based allocation systems

From the above, it is evident that there can be transportation systems where the uncertainties of the metering of the fields feeding into the transportation system can be markedly different; say process standard metering and fiscal standard metering. The allocation-by-difference solution is to determine by difference the production of the one producer who is allowed poor metering. Increasingly, there are transportation systems, particularly where there are producers of wet gas and producers of dry gas, where the quality of metering into the transportation system varies widely, but the producers want an allocation system that allocates the products equitably despite the differences in quality of the metering. At the export point from the transportation system, it is assumed there are high-accuracy meters for gas and liquid. Further, it is assumed that producers endeavour to correct their metering systems for systematic errors.

In a perfect transportation system, all metering errors would be zero, and the sum of the input metering figures would be equal to the output metering figure. In reality, there is always a difference between the sum of the input figures and the output figure, and it is evident that the difference is due to the input metering figures with high associated uncertainties. A pragmatic solution is to prorate the difference between the sum of the input metering figures and the output metering figure among the fields according to the uncertainties of the metering associated with the fields, and add the prorated figures to the field figures. In this way, the input metering figures from fields that have low uncertainty metering change by only a small amount; while fields with larger uncertainties have their input metering figures changed by a proportionately larger amount. In other words, producers who have higher-quality metering receive the benefit of the products they say they have produced, which is the best that one can reasonably expect.

The adjustment, A, for each field is determined as given in Equation (32):

$$A = \frac{\left[\sum_i \left(P_{\text{in},i} - P_{\text{out}} \right) \times U_{\text{in},i} \right]}{\sum_i \left(U_{\text{in},i} + U_{\text{out}} \right)} \tag{32}$$

where

$P_{\text{in},i}$ is the input product for field i;

P_{out} is the output product;

$U_{\text{in},i}$ is the metering uncertainty for field i;

U_{out} is the output uncertainty.

API RP85 discusses uncertainty-based allocation in depth.

11.2.7 LNG system

LNG plants probably represent the extreme of gas/condensate allocation systems. In most gas/condensate systems, the liquids represented by the condensate are usually a by-product. However, in LNG plants, most of the gas is liquefied and hydrocarbon liquids are the main product. Nonetheless, the allocation principles and measurement methods are essentially the same.

12 Mis-measurements — Measurement-correction and estimations

Measurement and allocation incidents can occur from time to time. Some allocation procedures have defined fallback routines for this purpose. This is especially necessary in case of a particular repetitive failure. However, most incidents are relatively unique and cannot be resolved by standard procedures. Most incidents originate from measurement failures; some are due to human error; others are caused in the hydrocarbon accounting process.

Measurement incidents can be split into the following categories:

- instrument failure or shifted value that can be corrected by applying a fixed offset over a determined period;
- assumed drift of an instrument value that can be corrected by a production adjustment or a time proportional offset in the instrument value over the period concerned;
- complete loss of the measurement value, which is necessary to replace by an estimation; common practice is to reconstruct the lost measurement value based on upstream (well head) data or downstream measurement values.

Human errors, such as typographical errors and errors in the allocation mechanism, are often traceable and can be corrected by a rerun or recalculation of the allocation process. This recalculation shall normally be done over the full time-base period of the allocation procedure, often on a monthly or sometimes on a daily basis.

In many cases, a corrective calculation is based on assumptions or estimations. Discussions with parties affected is then necessary. In these cases, an estimation of the uncertainty of the correction is necessary. In case of disputes or serious doubts, an independent expert opinion can resolve the issue.

Annex A
(informative)

Adjust for impurities

The mass of gas is corrected for water vapour using the fractions as given in Equation (A.1):

$$m_{\mathrm{MGCW},f} = m_{\mathrm{g},f} \times (1 - F_{\mathrm{wvc}}) \tag{A.1}$$

where

$m_{\mathrm{MGCW},f}$	is the mass of gas per field after correction for water;
F_{wvc}	is the water vapour correction factor, calculated using the Buckachek method (see ISO 8222) for each field, as given in Equation (A.2).

$$F_{\mathrm{WVC}} = \frac{A}{\overline{P}} + B \tag{A.2}$$

where the values A and B are derived using the gas temperature and the latest water tables.

