Husky Oil

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December 17, 2004

C-NOPB
5th Floor TD Place
140 Water Street
St. John's, NL
A1C 6H6

Ref. No.: HUS-CPB-WR-LTR-00005

Attention: Mr. Wayne Chipman, Chief Conservation Officer **File No.: 4.15.18**

Dear Mr. Chipman:

Subject: Decision 2001.01 – Condition 15

With reference to the White Rose Decision Report – Decision 2001.01, please accept the following report which outlines Husky's review of the reporting requirements associated with Condition 15 which states: "*The proponent, prior to initiating oil production, provide a procedure acceptable to the Chief Conservation Officer for estimating the liquids produced in association with coned gas and report these estimates to the Board as part of the monthly production report*".

As discussed at the December 7, 2004 meeting between C-NOPB and Husky representatives, there is a considerable degree of uncertainty associated with the estimation procedure developed to satisfy Condition 15. Furthermore, the validity of the estimated quantities cannot be verified since the estimation procedure is highly subjective, and based upon multiple assumptions. In this regard, NGL volumes reported in accordance with this condition would be contrary to established reporting practices that are based upon physical measurements, and traceable to national / international standards. As a result, Husky is very reluctant to report hydrocarbon quantities in this instance.

Enclosed is a report prepared by Husky staff which speaks to the shortcomings associated with reporting hydrocarbon quantities as per this Condition. Due to the high degree of uncertainty associated with the estimation procedure, Husky hereby requests dispensation from Condition 15.

If you have any questions, please feel free to contact Tony Harris at 724 3959.

Respectfully,

HUSKY OIL OPERATIONS LIMITED

Keith Deutsch
Subsurface Manager

Enclosures: 1. Report on Condition 15

CANADA-NEWFOUNDLAND and LABRADOR OFFSHORE PETROLEUM BOARD

HUSKY ENERGY
Ref No.
JUL 11 2005
File No. 4/5.18

July 6, 2005

File 8010 A1026 2001.01 Cond. 15

Husky Energy,
Suite 801, Scotia Centre
235 Water Street
St. John's, Newfoundland
A1C 1B6

Attention: Mr. Keith Deutsch
Subsurface Manager

Dear Mr. Deutsch

Subject: Condition 15, White Rose Decision Report

I refer to Husky Energy's request for consideration of our view of your activities in respect of Decision 2001.01 Condition 15 and the document "*Report on Condition 15 of Decision 2001.01*" submitted on December 22, 2004, in support of the request. We have completed our review of the information provided and concerns raised by Husky Energy and we are of the view that your activities and report have satisfied the requirements of Condition 15.

Yours truly,

Wayne Chipman
Chief Conservation Officer

Fifth Floor, TD Place, 140 Water Street, St. John's, Newfoundland, Canada A1C 6H6
Telephone (709) 778-1400 Fax (709) 778-1473

Husky Energy

Report on

Condition 15 of Decision 2001.01

Document ID: 003865236

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1.0 Executive Summary

Condition 15 of the White Rose Decision Report (Decision 2001.01) requires Husky to develop a procedure to estimate liquid quantities associated with Coned Gas. More specifically, Condition 15 states:

"*The proponent, prior to initiating oil production, provide a procedure acceptable to the Chief Conservation Officer for estimating the liquids produced in association with coned gas and report these estimates to the Board as part of the monthly production report*".

In an effort to satisfy Condition 15, Husky reservoir / production engineering staff formulated a conceptual approach by which coned gas quantities could be estimated. It was quickly realized that many assumptions would be required, and the resulting estimates would be highly subjective. Husky staff sought further guidance by conducting an exhaustive search utilizing resources such as the Society of Petroleum Engineers (SPE) Electronic Library, SPE Petroleum Engineering Handbook and various petroleum engineering text books and technical publications. The results of that search were unsuccessful with respect to finding any guidance in relation to Condition 15 requirements.

Husky then engaged the consulting services of a third party metering and flow measurement specialist from SGS Canada to investigate Condition 15 requirements, and provide guidance to Husky on how this Condition could be satisfied. It is worth noting that the SGS consultant offered a considerable depth of worldwide experience via work assignments in the United Kingdom, Norway, Middle East and North America. The consultant's findings were in agreement with those of Husky staff, which essentially suggested that estimates of coned gas quantities, and the associated liquids, would be:

- Highly subjective
- Based upon multiple assumptions
- Based upon a procedure / technique that cannot be validated
- Have an unknown level of uncertainty / accuracy
- Not in accordance with accepted industry practice

A key objective of Husky's reservoir management and optimization strategy is to minimize gas coning in an effort to maximize oil recovery. Husky feels that any procedure developed to satisfy Condition 15 would be of no value since there is no means to assess the integrity of the estimation procedure; and verification of the estimated quantities would be practically impossible. Furthermore, all hydrocarbon quantities reported by Husky, and other operators in the Newfoundland offshore area, are based upon industry accepted measurement practices, with traceability to National / International measurement standards. To Husky's knowledge, any procedure developed to satisfy Condition 15 requirements would be unprecedented. In this regard, Husky is very reluctant to report hydrocarbon quantities under such circumstances, and respectfully requests dispensation from Condition 15.

2.0 Introduction

Condition 15 of the White Rose Decision Report (Decision 2001.01) requires Husky to develop a procedure to estimate liquid quantities associated with Coned Gas. More specifically, Condition 15 states:

"*The proponent, prior to initiating oil production, provide a procedure acceptable to the Chief Conservation Officer for estimating the liquids produced in association with coned gas and report these estimates to the Board as part of the monthly production report*".

In an effort to satisfy Condition 15, Husky reservoir / production engineering staff formulated a conceptual approach by which coned gas quantities could be estimated. It was quickly realized that many assumptions would be required, and the resulting estimates would be highly subjective. The conceptual approach established by Husky staff contained several key assumptions, and consisted of a step-by step systematic procedure as follows:

1. Produce the field for a given period of time to establish the baseline GOR.
2. Once the producing GOR (Rp) surpasses a defined threshold (Rt), assume that all additional gas is coned gas.
3. Monitor the flowing bottomhole pressure of the offending well(s) and estimate the quantity of natural gas liquid (that remain in the coned gas) at that flowing pressure.
4. Multiply the assumed coned gas quantity [(Rp-Rt) x Qoil] by the estimated NGL quantity (X m3/MMm3) at that flowing pressure to get an approximation of the NGL quantities entering the wellbore.
5. Utilize process simulation (HYSYS) software to model the phase behavior (of the assumed NGL quantities) in the surface separation/process equipment to estimate the quantity of NGL's that would stabilize in the oil under typical tanker export requirements ie. RVP of 76 kPaa.
6. Report the estimated quantities from Step 5 on the cover sheet that accompanies the monthly S-Forms.

In considering the steps outlined above, Husky staff recognized several shortcomings with the proposed procedure. While not necessarily limited to the uncertainties listed below, some of the shortcoming associated with each of the steps is as follows:

Steps 1 & 2

- Each of the horizontal producers will have dynamic-production characteristics which may be unique for each well. This would make assignment of a baseline / threshold "*Field GOR"* difficult. As a result, each well would have to be considered separately which would make the process labour intensive. Also, selection of a "threshold" GOR (as a decision point with respect to when to begin estimating coned gas liquids) would be subjective. Given the fact that multiple assumptions are required, the estimated coned gas quantities would have a high degree of uncertainty, and the reliability of the estimates could not be quantified.

- As the field matures, a better understanding of the mechanisms occurring in the reservoir is gained via production history. In this regard, assumptions made early in the life of the field may be found (later in field life) to be incorrect. This is the major shortcoming with respect to reporting quantities that are not based upon a physical measurement.

Steps 3 & 4

Gas samples, together with gas DST measurements, from the White Rose field have shown NGL quantities of 168 m3/million m3 (~ 30 bbl/million scf). This quantity likely represents the average liquid content in the gas cap. Considering the fact that portions of the South Avalon gas cap has in excess of 200 m gross thickness it could be argued that the lower portions of the gas cap (which will cone first) will be richer in NGL's. Consequently, the NGL–to-gas volume ratio would be variable with time. This variability would result in a high degree of uncertainty with respect to the volume of NGL's that are introduced into the oil column. Tracking those liquid quantities that "drop out" in the oil column, and estimating when (if ever) those "coned liquid" volumes reach the wellbore is extremely difficult to even estimate.

For the coned gas quantities that do reach the wellbore, estimating the quantity of NGL's that may subsequently evolve would also have a high level of uncertainty (particularly since the NGL ratio may vary with time).

Step 5

HYSYS (process simulation software) is used by industry for design and analysis of surface separation / process equipment. It can be used to optimize plant design and improve existing plant operations under variable plant/process conditions (ie. it is not designed to model phase behavior in the wellbore).

The key to modeling the phase behavior of the fluid (under surface process conditions) is to accurately define the feedstock composition. In this case, accurate definition of the feedstock would not be possible since the estimated NGL quantities would be based upon multiple assumptions, and would be variable with time. In this regard, using HYSYS to simulate the quantity of coned-gas-NGL's going into storage with the oil would be meaningless.

Step 6

In consideration of the shortcomings associated with the above steps, it was obvious that the estimated coned-gas-NGL quantities would be highly subjective. Husky staff felt that further refinement of the estimation procedure (to reduce the high level of uncertainty) would be necessary for reporting purposes.

Husky staff sought further guidance by conducting an exhaustive search utilizing resources such as the Society of Petroleum Engineers (SPE) Electronic Library, SPE Petroleum Engineering Handbook and various petroleum engineering text books and technical publications. The results of that search were unsuccessful with respect to finding any guidance in relation to Condition 15 requirements.

Husky then engaged the consulting services of a third party metering and flow measurement specialist from SGS Canada to investigate Condition 15 requirements, and provide guidance to Husky on how this Condition could be satisfied. It is worth noting that the SGS consultant offered a considerable depth of worldwide experience via work assignments in the United Kingdom, Norway, Middle East and North America. The consultants experience included familiarity with the fluid measurement and production reporting requirements in those jurisdictions, and it was concluded that Condition 15 requirements were unprecedented. The consultant's findings were in agreement with those of Husky staff, which essentially suggested that estimates of coned gas quantities, and the associated liquids, would be:

- Highly subjective
- Based upon multiple assumptions
- Based upon a procedure / technique that cannot be validated
- Have an unknown level of uncertainty / accuracy
- Not in accordance with accepted industry practice

Due to the perceived high level of uncertainty, no formal procedure was developed by the third party consultant. Instead, the consultant approached Husky staff for further guidance on reservoir and PVT related issues. The proposed estimation procedure developed by Husky staff was reviewed and discussed with the consultant to determine if further refinement was possible. In the end, it was agreed that the conceptual approach proposed by Husky staff was technically sound. Overall, however, the procedure is still inadequate since the integrity cannot be verified, and the uncertainty surrounding the estimates cannot be quantified.

To ensure that nothing was overlooked from a measurement and reporting perspective, Husky referenced the following documents for further guidance:

- Newfoundland Offshore Area Petroleum Production and Conservation Regulations (P&C Regs)

- Measurement Guidelines Under the Newfoundland and Labrador and Nova Scotia Areas Petroleum Production and Conservation Regulations – October 2003 (Joint Measurement Guidelines)

- Guidelines Respecting Monthly Production Reporting for Producing Fields in the Newfoundland Offshore Area – September 2001

- Department of Trade and Industry – Guidance Notes for Petroleum Measurement Under the Petroleum (Production) Regulations – December 2003 (Issue 7)

- Petroleum Production Reporting System – Oil and Gas Directorate, Department of Trade and Industry. Submission Guidance "PPRS 2000" Revision 0: August 2000.

- Regulations Relating to Measurement of Petroleum for Fiscal Purposes and for Calculation of CO2-Tax (The Measurement Regulations). 1 November 2001. The Norwegian Petroleum Directorate.

2.1 Considerations with respect to the Newfoundland P&C Regs

Section 35 (1) of the P&C Regs states: An operator shall measure and record the rate of flow and the total volume of
(a) Each fluid that is
(i) Produced from or injected into each well, and
(ii) Transferred from the production installation, sold, flared or disposed of;
(b) Gas used
(i) As fuel for production operations, or
(ii) To assist gas lift operations;
(c) Oil that is used as a hydraulic power fluid for artificial lift; and
(d) Each fluid that enters or leaves a processing plant.

Husky Comment / Observation:

- There is no means to measure and record the rate of flow and total volume of coned gas, or the liquid (condensate) quantities associated with that gas.

Section 36 – P&C Regs

36 (1) An operator shall allocate group production of oil and gas from wells in a pool on a pro rata basis to the wells in accordance with a flow system and flow calculation procedure and an allocation procedure, approved pursuant to subsection (2)

36 (2) The CCO shall approve a flow system and flow calculation procedure and an allocation procedure if the system and procedures will permit reasonably accurate determination of the production from individual wells and the transfer of fluids from the production installation.

Husky Comment / Observation:

- With regard to subsection 1, the flow system, flow calculation and allocation procedures are based upon physical measurements of a given flow stream. Estimating liquid (condensate) volumes based upon assumed coned gas quantities is beyond the scope of the regulations.

- With regard to subsection 2, the solution gas cannot be differentiated from coned gas and therefore, the estimate/assumption of coned gas quantities will be highly subjective. As a result, the uncertainty surrounding liquid quantities will be high. Furthermore, there would be no means to demonstrate that the procedure is reasonably accurate

2.2 Considerations with respect to the Production Reporting Guidelines

Page 1 – Introduction **"**Part VI – Sections 35 - 44 of the Newfoundland Offshore Area Production and Conservation Regulations sets out the requirements for measurement and testing of production while Part XI, Section 74 of the regulations requires the operator of a producing field to submit a 'Monthly Production Report'."

Husky Comment / Observation:

- Parts VI and XI of P&C Regs does not include requirements for the measurement (or estimates) of coned gas, or the liquids associated with coned gas. Furthermore, sections 35 and 36 reference measurement of produced/injected gas or liquids.

- Subjective estimates of coned gas (and associated liquid quantities) is beyond the scope of the regulations /guidelines.

- Section 74(1) requires and operator to follow established production accounting procedures. Husky is not aware of any established procedures in relation to Condition 15 requirements.

Page 2 – Format of submission "The formats for submission of data have been defined by the Board. Operators must comply with these formats when reporting production data to the Board."

Husky Comment / Observation:

- C-NOPB has informally stated that the quantity of liquids produced in association with coned gas would not be reported via the S-forms.

- Husky is reluctant to report quantities (regardless of reporting format) determined via subjective estimates utilizing techniques that cannot be verified and are not accepted industry practice.

Page 3 – Filing – "All statements and worksheets require a contact name which is deemed to certify that the information supplied is accurate and correct."

Husky Comment / Observation:

- The quantities of liquids associated with coned gas could only be determined by subjective estimates that will not be accurate or correct since they will be based upon multiple assumptions.

- With commencement of gas lift operations (which will have ± 3% measurement uncertainty on gas lift quantities), the assumptions/estimates will become even more uncertain ie. gas lift volumes could account for upwards of 38% of total gas throughput onboard the FPSO

Page 5 – Purpose of NF-S1 “The NF-S1 is a monthly statement of crude oil, bitumen, condensate, gas, and water production for one or more wells that comprise an installation. NOTE: The guidance provided for the NF-S1 statement has been limited to crude oil installations. Where justified, this document will be expanded in future to include gas installations”

Husky Comment / Observation:

- Quantities of crude oil, gas and water production will be metered and measured by the FPSO in accordance with the approved Flow System, Flow Calculation and Allocation Procedure.
- Condensate quantities in the products stream that are separated by the process equipment (and remain stable at storage conditions) will be reported as oil production. This practice will be in keeping with the measurement and reporting practice of other operators in the NL offshore area.

2.3 Considerations with respect to DTI (UK) Measurement Guidelines (Issue 7 – December 2003)

All reported hydrocarbon quantities are based upon measurements (or weights) using methods customarily used in good oilfield practice.

If an operator proposes to use a new measurement system/approach the DTI requires the operator to establish an evaluation program to verify the suitability of the new measurement system/approach.

Husky Comments / Observations

- DTI does not have any reporting requirements in accordance with Condition 15
- Any procedure developed to satisfy Condition 15 will not be based upon “methods customarily used in good oilfield practice”.
- No evaluation program could be established to verify the suitability of Condition 15 reporting procedure.

