DEPARTMENT OF ENERGY GUIDELINES ON PETROLEUM MEASUREMENT: CHANGING PRACTICES

by

L N Philp
Department of Energy

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Summary

The paper outlines the amendments to petroleum licences introduced by the 1987 Petroleum Act and describes the detailed changes in the Department's guidance documents for the method of measurement for compliance with the measurement model clauses incorporated in petroleum licenses.

1. INTRODUCTION

The timing of the issues of revised metering Guidelines is not connected with the timing of amendments to the measurement model clauses incorporated in petroleum production licences for exploration for and production of petroleum within the UK and its continental shelf. However, the various Acts, and Regulations made under them, do provide the basis for the Guidelines, which represent the outcome of discussions and consultations on "good oilfield practice" with which, as stipulated in regulations, metering systems must comply. The recently revised Guidelines were issued only after such consultation with the representative industry bodies.

The latest legislation, the Petroleum Act 1987, received Royal Assent on the 9 April 1987. Section 17 makes provision for the amendment of model clauses incorporated in existing licences, and Section 18 makes provision for the amendment of model clauses for incorporation in future licences.

Schedule 1 - amends existing licences

Schedule 2 - amends model clauses in the current Regulations

These provisions (ie sections 17 and 18and Schedules 1 and 2) came into force on 30 June 1987.

2. THE AMENDMENTS

The amendments cover several aspects of the measurement of Petroleum which were not previously covered, usual practices within the UK oil and gas industry being recognised.

Appendix 1 - lists the relevant legislation

Appendix 2 - summarises the effects of the amendments in Schedules 1 and 2 on the measurement model clauses.

Appendix 3 - reprints of Department of Energy guidelines.

The existing model clauses incorporated in petroleum licences require the licensee to measure or weigh all petroleum won and saved from the licensed area. For Petroleum Revenue Tax (PRT) purposes petroleum is valued by reference to amounts won and saved from the relevant oil field(s) within a licensed area, reflecting the fact that production and measurement facilities are installed by licensees to produce and measure petroleum from fields of which there are frequently a number wholly or partly within a licensed area. As different oil fields within a licensed area may attract different PRT and royalty regimes it is important that the petroleum produced from each field should be capable of being separately measured.

The amendments which insert new paragraphs (1A) and (1B) in the mesurement model clause and which are reproduced in full in Appendix 2 have the effect that if separate parts of the licensed area are oilfields for the purpose of the Oil Taxation Act 1975, there may be a need for separate compliance with para (1) of the relevant model clause (sub para (a) of new para (1A)) for each field in the licensed area. This would also be the case for a separate field extending beyond the boundary of the licensed area (sub para (b)of new para (1A)), although unit agreement would be taken into account.

The reference in sub para (c) of new para (1A) to "each well .... not within such an oil field" covers measurement of petroleum won and saved from, for example, an extended well test where it is not yet established that the well is producing from a separate field. There may be a requirement for production from such wells, pending determination of their ultimate fiscal status, to be measured in compliance with para (1) of the relevant measurement model clause.

The inclusion in para (1B) of a requirement, if, and to the extent that, the Secretary of State directs, to measure quality or composition in the main formalises current practice. Some quality and/or composition measurements are needed to determine quantities. In the case of multifield pipeline operations or in the case of single tanker loading fields, quality measurements are needed to calculate dry oil quantities in mass units or volumes at reference conditions of pressure and temperature. Quality measurement is needed additionally for the purpose of valuing petroleum.

3. APPLICATION

Having outlined the changes in the measurement model clauses introduced in the new Act, I should like to point out that although these new provisions apply to existing licences, they are not automatic requirements and apply only if, and to the extent that, a direction is given by the Secretary of State. In addition I should emphasise that it is intended that these provisions will only apply to new fields and in particular there is no intention of requiring licensees to alter agreed methods of measurement or measuring appliances, except where a licensee proposes to make use of the measurement facilities of an existing field in measuring the petroleum won and saved from a new field. These provisions are to be applied with full regard to economic considerations.

The provisions of the measurement model clauses are administered by the Petroleum Measurement Inspectorate of the Gas and Oil Measurement Branch. It is not intended that measurement requirements should be so onerous as to stop worthwhile development of petroleum resources going ahead. The agreed method of measurement for any field development whether major or marginal has therefore always been arrived at as a result of dialogue between the operator and the Inspectorate and full consideration is given by the Inspectorate as to what constitutes "good oilfield practice" in the specific context of each proposed development. While separate measurement to full "fiscal" standards would be ideal, such systems imply, with the limitations of present-day technology, separate treatment. There will be a number of small but nevertheless valuable prospects which could not be economically developed if the full infrastructure associated with separate treatment were required to satisfy a strict metering requirement. However, measurement proposals for each field, development, etc are reviewed by the Inspectorate, which takes fully into account the need for and economic justification of the method of measurement ultimately agreed: but now to detailed measurement aspects as covered by the Guidelines themselves.

4. DEPARTMENT OF ENERGY METERING GUIDELINES

In June 1987 the Gas and Oil Measurement Branch of the Department of Energy issued revised versions of the three guidance documents.

> "Department of Energy Metering Standards for Liquid Petroleum Measurements,
>
> Department of Energy Approved Metering Stations - Operating Procedures (Liquid Hydrocarbon Measurement)
>
> Department of Energy Metering Standards for Gaseous Petroleum Measurements"

Some of the changes are administrative and apply to all three documents. There is a change of name and address for the responsible Branch including an issuing office address and an address and contact point for operational matters.

Changes have also been made in the sections listing reference standards. Here we have sought to cite the up-to-date titles and reference numbers of the current issues from the main standards organisations ie, BSI, ISO, IP, API. However as each of these organisations is actively reviewing many of its standards in the field of petroleum measurement and from time to time issues amendments or revisions as well as completely new documents, no statement can hope to provide an up-to-date position for long in this rapidly advancing field.