Annex B
(informative)

Adjustments for fuel/utility/vent/flare gas

It is necessary to account for any gas not available for transportation by (a) separate method(s), such as the generic methods suggested below.

a) The gas, $g_{\mathrm{C},f}$, for each field after correction for fuel gas and water can be calculated by subtracting the fuel/utility/vent/flare gas dedicated to the field supplied from its own source directly from the metered quantity, as given in Equation (B.1):

$$g_{\mathrm{C},f} = g_{\mathrm{CW},f} - g_{\mathrm{f,u,v,f}} \tag{B.1}$$

where

$g_{\mathrm{CW},f}$ is the gas corrected for water;

$g_{\mathrm{f,u,v,f}}$ is the fuel/utility/vent/flare gas.

b) Fuel/utility/vent/flare gas supplied from a common stream source may be subtracted using a method consistent with the allocation methodology in use, i.e. by component for mass component allocation, etc.

c) Fuel/utility/vent/flare usage may be proportioned to the differing sources by a number of methods including

- compression dependent equations,
- field dedicated equipment,
- common stream fuel/utility/vent/flare usage.

Annex C
(informative)

Wet gas

In the upstream area of gas and condensate production, wet gas should be considered as a hydrocarbon gas stream where liquid is physically present. These liquids can be either water or liquid hydrocarbons. In principle, wet gas is a two- or three-phase mixture. Any hydrocarbon gas stream that does not contain a liquid phase should be considered as a single-phase, dry gas stream. In principle, a single-phase gas stream can become a wet-gas stream when temperature and pressure changes during further processing. The physical occurrence of the hydrocarbon mixture during the measurement determines whether it is a single-phase gas measurement or whether it is a wet-gas measurement. Note that sometimes a wet-gas stream is defined as a single-phase gas stream that with further processing can deliver liquids. This latter definition should be avoided. As an example, an orifice plate measurement on a single-phase gas stream can be done according to ISO 5167-2 even if there are lots of heavier components present in the gaseous state. If the heavier components have condensed into liquid, the ISO 5167-2 guidelines are not valid anymore.

The above can best be demonstrated with an example. Gas produced from a reservoir can initially appear in the flow line as a single-phase gas (or dense phase). Here pressure and temperature are such that it is still outside the two-phase envelope in the pressure-temperature diagram (see Figure C.1). From a measurement point of view, this falls in the category of a single-phase flow measurement, hence single-phase flow meters like orifice plates, Venturi, etc., can be used. Subsequent processing, with a further reduction of pressure and temperature, can cause liquids to form and subsequently the sample falls within the two-phase envelope in the pressure-temperature diagram. Liquids are present and, from a measurement point of view, this is a two-phase flow measurement. As the liquid fraction is generally small compared to the gas fraction, this is often called a wet-gas measurement. Hence, from a measurement point of view, wet gas is defined as a gas stream in which liquids are physically present. Note that in most cases water also drops out at the surface because of the lower temperature.