2.4 Considerations with respect to NPD (Norwegian) Measurement Regulations (November 1, 2001)

Reference is made to recognized standards, including industry standards, as a means by which the requirements of the authorities may be complied with.

When technology or methods not described in recognized standards are used, criteria for development, testing and operation are required to be produced.

<u>Husky Comments / Observations:</u>

- NPD does not have any reporting requirements in accordance with Condition 15
- To Husky's knowledge, no recognized standards or industry standards exist in relation to Condition 15 requirements.
- Any procedure developed to satisfy condition 15 will be based upon subjective estimates and multiple assumptions. In this regard, there would be no means to test / verify the integrity of the estimation procedure.

3.0 Summary

Husky is not aware of any recognized standards, or industry standards, in accordance with Condition 15 requirements.

One of the objectives of Husky's reservoir management strategy for the White Rose South Avalon development is to minimize gas coning.

There would be no means to test / verify the integrity of the estimation procedure developed to satisfy Condition 15. As a result, the validity of the reported NGL quantities would be unknown, and consequently of little value.

The reporting requirements associated with Condition 15 is beyond the scope of the Newfoundland Offshore Area P&C Regulations, Joint Measurement Guidelines and the Production Reporting Guidelines.

Regardless of the estimation procedure developed to satisfy Condition 15, the estimates of coned gas, and associated liquid quantities, will be:

- Highly subjective
- Based upon multiple assumptions
- Based upon a procedure / technique that cannot be validated
- Have an unknown level of uncertainty / accuracy
- Not in accordance with accepted industry practice

Condition 15 requirements are unprecedented, and inconsistent with the reporting requirements for other operators in the Newfoundland offshore area.

Quantities reported to DTI / NPD are based upon measured quantities, and using techniques traceable recognized standards. Estimation procedures developed to satisfy Condition 15 will not be traceable to known / accepted measurement and reporting standards.

There are no royalty implications associated with Condition 15 requirements. Any Natural Gas Liquids that are stable in the oil under storage conditions will be measured by the rundown and custody transfer meters onboard the FPSO and reported as oil production.

4.0 Conclusion

To Husky's knowledge, there is no accepted industry practice for estimating hydrocarbon quantities in accordance with Condition 15 requirements. Furthermore, any procedure developed to satisfy Condition 15 would be highly subjective; have an unknown level of uncertainty; and would not be traceable to established measurement and reporting standards. As a result, the reported NGL quantities would effectively be meaningless or, at the very least, of questionable value.

Condition 15 does not have any implications with respect to royalty payments, or effective reservoir management, and is beyond the scope of the applicable regulations and reporting requirements for the Newfoundland offshore area. In consideration of the challenges outlined in this document, Husky is very reluctant to report hydrocarbon quantities in accordance with this Condition, and respectfully requests dispensation from Condition 15.

Reference Material

Newfoundland Offshore Area Petroleum Production and Conservation Regulations – 21 February, 1995.

Measurement Guidelines Under the Newfoundland and Labrador and Nova Scotia Offshore Areas Petroleum Production and Conservation Regulations – October 2003.

Guidelines Respecting Monthly Production Reporting for Producing Fields in the Newfoundland Offshore Area – September 2001 – Canada-Newfoundland Offshore Petroleum Board.

Appendix I: Department of Trade and Industry – Guidance Notes for Petroleum Measurement Under the Petroleum (Production) Regulations – December 2003 (Issue 7)

Appendix II: Petroleum Production Reporting System – Oil and Gas Directorate, Department of Trade and Industry. Submission Guidance "PPRS 2000" Revision 0: August 2000.

Appendix III: Regulations Relating to Measurement of Petroleum for Fiscal Purposes and for Calculation of CO2-Tax (The Measurement Regulations). 1 November 2001. The Norwegian Petroleum Directorate.

Petroleum Engineering Handbook – Society of Petroleum Engineers

Society of Petroleum Engineers – Electronic Library – www.spe.org

APPENDIX I

DEPARTMENT OF
TRADE AND INDUSTRY

LICENSING AND CONSENTS UNIT

GUIDANCE NOTES FOR PETROLEUM MEASUREMENT

UNDER THE PETROLEUM (PRODUCTION) REGULATIONS

DECEMBER 2003

ISSUE 7

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MODULE 1

INTRODUCTION

MODULE 1 INTRODUCTION

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1.1 RATIONALE

Purpose of Guidelines

1.1.1 Today, the North Sea is a mature oil province, and this fact is recognised throughout these Guidelines. Proposals for new systems featuring single-phase measurement of relatively high flow rates are now relatively rare.

Increasingly, the emphasis is on the development of more marginal fields whose economics do not support single-phase measurement. In addition, many major UK Continental Shelf (UKCS) developments have now passed their production plateaux, but continue to use measurement stations designed to perform optimally at peak plateaux flow rates. Both scenarios present considerable measurement challenges.

One of the principal aims of the DTI Licensing and Consents Unit is to maximise the economic benefit to the United Kingdom of its oil and gas resources. Though Royalty was abolished with effect from 1st January 2003, many older fields on the UKCS continue to pay Petroleum Revenue Tax (PRT) to the UK Government. In addition, *all* developments are subject to Corporation Tax, payable on the profits obtained from hydrocarbons in each 'ring-fenced' Licensed area.

The DTI Licensing and Consents Unit is committed to the goal of helping to maintain daily UK Oil and Gas production at a level of 3 million barrels of oil equivalent until at least 2010.

The DTI has therefore developed these Guidelines in order to help maintain a reasonable standard of measurement on 'PRT-paying' oil and gas, while remaining flexible enough to encourage the development of the remaining hydrocarbons in the North Sea.

Application of Guidelines

1.1.2 This document contains Guidelines for Licensees and Operators in Great Britain, the territorial waters of the United Kingdom and on the UK Continental Shelf (UKCS).

The Guidelines are intended for use in the design, construction and operation of metering systems for which the Secretary of State for Trade and Industry's approval is required under the Measurement Model Clause of the Petroleum (Production) Act 1934. This is reproduced in Appendix 1.1.

They do *not* apply to systems that are governed by HM Customs & Excise regulations.

1.1.3 These Guidelines should be interpreted as representing general *minimum* requirements. They should *not* be viewed as prescriptive, and whatever the 'class' of measurement agreed, alternative techniques to those described in this document will be considered provided that they can be shown to give a similar or greater level of accuracy and reliability.

1.1.4 These Guidelines routinely refer to the 'Operator' and the 'Licensee'. While the legal responsibility to meet the terms of the Measurement Model Clause rests with the Licensee, the DTI expects Operators to similarly adhere to the principles of 'good oilfield practice' and the two terms are used here interchangeably.

Petroleum Operations Notice 6

1.1.5 In order to assist the Licensee in establishing the appropriate method of measurement the DTI should be contacted at an early (pre-Field Development Plan) stage. Early consideration of measurement requirements will enable the Licensee to complete the screening of options at an earlier stage and so minimise the effort in system evaluation. This procedure is intended to avoid the pitfall of the Licensee proceeding with a system design that is not acceptable to the DTI.

The procedure to be followed regarding new developments, or modifications to existing measurement systems, is covered in the DTI's Petroleum Operations Notice, available on the DTI Licensing and Consents Unit website at:

www.og.dti.gov.uk/regulation/pons/pon_06.htm

The procedure is also summarised by the Flow Chart in Appendix 1.2.

Contacting the DTI

1.1.6. Organisation charts and contact details for the DTI Licensing and Consents Unit can be found also be found on the above website at:

http://www.og.dti.gov.uk/about_us/contacts_led.htm

1.2 REGULATORY FRAMEWORK

1.2.1. The principal legislation that applies to the oil and gas production industry, particularly in relation to petroleum measurement, is as follows:

The Petroleum (Production) Act 1934

The Act vests ownership of the petroleum that exists in its natural condition in strata in Great Britain and beneath the territorial waters of the United Kingdom in the Crown. It gives the Secretary of State, on behalf of the Crown, the exclusive right to grant licences to search and bore for and get petroleum. The Act also authorises the Secretary of State to make regulations which, inter alia, prescribe the model clauses for incorporation into such licences.

The Continental Shelf Act 1964

The Act extends the powers conferred by the 1934 Act to the United Kingdom Continental Shelf.

The Petroleum Act 1987

Sections 17 and 18 and Schedules 1 and 2 to this Act amend the measurement model clauses which were incorporated into licences in force at the time it was enacted.

1.2.2. Petroleum measurement is explicitly required by the Measurement Model Clause, but is also implied by obligations elsewhere in the Licence – 1.3.3 below refers.

DTI Inspection

1.2.3 In order to satisfy the Secretary of State that no unauthorised alterations to the approved method of measurement have been made, inspectors from the DTI may at their discretion inspect metering systems at any stage from construction through commissioning into production.

Method of Measurement

1.2.4. Where petroleum is delivered to the UK via a pipeline that serves as a common transportation route for a number of fields then the “method of measurement” will include:

- The measurement of petroleum at the terminal serving the relevant pipeline.
- The allocation procedures used to determine each contributing field’s share of the petroleum used at or exported from the terminal.

1.3 PURPOSE FOR WHICH MEASUREMENT IS REQUIRED

1.3.1 The first task in determining the suitability of a proposed measurement system or systems is to identify the purposes for which measurement is required. These broadly fall into the following two categories:

a) To account for petroleum won and saved from the licensed area.

b) For other purposes relevant to the licence.

Measurement of Petroleum Won and Saved

1.3.2 Among the most usual purposes under 1.3.1 (a) are to:

i) safeguard revenues from oil and gas fields.

ii) allocate terminal out-turns to contributing fields in shared transportation systems.

iii) account for production of petroleum won and saved from stand-alone fields not subject to PRT.

iv) account for petroleum in the form of crude oil, gas or LPG exported from terminals or other export facilities.

v) allocate production into shared transportation systems from different fields commingled in shared process equipment.

vi) account for quantities of gas flared.

vii) account for quantities of gas used for power generation.

viii) account for quantities of gas used for gas lift or for reservoir pressure maintenance.

Other Purposes relevant to License

1.3.3 And under 1.3.1 (b), to:

i) improve understanding of reservoir behaviour to enable effective reservoir management strategies to be implemented.

ii) account for flare gas measurement, for reporting and consent purposes.

iii) establish viability of reservoir as production prospect as for example with extended well tests (EWT).

iv) establish clearly whether a reservoir is no longer economically viable prior to initiating abandonment procedures.

1.3.4 With the above considerations in mind, the Department will seek at all times to implement measurement solutions that are appropriate and economically feasible.

APPENDIX 1.1 MEASUREMENT MODEL CLAUSE

As printed in The Petroleum (Production) (Seaward Areas) Regulations 1988 and subsequent regulations.

(1) 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.

(2)* 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 oilfield 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 oilfield.

(3)* 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 references to measuring or weighing included references to ascertaining quality or composition.

(4) The Licensee shall not make any alteration in the method or methods of measuring or weighing used by him or any appliances used for that purpose without the consent in writing of the Minister and the Minister may in any case require that no alteration shall be made save in the presence of a person authorised by the Minister.

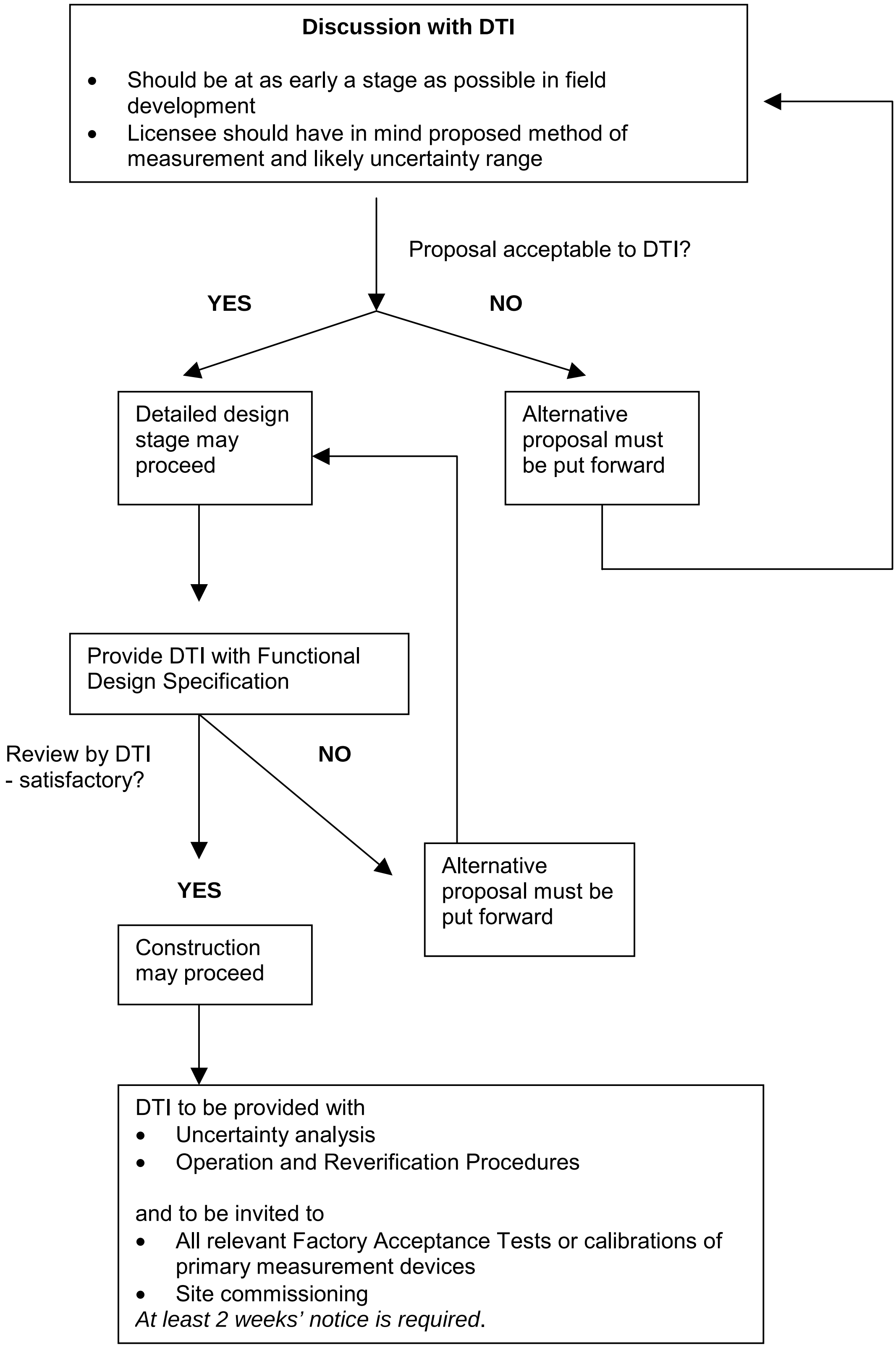
(5) The Minister may from time to time direct that any weighing or measuring appliance shall be tested or examined in such a manner, upon such occasions or at such intervals and by such persons as may be specified by the Minister's direction and the Licensee shall pay to any such person or to the Minister such fees and expenses for test or examination as the minister may specify.

(6) If any measuring or weighing appliance shall upon any such test or examination as is mentioned in the last forgoing paragraph be found to be false or unjust the same shall if the Minister so determines after considering any representation in writing made by the Licensee be deemed to have existed in that condition during the period since the last occasion upon which the same was tested or examined pursuant to the last foregoing paragraph.

* Paragraphs (2) and (3) are not incorporated into Licences which contain the model clauses in Schedule 6 to the Petroleum (Production)(Landward Areas) Regulations 1991.

APPENDIX 1.2 DTI LIAISON PROCEDURE

This Appendix illustrates the procedure to be followed when liasing with the DTI Oil and Gas Division when a new measurement system, or modifications to an existing one, are proposed.



DEPARTMENT OF
TRADE AND INDUSTRY

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GUIDANCE NOTES FOR PETROLEUM MEASUREMENT

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MODULE 2

MEASUREMENT APPROACHES

MODULE 2 MEASUREMENT APPROACHES

CONTENTS

2.1 TERMS OF REFERENCE

2.1.1 This Module is intended as a high-level overview of typical measurement options. It should be of particular use at the early stages of a field development plan.

The decision as to which measurement solution is appropriate for a particular field is arrived at following discussion between the Licensee and the DTI. A Measurement Approach for the field will be agreed, taking into account the technical and economic features of the proposed field development plan.