The remaining changes are of a detailed nature and specific to each document.

5. DEPARTMENT OF ENERGY METERING STANDARDS - GASEOUS PETROLEUM MEASUREMENT

Apart from the administrative changes already mentioned, we have been more specific in requiring the avoidance of carry-over of liquids into the metering section, (4.6 refers). We now include a stipulation of the requirement to be given at least 14 days prior notice of Factory Acceptance Testing and Calibrations.

6. DEPARTMENT OF ENERGY METERING STANDARDS - LIQUID PETROLEUM MEASUREMENT

The changes in the document covering liquid metering standards are intended to reflect the changing approach to the metering of liquid petroleum. Specific reference to turbine meters has been deleted to widen the scope to include suitable meters operating on other principles. Where appropriate PD, vortex shedding, coriolis, and orifice plate metering systems have been considered and no doubt there may be scope for devices operating on other physical principles.

Section 3 - Mode of Measurement

This section now makes specific mention of Petroleum (Production) Regulations which are the legal basis for the metering requirements. A new reference to the possible need for pressure compensators is also included.

Section 4 - Prover Loops and Sphere Detectors

This section now includes a specific requirement for the continuity of the pipework within the calibrated volume. Here also we introduce the possibility, where approved, of the use of small volume provers and liquids other than the service liquid for the re-calibration of prover loops.

The repeatability criterion for prover loop calibrations has been re-stated as $\pm$ 0.01% of the mean volume of five consecutive round trips or statistically equivalent criterion may be used when using a small volume prover to calibrate a large pipe prover.

The note added to 4.4 referring to "other designs" is intended to permit the use of small volume provers for proving meters in service where their use can be agreed to conform to "good oilfield practice". My view is that there is still some way to go to establish these devices in offshore service particularly when used with partially processed crude.

Section 5 - Meters and Associated Pipework

Specific reference to turbine meters has been deleted as we recognise that in certain circumstances instruments operating on different physical principles may be more appropriate. A new statement has been included emphasising the need to exercise care in the selection of temperature and density measuring points to ensure the measurements are as representative of the conditions at the meter inlet as is reasonably practical.

Where we refer to the use of mercury-in-glass thermometers for temperature loop checks, we now state clearly that these should be certified thermometers.

Section 6 - Recirculation Facilities

Where re-circulation systems are fitted around the metering system, we have removed the requirement for automatic gating out of meters and replaced it with a requirement to log fully all recirculated and any non-export flows.

Section 7 - Pulse Transmission

Provision is now made to accept pulse error alarms generated by an error rate as well as the previous system based on cumulative error counts.

Section 8 - Totalisers and Compensators

An extra statement has been added requiring operators to give an outline on the procedures to be adopted to correct errors in flows caused by periods of mis-measurement.

Section 11 - Calibration Facilities

Here we now state that the calibrations of test equipment be traceable to National Standards of Measurement. This generally means UK National Standards but for imported equipment, initial traceability to the National Standards of the Country of origin would generally be accepted for the currency of the initial certification and subsequent re-calibrations should then be traceable to UK National Standards.

7. OPERATING PROCEDURES FOR LIQUID HYDROCARBON MEASUREMENT

Foreword

Reference is now made to types of meter other than turbine meters and the requirement where necessary to modify operating procedures to account for different characteristics particularly with "difficult" fluids such as viscous crudes or low lubricity fluids such as gas condensates.

We now require operators to submit their proposals for operation and calibration of their systems in duplicate to the Aberdeen office prior to commisioning and operation of the metering systems.

Section 1 - Prover Calibration

Apart from the name change the only new requirement is for two copies of prover loop calibration certificates.

Section 3 - Meter Proving in Service

This revised section gives more detailed advice on when to re-prove meters as a consequence of a change in flowrate.

Also included is a new paragraph dealing with proving requirements for meters other than turbine meters.

Section 4 - Meter Factors

The repeatability requirement for proving meters in service has been re-stated as $\pm$ 0.05% of the mean of five consecutive proof runs.

Section 6 - Documentation to be kept at the Meter Station

The log keeping requirements now includes density where this is measured continuously.

The minimum period for the retention of logs at the metering site has been increased from 3 to 4 months.

Section 7 - Direct Reporting

Specific reference to turbine meters has been deleted to account for systems where other types of flow meters may be employed.

Any reports required under this section should now be sent direct to Gas and Oil Measurement Branch. In the case of land terminals, the option to submit reports via Customs and Excise has been cancelled.

APPENDIX 1

Legislation pertaining to Petroleum Production Measurement

The Petroleum (Production) Act	1934
The Continental Shelf Act	1964
The Petroleum and Submarine Pipe-lines Act	1975
The Oil Taxation Act	1975
The Petroleum Act	1987

The various sets of Petroleum (Production) Regulations made by the Secretary of State in pursuance of powers conferred on him by Section 6 of the Petroleum (Production) Act 1934.

One of the provisions of the measurement model clause incorporated in petroleum production (and landward appraisal) licences is as follows:

"The Licensee shall measure or weigh by a method or methods customarily used in good oilfield practice and from time to time approved by the Minister all petroleum won and saved from the licensed area".

APPENDIX 2

PETROLEUM ACT 1987 - MEASUREMENT MODEL CLAUSE AMENDMENTS

Section 17 and 18

Section 17 amends existing licences as provided by Schedule 1 to 1987 Act.