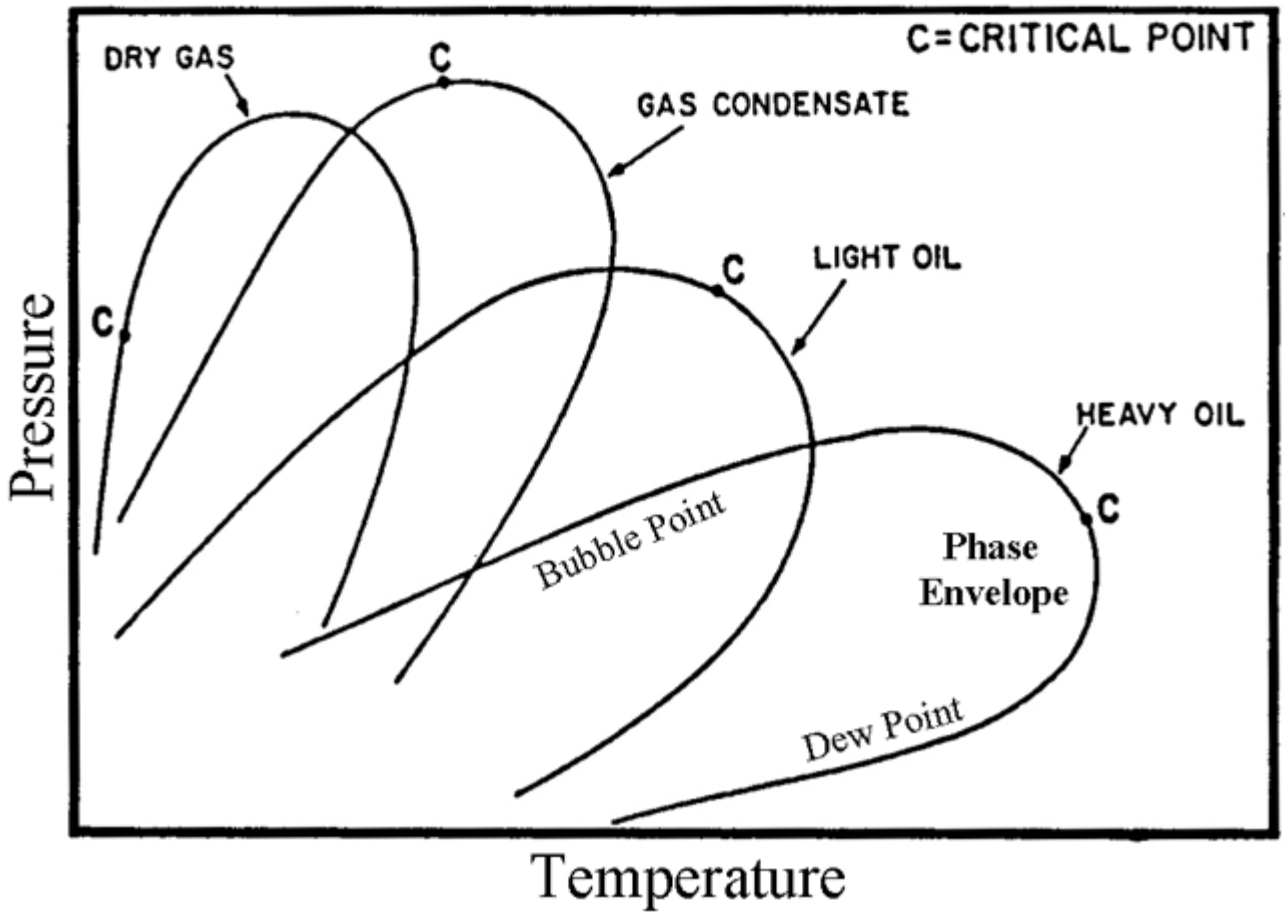


Figure C.1 — Phase diagram for different types of well production

The wet-gas area is the lower right area of the two-phase flow map, generally with GVF's comprising more than approximately 90 % to 95 %. The exact position of this boundary is not defined but often the Lockhart Martinelli, LM, parameter is used. Often the region LM $<$ 0,3 is considered to be the wet-gas area of the two-phase flow map. Under conditions after the choke, the mass fractions of liquid and gas are approximately the same, i.e. 50 % each. However, this region is determined only because correlations used in the wet-gas measurement have been developed up to this value.

Parameters/terminology that can be encountered in a wet gas system are gas volume fraction (GVF), as given in Equation (C.1), and gas volume fraction (GMF), as given in Equation (C:2):

$$\mathrm{GVF} = \frac{V_{\mathrm{gas}}}{V_{\mathrm{gas}} + V_{\mathrm{liquid}}} \tag{C.1}$$

or

$$\mathrm{GMF} = \frac{V_{\mathrm{gas}}\rho_{\mathrm{gas}}}{V_{\mathrm{gas}}\rho_{\mathrm{gas}} + V_{\mathrm{liquid}}\rho_{\mathrm{liquid}}} \tag{C.2}$$

For wet gas applications, the inequalities in Equation (C.3) generally hold.

$$\mathrm{GVF} > 0{,}9 \text{ and } \mathrm{GMF} > 0{,}5 \tag{C.3}$$

The gas Froude number, $\mathrm{Fr_g}$, is defined as given in Equation (C.4):

$$\mathrm{Fr_g} = \frac{U_{\mathrm{gs}}}{\sqrt{gD}} \sqrt{\frac{\rho_{\mathrm{gas}}}{\rho_{\mathrm{liquid}} - \rho_{\mathrm{gas}}}} \qquad \text{(C.4)}$$