2.1.2 This Module is not intended to be exhaustive or prescriptive, but rather to:

- outline the typical scenarios in which each of the Measurement Approaches is appropriate.
- describe the typical characteristics of each Measurement Approach and the typical uncertainties that are potentially achievable with each.

Further guidance on the design, installation and reverification for each Approach are given in later dedicated Modules of the Guidelines.

2.2 SELECTION OF MEASUREMENT APPROACH

Discussion with DTI

2.2.1 For new field developments, Licensees ***must*** contact the DTI so that a meeting may be arranged in order to discuss the appropriate measurement approach.

It is in the Licensee's own best interest that this meeting takes place at as early a stage in the field development as possible.

2.2.2 The overall goal is for the measurement technique, uncertainty and operating procedures to be appropriate for the fluid and service in question. The available measurement options may be severely limited by the nature of the fluid measured.

Rather than 'fitting' a measurement approach to a particular field development, it is more appropriate to consider at the design stage the economics of the field and the standard of measurement that will thereby be supported. Essentially this reduces to whether or not the project economics will support separation and dedicated processing of fluids prior to their measurement and export. Once the likely fluid characteristics are clear (e.g. 'single phase', 'wet gas') it will then be clear which of the measurement approaches are realistically achievable.

It may also have to be borne in mind that the fluid characteristics may change throughout the field life. For example, production from a dry gas field may become wet due to falling reservoir pressure, or the water cut of an oil field may increase to the extent that the measurement solution can no longer be considered a 'single phase' application. Here it may be necessary to establish review dates at which the agreed method of measurement will have to be reconsidered.

The DTI will normally press Licensees for the best standard of measurement consistent with these economic considerations. The Licensee is then expected to ensure that appropriate design and operating procedures are followed.

2.2.3 Once the appropriate Measurement Approach for a particular development has been agreed, this must be regarded as no more than a 'first step'. Whatever the class of measurement system, the target uncertainty will only be met if adequate supporting measures are taken. The fact that a liquid measurement system has been designed, to, for example, Custody Transfer standards does not in itself imply that its measurement will meet its design uncertainty of 0.25%. Rather, that this is the level of uncertainty that such a system may achieve, if operated and maintained correctly.

The appropriate level of maintenance for a measurement system will of course depend on the measurement approach selected. The overall aim of any maintenance programme is to maintain the measurement system within its target design uncertainty. Custody Transfer systems will generally require the highest degree of attention.

Marginal Field Developments

2.2.4 The highest standards of measurement are only achievable on single-phase fluids, and the following requirements:

- 3-phase separation
- Gas processing and drying (without which the gas is saturated and liable to liquid dropout at the slightest decrease in pressure)
- Oil processing to ‘low pressure’ conditions (without which the oil may contain a considerable amount of gas and water vapour in solution)

have the potential to make some ‘marginal’ field developments uneconomic.

Therefore, when reviewing a Licensee’s measurement proposals for a ‘marginal’ field, the DTI is fully prepared to agree to the necessary relaxations in measurement uncertainty in the interests of encouraging the development of remaining North Sea oil and gas reserves.

For such relaxations to be granted, the DTI will however require economic justification from the Licensee. This need only be a ‘broad-brush’ indication, but it should include the following:

a) Details of the relevant field economic parameters (e.g. predicted production profiles and development costs).

b) The measurement options considered (one of which may necessarily be a Custody Transfer solution).

c) The approximate cost to the project that would have been incurred by the installation of a lower-uncertainty (e.g. Custody Transfer) measurement system and the economic justification for its rejection.

Economic Exposure

2.2.5 At the field development stage, the economic ‘exposure’, both to the Licensee and the Government (where ‘taxable’ petroleum is involved) can be calculated from the product of the following projected parameters:

- Throughput of the metering system (taking into account expected field life)
- Uncertainty of the measurement system

This is a useful parameter when determining the appropriate measurement solution. By investing more money in a higher-quality measurement system, it may be possible to reduce the uncertainty and hence the exposure, although to some extent a law of ‘diminishing returns’ may apply. This calculation will normally form a central part of the preliminary discussions with the DTI.

‘Fiscal’ Measurement - Clarification

2.2.6 The use of the phrase ‘fiscal metering’ does not necessarily imply any single expectation of the quality of the instrumentation to be installed. ‘Fiscal’ refers to the meter’s service, not its quality.

High accuracy metering systems installed to determine quantities and quality at points of custody transfer are frequently also fiscal, so the misunderstanding has arisen that only such high accuracy export meters are fiscal.

The following may help clarify the question of what constitutes a fiscal metering system.

'Fiscal' literally means 'concerned with government finance'. Under the present (May 2003) tax regime, Government revenue can be affected through:

- ***Petroleum Revenue Tax*** (typically 50%). This is levied on sales revenue, less certain chargeable costs (such as those incurred in 'conveying and treating'). PRT was abolished for new field developments in 1993.

- ***Ring-Fence Corporation Tax*** (total 40%); this is levied on profit from each field on the UKCS; each field is 'ring-fenced' for tax calculation purposes

A fiscal meter is therefore any system, or element of that system, that is used to determine production rates that will ultimately generate revenue for the Government.

From the Operator's standpoint, fiscal metering systems can be viewed as central to the collection of their own revenues. Operators therefore have a duty to themselves and other stakeholders to ensure that fiscal metering systems, whatever their 'accuracy', are treated with due importance.

Depending on the particular allocation mechanism for a field, any of the following measurements:

- Separator flow rates
- Well-test flow rates
- Gas flared
- Fuel and utility gas
- Gas injected
- Produced water discharged

may potentially be fiscal.

Measurement Approaches and Typical Uncertainties

2.2.7 The following 5 Measurement Approaches are typical:

Approach	Typical Uncertainty in Mass Flow Rate Measurement (%)	
	Liquid	Gas
Custody Transfer	0.25	1.0
Custody Transfer (Non-PRT)	0.25 - 1.0	n/a (see Module 5)
Allocation	0.5 - 5	2 - 5
Well Test	10	
Multiphase Metering	10 - 20	

Of these uncertainty limits, only those of Custody-Transfer are clearly defined by Industry consensus. The remainder are approximations, reflected by the relatively wide ranges quoted here. Indeed, there seems little point in defining limits that cannot be demonstrably adhered to through traceable measurements; in many cases meaningful comparison with a standard is simply not possible.

The characteristics of these approaches are discussed in turn in sections 2.5-2.10. Design, operation and reverification considerations are covered in detail in dedicated Modules of these Guidelines.

Fuel and Utilities Gas

2.2.8 Fuel gas measurement systems should normally be designed and operated to meet Allocation uncertainty levels.

Flare Gas

2.2.9 A dedicated module on flare gas measurement has now been incorporated into these Guidelines (Module 10).

2.3 'BY DIFFERENCE' MEASUREMENT

Factors Affecting Uncertainty

2.3.1 The uncertainty of a quantity measured 'By Difference' depends on the following factors:

- The measurement uncertainty of each of the other elements of the allocation system.
- The relative proportion of the 'by difference' quantity to total allocation system throughput.

This uncertainty is therefore not a static value, as the second of these, in particular, is subject to change.

New Measurement Systems

2.3.2 Operators of fields where measurement 'By Difference' is proposed are expected to provide details of the anticipated uncertainty throughout field life, taking into account the factors listed in 2.3.1 above.

Existing Measurement Systems

2.3.3 Operators of fields where 'By Difference' measurement is already in place are expected to place the uncertainty of their measurement under continuous review, perhaps by means of 'dynamic modelling' using Monte Carlo simulation methods.

There are many measurement systems on the UKCS that would by normal standards be Custody-Transfer quality but where 'By Difference' Measurement has been agreed. The DTI should be contacted if measurement uncertainty exceeds the levels defined above in 2.2.7 (i.e. 0.25% for liquid, 1.0% for gas).

Where the Government's financial exposure becomes unacceptably high, the Operator may be asked to consider the retro-fitting of 'direct' measurement techniques.

Use of Statistical Uncertainty Models

2.3.4 There is considerable scope for the use of statistical uncertainty models in this area. These are potentially very powerful tools, enabling both Regulator and Operator to determine where maintenance should be targeted in order to gain the maximum return in improved measurement uncertainty.

2.4 SELECTION OF PRIMARY MEASUREMENT DEVICE

2.4.1 The selection of an appropriate primary measurement device is a critical step in any measurement approach. BS 7405 provides useful guidance in this area.

Liquid Hydrocarbons

2.4.2 The most commonly used primary device for Custody Transfer levels of measurement of liquid hydrocarbons is the turbine meter, normally with a facility for in-situ verification with a pipe or compact prover. The use of master meters for verification purposes may also be suitable for smaller-scale applications.

Coriolis meters are also widely used for liquid hydrocarbon flow measurement, both as primary devices and as ‘master meters’. They are particularly suitable for the measurement of LPG or condensate.

The use of positive displacement meters should be considered for flow measurement of highly viscous fluids.

The use of multi-path ‘spool-piece’-type ultrasonic meters for Custody Transfer applications is now well established.

2.4.3 Where single-phase flow cannot be guaranteed (for example, in separator metering applications) measurement challenges become significantly more pronounced. The correct choice of meter will be influenced by process flow considerations. Gas breakout and high water cut can have significant adverse effects on the operation of turbine meters and ultrasonic meters respectively. Separator design and maintenance can often be enhanced to minimise the impact of either or both of these factors.

Gaseous Hydrocarbons

2.4.3 For dry gas applications the orifice plate is still the most widely-used meter for Custody Transfer measurement of large volumes of high-pressure gas. However, their effective operation is critically dependent on the judicious application of the provisions of ISO 5167. In particular, the flow should be single phase if an uncertainty of 1.0% or less is required. The Operator must also be able to demonstrate that the orifice plate and meter tubes are in an acceptable condition, and the need for regular inspection of these should always be borne in mind at the design stage.

The use of other differential-pressure devices, such as Venturi or V-cone meters, may also be considered.

Multi-path ultrasonic meters have been in use for a number of years now and have gradually gained acceptance for use in Custody Transfer and Allocation applications. A large amount of data has been collated on these devices and the first standards have now been published. Further work is presently being carried out and revisions to these standards are expected in the next couple of years.

Coriolis meters are now widely accepted as being capable of performing at Custody Transfer uncertainty levels in gas applications.

Turbine meters have traditionally been used for low pressure and smaller volumes of gas. More recently, with the facility to calibrate at higher pressures, turbine meters have also been used for high pressure and higher volume applications. However, these meters remain particularly susceptible to damage by any liquids present in the gas and they are not therefore regarded as suitable for use in typical offshore applications on the UKCS.

Wet Gas and Multiphase Hydrocarbons

2.4.4 Orifice plate meters, Venturi meters, V-cone meters and, to a lesser extent, ultrasonic meters, have been widely used in wet gas applications.

When an orifice plate is used in applications where a significant amount of liquid is present (for example, in separator metering applications) the use of a plate with a drain-hole is strongly recommended. The additional uncertainty introduced is likely to be small compared with that which would be introduced by a build-up of liquid upstream of the plate. Recent independent tests have shown that the V-cone meter may be particularly suited to wet gas metering applications. A new generation of 'hybrid' meters is presently under development and several of these devices are already in use on the UKCS.

Ultrasonic meters should not be used for the measurement of wet gas if the liquid content is expected to exceed 0.5% by volume.

2.4.5 For 3-phase applications where oil, gas and water are to be measured simultaneously, the optimum choice of meter is very much application-dependent. Module 8 of these Guidelines presents more detailed guidance in this area.

New Technology

2.4.6 The DTI encourages Operators to continue to develop and deploy new technology, consistent with the retention of a satisfactory degree of measurement integrity.

Where a Licensee wishes to use new technology or to deploy existing technology in a novel setting, the DTI may:

- Require that the Licensee establishes an evaluation programme
- Wish to be involved in the design, implementation and evaluation of the findings of any such programme.

2.5 CUSTODY TRANSFER MEASUREMENT

Custody Transfer Measurement Scenario

2.5.1 Economic considerations aside, Custody Transfer uncertainty levels for a new field development will be generally be regarded as appropriate when either of the following conditions apply:

(i) Hydrocarbons from the field are subject to Petroleum Revenue Tax (PRT).

(ii) Hydrocarbons from the field are part of an allocation system containing hydrocarbons from other fields that are subject to PRT.

Condition (i) is unlikely to be encountered for new field developments under the existing Tax Regime (2.2.6 refers).

2.5.2 It must also be borne in mind that there may be commercial factors (e.g. pipeline agreements) that dictate the need for Custody Transfer uncertainty levels, irrespective of the DTI's stance based on the considerations of 2.5.1.

2.5.3 Custody Transfer uncertainty levels will generally only be achieved by the implementation of the highest quality design, installation and operating practices. It is necessarily expensive to achieve, but offers the benefit of reducing financial exposure to potentially prolonged and undetectable systematic mismeasurement.

2.5.4 Guidance on the installation, operation and verification of such systems is presented in detail in Modules 3 and 4 of these Guidelines, for liquid and gas systems respectively.

However, there are some high-level features common to both, which are dealt with here.

System Design

2.5.5 Custody-Transfer level measurement systems will normally have to employ tried-and-tested measurement techniques designed and installed to recognised industry standards, where these exist.

Where a Licensee wishes to employ 'new' technology in such an application due regard should be given to 2.4.6 above.

Maintenance and Operation

2.5.6 The correct maintenance and operation of a Custody Transfer measurement system plays a critical part in helping the system achieve its potential uncertainty target.

2.5.7 In recent years, in an effort to drive down operating costs, there has been a tendency to reduce the presence, on site, of dedicated measurement personnel. In certain extreme cases, experienced metering personnel only visit the site to perform routine reverification of primary and secondary instrumentation. While the DTI fully supports Operators in their drive to extend the economic life of fields, this process must be commensurate with the retention of an acceptable level of measurement integrity.

The presence of a complete set of 'as found/as left' routine calibration procedures may give the superficial impression that a metering system is being operated correctly. However, in itself, this is not sufficient. Appropriate day-to-day operation of a measurement station is the critical factor.

The lack of full-time, on-site, presence of dedicated metering personnel is only acceptable for Custody Transfer applications provided the following concerns have been addressed fully:

- The responsibilities for the day-to-day operation of the measurement station must be clearly defined, and the relevant personnel trained to an acceptable level. The DTI may require evidence of the training received by these personnel, and details of any independent competence assessment involved. For oil metering systems reliant on meter proving, particular attention should be given to the theory and practice of proving, and the correct practice to be followed with regard to the acceptance of the results of meter proves (section 3.7.4 of these Guidelines refers).

- Operational Procedures need to be readily available at all times. Particular attention must be paid to alarm-handling; both in terms of responsibilities for checking alarms, and the procedures to be followed in the event that they are found to be active.

- Remote metering support may need to be enhanced. Should active alarms or other measurement issues be encountered, there must be available at all times an expert point of contact for the on-site operating personnel.

The acceptability to the DTI of these strategies may depend on the provision of a remote (e.g. onshore) monitoring capability.

2.5.8 In general, maintenance schedules for the reverification of primary and secondary instrumentation should initially be as tight as economically justifiable. If a 'calibration', rather than 'health-checking' regime is proposed, initial recalibration frequencies will typically be monthly for gaseous hydrocarbon systems and 3-monthly for liquid hydrocarbon systems. These may subsequently be relaxed once confidence in the system has been demonstrated.

2.6 CUSTODY TRANSFER (NON-PRT) MEASUREMENT

2.6.1 This class of measurement refers to continuous measurement of hydrocarbons in dedicated, post-separation measurement stations, when neither of the conditions in 2.5.1 apply, i.e.

(i) Hydrocarbons from the field are not subject to Petroleum Revenue Tax (PRT).

(ii) Hydrocarbons from the field do not enter an allocation system containing hydrocarbons from other fields that are subject to PRT.

2.6.2 This class of measurement will be regarded by the DTI as the minimum requirement for 'non-marginal' developments satisfying the above conditions.

2.6.3 Guidance on the installation, operation and verification of such systems is presented in detail in Modules 5 of these Guidelines.

Custody Transfer (Non-PRT) Measurement Scenario

2.6.4 Examples where this class of measurement is appropriate include:

- Offload meters for stand-alone FPSO or FSU vessels where hydrocarbons are not subject to Petroleum Revenue Tax

2.7 ALLOCATION MEASUREMENT

2.7.1 Allocation measurement refers to *continuous* measurement by which a quantity of hydrocarbon, metered to Custody Transfer standard, is attributed to different sources.