Schedule 1 amends existing licences in

1975 PETROLEUM SUBMARINE PIPELINE ACT

Part II Schedule 2 (Seaward Areas)	Measurement Model Clause 12
Part II Schedule 3 (Landward Areas)	Measurement Model Clause 12

1976 PETROLEUM (PRODUCTION) REGULATIONS

Schedule 4 (Landward Areas)	Measurement Model Clause 12
Schedule 5 (Seaward Areas)	Measurement Model Clause 12

1982 PETROLEUM (PRODUCTION) REGULATIONS

Schedule 4 (Landward Areas)	Measurement Model Clause 12
Schedule 5 (Seaward Areas)	Measurement Model Clause 11

1984 PETROLEUM (PRODUCTION) (LANDWARD AREAS) REGULATIONS

Schedule 4 (Landward Areas) (appraisal licences)	Measurement Model Clause 10

Schedule 2 amends Model Clauses (for incorporation in future licences)

1982 PETROLEUM (PRODUCTION) REGULATIONS

Schedule 5 (Seaward Areas)	Measurement Model Clause 11

1984 PETROLEUM (PRODUCTION) (LANDWARD AREAS) REGULATIONS

Schedule 4 (Landward Areas) (appraisal licences)	Measurement Model Clause 10
Schedule 5 (Landward Areas) (development licences)	Measurement Model Clause 11

These amendments insert after paragraph (1) of the relevant Measurement Model Clause the two following paragraphs:-

"(1A) If and to the extent that the Minister so directs, the duty imposed by paragraph (1) of this clause shall be discharged separately in relation to petroleum won and saved -

(a) from each part of the licensed area which is an oil field for the purposes of the Oil Taxation Act 1975,

(b) from each part of the licensed area which forms part of such an oil field extending beyond the licensed area, and

(c) from each well producing petroleum from a part of the licensed area which is not within such an oil field.

(1B) If and to the extent that the Minister so directs, the preceding provisions of this clause shall apply as if the duty to measure or weigh petroleum included a duty to ascertain its quality or composition or both; and where a direction under this paragraph is in force, the following provisions of this clause shall have effect as if reference to measuring or weighing included references to ascertaining quality or composition."

APPENDIX 3

JUNE 1987
ISSUE 3

DEPARTMENT OF ENERGY METERING STANDARDS FOR GASEOUS PETROLEUM MEASUREMENTS

1. INTRODUCTION

1.1 This document comprises a set of guidelines, issued to Licensees and Operators in the UK Continental Shelf and Landward Areas, for use in the design, construction and submission of gas metering systems that are to gain Department of Energy approval. It also covers the construction and operation of electronic computing and totalising systems.

1.2 It is intended that these specifications should be interpreted as general minimum requirements and that relaxed requirements will only be appropriate in special circumstances. Alternative specifications to those given in this document will be permitted provided that they can be shown to provide a similar or greater level of fidelity and accuracy. With this in mind Operators are required to submit metering proposals in duplicate to the Department of Energy, Gas and Oil Measurement Branch (GOMB) prior to the commencement of manufacture or, where practicable, at the design stage. The Branch address is:-

Department of Energy
Gas and Oil Measurement Branch
Greyfriars House
Gallowgate
Aberdeen
AB9 2ZV

1.3 The metering requirements apply to:

1.3.1 Custody Transfer of gas covering sale, export or import. This includes the transfer of gas from one licensed area to another where both licences are held by the same licensee.

1.3.2 Allocated Utility and Fuel Gas. This category covers the measurement of gas used for process and power where the quantities of gas are used in allocating the production gas to more than one licensed area.

1.3.3 Continuous Flare Gas and Utility and Fuel Gas other than that covered by 1.3.2.

1.4 Gas Streams other than those indicated above, e.g. vent, reinjection or lift gas, should be accounted for. Special provisions will apply where gas is stored in conjunction with production.

2. REFERENCE STANDARDS

2.1 Gas metering systems should generally conform to the following standards where applicable.

a) BS 1042: Part 1: Section 1.1: 1981
Methods of measurement of fluid flow in closed conduits: Orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full.
or its near equivalent
ISO 5167: 1980
Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross-section conduits running full.

b) BS 5844: 1980
Measurement of fluid flow - Estimation of uncertainty of flow-rate measurement.
or
ISO 5168: 1978
Measurement of fluid flow - Estimation of uncertainty of flow-rate measurement.

c) BS 4161: Part 6: 1979
Rotary displacement and turbine meters for gas pressures up to 100 bar.

d) Institute of Petroleum, Petroleum Measurement Manual:

i) Part VII Density: Section 2: 1983 Continuous Density Measurement.

ii) Part XIII Fidelity and Security of Measurement Data Systems Section 1: 1976 Electric and/or Electronic Pulsed Data Cabled Transmission for Fluid Metering Systems (IP 252/76).

iii) Part XIII Fidelity and Security of Measurement Data; Section 3: 1985 Electrical and/or Electronic Data Capture Systems for Flow Metering.

3. MODE OF MEASUREMENT

3.1 All measurements should be made on single phase gas streams.

3.2 Hydrocarbon measurements may be in either volumetric or mass units. The choice of measurement should however be discussed with the Department of Energy. Volumes should be measured in cubic metres and mass in tonnes.

3.3 Where volume is the approved measurement, it should be referred to the standard reference conditions of 15°C temperature and 1.01325 bar absolute pressure (dry).

3.4 Where gas is subject to custody transfer, or used as a fuel where 1.3.2 applies, suitable sampling facilities shall be provided for the purpose of obtaining representative samples. This requirement may be influenced by the type of instrumentation incorporated in the measuring system.

3.5 The continuous measurement of gas density is preferred for custody transfer but the density of the gas being metered may, under certain circumstances, be computed from pressure and temperature measurements together with gas composition using a suitable equation of state and agreed computational techniques.