The Lockhart-Martinelli parameter, LM, is defined as the ratio, X, of the liquid and gas superficial inertia forces (in the same way as the Reynolds number is the ratio of a fluid's inertia forces to viscous forces), as given in Equation (C.5):

$$\mathrm{LM} = \frac{\mathrm{Fr_{liquid}}}{\mathrm{Fr_{gas}}} = \frac{U_{\mathrm{ls}}}{U_{\mathrm{gs}}} \sqrt{\frac{\rho_{\mathrm{liquid}}}{\rho_{\mathrm{gas}}}} \qquad \text{(C.5)}$$

For a typical wet gas application, the Lockhart-Martinelli parameter is generally $< 0{,}35$.

On plots of wet-gas data, the over-reading is presented as a factor, e.g. 1,35, which means that there is a systematic 35 % over-reading relative to the “gas-only reading ” The plot below is a typical example for a Venturi and Cone meter.

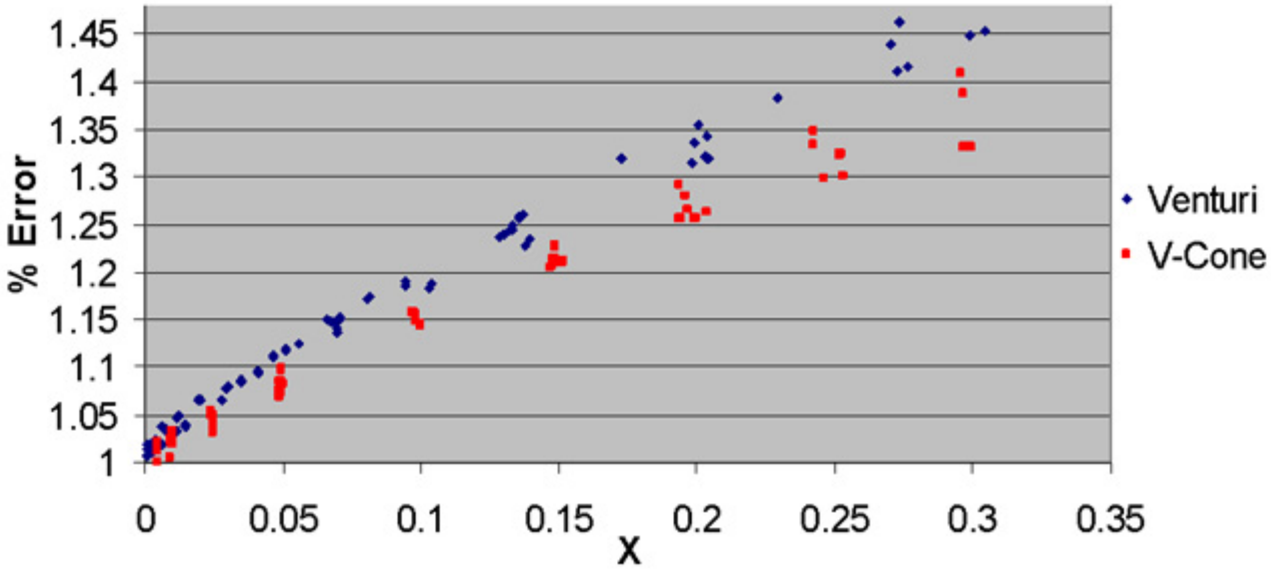


Figure C.2 — Over-reading for wet-gas data

Annex D
(informative)

Codes, abbreviations and acronyms

D.1 Three letter codes

D.1.1 Input type

A	allocated	O	own use
B	blown-off	P	platform or production site
C	calculated	R	reconciled or reconciliation factor
D	direct	S	sales
E	entry Point	T	total
I	indirect or input	U	unreconciled
M	mixed	W	wet (gas)

D.1.2 Physical stream

C	condensate
G	gas
H	hydrocarbons
I	input
S	stream

D.1.3 Units

C	constant	—
D	density	kilograms per cubic metre (kg/m^3)
F	fraction	—
H	heating value	megajoules per cubic metre (kg/m^3)
E	energy	megajoule (MJ)
M	mass	kilogram (kg)
V	volume	cubic metre (m^3)
R	ratio	—
S	stream	—