For the measurement of a field's hydrocarbons to achieve Allocation levels of uncertainty, dedicated processing facilities for that field will be required.

2.7.2 The best levels of Allocation metering may approach Custody Transfer standards. The worst cases may have uncertainty levels only marginally lower than optimal Well-Test systems.

The wide range of uncertainties that may result from this general class of metering is a reflection of the fact that there are no established standards for its deployment, and that there is therefore considerable scope for variation in system design and operation. These areas are discussed in detail elsewhere in these Guidelines – particular attention should be paid to Module 6 (Separator Measurement).

Allocation Measurement Scenario

2.7.3 Allocation measurement may be appropriate when the field economics are not sufficient to support Custody Transfer standards of measurement but are nevertheless able to support dedicated separation and process trains with continuous measurement.

2.7.4 Practical examples where allocation measurement may be appropriate may include, but are not limited to, the following scenarios:

- Marginal satellite developments across existing infrastructure where spare separator capacity exists – for example, where all the production from the host field can (due to declining production rates) be routed through one separator, freeing another one for dedicated use with the satellite field.

- Marginal satellite developments across existing infrastructure where there is insufficient spare separator capacity for the above option; in such cases the host facility's test separator may effectively become a production separator for the satellite field.

- Development of a marginal gas field where condensate is expected to be present in significant quantities, with the wet gas exported into a shared pipeline for transport onshore - production from this field will subsequently be allocated on the basis of the figures reported by the offshore wet gas meter and the Sales figures from the onshore terminal.

Minimising Measurement Uncertainty

2.7.5 The measurement uncertainty of an Allocation system will be minimised by the following steps:

- Appropriate design and operation of the Production Separator (Module 6 refers).

- A regular programme of routine calibration for all primary and secondary instrumentation. Particular attention should be paid to the condition of primary measurement devices, particularly orifice plates if used.

- The installation of a water-in-oil meter in the oil take-off line, although attention is required to obtain the best possible results with these devices.

2.8 WELL TEST MEASUREMENT

2.8.1 Well Test measurement refers to *intermittent* measurement of production rates by test separator metering. Flow rates of each of the three phases are related to well-head parameters (such as choke position or well-head flowing pressure), and the production from each well is integrated over a flowing period to give the total production from each well, and hence the field.

This strategy is fairly widely employed and is often referred to as ‘Flow Sampling’.

2.8.2 As with Allocation measurement, there are no established standards for its deployment, and there is therefore considerable scope for in system design and operation. These areas are discussed in depth in elsewhere in these Guidelines – particular attention should be paid to Module 6 (Separator Measurement)

Well Test Measurement Scenario

2.8.3 Well Test measurement will be regarded by the DTI as appropriate for marginal developments whose economics do not support the provision of dedicated separation and process trains and the facility for continuous measurement.

2.8.4 Typical examples of Fiscal Well Test measurement systems include, but are not restricted to, the following scenarios:

- Satellite developments across existing facilities where there is insufficient spare separator capacity (either test or production) to permit separate processing of the new field. The existing well-test programme is then extended to include additional well tests from the satellite field.

- Development of a number of satellite fields to a central ‘hub’ facility; allocation to each field will be by ‘flow sampling’, with Custody Transfer standard measurement of the commingled fluids at export.

Minimising Measurement Uncertainty

2.8.5 The levels of uncertainty achievable in Well Test applications depends on a number of parameters, among the most important of which are the frequency and scheduling of well testing, and the state of repair of the test separator and its associated metering instrumentation.

2.8.6 The measurement uncertainty of a Well Test system will be minimised by the following steps:

- Appropriate design and operation of the Test Separator (Module 6 refers).

- The implementation of a regular programme of routine calibration of all primary and secondary instrumentation. Particular attention should be paid to the condition of orifice plates if used.

2.8.7 Hydrocarbon accounting procedures may have a considerable influence on quantities allocated to fields in well-test measurement regimes. Particular attention should be paid to the 'decay factors' used to interpolate between the results of well tests.

2.9 MULTIPHASE MEASUREMENT

2.9.1 Fiscal Multiphase measurement refers to simultaneous measurement of all three phases (oil, gas and water).

2.9.2 For a proposal for Fiscal Multiphase measurement to be acceptable to the DTI, it will normally include plans for the periodic reverification of the multiphase meter, for example by its comparison with a separator. Modules 6 and 8 should be consulted for guidance on Separator and Multiphase measurement respectively.

Multiphase Measurement Scenario

2.9.3 Examples of typical scenarios where multiphase measurement are likely to be acceptable to the DTI include, but are not restricted to, the following:

- Satellite developments across existing facilities where field economics do not permit the provision of a dedicated process and separation train for the satellite field

2.9.4 In many cases, a multiphase approach may be preferable to a solution based on well testing. While it is true that the instantaneous measurement uncertainties on a multiphase meter may be relatively high (compared to those possible on a test separator), the ability to allocate production on the basis of continuous, rather than intermittent, measurement may be a more significant factor.

2.10 SUBSEA/DOWNHOLE MEASUREMENT

2.10.1 The provision of subsea or even downhole measurement is essentially seen by the DTI as a method of 'last resort', to be used only when there is no other technically or economically feasible means of attributing production to a field. Module 9 of these Guidelines provides some further Guidance in this area.

2.10.2 The principal challenges to the acceptability of a measurement proposal based on subsea or downhole measurement are:

- The feasibility of the proposed method for the reverification of the meter.
- The presence of an acceptable contingency plan for adoption in the event of meter failure.

Subsea/Downhole Measurement Scenario

2.10.3 Examples of typical scenarios where multiphase measurement are likely to be acceptable to the DTI include, but are not restricted to, the following:

- Satellite developments tied back to subsea templates prior to processing on a host facility.
- Single-well satellite developments tied back directly to a host facility where there is no tax or equity differential between commingled fields; in this case measurement is required for reservoir management purposes only.

DEPARTMENT OF
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MODULE 3

CUSTODY TRANSFER STANDARD
LIQUID PETROLEUM MEASUREMENT

DESIGN, OPERATING AND
REVERIFICATION GUIDELINES

MODULE 3 CUSTODY TRANSFER STANDARD LIQUID PETROLEUM MEASUREMENT

CONTENTS

3.1 TERMS OF REFERENCE

3.1.1 These notes are intended to provide the industry with guidance on high-quality flow measurement of petroleum in the liquid phase.

This Module of the DTI Measurement Guidelines is intended for use with liquid petroleum that is sufficiently above its vapour pressure that there is no significant risk of gas break-out at the meter. Where this condition is not met, operators are strongly advised to exercise caution in applying the principles and advice provided here.

This module deals with 'Custody-Transfer' standard liquid hydrocarbon flow measurement. By industry consensus, this is defined as dry mass flow measurement with an overall uncertainty of ±0.25% or better. The overall uncertainty is derived from an appropriate statistical combination of the component uncertainties in the measurement system.

The equipment used to achieve this level of performance will vary according to the particular circumstances of each development.

3.1.2 A substantial proportion of the metering stations covered by this Module of the Guidelines are based on 'conventional' turbine meter and bi-directional prover loop systems with associated on-line density measurement and automatic sampling. However, an increasing number of Custody Transfer metering systems are making use of alternative technologies, such as ultrasonic meters, for flow measurement. There may be very sound technical reasons for doing so.

Many fields on the UKCS have now passed their production plateaux, and as flow rates decline the original method of measurement agreed with the Department may no longer be suitable. For example, there may be significant problems associated with the operation of turbine meters and prover loops at flow rates considerably lower than their design maxima.

Alternative means of operation in such circumstances (for example, the use of smaller turbine meters, with a master meter for reverification purposes) are considered in this Module.

3.2 MODE OF MEASUREMENT

Volume or Mass Measurement

3.2.1 Hydrocarbon measurements may be either in volumetric or mass units. The choice of measurement should be discussed with the DTI.

3.2.2 Volume will normally be used for stand-alone field tanker loading operations and mass for multi-field pipeline or offshore pipeline with an allocation requirement.

3.2.3 Where the measurement is in volume units, these should be referred to standard reference conditions of 15°C temperature and 1.01325 bar absolute pressure. The metering system should compute referred volumes by means of individual meter temperature compensation and totalisers.

3.2.4 Mass measurement and reporting may be achieved either by

a) Measurement of volume flow rate (for example, by turbine or ultrasonic meter) and fluid density

b) Direct mass measurement by Coriolis meter

If the method a) is preferred, the density should if necessary be compensated to the volume flow meter inlet conditions. Mass flow rate may then be computed as the product of this density and the measured volume.

Volume Correction Factors

3.2.4 Liquid volume correction factors should be calculated as described in the IP Petroleum Measurement Manual, Part VII ('Density').

The original issue of this paper described a computer routine for the calculation of C_{tl} and C_{pl} for crude oil and condensate. This routine has since been incorporated into many commercial agreements and flow computer software. It used the 'Downer' equation in the calculation of oil and condensate compressibility, and specified requirements for rounding and truncation of input values and constants.

The DTI has since accepted a modified form of the IP Routine that incorporates the equation and constants described in API 11.2.1M for the calculation of compressibility. It is also accepted that the rounding and truncation provisions of the IP method may not necessarily be appropriate for modern flow computers and may be ignored.

3.2.5 It is essential, however, that the values of K_0 and K_1 input into the flow computer for use in the calculations are representative of the type of oil being measured.

Appropriate values of K_0 and K_1 for oil are given in Appendix F of IP Petroleum Measurement Paper 2.

3.2.6 Operators are encouraged to consider the use of specific constants derived for the particular application by laboratory analysis of representative samples.

It should be borne in mind that the 'generalised' values of K_0 and K_1 referred to in 3.2.5 were derived from the analysis of a relatively small sample of stabilised, non-North Sea, crude oils. The derivation of application-specific constants is therefore particularly recommended for systems with high crude oil vapour pressures, as it is to these systems that the 'generalised' constants are likely to be least applicable.

3.3 GENERAL DESIGN & INSTALLATION CRITERIA

3.3.1 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 and pressure transducers and density meters.

However if product of differing physical properties is produced by separate production trains and is not fully commingled before metering then it may be necessary to have separate measurement of the differing fluids.

Meter Runs

3.3.2 A sufficient number of parallel meter streams should be provided to ensure that, at the nominal maximum design production rate, at least one standby meter is available.

Isolation Valving

3.3.3 Adequate valving should be provided such that individual meters may be safely removed from service without necessitating the shut-down of the entire export system.

3.3.4 The Operator should be able to demonstrate the integrity of all vent and drains systems, particularly those downstream of the meter. For example, the use of 'double-block and bleed' valves, or sight-glasses, or 'spades' can be considered.

Recirculation Facilities

3.3.5 The DTI does not normally permit the fitting of recirculation loops to metering systems except in production systems featuring rapid tanker loading. Where recirculation systems are fitted around the metering system, full details of recirculation and any other non-export flows through the meters must be recorded.

Sampling System

3.3.6 Fiscal Quality 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.

Sampling systems should be broadly in accordance with ISO 3171. Due attention should be paid to the recommendations of the IP Petroleum Measurement Manual, Part VI ('Sampling').

Analysis of the samples obtained will ultimately be used to apportion production to the field from which the liquid hydrocarbons are being measured. They may also form the basis for any Crude Oil Valuation Procedures.

The sampling system is therefore a critical part of any Fiscal Quality measurement system. Any errors introduced through sampling error will generally have a direct, linear effect on the overall measurement.

3.3.7 As with any sampling system, it is important that properly-designed sampling probes are used and positioned in such a way as to ensure representative sampling.

3.3.8 Sampling flow rates should be 'isokinetic', as defined by ISO 3171. Sample lines should be provided with flow indicators to help demonstrate that this condition is being met.

Water-in-Oil Meters

3.3.9 Corrections to metered throughput for water and sediment content will normally be based on a retrospective analysis of flow-proportional samples.

However, the DTI may consider the use of on-line water-in oil meters in certain applications.

There are problems inherent in the comparison of any on-line technology with its 'sampling' equivalent. Disparity in their results may be caused by a systematic inaccuracy in the on-line meter, but it may equally be due to a lack of representivity of the samples.

A lengthy period of intercomparison and investigation of the relative merits of the two methods operating on the same, preferably 'typical' system, would be very beneficial to the industry as a whole, and the DTI would be very interested in Operators' proposals for any such field trials.

Temperature and Pressure Measurement

3.3.10 Temperature and pressure measurement points should be representative of conditions at the meter inlet and situated as close to the meter as possible without infringing the requirements of the API Measurement Manual. In practice, this means approximately 5 diameters downstream of the meter location.

3.3.11 Temperature measurements that affect the accuracy of the metering system should have an overall loop accuracy of 0.5°C or better, and the corresponding readout should have a resolution of 0.2°C or better - this is equivalent to an uncertainty of approximately 0.05% in C_{TL}.

Thermowells should be provided adjacent to the temperature transmitters to allow temperature checks by means of certified thermometers.

3.3.12 Pressure measurements that affect the accuracy of the metering system should have an overall loop accuracy of 0.5 bar or better and the corresponding readout should have a resolution of 0.1 bar or better.

Densitometer Installation

3.3.13 Due attention should be paid to the recommendations of the Part VII of IP Petroleum Measurement Manual (‘Density’).

3.3.14 Dual densitometers should normally be used and should feature a density discrepancy alarm system (typically 1.0kg/m^3). Where single-densitometer systems are used, high and low set point alarms should be used.

3.3.15 Provision should be made for solvent flushing on systems where wax deposition may be a problem.

3.3.16 Densitometers should be installed to the manufacturer’s specification and as close to the volume meters as possible. They should be provided with thermowells and pressure indicators so that it may be demonstrated that there is no significant difference from the volume meters’ inlet conditions. If this is not the case, temperature and pressure compensation must be applied.

3.4 SPECIFIC DESIGN AND INSTALLATION CRITERIA FOR TURBINE METER/PROVER LOOP SYSTEMS

Pulse Counting

3.4.1 The metering signals 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. This is to indicate if signals are "good" or to warn of incipient failure of meter or pulse transmission.

3.4.2 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 should 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. This is to avoid the initiation of alarms for routine process situations thereby tending to induce a casual attitude to alarms in general.

Prover Loop Design

3.4.3 Prover loops should preferably be of the bi-directional type to eliminate possible directional bias. The prover loop swept volume should have a suitable internal lining. The flanged joints within the calibrated volume should have metal-to-metal contact and there should be continuity within the bore.

3.4.4 Connections should be provided on the prover loop to facilitate recalibration with suitable calibration equipment which may be a dedicated water draw tank, portable calibration prover loop and transfer meter, or small-volume-type prover.

3.4.5 Provers should be constructed according to the following criteria:

- Unless ‘pulse-interpolation’ techniques are to be used, the number of meter pulses generated over the swept volume should be at least 20,000 pulses. (This is equivalent to 10,000 pulses between detectors on bi-directional provers.)

- The resolution of the detector/displacer system should be compatible with the above requirement.

- The displacer velocity should not normally exceed $3ms^{-1}$ to avoid slippage past the displacer but higher velocities may be acceptable with piston-type provers if seal integrity can be demonstrated.

3.4.6 Because the resolution of the detector/displacer system can only be gauged by the actual performance of the prover, the DTI expects the manufacturer to demonstrate an acceptable repeatability 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.

3.5 SPECIFIC DESIGN AND INSTALLATION CRITERIA FOR ULTRASONIC METER SYSTEMS

3.5.1 For Custody Transfer applications, only transit time multi-path ultrasonic meters should be used.

Meter Diagnostics

3.5.2 Multi-path ultrasonic flow meters incorporate a variety of functions that can either individually or collectively be employed for 'health care' monitoring. Provision for data acquisition should be made at the design phase, so that this information may be used for 'footprinting' and monitoring meter performance.

Meter Reverification

3.5.3 The need to periodically re-verify the meter must be considered at the design stage.

The use of meter diagnostics alone is not presently regarded as sufficient in this respect. An additional means of meter reverification is necessary. Essentially there is the choice between:

a) The use of a master meter.

b) Removal of the meter for calibration at a recognised test facility.

c) Comparison of the meter with a pipe prover.

These topics are covered in greater depth in Section 3.10 of these Guidelines.

Use of Master Meter in By-Pass Line

3.5.4 Should option a) in 3.5.3 be preferred, the master meter should be placed in a by-pass line, with the facility to flow simultaneously through the 'duty' and 'master' meters for comparison purposes. The master meter should preferably be a meter operating on a different physical principle (e.g. a helical-bladed turbine meter). However, there may be practical advantages (e.g. the provision of a meter that could potentially be used as a spare) in the use of a second ultrasonic meter. Periodic comparison of the 'duty' and 'master' meters would immediately reveal the presence of contamination, since the 'master' meter will not have been exposed to the same degree of contamination.