4. DESIGN -CRITERIA

4.1 Custody Transfer Gas

4.1.1 Where orifice meter systems are used, the design and operation should comply with BS 1042 : 1981 (ISO 5167) but with the additional specifications given below:-

a) Maximum beta ratio 0.6

b) Maximum Reynolds number 3.3×10^7

c) Maximum differential pressure 0.5 bar is preferred. Higher differential pressures may be used where it is demonstrated that the conditions of e), f) and g) are met.

d) The meter should be designed and constructed such that the minimum uncertainties specified in BS 1042 : 1981 are achieved.

e) The elastic deformation of the orifice plate at maximum differential pressure shall be less than 1%.

f) The uncertainty in flow caused by elastic deformation of the orifice plate shall be less than 0.1%.

g) The location of the differential pressure tappings with respect to the orifice plate shall remain within the tolerances given in BS 1042 : 1981 over the operating range of differential pressures.

h) Special considerations may be applicable where pulsations are unavoidable but normally the uncertainty due to any such effects should be kept below 0.1%.

4.1.2 Where metering systems other than orifice plate metering are to be used, the systems together with their flow compensating devices should be of the types agreed by the Department of Energy (see para 1.2) and should be calibrated over as much of the operating pressure, temperature and flow range as is reasonably practicable. Proposals for any extrapolation of such calibrations and correlations of the operating conditions should be presented.

4.1.3 Secondary instrumentation, line pressure and temperature, differential pressure, flowing density, density at base or reference conditions where appropriate and the flow computers should be specified and their positions in the system should be located such that representative measurement is ensured. In many applications the compositional analysis of the gas is required and it is necessary to provide for gas sampling or on-line analysis.

4.2 Allocated Utility and Fuel Gas

4.2.1 The total quantity of gas should be metered at one off-take if this is practicable. It is not necessary to meter gas streams to individual points of consumption (e.g. individual compressors) if the flow can be obtained from a single set of meters giving the total flow to the (compressor) station.

4.2.2 Where orifice plate meters are used the design and operation should comply with BS 1042 : 1981 (ISO 5167) The specifications given above in paragraph 4.1.1 a), b), c) and d) need not apply, but the design should meet the requirements of 4.1.1 e), f), g) and h).

4.2.3 Where meters other than orifice plate meters are used the requirements given in paragraph 4.1.2 shall apply.

4.3 Continuous Flare Gas and Utility and Fuel Gas other than that covered by 1.3.2

Proposals for determining these quantities (either directly or indirectly) should be presented. It is assumed that the venting of gas would be under abnormal or emergency conditions only. Provisions for estimates of such quantities should be made.

4.4 For custody transfer (1.3.1) and for allocated utility gas (1.3.2), sufficient meter runs should be provided to ensure that, at the nominal designed field production rate or utility rate, at least one stand-by meter is available. Due consideration should be given to the provision of adequate valves so that individual meters may be removed from service without shutting down the entire metering system.

4.5 Consideration should be given during design to the provision of back-up instrumentation to cover the failure of normal instrumentation, and to the on-site calibration of primary and secondary metering equipment.

4.6 Metering stations should be designed to be free from any carry over into the metering section, and from any condensation or separation, that would have a significant effect on measurement uncertainties.

4.7 An indication of the overall design accuracy and uncertainty in measurement of the metering system together with the sources of error should be given (paragraph 10.1 of BS 1042 : 1981) The assessment of uncertainties in gas measurement should preferably be calculated in accordance with BS5844 : 1980. (The Appendix contains guidance.)

4.8 Computers and Compensators

4.8.1 A flow computer should be dedicated to each meter run.

4.8.2 For custody gas (1.3.1) and utility gas (1.3.2) all computer and compensating functions, other than data input conversions, should preferably be made by digital methods. All calculation constants should be securely stored in the computer and should be easily available for inspection. Equipment should be designed so that constants can be adjusted, but only by authorised personnel. After initial agreement of stored constants subsequent changes in the computer should be made only with agreement of the Department. Where it is necessary to use manual inputs of data into the computer e.g., base density, the use of this data should be automatically logged.

4.8.3 Totalisers on individual and station summators should have sufficient digits to prevent roll-over more frequently than every two months. Totalisers should normally have a resolution of 1 tonne or 1000 standard cubic metres, or decimal submultiples thereof. Totalisers and summators should be non-resettable.

4.8.4 Where rotary positive displacement or turbine meters are used both compensated and uncompensated flow quantities should be recorded.

5. GENERAL

5.1 A comprehensive dossier containing the following information should be submitted as early as possible.

(a) Basic data.

(b) Design formulae and calculations.

(c) Secondary instrumentation specifications.

(d) Overall accuracy, or uncertainty in measurement.

(e) Relevant drawings.

(f) Outline of calibration and verification methods.

5.2 In a gas gathering system the operator responsible for the gathering should ensure that the basic metering data, flow formulae and computational techniques are compatible throughout all the fields connected to the gathering system.

5.3 The Petroleum Production Reporting System, agreed between the UKOOA and the Department of Energy calls for the average calorific value (energy per unit volume) of custody transfer gas to be reported to the Department monthly. Provision for the determination of the calorific value of custody transfer gas should therefore be considered.

5.4 The Department of Energy will require adequate notice (normally at least 14 days) of the factory inspection and calibration of primary and secondary equipment, including flow computers, in order that GOMB may witness these tests at their discretion.

5.5 Adequate verification or, where appropriate, calibration equipment should be provided to enable the performance of meters, computers, totalisers etc, to be assessed. Reference or transfer standards shall be certified by a laboratory with recognised traceability to National Standards (e.g. British Calibration Service).

Issued by:-
Department of Energy
Gas & Oil Measurement Branch
3 Tigers Road
South Wigston
Leicester
LE8 2US

Telephone 0533 785354
Telex 342457
June 1987

Contact point on operational matters:-
Telephone 0224 647961
Telex 739283

APPENDIX

The Calculation of Design Uncertainties in Flow Measurement using Orifice Plate Meters
BS 1042 : 1981 (ISO 5167) ; BS 5844 : 1980 (ISO 5168)

1. The uncertainty in the measurement of a mass flow rate, q m, should be calculated using the simplified formula given in BS 1042 paragraph 10.2.2 (see list of equations, equation 1).