D.2 Subscripts

i	field or contract
j	day in the month

D.3 Examples

$\text{SGV}_{(j)}$	sales gas in volume, expressed in cubic metres, at day j
RCF	reconciliation factor for condensate
$\text{BGM}_{(i,j)}$	mass, expressed in kilograms, of blown-off gas for field i at day j
$\text{PGV}_{(i,j)}$	volume, expressed in cubic metres, of the gas of field i at day j

Annex E
(informative)

Conversion of molar percent to mass percent

Component properties are in accordance with ISO 6976:1995.

Input to this calculation is the composition, expressed in mole percent, of the fluid (gas or condensate), as given in Table E.1. Table E.2 shows an example calculation.

Table E.1 — Input for conversion of mole percent to mass percent

Component	Concentration mol %	Relative molecular mass	Mass contribution	Concentration mass %
C1	m_{C1}	M_{rC1}	$m_{\text{C1}} \times M_{\text{rC1}}$	$\left(\dfrac{m_{\text{C1}} \times M_{\text{r C1}}}{\sum_{i=1}^{10} m_i \times M_{\text{r}\,i}} \right) \times 100$
C2	m_{C2}	M_{rC2}	$m_{\text{C2}} \times M_{\text{rC2}}$	$\left(\dfrac{m_{\text{C2}} \times M_{\text{r C2}}}{\sum_{i=1}^{10} m_i \times M_{\text{r}\,i}} \right) \times 100$
.....	.....	.....	.....	.....
Summation	100		$\sum_{i=1}^{12} m_i \times M_{\text{r}\,i}$	100

Table E.2 — Example calculation

Component	Concentration mol %	Relative molecular mass	Mass contribution	Concentration mass %
C1	85,46	16,043	1 371	69
C2	6,45	30,070	194	9,8
C3	3,48	44,097	153	8
*i*C4	1,04	58,123	60	3
*n*C4	0,80	58,123	46	2
*i*C5	0,31	72,150	22	1
*n*C5	0,31	72,150	22	1
*i*C6	0,13	86,177	11	1
*n*C6	0,12	86,177	10	1
*n*C7	0,16	100,204	16	1
CO_2	1,66	44,010	73	4
N_2	0,08	28,0135	2	0
Summation	100,00	—	1 980	101

Annex F
(informative)

Conversion of mole percent to per cent of the calorific value

Component properties are in accordance with ISO 6976:1995.

Input to this calculation is the composition, expressed in mole percent, of the fluid (gas or condensate), as given in Table F.1. Table F.2 shows an example calculation.

Table F.1 — Input for conversion of mole percent to percent of the calorific value

Component	Concentration mol %	Calorific value	Calorific value contribution	Calorific value %
C1	m_{C1}	$C_{\text{V,C1}}$	$m_{\text{C1}} \times C_{\text{V,C1}}$	$\left(\dfrac{m_{\text{C1}} \times C_{\text{V,C1}}}{\sum_{i=1}^{10} m_i \times C_{\text{V},i}} \right) \times 100$
C2	m_{C2}	$C_{\text{V,C2}}$	$m_{\text{C2}} \times C_{\text{V,C2}}$	$\left(\dfrac{m_{\text{C2}} \times C_{\text{V,C2}}}{\sum_{i=1}^{10} m_i \times C_{\text{V},i}} \right) \times 100$
.....	.....	.....	.....	.....
Summation	100		$\sum_{i=1}^{12} m_i \times C_{\text{V},i}$	100

Table F.2 — Example calculation

Component	Concentration mol %	Calorific value	Calorific value contribution	Calorific value %
C1	85,46	891,56	761,93	73,76
C2	6,45	1562,14	100,76	9,75
C3	3,48	2221,10	77,29	7,48
*i*C4	1,04	2870,58	29,85	2,89
*n*C4	0,80	2879,76	23,04	2,23
*i*C5	0,31	3531,68	10,95	1,06
*n*C5	0.31	3538,60	10,97	1,06
*i*C6	0,13	4190,62	5,45	0,53
*n*C6	0,12	4198,24	5,04	0,49
*n*C7	0,16	4857,18	7,77	0,75
CO_2	1,66	0	0	0,00
N_2	0,08	0	0	0,00
Summation	131	—	1 033,05	100

Annex G
(informative)

Conversion of mole per cent to volume percent

Component properties are in accordance with ISO 6976:1995.