3.5.5 Provision of suitable pressure and temperature measurement points is required at both the 'duty' and 'standby' stations in order that the appropriate correction volume factors may be applied when comparing the two meters.

Upstream and Downstream Pipework

3.5.6 The straight pipe sections located immediately upstream and downstream of the meter should be selected, fabricated and installed to ensure minimum impact on the performance of the metering station or the specified measurement uncertainty.

Meter manufacturers should be consulted regarding the minimum number of straight lengths required upstream and downstream of the meter.

Flow Conditioners

3.5.7 The use of flow conditioners removes one of the principal operational advantages offered by ultrasonic meters, i.e. the absence in the flow line of any flow restriction. However, their use may be necessary in order to address what may be quite serious concerns over possible installation effects.

3.5.8 If flow conditioners are proposed as part of the system design then the type and location of these devices should be discussed with the meter manufacturer prior to installation.

3.6 SPECIFIC DESIGN AND INSTALLATION CRITERIA FOR CORIOLIS METER SYSTEMS

3.6.1 This section of the Guidelines highlights the principal points that must be borne in mind when designing and installing Coriolis metering systems. ISO 10790 should be consulted for more detailed guidance in this area.

Flow Profile

3.6.2 Coriolis meter performance is not affected to any significant extent by the presence of a 'non-ideal' flow profile at the meter. Coriolis meters are also relatively unaffected by changes in flow profile. These features of the Coriolis meter have the following implications:

a) The configuration of the upstream and downstream pipework is of relatively minor importance

b) There is no need to consider the use of flow conditioners.

c) If the meter is to be removed for recalibration, it is not necessary to ensure that the flow profile at the test facility is representative of that experienced by the meter 'in service'.

Pressure Drop Across Meter

3.6.3 The pressure drop across Coriolis meters is relatively high. To minimise the potential for 'flashing' of lighter hydrocarbons (with consequent degradation of meter performance) any flow control valves in series with the meter should be placed downstream of it.

Plant Vibration

3.6.4 Mechanical vibration has the potential to degrade Coriolis meter performance. If the meter is to be installed in an area with high levels of plan vibration, it may therefore be necessary to clamp or mount the meter in order to minimise this effect.

Temperature Effects

3.6.5 Large differentials between the ambient temperature and the temperature of the oscillating tubes of the Coriolis meter may lead to increased error in the temperature compensation routine used to correct the results of the meter's flow calibration to its 'in service' conditions. Where the operating temperature is expected to differ significantly from ambient, the meter should therefore be lagged in order to minimise this effect.

Meter Orientation

3.6.6 U-tube devices should be installed with the 'U' vertical to prevent the build-up of gas within the meter body.

3.7 OPERATING AND RE-VERIFICATION PROCEDURES – TURBINE METER/PROVER LOOP SYSTEMS

Turbine Meter K-Factor

3.7.1 The correct operation of these systems is critically dependent on the determination of representative k-factors for the turbine meter. The k-factor used by the stream flow computer (normally that determined at the most recent meter prove) should at all times be within a predefined value, δ, of the 'true' k-factor being generated by the turbine meter in its current operating conditions.

The value of δ is defined by the Operator at the system design stage. Its value is constrained by the need to retain the overall dry mass uncertainty within ±0.25%, and is typically 0.1%.

Turbine Meter Linearity

3.7.2 For new or modified meters that are to be operated over a wide flow range covering flow rates below 50% of maximum, a characteristic 'Performance Curve' of meter factor versus flow rate should be determined for each meter. This allows the Operator to determine the variation in flow rate that would cause a shift in k-factor of greater than the value of δ referred to in 3.7.1 – essentially this is one of the 're-prove alarm limits'.

These curves should cover a range from 10% to 100% of maximum flow rate, subject to any system restriction on flow rate. It is recommended that a number of proves (typically 5) are completed at each of these nominal flow rate points, between which intervals of 10% are suggested.

3.7.3 Turbine meters used for 'fiscal-quality' measurement of oil are expected to demonstrate a good degree of linearity in their performance curves. The DTI typically expects the linearity of meters to be within ±0.15% across the expected operating range of flow rates.

If the variation in k-factor of a turbine meter under normal operating conditions is significantly greater than the value of δ referred to in 3.7.1 there will be an increase in the requirement to re-prove the meter due to excursions outwith the re-prove alarm limits. The resultant increased wear on the prover system will inevitably have an adverse effect on the duration of its life in service.

Operators are therefore strongly encouraged to use turbine meters with a high degree of linearity. Any extra expense incurred in their purchase is likely to be more than offset by a reduced requirement to reprove the meters during the lifetime of the field.

Proving Regime

3.7.4 The requirements governing the intervals between turbine meter proving in a continuous production system (as distinct from tanker loading or batch export systems) are:

- For a newly commissioned metering station, for a new meter, or for a meter which is being returned to service after repair, meters should be proved three times per week, at approximately equal intervals between proving, for the first month of operation.
- Provided the meter factor performance for this month is acceptable to the DTI, this frequency may be reduced to twice per week for the second month of operation.
- If meter factor performance for this second month is still acceptable, proving frequency may be reduced to once per week at the end.

3.7.5 After the initial 'settling in' period described in 3.7.4, the appropriate proving frequency is determined by the proportion of k-factor shifts in excess of the value δ referred to in 3.7.1 (typically 0.1%).

The maximum interval between successive proves should be no more than 7 days for a stream in continuous operation. Subject to this condition, the proving frequency should be adjusted so that no more than 5% of proves indicate a k-factor shift in excess of δ.

3.7.6 A meter should also be reproved

a) When the flow rate through the meter changes by an amount sufficient to cause a change in meter factor greater than 0.1%. This amount will be dependent on the turbine meter's linearity.

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

(b) When any significant change in a process variable such as temperature, pressure or density of the liquid hydrocarbon 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. These values can be determined by a 'regression analysis' of the turbine meters' response to changes in each of these parameters. In typical North Sea production systems practical values of these limits are of the order of 5°C temperature, 10 barA pressure and 2% density.

3.7.7 For tanker loading or batch export systems, the frequency of proving will depend on the duration of export and may require several meter factors covering 'ramp up', 'load' and 'ramp down' export rates as well as shifts in fluid temperature.

The frequency of proving will therefore be subject to the approval of the DTI on a case-by-case basis.

Determination of K-factors

3.7.8 For normal operating conditions:

- Meter factors should normally be based on the average of at least five proof runs.
- The meter factor calculated for each of the consecutive five proof runs must lie within ±0.05% of the mean value of all five.

3.7.9 If it proves problematic to satisfy the above condition, for example due to the continual process instability common on some older installations, then an equivalent statistical method may be agreed with the DTI.

The DTI has seen many examples in practice where the search for 5 consecutive k-factors within ±0.05% of the mean of all five has not been successful until a great many (as many as 50 in some instances) runs have been completed. The great majority of these runs are then rejected in favour of the last 5. From a purely statistically standpoint, such a practice is highly dubious.

Similarly, the DTI has seen cases where 'non-typical' operating conditions have been invoked to allow k-factors to be determined more readily. For example, separators have been placed on manual control to stabilise the flow through the meter – with the result that the meter may not be proved at a representative flow rate.

It must always be borne in mind that goal is not simply to satisfy the requirement in 3.7.8, but rather to obtain a representative k-factor for use until the next meter prove is carried out. Operators are encouraged to be flexible rather than adhere slavishly to the 'traditional' approach.

3.7.10 The following points should be considered when devising a strategy for statistical proving:

- If it is not possible to achieve the repeatability criteria given in 3.7.8 within 10 runs, then it may be the case that attempts to obtain a representative k-actor will be unsuccessful even if many more runs are completed.

- Under these circumstances it is recommended that a simple arithmetic average of a large number of runs is calculated. The number of runs required will depend on the specific circumstances.

- The poor repeatability may be caused by process instability. If this instability is in some way 'cyclical' then the number of runs should be sufficient to cover a complete 'cycle', even if this number is relatively large. Alternatively, if the instability is not regular, a smaller number of runs would probably be sufficient.

- A large number of runs may be impractical in certain circumstances, especially those where, due to the large size of the prover or the low prevailing flow rates, the time taken to complete all the proves would be unacceptably high.

- Where the number of averaged prove runs is less than 20, a statistical analysis should be performed on them in order that 'outliers' can be rejected. This can also be performed when the number of runs exceeds 20, although there the larger total provides some insurance against the undue influence of individual 'rogue' proves.

Data to be Recorded

3.7.11 Full details of the proof runs should be entered in the record of meter proves, together with the following information:

- Date and time of prove.

- Fluid temperature.

- Fluid pressure.

- Fluid density.

- Fluid water cut.

- K-factor shift from previous meter prove.

This information may be extremely useful as supporting data should it become necessary to predict k-factors, for example in the event of the failure of a critical element of the meter prover.

K-factor Acceptance Criteria

3.7.11 Any unexplained shift in k-factor in excess of 0.1% should be reverified by a repeat run prior to its acceptance.

3.7.12 The performance of a turbine meter should be monitored throughout its service in order to detect any short or long-term change in its characteristics. This is normally achieved by the use of a 'Control Chart', which is essentially a graph of the turbine meter's k-factor history.

Statistical methods may then be employed to assist the operator in deciding whether the result of a meter prove should be accepted. The IP Petroleum Measurement Manual, Part X (' Meter Proving') should be consulted for guidance in this area.

Good proving practice is fundamental to the correct operation of any turbine meter/prover loop system, and as such Operators' strategies will be subject to continuous review by the DTI.

Prover Failure

3.7.13 In the event of the failure of any critical element of the prover the DTI must be contacted so that an appropriate strategy for the reverification of the turbine meters may be agreed.

3.7.14 In the absence of an effective operational prover, it may be necessary to calculate meter factors.

This may be possible using a combination of flow rate (or meter pulse output frequency), meter temperature, meter pressure, water cut, and meter density, using constants which have been generated on the basis of the historical data for that particular turbine meter by use of standard mathematical 'curve-fitting' or 'regression' techniques.

The use of ‘calculated’ k-factors requires prior authorisation from the DTI. For such a method to be acceptable to the DTI, it is important to ensure that:

- No part of the meter has been modified or replaced since the historical data were gathered.
- Although the range of operating conditions whose data are used should be as broad as possible, non-typical data ('outliers'), identified according to standard statistical techniques, have not been included in the regression calculation.
- Current operating parameters can be shown to fall within the spread of the historical data to be used.
- The set of historical data, the regression calculations used, and the coefficients calculated for each meter are all recorded for possible scrutiny or verification by the DTI.
- Sufficient computer facilities and manpower are available to process the large number of calculations involved in a timely manner.

3.7.15 Operators should be aware that where turbine meter performance has been affected by contamination of the meters (e.g. by scale formation on the meter blades), regression analysis may not be appropriate.

Spare Prover Sphere

3.7.16 A spare prover sphere of the appropriate size and material type should always be available.

This sphere should be stored such that it does not deform under its own weight. Practical solutions to this problem typically involve the storage of the sphere on a bed of polystyrene beads, or the hanging of the sphere in a sack, (but not a net, as the sphere may extrude and deform).

Use of Equipment Outwith its Design Capacity

3.7.17 The DTI strongly encourages Operators to keep the suitability of their measurement systems under continuous review, and to replace unsuitable equipment as required. Nevertheless it is recognised that the turbine meters and provers installed on some older installations may now be over-sized with respect to current production rates.

Given the characteristic operating curve of a turbine meter, with a particularly steep slope and ‘hump’ at the lower part of the flow range, this may lead to inaccurate measurement unless the proving frequency is increased in accordance with 3.7.5.

Quite apart from the increased wear on the prover that this would entail, it may in practice be extremely problematic. If significant flow instability is present, it may become difficult or impossible to prove at all. Alternatively, flow energy may be insufficient to drive the sphere through the prover smoothly or reliably. In such low or unstable flow conditions, temperature, pressure, density, and water content may also fluctuate. As viscosity, which may be affected by each of these parameters, is also a dominant influence in turbine meter operation, meter proving may be especially unreliable.

In such circumstances the Operator is encouraged to consider either the alternative proving methods discussed in 3.7.9 and 3.7.14, or the use of a ‘master meter’ (this is covered in 3.9).

3.8 PROVER CALIBRATION

3.8.1 The calibration of the prover is probably the most significant single event in the operation of any measurement station that relies on proving for the reverification of its flow meters. Any error introduced at this stage will persist until the prover is recalibrated – this may be a year or more later – and all flow meter calibrations in the interim will be subject to this error.

Inadequate preparation on the part of the Operator has the potential to lead to delays in the completion of the calibration process. It is in the Operators own interest that the calibration is completed without any unnecessary delays (consistent with the correct calibration procedures being followed). The cost of the calibration, direct and indirect, will thereby be minimised, as the Calibrating Authority is normally paid on a daily rate, and any deferment of production caused by the calibration procedure will be minimised.

Appendix 3.2 contains some important guidance for Operators to help ensure that the prover calibration proceeds as smoothly as possible.

3.8.2 Prover loops should be calibrated at the manufacturer's works by methods described in IP or ISO standards as part of their systems checks, and again after installation on site. One copy of the calibration certificate for each of these and all subsequent calibrations should be sent to the DTI.

These certificates should contain the following information:

- The reference numbers of the sphere detectors and detector seals used in the calibration
- Prover internal diameter and wall thickness
- Prover steel expansion coefficients
- The value of Young’s modulus for the prover steel.
- Details of the traceability to national standards of the calibration equipment

The values of these constants should not change from year-to-year without the prior approval of the DTI.

3.8.3 The DTI must be given at least 14 days notice of all prover loop calibrations so that arrangements for possible witnessing can be made.

3.8.4 Any maintenance work on the prover that could affect the swept volume (for example, changes of sphere detectors and switches) should not be undertaken without prior notification of the DTI. The DTI will advise if a recalibration is required.

3.8.5 Inspection of all critical valves and instrumentation along with the sphere, checking of sphere size, sphericity, etc. should take place prior to calibration. After calibration the sphere detectors and all vents and drains should be sealed.

Recalibration Frequency

3.8.6 While a metering station is in service, prover loops should normally be calibrated at a frequency of not less than once per year. There are certain circumstances under which the DTI may permit the interval between successive prover calibrations to be extended to 2 years, on the basis of historic stability and low production rates. Further details of these conditions are given in Appendix 3.1.

Where the agreed interval between successive calibrations has to be extended for operational or weather reasons, a two-month ‘period of grace’ will be allowed. Operation beyond this period requires dispensation from the DTI. Any agreed delay should not be carried forward to the next calibration. For example, if an annual calibration is delayed by 2 months, the next calibration will be due in 10 months’ time.

Acceptance of Results of Prover Calibration

3.8.7 For a prover base volume calibration to be acceptable, it should be based on 5 consecutive round trips where the range of volumes is within ±0.01% of the mean of these 5 volumes.

3.8.8 The DTI expects the values of base volumes obtained to agree to within ±0.02% from year to year. There is a degree of flexibility in the interpretation of this limit, depending on the ease with which the initial repeatability criterion (defined in 3.8.7) is met - i.e. it may be interpreted as meaning ±0.02% rather than ±0.020%.

For example, a result with a shift of 0.024% from the previous year's value would not be acceptable as a first attempt, but would perhaps be acceptable if it was obtained after several days of previously unsuccessful attempts to obtain 5 runs which agree to within ±0.01% of the mean.

Any shift of >0.025% should certainly be verified by a repeat calibration at a different flow rate. The difference in flow rate should be at least 25%, if operating conditions permit.

The Operator must seek approval from the DTI before any shift in excess of 0.02% is accepted.

Calibration using Water as the Process Medium

3.8.9 The DTI prefers that calibrations are carried out at line conditions, using the process fluid as the flowing medium. However, under certain circumstances the use of water, rather than the process fluid, may be justified.

If the levels of stability referred to in Section 6 cannot realistically be achieved then the use of water, rather than the process fluid, should be seriously considered by the Operator.

There are number of reasons why calibration on water may be desirable. For example:

- Calibration of the prover on product may result in the deferment of production.
- There may be concerns that the required level of process stability may not be realistically achievable.
- The calibration may be completed more rapidly using water, given the better levels of temperature stability achievable, and this may result in a cost saving for the Operator.
- There may be environmental or safety concerns over the use of hydrocarbon as the flowing medium.