   The percentage uncertainty E of a variable can be substituted for the relative uncertainty throughout this equation (equation 2).

2. The uncertainties used should be those with a confidence level of 95%. At this confidence level uncertainty can be assumed to be equal to twice the standard deviation of measurements.

   If no information is available for the uncertainty of any particular variable an estimate should be made of the highest and lowest probable true values. The uncertainty should then be taken as half the difference between these values.

3. The uncertainty in should be taken as the uncertainty in C from BS 1042 paragraph 7.3.3.

   The uncertainty in the expansion factor should be taken from paragraph 7.3.3.2 of BS 1042

4. The uncertainties in D and d should be taken as those given in BS 1042 paragraph 10.2.2.3

5. The uncertainty in the differential pressure, E p, should include the uncertainties in signal conditioners or converters and any other transmission component. These uncertainties should be combined with the transducer uncertainty on a root-sum-square basis.

   This procedure also applies to the derivation of the uncertainty in the measurement of the operating density, E .

6. The uncertainty of the computer should be included by means of an additional term, (E_c) under the square root sign in equation 2, (equation 3).

7. Where volume flow qv is being computed, the uncertainty in the measured value of density at base conditions E b, should be derived, giving consideration to the principles of paragraph 5.

   The term (E b) should be included under the square root sign in equation 3, (equation 4).

8. If the operating density is calculated from measurements of pressure, temperature compressibility factor, and molecular weight then the term (E) should be deleted from equations 2, 3 and 4, and the following terms substituted (see annex equation 5), respectively,

where E is the percentage uncertainty in the measured operating pressure etc.

9. The uncertainty of a meter tube should be calculated at the design flow rate and one third of this flow rate.

10. In the statement of uncertainty of flow rate it is not necessary to distinguish between random and systematic components.

11. Where the gas flow is shared equally amongst a number of meters of identical design arranged in parallel the uncertainties in the factors alpha and epsilon should not be considered to be randomly distributed between the meters. The following procedure for calculating the uncertainty in the total flow, E , should be carried out.

Considering a single meter, the sum of the first two terms under the square root sign in equations 2-5 should be called (E) .

The uncertainty in the total flow, E , is then given by

equation 6

Where N is the number of meters in parallel, and (Ey) is the sum of the remaining terms in equations 2-5.

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DEPARTMENT OF ENERGY METERING STANDARDS FOR LIQUID PETROLEUM MEASUREMENTS

1. INTRODUCTION

1.1 This document consists of a set of guidelines, issued to Licensees and Operators in the UK Continental Shelf and Landward Areas for use in the design and construction of metering systems that are to gain Department of Energy approval under the terms of the measurement model clauses included in the licensee's production licence. It covers the construction and operation of prover loops, metering systems and electronic totaliser systems.

1.2 It is intended that these standards should be interpreted as general minimum requirements, and that relaxed requirements will only be appropriate in special circumstances. Alternative specifications to those given in this document will be permitted provided they can be shown to provide a similar or greater level of fidelity and accuracy. With these considerations in mind, Operators are required to submit design proposals in duplicate to the Gas and Oil Measurement Branch (GOMB) prior to the commencement of manufacture.

The Branch address is:-

Department of Energy
Gas and Oil Measurement Branch
Greyfriars House
Gallowgate
Aberdeen
AB9 2ZV

1.3 It is not mandatory that existing metering stations should be modified to comply with any new requirements given in this document.

2. REFERENCE STANDARDS

2.1 Metering systems should generally conform to the latest issues of the following standards:-

2.2 American Petroleum Institute:-

Manual of Petroleum Measurement Standards plus the following available separately:-

a) For crude:

Chapter 11.1, Volume VII, August 1980 (ANSI/ASTM D 1250) (IP200) (API Std 2540)
Table 53A - Generalised Crude Oils, Correction of Observed Density to Density at 15^{o}C
Table 54A - Generalised Crude Oils, Correction of Volume to 15^{o}C Against Density at 15^{o}C

b) For computer programming:

Chapter 11.1, Volume X, August 1980 (ANSI/ASTM D 1250) (IP200) (API Std 2540)
Background, Development and Computer Documentation

2.3 Institute of Petroleum:-

a) Petroleum Measurement Manual:

i) Part VII Density: Section 2: 1983 Continuous Density Measurement.

ii) Part X Meter Proving: Section 1 (Tentative): 1979 Field Guide to Proving Meters with a Pipe Prover.

iii) Part XIII Fidelity and Security of Measurement Data Systems Section 1: 1976 Electric and/or Electronic Pulsed Data Cabled Transmission for Fluid Metering Systems (IP 252/76)

iv) Part XIII Fidelity and Security of Measurement Data; Section 3: 1985 Electrical and/or Electronic Data Capture Systems for Flow Metering.

b) Petroleum Measurement Paper No.2

Guidelines for Users of the Petroleum Measurement Tables (API Std 2540; IP200; ANSI/ASTM D 1250) - September 1984.

2.4 For condensate:

a) ASTM - IP - API Petroleum Measurement Tables for Light Hydrocarbon Liquids. London; John Wiley & Sons, 1986.

3. MODE OF MEASUREMENT

3.1 Hydrocarbon measurements for requirements under the Petroleum (Production) Regulations should be either in volumetric or mass units. The choice of measurement should be discussed with GOMB. Volumes should be measured in cubic metres and mass in tonnes (in vacuo).