Input to this calculation is the composition in mol% of the fluid (gas or condensate), as given in Table G.1. Table G.2 shows an example calculation.

Table G.1 — Input for conversion of mole percent to volume percent

Component	**Concentration** mol %	**Compression factor** z	**Volume contribution**	**Volume** %
C1	m_{C1}	z_{C1}	$m_{C1} \times z_{,C1}$	$\left(\frac{m_{C1} \times z_{C1}}{\sum_{i=1}^{10} m_i \times z_i}\right) \times 100$
C2	m_{C2}	z_{C2}	$m_{C2} \times z_{C2}$	$\left(\frac{m_{C2} \times z_{C2}}{\sum_{i=1}^{10} m_i \times z_i}\right) \times 100$
.....	.....	.....	.....	.....
Summation	100		$\sum_{i=1}^{12} m_i \times C_{V,i}$	100

Table G.2 — Example calculation

Component	**Concentration** mol %	**Compression factor** z	**Volume contribution**	**Volume** %
C1	85,46	0,998 0	85,29	86
C2	6,45	0,991 5	6,40	6
C3	3,48	0,982 1	3,42	3
*i*C4	1,04	0,968 0	1,01	1
*n*C4	0,80	0,965 0	0,77	1
*i*C5	0,31	0,948 0	0,29	0
*n*C5	0,31	0.937 0	0,29	0
*i*C6	0,13	0,925 0	0,12	0
*n*C6	0,12	0,913 0	0,11	0
*n*C7	0,16	0,866 0	0,14	0
CO_2	1,66	0,994 4	1,65	2
N_2	0,08	0,999 7	0,08	0
Summation	100,00	—	99,75	99

Annex H
(informative)

Components of gas and liquid reported

The components should be reported in mole percent.

Component properties are in accordance with ISO 6976:1995.

Real molar volume is calculated for standard conditions using Equation (H.1):

$$V_{\mathrm{m(real)}} = \frac{z \times R \times T_2}{p_2} \tag{H.1}$$

where $R = 8{,}314\ 51$ l/mol, $T_2 = 288{,}15$ K and $p_2 = 101{,}325$ kPa.

Values for the compression factor, z, calculated at standard conditions, are given in Table H.1.

Table H.1 — Compression factors calculated at standard conditions

Component number	Component	Name	Relative molecular mass kg/kmol	Calorific value kJ/mol	Compression factor z	Real molar volume m^3/kmol
1	C1	methane	16,043	891,56	0,998 0	23,597 7
2	C2	ethane	30,070	1 562,14	0,991 5	23,444 0
3	C3	propane	44,097	2 221,10	0,982 1	23,221 7
4	*i*C4	2-methylpropane (iso-butane)	58,123	2 870,58	0,968 0	22,888 3
5	*n*C4	butane (normal-butane)	58,123	2 879,76	0,965 0	22,817 4
6	*i*C5	2-methylbutane (iso-pentane)	72,150	3 531,68	0,948 0	22,415 4
7	*n*C5	pentane (normal-pentane)	72,150	3 538,60	0,937 0	22,155 3
8	*i*C6	2-methylpentane (iso-hexane)	86,177	4 190,62	0,925 0	21,871 6
9	*n*C6	hexane (normal-hexane)	86,177	4 198,24	0,913 0	21,587 9
10	*n*C7	heptane (normal-heptane)	100,204	4 857,18	0,866 0	20,500 0
11	CO_2	carbon dioxide	44,010	0	0,994 4	23,512 6
12	N_2	nitrogen	28,0135	0	0,999 7	23,637 9

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NOTE from ISO EDIT: Complete citations are needed for the following:

[8] Murdock

[9] Chisholm

[10] de Leeuw

[11] Multiphase '97 Conference in Cannes

[12] Steven et al. (work carried out at NEL)

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[15] AGA3

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