Where the Operator is considering the use of water then prior consultation with the DTI is required.

At the moment there is no evidence to suggest that the use of water introduces significant additional uncertainty to the calibration procedure. However, should such evidence come to light then the DTI may wish to review its non-objection to the use of water as the calibration medium.

3.9 THE USE OF MASTER METERS FOR IN-SITU RE-VERIFICATION OF TURBINE METERS

3.9.1 Where the problems with proving described in 3.7.19 are encountered, or where it can be shown that flow rates on the installation concerned have declined to the extent that the existing prover is now over-sized, the DTI may be prepared to consider meter proving by use of a suitable master meter.

3.9.2 The proposed master meter should be appropriate for the nature of the fluids concerned.

Common-Mode Error

3.9.3 One of the arguments against the use of a master meter is the possibility of 'common-mode' errors. These may be caused by:

1) A change in the fluid's characteristics that affects equally the response of the 'duty' and the 'master' meter.

2) A long-term 'drift' in the response of both the 'duty' and 'master' meter caused by their continued use.

3.9.4 In order to guard against the first of these, it has until recently been thought to be a necessary condition that the master meter should be based on a different operating principle from that of the meters being proved.

While this is perhaps still advisable, recent experience with helical-bladed turbine meters suggests that they may be sufficiently insensitive to changes in the process fluid to make the first of these sources of common-mode error unlikely.

3.9.5 In order to guard against the second source of common-mode error, the 'master' meter should be by-passed and isolated when not in use so that any long-term drift would be detectable when the 'duty' meter is compared with the 'master' meter.

Installation Considerations

3.9.6 A master meter installation should include:

- Sufficient upstream filtering of the fluid to protect the master meter from damage.
- Sufficient uninterrupted straight lengths of pipe upstream of the master meter to ensure unbiased flow at the meter.
- Sufficient valving to allow the master meter to be removed for inspection and calibration without disturbing normal flow.
- A dedicated master meter flow computer capable of determining master meter flow, temperature, pressure, and density to a level of accuracy equal to that of the flow computer used with the meter being proved. Such a master meter flow computer should ideally be programmed to control proving sequences and to calculate meter factors.

Recalibration of Master Meter

3.9.7 The master meter should normally be recalibrated at intervals not exceeding six months, or whenever its operation is thought to be suspect. The meter should be calibrated as a complete working unit – combined spool and internals, along with any dedicated interface electronics as required.

3.9.8 The master meter should be calibrated on the in-service fluid, where possible, across at least the range of flow rates commonly met in operation. Use of any other calibration fluid should be discussed with the DTI well in advance. Alternative calibration fluids should, if possible, be of the same viscosity range as the service fluids likely to be encountered during the master meter's service.

3.9.9 A spare calibrated master meter should be held at the metering station, ready to be placed in service during periods when the other master meter is being calibrated or inspected.

3.9.10 The DTI may require to witness calibrations of master meters, and should be given at least 14 days' notice of such calibrations.

3.10 OPERATING AND RE-VERIFICATION PROCEDURES – ULTRASONIC METERS

Initial Calibration

3.10.1 Meters should under all circumstances be flow calibrated at a recognised laboratory prior to their use in service. This applies equally to master meters, where their use is proposed.

The meter should be calibrated over as much of the full anticipated flow range as possible, with particular attention paid to the expected operating flow rate. The meter should normally be calibrated at least six ‘nominal’ flow rates evenly-spaced within the range, with interpolation of the calibration offset for flow rates not directly covered. To maintain traceability, the calibration data and interpolation calculations should be stored within the flow computer rather than the meter electronics.

3.10.2 While it is recognised that meters may have built-in viscosity correction features, the dependence on these factors should be minimised by calibrating the meter on a fluid that resembles, as closely as possible, the in-service process fluid.

It is recognised that this may be a potential barrier to the use of ultrasonic meters for fields with high export flow rates, as suitable calibration facilities may not exist. There may be scope to use onshore terminal facilities as calibration sites. Metering stations equipped with turbine meter and prover loop designed for ‘batch’ export may be particularly suitable for this purpose.

3.10.3 In addition, the flow profile at the calibration must be representative of that predicted at the ‘in-service’ meter conditions. If this condition cannot be met then the use of flow conditioners may be necessary (see also 3.5.7).

In-Service Reverification

3.10.4 It is recognised that the inherent diagnostic features of ultrasonic meters are a potentially very powerful tool. These potentially offer the user the ability to extend the ‘health care monitoring’ strategy to the extent that either meter removal and recalibration, or an alternative in-situ reverification (such as meter proving) become unnecessary.

However, it has not been demonstrated to the Department’s satisfaction that there is sufficient quantitative information contained within the diagnostics for such a scenario to be acceptable. The information offered by the diagnostics is qualitative rather than quantitative, and as such cannot be relied upon to demonstrate that meter performance has changed by a pre-determined amount that would necessitate meter removal and recalibration.

Therefore, as indicated in Section 3.5.3, there are essentially 3 methods for reverification of ultrasonic meters. These are:

- The use of a master meter.
- Removal of the meter for calibration at a recognised test facility.
- Comparison of the meter with a pipe prover.

Master Meters

3.10.5 The ‘duty’ meter should be compared with the ‘master’ meter at a frequency agreed with the DTI. This will typically be weekly at first, with the possibility to extend the interval between successive calibrations subject to satisfactory meter performance.

Flow rate should be integrated over an interval agreed with the DTI so that the ‘flowed’ volumes calculated by the two meters may be compared, taking account of the necessary volume correction factors. The extent of the calibration interval will depend on the flow rates concerned, but will typically be in the order of 1 hour.

3.10.6 To guard against the possible ‘drift’ of both ‘master’ and ‘duty’ meters, the master meter must be periodically removed and calibrated at a recognised onshore facility.

The interval between successive recalibrations of the master meter should take place at intervals agreed with the DTI.

Meter Removal/Recalibration

3.10.7 The comments in 3.10.1-3.10.3, on the initial flow calibration, above apply equally to subsequent re-calibrations of the meter.

3.10.8 The interval between successive recalibrations will be determined on a case-by-case basis following discussions between the Operator and the DTI.

Proving

3.10.9 The use of pipe provers to calibrate ultrasonic meters has been tried in practice, but with limited success. Ultrasonic meters do not have the inherent inertia of turbine meters, with the result that instantaneous fluctuations in flow rate, which are to some extent ‘damped’ by turbine meters, are generally detected by their ultrasonic equivalents. As a result, repeatability may not be sufficient for meaningful comparisons to be made. This problem is even more pronounced with small volume provers.

There is considerable scope, however, for the use of statistical methods in interpreting the results from pipe provers (see, for example, *Folkestad*) although these have yet to be adopted in practice in the UK.

3.11 OPERATING AND RE-VERIFICATION PROCEDURES – CORIOLIS METERS

Meter Calibration

3.11.1 The Coriolis meter should be flow calibrated prior to installation.

3.11.2 Since the Coriolis meter is a direct mass meter, calibration against a similar mass flow rate standard is preferred. Where the Coriolis meter is calibrated against a volume flow rate standard, the uncertainty in the density of the test fluid (at meter conditions) must be considered when interpreting the calibration results.

3.11.3 The calibration conditions should generally be as similar as practically possible to the anticipated ‘in service’ conditions.

This requirement does not extend to the upstream pipe configuration, since Coriolis meters are relatively insensitive to flow profile effects (3.6.2 refers).

Zero Flow Check

3.11.4 The following parameters:

- Stresses on the meter from the surrounding pipework
- Fluid and ambient temperature
- Fluid pressure
- Fluid density

may differ substantially from ‘calibration’ to ‘installation’. The effect of each of these differences will be a shift in the meter’s output at zero flow.

Therefore, once the meter is installed, the net impact of these installation effects can be quantified by performing a zero-flow check.

3.11.5 To check or adjust the zero-flow output, the meter should be 'full' and all flow stopped.

3.11.6 Zero adjustment, if necessary, should only be made under process conditions of fluid temperature, pressure and density.

Meter Reverification

3.11.6 The meter may be reverified by

- Periodic comparison with a prover
- Removal and recalibration at a recognised test facility

APPENDIX 3.1 PRE-CONDITIONS FOR POSSIBLE 2-YEARLY PROVER CALIBRATION

The DTI may consider the case for extending to 2 years the interval between successive recalibrations of a prover provided that the following conditions are met:

1. The nominal production rate through the meters routinely calibrated by the prover must not exceed 50,000 barrels/day.

Considering the 5 most recent prover calibrations, for each prover volume to be used:

2. The calibrated volume has remained within a range of ±0.02% of its mean.

3. The shift between the 1st and the 5th prover calibrations is no greater than ±0.02%.

Operators wishing to pursue the possibility of 2-yearly prover calibration, and whose systems meet the above criteria, should contact the DTI in order that the matter may be discussed more fully.

APPENDIX 3.2 PROVER RECALIBRATION – A GUIDE FOR OPERATORS

To ensure that the process of prover recalibration proceeds as smoothly as possible, Operators must take account of the following guidance.

The calibration of the prover will normally be carried out by an independent third party, referred to here as the 'Calibrating Authority'.

Prior to the Prover Calibration

Prior to arrival of the calibration rig:

1 The Operator should appoint a member of site personnel to liaise with the Calibrating Authority's calibration engineer.

2 Site management responsible for production should when possible plan the prover calibration work so that it fits into a period of stable process conditions.

(This does not apply when the calibration takes place using fluids other than the process fluids as the calibration medium – see 3.7.9)

3 A 'lay-down' area for the prover calibration rig should be prepared prior to its arrival.

4 All necessary Permits-to-Work and/or Isolations should be in place in order to enable the calibration to proceed as soon as possible after the Calibrating Authority's personnel arrive on site.

5 Unless an 'As Found' calibration is required, the site prover should be drained, with the prover sphere removed and ready for immediate inspection by the Calibrating Authority.

6 The installation Management should ensure that all relevant site staff have been briefed in advance of their roles and responsibilities so that disruption during the proving process is minimised.

7 Immediately in advance of the arrival of the calibration rig, the Operator should ensure that:

- The prover's 4-way valve is not leaking.
- All relevant isolation valves are leak free, and a means of testing or proving their integrity established.
- All relevant thermowells have been cleaned out and filled with thermally-conducting oil.

8 As a minimum, the following spares should be held:

- 4-way valve slips
- Prover door seals
- One complete set of prover detector switches; these should have been checked for correct operation and for correct insertion depth.
- Prover sphere valves.

9 The Operator should check that a spare prover sphere of the correct size, material, and condition is available, as well as all necessary sphere tools and a sphere pump. A readily available supply of glycol should also be provided.

10 The Operator should contact the Calibration Authority to determine which specific site services are necessary, and then ensure that that these are provided. For example, the provision of the following may need to be considered:

- Power supplies (440Vac, 240Vac or 110Vac) with suitable connections.
- Potable water for flushing the master prover at the end of the calibration.
- Dry white spot nitrogen at 1000 psi.

11 The Operator should have available a suitable pump for hydro-testing or leak-testing the hook-up of the site prover to the calibration rig.

During the Prover Calibration

12 During prover calibration, the Operator should strive to maintain, as far as possible, steady flow through the metering station, and remain attentive to the requirements of the calibration, as determined by the Calibration authority's engineers.

13 The decision as to whether or not the calibration has been completed satisfactorily ultimately rests with the DTI. However, the Calibrating Authority should normally be competent to decide whether or not the relevant criteria have been met.

After the Prover Calibration

14 After the prover calibration has been completed, the Operator's personnel should endeavour to isolate and depressurise the prover pipework as quickly as possible without compromising safety.

15 Once the master prover has been put back in its container, the Operator must make every effort to ensure that the master prover container is removed from site as soon as possible, in order not to create any 'knock-on' delays at the site of the next prover calibration.

APPENDIX 3.3 REFERENCES/TECHNICAL PAPERS

FOLKESTAD, T. Testing a 12” Krohne 5-path Altosonic V Ultrasonic Liquid Flowmeter on Oseberg Crude Oil and on Heavy Crude Oil. North Sea Flow Measurement Workshop, Kristiansand, Norway 2001.

COUSINS.T, AUGENSTEIN.D Proving of Multipath Liquid Ultrasonic Flow Meters. North Sea Flow Measurement Workshop, St Andrews, Scotland 2002.

DEPARTMENT OF
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LICENSING AND CONSENTS UNIT

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PETROLEUM MEASUREMENT

UNDER THE PETROLEUM
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MODULE 4

CUSTODY TRANSFER STANDARD GASEOUS PETROLEUM MEASUREMENT

DESIGN, OPERATING AND REVERIFICATION GUIDELINES

MODULE 4 CUSTODY-TRANSFER STANDARD GASEOUS PETROLEUM MEASUREMENT

CONTENTS

4.1 TERMS OF REFERENCE

4.1.1 These notes are intended to provide the industry with guidance on high-quality flow measurement of petroleum in the gaseous phase.

This Module of the DTI Measurement Guidelines is intended for use exclusively with single-phase gas. Where liquids or other contaminants are thought to be present, operators are strongly advised to exercise caution in applying the principles and advice provided here.

A separate module of the Guidelines (Module 7) deals with Wet Gas metering.

4.1.2 This module deals with Custody-Transfer standard gas flow measurement. By industry consensus, this is defined as mass flow measurement with an overall uncertainty of ±1.0% or better. The overall uncertainty is derived from an appropriate statistical combination of the component uncertainties in the measurement system.

Primary Measurement Device

4.1.3 The equipment used to achieve this level of performance will vary according to the particular circumstances of each development. Almost all of the gas metering stations covered by this Module of the Guidelines make use of either orifice plate or ultrasonic meters. These notes deal principally with these two types of system.

Coriolis meters are beginning to be accepted for Custody Transfer gas applications, but there is relatively little experience in this area. The DTI is of course open to proposals for their use.

Whichever method of measurement is adopted, there are certain common principles that must be adhered to; these are covered in section 4.3 of these Guidelines.

4.2 MODE OF MEASUREMENT

Volume or Mass Units

4.2.1 All measurement should be made on single-phase gas streams.

4.2.2 Hydrocarbon measurements may be in either volumetric or mass units. The choice of measurement should however be agreed with the DTI.

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

Sampling

4.2.3 Suitable facilities should be provided for the purpose of obtaining representative samples. The type of instrumentation incorporated within the measuring system may influence this specific requirement.

Gas Density

4.2.4 Gas density at the meter may be determined either by:

a) <u>*continuous direct measurement*</u>, by on-line densitometer

b) <u>*calculation*</u>, using a recognised equation of state together with measurements of the gas temperature, pressure and composition

The continuous measurement of gas density is preferred. However, both methods may be used simultaneously, and the comparison of their respective results may provide additional confidence in the accuracy of each method. This method is discussed in more detail in 4.6.9 below.

4.2.5 Where measurement is reported in volume, the continuous determination of gas relative density and hence density at standard reference conditions is preferred. However, the standard reference density of the gas being metered may, under certain circumstances, be calculated using a recognised equation of state together with measurements of the gas temperature, pressure and composition.

Calorific Value Determination

4.2.6 The Petroleum Production Reporting System (PPRS), agreed between UKOOA and the DTI, calls for the average calorific value (energy per unit volume) of custody transfer gas to be reported monthly to the DTI's PPRS administration unit in London. Provision for the determination of the calorific value (CV) of custody transfer gas should be made.

4.3 GENERAL DESIGN & INSTALLATION CRITERIA FOR GAS METERING STATIONS

Avoidance of Liquid Carry-Over

4.3.1 Metering stations should be designed to minimise the probability of liquid carry-over into the metering section, and from any condensation or separation that would have a significant effect on measurement uncertainties.

Secondary Instrumentation

4.3.2 Secondary instrumentation shall generally be required for the measurement and recording of the following parameters:

- Line pressure.
- Differential pressure (where applicable).
- Line temperature.
- Flowing density.
- Density at base or standard reference conditions.
- Gas composition (where applicable).

The position of the instrumentation within the system should be such that, as far as possible, representative measurement is ensured.

4.3.3 Consideration should be given during the design of a measurement system for the provision of back-up instrumentation to cover the failure of normal instrumentation, and also for the provision of suitable facilities for the on-site verification of secondary metering equipment.