3.2 Where the approved measurement is in volumes, these should be referred to standard reference conditions of 15 deg.C temperature and 1.01325 bar pressure. The metering system should compute referred volumes by means of individual meter temperature compensators and totalisers. Where appropriate, consideration should be given to the provision of pressure compensators. Alternative systems giving equivalent results can be considered.

3.3 Where the approved measurement is in mass units the metering system should feature dual or single density meters, (the former being normally required), together with automatic mass computation. Dual density meter systems should feature a density discrepancy alarm system - single density meter systems should feature high and low set point alarms. Suitable sampling facilities shall be provided in close proximity to the density meter(s) in all cases. The mass computers should compute total station mass throughput from volume and density at line conditions of pressure and temperature and should have facilities for manually over-riding the density input signal.

4. PROVER LOOPS AND SPHERE DETECTORS

4.1 Preferably prover loops should be of the bi-directional type with a suitable lining. The flanged joints within the calibrated volume should have metal to metal contact and there should be continuity within the bore. Connections should be provided on the prover loop to facilitate recalibration with a portable calibration prover loop and transfer meter or small volume type prover, where this is approved by GOMB for use in the particular application using the in-service liquid as the transfer medium, or other suitable liquid if approved by GOMB.

4.2 Provers should be constructed according to the following criteria:-

i. Number of meter pulses generated over swept volume to be 20,000 pulses. (This is equivalent to 10,000 pulses between detectors on bi-directional provers.)

ii. Resolution of detector/displacer system to be compatible with requirement (i).

iii. Displacer velocity not to exceed 3m/s.

Because the resolution of the detector/displacer system can only be gauged by the actual performance of the prover, the Department expects the manufacturer to demonstrate an acceptable repeatibility during calibration of the prover, such that on 5 consecutive round trips the range of volumes does not exceed +/- 0.01% of the mean volume. Alternatively, a statistically equivalent repeatability criterion for small volume provers or meter pulse gating systems may be used.

4.3 For offshore use, or in remote locations, prover loops should be fitted with dual sphere detectors and switches at each end of the swept volume. At least two volumes should be calibrated so that failure of a detector or switch does not invalidate the prover calibration. The detector should be designed such that the contacting head of the detector protrudes far enough into the prover pipe to ensure switching takes place at all flow rates met with during calibration and normal operation. Detectors and switches should be adequately waterproofed against a corrosive marine environment.

4.4 In the case of mechanical switches, each sphere detector should have a dedicated micro-switch. The actuation of each detector unit should be set during manufacture so that should it be necessary to replace a detector unit during service there will be a minimal change in prover calibrated volume.

NOTE: Other designs of prover may be considered subject to their being in accord with good oilfield practice.

5. METERS AND ASSOCIATED PIPEWORK

5.1 The meter should generate the electrical signal directly from the movement of the meter internals without any intermediate gearing or mechanical parts. Electrical interpolation systems may be accepted.

5.2 Enough meter runs should be provided to ensure that, at the nominal designed field production rate, at least one stand-by meter is available. Adequate valving should be provided such that individual meters may be removed from service without shutting down the entire metering system.

5.3 Metering stations should have a common inlet header and, if necessary, a common outlet header to ensure uniform measuring conditions at all metering streams, temperature transducers and density meters.

5.4 Temperature and density measuring points should be representative of conditions at the meter inlet and situated as follows:-

(a) In volumetric measurement systems: as close to the meter as possible without infringing the requirements of the API Measurement Manual.

(b) In mass measurement systems: as close to the densitometers as possible, which should also be located as near the meters as possible, without infringing the API Measurement Manual.

5.5 Metering systems should be provided with enough thermo-wells to facilitate temperature checks by means of certified mercury-in-glass thermometers.

5.6 Metering stations should be provided with correctly positioned sampling probes so that representative samples may be taken from the system. It is equally important to ensure that density meters are correctly located to ensure representative sampling.

6. RECIRCULATION FACILITIES

6.1 The Department does not normally permit the fitting of recirculation loops to metering systems except in production systems featuring rapid tanker-loadings. Where recirculation systems are fitted around the metering system, full logging of recirculation and any other non-export flows through the meters must be maintained.

6.2 Recirculation facilties intended for the use of pump testing etc. should be fitted upstream of the metering system.

7. PULSE TRANSMISSION

7.1 The metering signals (see also 5.1 above) should be generated by a dual meter head pick-up system in accordance with either Level A or Level B of the IP 252/76 Code of Practice.

7.2 A pulse comparator should be installed which signals an alarm when a pre-set number of error pulses occurs on either of the transmission lines in accordance with the above code. The pre-set alarm level should be adjustable, and when an alarm occurs it should be recorded on a non-resettable comparator register. Where the pulse error alarm is determined by an error rate, the error threshold shall be less than 1 count in 10^6. Pulse discrepancies that occur during the low flow rates experienced during meter starting and stopping should be inhibited.

7.3 The pulse transmission to the prover counter should be from one or both of the secured lines to the pulse comparator, and precautions should be taken to avoid any signal interference in the spur from the comparator line.

8. TOTALISERS AND COMPENSATORS

8.1 All totalising and compensating functions, other than data input conversions, should be by digital methods.

8.2 Each meter run should have an instrument computing uncorrected volumes at line conditions in which meter factors should be capable of being set to a resolution of at least 0.03%. In volumetric measuring systems, a liquid pressure correction may be included in the computation as this correction is usually small and of constant magnitude.

8.3 Totalisers on individual meter run instruments, and on station summators, should have sufficient digits to prevent roll-over more frequently than every 2 months and normally have a resolution of 1 unit of volume or mass. Totalisers should be non-resettable and, where they are of the non-mechanical type, should be provided with battery driven back-up memories.

The procedures to be used for correcting flow during any period of mis-measurement should be made available.

8.4 For the volumetric mode of measurement, automatic temperature compensation is required. Temperature compensation should be carried out on each individual meter-run. The liquid thermal expansion coefficient set into the compensator should be fully adjustable over the range likely to be encountered in practice and have a resolution of at least 2 significant digits.

8.5 Corrections to meter throughput for water and sediment content should be applied retrospectively based on the analysis of the flow-proportional sample.

9. OTHER INSTRUMENTATION

9.1 Temperature measurements that affect the overall accuracy of the metering system should be to an accuracy of at least 0.5 deg C, and the corresponding readout should have a resolution of at least 0.2 deg.C.

9.2 To provide a history of meter operation and flowing conditions and a record of meter malfunctions, each meter-run should be provided with a continuous chart recording of flow rate and metering temperature. Alternatively, electronic data recording will be accepted provided that the recording frequency is adequate and the system logs all metering alarms. Recording intervals no greater than 4 hours will normally be considered adequate.

9.3 In mass measurement systems, the density signals from the density meters should also be recorded continuously by a chart recorder or electronic data recorder at the same interval as in 9.2 above. A digital read-out is also required with a resolution of at least 4 significant figures.

9.4 Crude oil metering systems should be provided with automatic flow proportional sampling systems for the determination of average water content, average density and for analysis purposes.

9.5 In crude oil systems where slugs of water may be experienced, in-line water detection probes should be fitted to detect abnormal levels of water content. Continuous recordings of percentage water content and a high-level alarm system should be provided. Data from this source should not normally be used in determining dry oil quantities.

10. SECURITY

10.1 All meter factor settings and reset buttons, where allowed, should be secured with a seal or lock to prevent unauthorised adjustment. Prover loop sphere detectors and associated micro-switches should also be secured by locks or seals.

10.2 Valves on re-circulation lines provided for the purposes of off-line meter testing via re-circulation loops must be provided with approved type locks.

11. CALIBRATION FACILITIES

11.1 Adequate test facilities should be provided with metering systems to facilitate the checking and calibration of all computing and totalising systems. The calibration of test equipment shall be traceable to National Standards of measurement.

Issued by:-
Department of Energy
Gas & Oil Measurement Branch
3 Tigers Road
South Wigston
Leicester
LE8 2US

Telephone 0533 785354
Telex 342457

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Contact point on operational matters:-
Telephone 0224 647961
Telex 739283

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ISSUE 3

DEPARTMENT OF ENERGY
APPROVED METERING STATIONS - OPERATING PROCEDURES
(LIQUID HYDROCARBON MEASUREMENT)

FOREWORD

To comply with the requirements of UK Licences for Petroleum Exploration and Production, all petroleum gases and liquids won and saved from both the UK Continental Shelf and Landward Areas have to be measured in accordance with good oil field practice. To define this requirement in respect of operational procedures for liquid measurement, the Department of Energy's Gas and Oil Measurement Branch has formulated these Operating Procedures, which were originally published by the Petroleum Engineering Division in September 1976. This third issue now supercedes the original publication. The organisation within the Department of Energy now responsible for metering is the Gas and Oil Measurement Branch (GOMB) whose address is:-

Department of Energy
Gas and Oil Measurement Branch
Greyfriars House
Gallowgate
Aberdeen
AB9 2ZV

The procedures cover the metering of liquid mass and volume with particular emphasis on crude oil measurement, and are based on the operational characteristics to be expected of a typical metering station equipped with turbine meters. Where other types of meter have been approved a variant of these procedures may be appropriate. The performance of individual metering stations will depend on the particular characteristics of both the metering system and flow system and the type of hydrocarbon being metered: therefore deviations from these procedures may be necessary in special cases, for example measurements on very viscous crude oils, or low lubricity fluids such as gas condensate.

In addition to satisfying the relevant requirements of the Department of Energy (GOMB), the procedures where applicable meet the corresponding requirements of Her Majesty's Customs and Excise for measurement at land terminals.

Operators are required to submit their proposals for the operation and calibration of their metering systems in duplicate to the Aberdeen address prior to the commencement of commissioning and operation.

ISSUE 3 of these Operating Procedures has been revised and contains detail changes.

1. PROVER CALIBRATION

1.1 Prover loops should be calibrated at the manufacturers works as part of their systems checks, and after installation on site. Two copies of the calibration certificates for each of these and all subsequent calibrations should be sent to the GOMB Aberdeen Office. Such certificates should show the reference numbers of the sphere detectors used in the calibration.

1.2 While a metering station is in service, prover loops must be calibrated at a frequency of not less than once a year. Where this is not possible for operational or weather reasons a two month period of grace will be allowed. Inspection of the sphere, checking of sphere size, sphericity etc. should take place prior to calibration. After calibration the sphere detectors and switches should be sealed.

1.3 Any maintenance work on the prover that could affect the swept volume, eg changes of sphere detectors and switches, should not be undertaken without prior notice to GOMB who will advise if a recalibration is required.

1.4 GOMB must be given at least 14 days notice of all prover loop calibrations so that arrangements for witnessing can be made.

2. DETERMINATION OF METER CHARACTERISICS

2.1 For new or modified meters which are to be operated over a wide flow range covering flow rates below 50% of maximum, charac-teristic curves of meter factor versus flow rate should be determined for each meter. These curves should cover a range of approximately 20% to 100% of maximum flow rate, subject to any system restriction on flow rate. From these curves the permissable flow rate variations at a given meter factor setting will be determined.

2.2 Meters that are to be operated normally only at above 50% maximum flow rate, except during starting and stopping, will not be subject to the above requirement (Section 2.1) provided it can be shown that a meter factor variation of not greater than 0.1% occurs over the working flow rate range.

3. METER PROVING IN SERVICE

3.1 The requirements governing the intervals between turbine meter proving are:-

3.1.1 For a newly commissioned metering station in a continuous production system (as distinct from tanker loading), meters shall be proved three times a week at approximately equal intervals between proving. Provided the meter factor scatter is acceptable to GOMB, this frequency may be reduced to twice a week at the end of the first month, and once a week at the end of the second month.