Density Measurement

4.3.4 Gas density is normally measured in a 'by-pass' line to avoid introducing flow profile disturbances. Useful guidance on correct design is provided by the IP Petroleum Measurement Manual, Part VII ('Density').

It is important that the gas entering the densitometer is representative of the gas in the line, in respect of composition, temperature, and pressure. This becomes critically important if, as is generally the case, the pressure and temperature are not measured directly at the densitometer.

In the DTI's experience, failure to take account of this factor in the design of densitometer installations is one of the principal causes of significant mismeasurement in 'real' North Sea applications.

Operators may therefore consider the use of densitometers fitted with temperature elements, although the reverification of these temperature elements may itself be problematic. No standard facility presently exists to measure temperature directly at the densitometer.

Therefore, unless the temperature is measured directly at the densitometer, installations *must* be designed to so that

- The effect of ambient conditions (normally a cooling one) on the temperature of the gas sample is minimised. This may mean keeping the densitometer inlet line in close thermal contact with the meter tube; ideally it should be placed under any lagging. In extreme cases it may be necessary to heat-trace the line; in this case care must be taken not to over-heat the sample.

- There is no pressure drop between the densitometer and the point in the system where pressure is normally measured. Therefore all isolation valves between the densitometer and the pressure measurement point must be of the full-bore type.

In systems where gas density is also 'calculated' (as described in 4.2.4 (b) above), the comparison of the 'measured' and 'calculated' values can provide a valuable means of demonstrating confidence in the measured value. This is covered in greater detail in 4.6.9 below.

Densitometer installations should be designed so that, as well as meeting the above criteria, they also offer the facility for easy and efficient removal of densitometers and, preferably, the facility to readily view their Serial Numbers for auditing purposes.

Gas Chromatographs

4.3.5 Where it is planned to use gas chromatographs, these should be installed at 'high-points' in the system whenever possible, in order to reduce the probability of liquid contamination.

The distance of the chromatograph from sample take-off points (from both the meter streams and the calibration cylinders) should be minimised. Sample lines should be lagged and heat traced to maintain the temperature of the gas above its dew-point.

A low temperature shut-off valve should be installed on the sample inlet to the pressure let-down system to prevent any liquid drop-out being transmitted to the gas chromatograph.

4.3.6 Calibration gas cylinders should be prepared by recognised laboratories following procedures accredited by UKAS or equivalent overseas accreditation bodies.

These cylinders should be maintained at a temperature above the 'minimum storage temperature' stated on their calibration certificates. Either the cylinders should be stored in a heated enclosure, or the mixtures should be certified to -10ºC or lower.

When a cylinder has been stored at temperatures below this minimum temperature (for example, during transportation offshore) it should be 'rolled' prior to its use in order to homogenise, as far as possible, the cylinder contents. If this is not done, or if the cylinder is used while stored below its minimum temperature, it is likely that the lighter components may be preferentially sampled during chromatograph calibration. This effectively invalidates the calibration gas cylinder's certification.

4.3.7 Pressure let-down systems for use with gas chromatographs should, under normal circumstances, be designed so that the ratio of absolute pressures across each pressure reduction stage is constant.

With the possible exception of the final stage let-down valve, pressure let-down valves should be heated to prevent any liquid drop-out caused by Joule-Thompson cooling of the gas as it expands. In practice this normally means that valves should be 'hot to the touch'.

4.3.8 Flow computers and/or databases should be set with alarm limits on each of the components downloaded from the gas chromatograph in order to prevent the acceptance of a spurious composition in the event of system failure.

Choice of Primary Measurement Device

4.3.9 Where metering systems other than orifice plate or ultrasonic metering are to be deployed, these systems together with their flow compensating devices (if applicable) should be of the types agreed by the DTI.

4.3.10 If it is proposed to use new technology then details of the proposed equipment, layout and verification procedures should be discussed with the DTI at the earliest opportunity.

Consistency within Systems

4.3.11 In a gas gathering system, the pipeline Operator should ensure that the basic metering data, flow formulae and computational techniques are compatible throughout all the fields or stations connected to the gathering system. Independent validation of the calculations should be performed.

Requirement for Notification of DTI

4.3.12 The DTI 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 the Petroleum Measurement Inspectors may witness these tests at their discretion.

4.4 SPECIFIC DESIGN & INSTALLATION CRITERIA FOR ORIFICE METERING SYSTEMS

Application of ISO 5167

4.4.1 For new measurement systems the design, installation and operation will normally be expected to comply with the principles of ISO 5167. Any proposed departure from the most recent revision of this ISO standard should be discussed with the DTI prior to implementation.

For existing metering systems, proposals to implement new or modified requirements contained within the current revision of ISO 5167, either partially or in full, should be discussed with the DTI prior to implementation.

In this regard the comments in 4.4.2 must be considered carefully.

Discharge Coefficient Equation

4.4.2 In 1998 the Reader-Harris/Gallagher equation replaced the Stoltz equation for the determination of orifice plate discharge coefficient in ISO 5167. The effect of this change, for typical North Sea applications, is that the reported mass flow is decreased by a systematic factor in the region of 0.1-0.2%.

It is of course desirable in principle that the latest version of the discharge coefficient equation should be used wherever possible. However, the following points must be considered:

a) Where there is more than one entrant to a pipeline allocation system using exclusively orifice plate measurement systems, uniformity in the use of discharge coefficient equation at pipeline entry points is paramount, in order to avoid the introduction of a systematic bias. This consideration over-rides the desire to use the latest version of the discharge coefficient equation.

b) Terminal measurement systems should wherever possible use the latest version of the discharge coefficient equation, as no systematic bias is introduced as a result.

For allocation systems involving ultrasonic meters as well as orifice plates, the use of the Reader-Harris/Gallagher equation is preferred for all new developments, as these are more likely to be consistent with the ultrasonic meter measurements. Every opportunity should be made to upgrade older orifice plate systems from the Stoltz equation to the Reader-Harris/Gallagher equation.

Design Considerations

4.4.3 The orifice plate metering assembly should, be designed and constructed such that the minimum uncertainties specified in ISO 5167 are achieved and adherence is maintained to the limiting factors detailed in the standard together with the additional specifications detailed below:

a) Maximum Reynolds number should not exceed 3.3×10^7

b) The total deformation including static and elastic deformation of the orifice plate at maximum differential pressure should be less than 1%

c) The uncertainty in flow measurement caused by the total deformation of the orifice plate should be less than 0.1%

d) The location of the differential pressure tappings with respect to the orifice plate should remain within the tolerances given in ISO 5167 over the full operating ranges of the differential pressure transmitters. Where plate carriers utilise resilient seals, care should be taken to ensure that the load on the plate caused by the maximum differential pressure does not move the plate out of the pressure tapping tolerance

e) If the maximum differential pressure across the orifice exceeds 500mbar bar, it should be demonstrated that the conditions of b), c) and d) are met

4.4.4. The latest version of ISO 5167 provides increased scope for the use of ß-ratios higher than 0.6. Higher ß-ratios may be used, provided the overall uncertainty remains below 1.0%.

Meter Runs

4.4.5 Sufficient meter runs should be provided to ensure that, at the maximum design production rate of the field, at least one stand-by meter is available.

The operator will normally be expected to provide an adequate level of isolation valving so that individual orifice plates may be removed from service without the need to shut down the entire metering or process system. Such requirements may, under certain circumstances, be waived if suitable alternative fallback options can be formulated and agreed in advance with the DTI.

Flow Pulsations

4.4.6 The orifice metering station should be located such that pulsations in the flowing gas are avoided. Where these are unavoidable, the uncertainty in flow due to any such effects should be kept below 0.1%.

Useful guidance in such situations may be found in ISO Technical Report 3313.

Upstream and Downstream Pipework

4.4.7 The metering station should be positioned within a process facility such that the effects of fittings and pipework, both upstream and downstream of the orifice meters, do not impact on the minimum straight length requirements given in ISO 5167.

4.4.8 If flow conditioners are proposed as part of the design, the type and location of these devices should be discussed with DTI. In addition, provision should be made to periodically inspect these devices, ideally in situ.

4.5 SPECIFIC DESIGN & INSTALLATION CRITERIA FOR ULTRASONIC METERING SYSTEMS

4.5.1 For Custody Transfer standard applications, only transit time multi-path ultrasonic meters should be used.

Application of Standards

4.5.2 Where ultrasonic meters are proposed or used as part of a metering system, the design, installation and operation should comply primarily with general guidance given in ISO 12765, BS 7965 and also in AGA 9 plus specific recommendations from the meter Manufacturer.

Meter Redundancy

4.5.3 Multi-path ultrasonic meters clearly have an inherent redundancy capability. However, reliance on 'back-up' chords may not be sufficient, since an ultrasonic meter's accuracy will be adversely affected in the event of chord failure, potentially increasing the overall uncertainty of the metering system outwith the agreed limits.

It is recommended that the degree of redundancy of an ultrasonic meter is clearly established at its initial flow calibration, i.e. chords should be intentionally 'failed' by removing the relevant transducers and the performance of the meter can then be evaluated in each case. This will help establish at what point it becomes necessary to remove the meter altogether in the event of the failure of one or more chords.

Alternatively, sufficient meter runs may be provided so that a standby stream, fitted with a calibrated ultrasonic meter, is available at all times.

Isolation Valving

4.5.4 The operator will normally be expected to provide an adequate level of isolation valving so that the ultrasonic meter may be removed from service without the need to shut down the entire metering or process system.

Removal of the meter may be necessitated by the failure of one or more of its components. The need for periodic removal of the meter for recalibration at an onshore laboratory must also be considered.

Meter Diagnostics

4.5.5 Multi-path ultrasonic flow meters incorporate a variety of diagnostic tools that can either individually or collectively be employed for 'health care' monitoring. The use of data acquisition features that permit this information to be logged (and perhaps accessed remotely in real time) is strongly recommended, as it may eventually be possible to use this information to justify an extension to the interval between meter recalibrations. Section 4.6 provides further Guidance in this area.

Presence of CO2

4.5.6 The presence in high levels of some components, such as CO_2, in the gas can influence and possibly even inhibit the operation of the meter. The Manufacturer should be consulted on this issue if CO_2 levels are expected to approach 8% or if the meter is operating near the critical gas density.

Upstream and Downstream Pipework

4.5.7 When assessing the potential impact of pipe geometry on the performance of the meter, the manufacturer should be consulted and the following factors considered:

- The general configuration of the pipework and fittings upstream and downstream of the metering system.

- The presence of any self-compensating features associated with the ultrasonic meter.

4.5.8 The metering station should not be installed where vibration or noise levels can interfere with the performance of the meter. In particular, ultrasonic noise from the so-called 'quiet' control valves can interfere with the operation of ultrasonic meters, as can the close proximity of pressure reduction devices.

4.5.9 The straight pipe sections located immediately upstream and downstream of the meter should be selected, fabricated and installed to ensure minimum impact on the performance of the metering station or the specified measurement uncertainty.

The step between the ultrasonic meter and the upstream spool should meet the requirements of 4.5.2, both 'in-service' and at the calibration facility.

4.5.10 If flow conditioners are proposed as part of the system design then the type and location of these devices should be discussed with the meter manufacturer prior to installation. In particular, care should be taken to ensure that these devices do not generate ultrasonic noise or interact with self-compensating features built into some types of meter. If flow conditioners are installed then provision should be made to periodically inspect these devices, ideally in situ.

Density Measurement

4.5.11 Due to their linear, rather than square-root, relationship with density, flow rates determined using ultrasonic meters are more sensitive to density error than those based on orifice plate meters. Special care should therefore be taken to ensure the location of secondary instrumentation is both representative and accurate. This is particularly important when density is calculated, as described in 4.2.4 (b).

4.6 GENERAL OPERATING AND RE-CERTIFICATION PROCEDURES FOR CUSTODY TRANSFER GAS METERING STATIONS

Isolation of Secondary Instrumentation

4.6.1 Secondary instrumentation, which may be susceptible to damage or malfunction if exposed to foreign matter, should be isolated from the process for the first 24 to 48 hours after start-up. Instruments most likely to be affected are densitometers, relative density analysers and gas chromatographs. During this period the flow computers should preferably use a default gas composition to calculate the gas density at operating and reference conditions or where appropriate, 'keypad' values may be manually entered. The computer should be returned to 'live input' density (line and standard reference) as soon as the process clean-up is complete.

Recalibration of Secondary Instrumentation

4.6.2 Detailed procedures for the verification of secondary instrumentation, such as that used to monitor and record differential pressure, pressure, temperature, gas composition, density and relative density should be prepared for review by the DTI.

4.6.3 The re-calibration frequency for each component in the measurement system (primary & secondary instrumentation) should be included within the recertification procedure document. Initially, the re-certification frequency for most components should be monthly. As a history of equipment stability is built up it may be appropriate to increase the intervals between recalibrations. Prior permission to relax these calibration frequencies must be sought from the DTI. In order to support such an application it will be necessary to show that the instruments remain within tolerance on a number of successive re-calibrations and are returned to service in the 'as found' condition.

4.6.4 Test equipment used for the calibration of secondary instrumentation should be calibrated following procedures accredited by UKAS (or an equivalent overseas body) whenever possible.

This test equipment should be dedicated to the metering systems and should be stored securely.

4.6.5 The tolerances used when re-calibrating secondary instrumentation should be set at a level which, while not being so tight as to make their achievement under field conditions extremely difficult, should not be so lax as to risk compromising the overall target uncertainty of the measurement system.

4.6.6 The DTI may consider a re-calibration schedule based on 'health checking' procedures in circumstances where signal data analysis systems are in place to monitor the condition of the instrumentation and indicate when an instrument is moving out of its specification. A full justification should be supplied if an Operator wishes to adopt such procedures. This should include an analysis of the impact such procedures would have on the overall uncertainty of the metering system.

4.6.7 Where other methods of measurement are employed such as turbine meters or PD meters, either singly or in combination, the appropriate operating procedure and also procedures for periodic verification should be discussed at the design stage with the DTI.

Use of 'Calculated' Gas Density

4.6.8 When density is calculated, as described in 4.2.4 (b), the accuracy of the ancillary instrumentation has an additional significance. Typical sensitivities of calculated density to process variables are:

Variable	*Change*	*% Change in Density*
pressure	1%	1.0
temperature	1°C	0.7
Molecular weight	1%	1.6

Measured/Calculated Gas Density Discrepancy

4.6.9 In view of the absence of any possible 'common-mode' error, where both 'measured' and 'calculated' density is in place, the discrepancy between these parameters should be monitored continuously as a means of demonstrating the reliability of each measurement.

The system should incorporate an 'alarm limit' to highlight the occurrence of a higher-than-normal discrepancy. This alarm limit should not normally exceed 2% of the value of the density being measured.

In the DTI's experience, gas density discrepancy is more often caused by error in the 'measured' quantity (4.3.4 refers). Provided that the reliability of the 'calculated' density has been demonstrated, the system should be set up so that the 'calculated' mode becomes the primary measurement whenever this alarm limit is exceeded.

Gas Chromatographs

4.6.10 Gas chromatographs used in high-quality gas measurement applications normally feature a 'self-calibration' facility.

Calibration reports should feature a value for the 'un-normalised' component total. This value should be monitored, as it demonstrates the reliability of the chromatograph's 'response factors'. Under normal circumstances, it should lie within the range 100 ± 2%. For onshore 'sales gas' measurement stations this tolerance will normally be tighter – typically 100 ± 1%.

4.7 OPERATING AND REVERIFICATION PROCEDURES – ORIFICE METERING SYSTEMS

Pre-Commissioning

4.7.1 The Operator should prepare a schedule of pre-commissioning tests to demonstrate the operability of salient aspects of the flow measurement metrology as detailed within ISO 5167. In particular, the interior of the meter tubes and of the orifice bores should be examined to ensure they conform to the relevant provisions of the Standard.

Start-up Plates

4.7.2 If there is a risk that debris including dust, mill scale or other foreign matter may be present in the process upstream of the meters then consideration must be given to the use of ‘start-up’ orifice plates to avoid damage to the primary elements intended for long-term metering service.

Inspection of Orifice Plates and Meter Tubes

4.7.3 The interval between successive orifice plate inspections should initially be one month.

Once it has been established that plate contamination is not likely, this interval may be extended after consultation with the DTI. A typical inspection sequence, assuming that the condition of the plates is satisfactory on each occasion, might be:

- 6 plate inspections at 1-month intervals.
- 2 plate inspections at 3-month intervals.
- 2 plate inspections at 6-monthly intervals.
- Annual plate inspection.