3.1.2 For tanker loading systems, the frequency of proving will depend on the duration of the loading and the individual production system characteristics. The frequency of proving will therefore be subject to the approval of GOMB on an individual basis.

3.2 Meters must also be proved:-

(a) When the flow rate through the meter changes - this change in flow will depend on the gradient of the meter's flow characterisitics in any particular installation, (see Section 2.0), and would normally be such that a change in meter factor greater than 0.1% does not arise from the change in flow rate. If the change in flow rate is a

scheduled long term change then the meter(s) should be reproved at the first opportunity. If the flow rate change is unscheduled then the meters should be reproved if the estimated duration of the changed flow is 6 hours or more.

(b) When any significant change in temperature, pressure or density of the crude oil occurs for extended periods as for flow in (a) above that is likely to cause a change in meter factor of 0.1% or more. (In typical North Sea production systems practical values of these limits are of the order of 5^{o}C temperature, 10 bar pressure and 2% density).

3.3 Where meter types other than turbine meters are in use, the type and frequency of meter factor proving by the licensee will be determined on an individual basis by GOMB after consultation with the licensee. Account will be taken of the meter type, process fluid and operational load cycle. Where meters employing novel technology are to be used, extra evaluation periods and tests will usually be required before acceptance of a long term operational schedule can be determined.

4. METER FACTORS

4.1 Meter factors should be based on the average of at least five proof runs. All consecutive five proof runs must lie within $\pm$ 0.05% of the mean value. Full details of the proof runs, together with flow rates, pressures and temperatures should be entered in the Record of Meter Provings. (See 6.3).

4.2 On metering installations where the meter factor is set manually, the change in factor should be done in such a way as to prevent loss in the measured flow. Also, the new factor setting should be checked by a second person who should sign to this effect in the Record of Meter Provings.

5. GENERAL PROCEDURES

5.1 Metering stations should be operated and maintained in accordance with the manufacturers recommendations: particular attention should be paid to flow stabilization prior to meter proving, checking of block and bleed valves for leaks.

5.2 The temperature-compensated totalisers associated with the individual meters are to be used as the basis of the approved measurements at each metering station, except where the approved measurement is in mass units.

5.3 The operator should check the accuracy of the individual meter temperature compensation daily to detect the occurrence of possible errors. Correspondingly, in a mass measurement system a daily check of the mass computation should be done by comparing the totalised mass with that calculated from the individual metered volumes and density meter readings.

6. DOCUMENTATION TO BE KEPT AT THE METER STATION

6.1 The operator must maintain a log book for the prover detailing all calibrations, sphere detector serial numbers and any maintentance work done on the prover loop and its associated equipment.

6.2 A log must be kept for each meter showing details of:-

(i) type and identifying particulars including location and product measured;

(ii) totaliser reading(s) on commencement of metering;

(iii) all mechanical or electrical repairs or adjustments made to the meter or its read-out equipment;

(iv) metering errors due to equipment malfunction, incorrect operation etc., including date, time and totaliser readings both at the time or recognition of an error condition and when remedial action is completed;

(v) alarms, together with reasons;

(vi) any breakdown of meter or withdrawal from normal service, including time and totaliser readings;

(vii) replacement of security seals when broken.

6.3 The operator must also keep a Meter Proving Record for each meter giving the full details of each proof run. This record should include a running plot, or similar control chart, so that any undue change or fluctuation in meter factors may be easily detected.

6.4 A manual log or automatic recording should also be kept, at intervals of not more than 4 hours, of the following parameters:-

(i) all meter totaliser readings;

(ii) meter flow rates (also relevant meter factors), pressure and temperature, and (if measured continuously) density;

(iii) meter pulse comparator register readings.

One of these sets of readings should be recorded at 24.00 hours, or at the agreed time for taking daily closing figures if different.

Other parameters such as liquid density and percentage BS & W content should be recorded at agreed intervals, if not already included in the automatic log.

6.5 Records of parameters such as meter flow rate, liquid temperature and density should be kept at the metering station for at least 4 months.

6.6 All above records should be available at all reasonable times for inspection by GOMB.

7. DIRECT REPORTING TO THE GAS AND OIL MEASUREMENT BRANCH (GOMB)

7.1 For offshore tanker loading systems GOMB require for each tanker load a copy of the bills of lading, details of opening and closing totaliser readings and meter factors.

7.2 Operators should notify GOMB prior to any major maintenance or re-calibration work on the metering and proving system. GOMB should also be notified, preferably by telephone, when any abnormal situation or error occurs which could require significant adjustments to the totalised meter throughputs.

7.3 If a flow or density meter should require removal for maintainance work or replacement, a telex should be sent to GOMB detailing the serial numbers of the meters concerned and the reasons for the action taken.

7.4 When corrections to meter totalised figures are required due to known metering errors, a formal report should be submitted to GOMB detailing the times of the occurrence, totaliser readings at start and finish, required corrections to these readings, and reasons for the errors occurring.

7.5 The reports on the previous pages should be sent to:-

Department of Energy
Gas and Oil Measurement Branch
Greyfriars House
Gallowgate
AB9 2ZV
Telephone: 0224 647961
Telex: 739283

Issued by:-
Department of Energy
Gas & Oil Measurement Branch
3 Tigers Road
South Wigston
Leicester
LE8 2US

Telephone 0533 785354
Telex 342457

June 1987

Contact point on operational matters:-
Telephone 0224 647961
Telex 739283

References

[1] Paper presented at the North Sea Flow Measurement Workshop, a workshop arranged by NFOGM & TUV-NEL

Note that this reference was not part of the original paper, but has been added subsequently to make the paper searchable in Google Scholar.