On plate contamination or damage being encountered, the inspection frequency should automatically revert to the previous stage in the above sequence.

4.7.4 When carrying out an examination of an orifice plate in the field it is not necessary to conduct a full gauging examination to the provisions of ISO 5167 [30]. The main points of focus for an orifice plate field inspection are:

- Freedom from damage to the plate surfaces, particularly damage or rounding to the upstream edge within the orifice bore.
- Correct orientation within the carrier.
- Plate flatness.
- Plate cleanliness.

4.7.5 ISO 5167 allows an edge roughness of up to 0.0004*d* (where *d* is the orifice diameter).

However, ISO TR 15377 indicates that there is a more or less linear relationship between edge roughness and overestimation of discharge coefficient, C_d. On the tolerance limit (0.0004*d*), systematic overestimation of C_d by 0.1% can be expected.

The cost involved in re-machining the straight edge is likely to be insignificant compared with the costs involved in systematic mismeasurement of mass flow rate by up to –0.1%. Therefore if any damage to the upstream straight edge has occurred, it should always be re-machined prior to re-use.

4.7.6 It may be necessary from time to time to examine the condition of the meter tubes, to ensure that corrosion, erosion or contamination has not occurred to an extent likely to affect the accuracy of the meter. These examinations may be necessary if periodic plate inspections show persistent contamination. Particular attention should be paid to the bore of the pipe section extending 2 pipe-diameters upstream of the orifice plate and also to the condition of the upstream and downstream pressure tappings at their respective points of breakthrough into the meter tube wall. If flow conditioners are used, these should also be examined for contamination and any obvious surface damage at the same frequency as the orifice plates are themselves inspected.

It is recommended that boroscopes are used for inspection purposes, and video recording facility should be utilised where possible in order to provide a traceable record of the inspection.

Differential Pressure Measurement

4.7.7 For *onshore metering stations*, differential pressure transmitters should be calibrated at high static pressure representative of the normal operating pressure for the instrument.

An exception can be made where measurement is for ‘allocation’ rather than ‘sales’ purposes, where the use of ‘footprinted’ transmitters may be permissible.

4.7.8 For *offshore metering stations*, high static calibrations should be performed at a suitable calibration facility and subsequently ‘footprinted’ at atmospheric pressure for use in periodic verifications offshore. The high-static pressure should be representative of that likely to be encountered offshore under normal operating conditions.

Recent years have seen significant advances in differential pressure measurement and calibration techniques. Consequently, in the event of a differential pressure cell failing its ‘footprint’ check, once liquid contamination, adverse pressure shocks etc. have been ruled out as possible reasons for the failure, adjustment offshore at zero static pressure may now be considered. The following conditions apply:

a) The static shift exhibited by the differential pressure cell at its onshore calibration is less than 0.05% per 100 bar.

b) The differential pressure transmitter has a proven history of static shift stability, i.e. at least two successive ‘footprints’ demonstrating compliance with the criteria.

c) The differential pressure transmitter damping factor is less than ≈1s (this gives a ≈5s response time to a step-change in differential pressure).

d) The uncertainty of the calibration standard is an order of magnitude lower than the operating tolerance of the transmitter under calibration.

e) The facilities provided for the calibration are conducive to good calibration practice – for example, a stable environment for the mounting and operation of the calibration standard will normally be required.

If an operator wishes to pursue this strategy, supporting data should be made available to the DTI, who may then agree to the atmospheric calibration of differential pressure transmitters on an instrument-by-instrument basis.

In order to guard against long-term drift of the differential pressure transmitter, it should be returned onshore for calibration after 12 months in service, irrespective of its performance in periodic reverification offshore.

4.7.9 Differential pressure transmitters used in offshore applications should be introduced into service no more than 12 months after the date of their onshore calibration. Their period in service should then not exceed 12 months.

Densitometer Recalibration

4.7.10 Gas densitometers used in offshore applications should be introduced into service no more than 12 months after the date of their onshore calibration. Their period in service should then not normally exceed 12 months.

4.8 OPERATING AND REVERIFICATION PROCEDURES – ULTRASONIC METERING SYSTEMS

Recalibration Strategy

4.8.1 It is now approximately 7 years since multi-path ultrasonic meters first became generally accepted as being suitable for use in Custody-Transfer applications in the upstream sector. Throughout this period it has been the policy of both the DTI and commercial pipeline regulators to insist on the periodic removal of the meters for calibration at a recognised test facility. The period between recalibrations varies from application to application, generally depending on calibration history and meter throughput, but as a rule it does not exceed 12 months.

4.8.2 As already referred to in 4.5.5 above, multi-path ultrasonic meters offer a number of inherent diagnostic capabilities that can be used to give at least a qualitative indication that the meter has not shown any drift in its operating characteristic.

Should these self-diagnostic facilities become sufficiently well understood, it may be possible to extend the interval between meter calibrations beyond the current 12 month horizon; it may even ultimately be possible to abandon the strategy of removal and recalibration altogether, in favour of a continuous ‘health-checking’ regime. This is in fact the ultimate goal of Government, Operators and meter manufacturers.

4.8.3 A ‘health-checking’ regime, as permitted by currently-available technology, offers the following advantages relative to a ‘removal and recalibration’ strategy:

a) Operating costs may be reduced.

b) Shifts in meter performance could potentially be detected (at least qualitatively) when they occur, rather than at the next meter calibration.

c) Shift in meter characteristic caused by physical shock during removal and transport to and from the calibration facility would be prevented.

d) The introduction of a systematic shift due to faulty procedures at the recalibration facility (for example, failure to install a flow conditioner) would be prevented.

However, it also has the following disadvantages:

e) The diagnostic facilities are presently qualitative, rather than quantitative

f) The Operator could be exposed to mismeasurement for longer than 12 months, unless the source of measurement was detectable by the meter diagnostics.

4.8.4 With reference to 4.8.3, the DTI currently believes that the disadvantages listed in 4.8.3, though fewer in number, are more significant than the advantages.

The meter diagnostics may indicate that a shift in meter characteristic has occurred. However, it has not been demonstrated to the Department’s satisfaction that the level of shift in meter diagnostics can be related quantitatively to a shift in meter performance. It is therefore currently impossible to determine whether a pre-defined ‘trigger level’ of meter shift, necessitating meter removal and recalibration, has occurred.

Consequently, the requirement to remove and recalibrate ultrasonic meters remains in place.

The disadvantages referred to in 4.8.3 can to some extent be mitigated by the adoption of a 'combined' strategy. For example, very significant change in meter diagnostics (an extreme example of which is chord failure) can be taken as an indication that meter removal is necessary; these may occur in the normal course of the meter's service or they may be evidence that the meter has been 'shocked' in some way between the recalibration facility and the metering station. Sources of systematic shift from recalibration facilities are now better understood and can be minimised or eliminated altogether by the adoption of the practices referred to in 4.8.10 below.

Flow Profile

4.8.5 The Licensee must ensure that the flow profile during meter calibrations matches, as far as possible, the predicted 'in-service' flow profile.

If the meter is to be installed with a flow conditioner, it must be calibrated with the same design of flow conditioner, in the same orientation and position within the meter run.

Initial Flow Calibration

4.8.6 The ultrasonic meter should be flow-calibrated prior to initial installation. This should take place at a recognised test facility, demonstrating either National or International accreditation.

Recalibration of Ultrasonic Meters

4.8.7 As discussed in 4.8.4 above, the Department currently requires ultrasonic meters to be periodically removed and recalibrated. The recalibration, in common with the initial flow calibration, should take place at a recognised, accredited, test facility.

4.8.8 The Department recognises that there have been cases of unexplained systematic offsets between some of the principal European calibration facilities; the recent 'harmonisation' between facilities in Germany and the Netherlands may be cited as an example.

In order to minimise the cumulative effect of any such systematic bias, the Department therefore advises Licensees to return meters to the same facility throughout the meters' life in service.

4.8.9 Intervals between successive calibrations will be agreed with the DTI on a case-by-case basis. In common with the Department's approach in other areas, the economics of the particular field development will be taken into account when assessing the appropriate recalibration period.

When determining the intervals between successive recalibrations, the Department may also consider the availability and relevance of 'health-check' procedures that utilise the diagnostic facilities available via the ultrasonic meter electronics (4.8.4 refers).

4.8.10 The meter should preferably be calibrated on a representative fluid, although recent work (*Hall*) suggests that the results of a meter calibration on, for example, air or nitrogen is transferable to a natural gas application.

4.8.11 Recent work (*Hall*) suggests that there is no significant 'pressure effect' for ultrasonic meters, i.e. the meter may be calibrated at one pressure and operated at another with no significant shift in meter response as a result. However, until this is proved definitively, it does make sense to calibrate meters at conditions as close as possible the anticipated operating conditions.

4.8.12 Meters should normally be calibrated in their 'as found' state so that any shift in meter performance from the previous calibration can be quantified.

Experience with ultrasonic meters over the past 7 years has shown that meters are likely to show the greatest shifts in the first 6 months of operation. It appears that the meter bore become 'conditioned' in-service during this period. Cleaning of the meter bore may therefore be counter-productive and is not recommended.

4.8.13 At each meter calibration, the following information should be recorded:

- Serial Numbers of the reference meters used at the test facility.
- Full details of the configuration of the pipework between the reference meter and the meter under calibration – type and position of bends, step changes in pipe diameter, etc.
- The position and type of any flow conditioners in the test line.

Operators should retain this information for each meter (preferably in a dedicated dossier). The relevant information should be available for inspection at all times.

4.8.14 Industry standard practice at present (May 2003) is for at least 3 runs to be performed at least 6 different flow rates, spaced more or less evenly between the minimum and maximum design flow rates for the meter.

Statistical interpretation of any data from ultrasonic meter calibrations should take into account the number of test runs at each flow rate. Following the principle of the ‘1/√N’ law, the calibration uncertainty reduces with an increasing number of test runs (provided of course, that the test flow rate remains constant).

It is recognised that the practical possibility of increasing the number of test runs at each flow rate may be subject to financial and/or time constraints. Operators may therefore wish to consider whether increased attention should be paid to the expected operational flow rate, if necessary at the expense of other, less ‘representative’ flow rates. Such an approach has the potential to reduce the meter’s operational uncertainty.

4.8.15 Replacement of the ultrasonic meter transducers/detectors or electronics will normally necessitate recalibration of the meter, unless the effect of these actions has been quantitatively determined at the meter calibration and found to be insignificant.

Operators may wish to consider this requirement when planning recalibration strategy. Time thus spent at the meter recalibration may prove to have been well spent should any critical components fail in service.

Implementation of Calibration Data

4.8.16 Correction routines employed to compensate for process and environmental effects on the performance of the meter should, as far as possible, be undertaken within the flow computer and not the USM electronics. Similarly, routines adopted to generate instantaneous flow rate corrections based on multi-point calibration data should also be performed within the flow computer.

4.8.17 The preferred option is point-to-point linear interpolation. A single point flow-weighted average may be applied if all calibration points lie within ±0.1% of their average value.

Inspection of Meter Spool and Associated Pipework

4.8.18 It may be necessary from time to time to examine the condition of the meter spool and associated straight pipe sections, to ensure that corrosion, erosion or particulate contamination has not occurred to an extent likely to affect the accuracy of the meter. Particular attention should be paid to the bore of the meter and the transducer/detector ports and, where appropriate, the condition of the pressure tapping at the point of breakthrough into the meter wall. If flow conditioners are used, these should also be examined for contamination and any obvious surface damage.

Reference Standards

4.8.19 Adequate verification or, where appropriate, calibration equipment should be provided to enable the performance of meters, transducers, computers, totalisers, etc. to be assessed. Reference or transfer standards should be certified by a laboratory with recognised traceability to National or International Standards.

Minimum Operating Pressure

4.8.20 Ultrasonic transducers/detectors require a minimum operating pressure for acoustic coupling. As a field declines, consideration should be given to the periodic review of performance limitations and also the most appropriate calibration range for the meter.

4.9 THE CALCULATION OF UNCERTAINTIES IN FLOW MEASUREMENT SYSTEMS EMPLOYING ORIFICE PLATE METERS IN ACCORDANCE WITH ISO 5167 AND ULTRASONIC METERS IN ACCORDANCE WITH BS 7965

Orifice Metering Stations

4.9.1 For an orifice metering station, the uncertainty in the measurement of a mass flow rate should be calculated using the simplified formula presented in ISO 5167. ISO 5168 offers further guidance in this area.

4.9.2 In the case of differential pressure transmitters, it is important to use realistic field values as the choice of uncertainty value has an impact on the operational turndown of the system and also on the setting of the change over point(s) for metering systems incorporating both high and low range transmitters.

Ultrasonic Metering Stations

4.9.3 For an ultrasonic metering station, the uncertainty in the measurement of a mass flow rate may be calculated using the method presented in Annex A of BS 7965.

4.9.4 Alternative methods may be employed for the determination of uncertainty budgets for the measurement of mass flow rate; the choice should however be discussed with the DTI prior to implementation.

Uncertainties of Secondary Instrumentation

4.9.5 When calculating the overall uncertainty budgets for metering installations, Operators should use realistic 'field' values for the uncertainties of the secondary instrumentation rather than the Manufacturers' claimed values. The uncertainties claimed by Manufacturers for their equipment is usually the best that the equipment is able to deliver under ideal conditions.

Monte Carlo Simulation

4.9.6 Uncertainty calculations using Monte Carlo Simulation can be used as an alternative. Further Guidance in this area will be published shortly.

APPENDIX 4.1 REFERENCES/TECHNICAL PAPERS

HALL.J et al. Calibration of Ultrasonic Flow Meters at Conditions Different Than Their Operation. North Sea Flow Measurement Workshop, St Andrews, Scotland 2002.

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MODULE 5

CUSTODY TRANSFER (NON-PRT) STANDARD PETROLEUM MEASUREMENT

DESIGN, OPERATING AND REVERIFICATION GUIDELINES

MODULE 5 CUSTODY TRANSFER (NON-PRT) STANDARD PETROLEUM MEASUREMENT

CONTENTS

5.1 TERMS OF REFERENCE

5.1.1 This Module is intended to provide Guidance on the DTI's expectations for the measurement of petroleum in allocation systems where there is no Petroleum Revenue Tax (PRT) involved.

5.1.2 In 1994 the Department took the decision to relax the regulatory regime for allocation systems where there was no Royalty or PRT at stake. Royalty and PRT on new fields were abolished in 1978 and 1993 respectively.

5.1.3 Export into a pipeline normally involves commercial requirements to meet Custody Transfer uncertainty levels at the point of entry, irrespective of the regulatory position of the DTI. Since gas production invariably involves pipeline export, the relaxation referred to in 5.1.2 above has in practice only affected stand-alone oil measurement systems.

5.1.4 Many of the new generation of fields developed post 1994 using Floating Production Storage and Offload (FPSO) technology fall into this category. It is for these developments that this Module will have the greatest practical relevance.

5.2 BACKGROUND

Floating Production, Storage and Offload (FPSO) Developments

5.2.1 FPSO field operation normally comprises the following elements:

- Production and processing of hydrocarbons on the FPSO
- Storage of the crude oil in dedicated tanks on the FPSO
- Periodic export of the crude oil from the FPSO to a shuttle tanker (the export figure referred to as the 'bill of lading')
- Sale of the crude oil by the shuttle tanker at a port of discharge (the export figure referred to as the 'terminal outturn')

Other configurations, for example the use of permanently-moored 'producing' and 'storage' vessels, are of course possible. However, the general principles explored in this section are still applicable to such set-ups.

5.2.2 Revenue from the sale of the crude oil is generated on the basis of measurements made at the port of discharge. The adoption of the appropriate procedures for the determination of quantity and quality at the port of discharge is therefore critically important.

Government Revenue

5.2.3 Paragraph 2.2.6 of these Guidelines explains what is meant by 'fiscal' oil and gas measurement. It is worth reiterating the following points in the present context:

- Although post-1993 developments are not subject to PRT, profit from these fields is subject to Corporation Tax
- The profit and loss calculations are 'ring-fenced' for each field

5.2.4 Clearly, one of the fundamental parameters in the calculation of 'ring-fenced' profit and loss (and hence Corporation Tax payable) is the revenue generated from the field. The sales point at the port of discharge (referred to in 5.2.1 as the 'terminal outturn') is therefore a 'fiscal' measurement.

'Bill of Lading'

5.2.5 The DTI has neither the means nor the authority to inspect measurement systems at ports of discharge that may potentially be anywhere in the world. The measurement made on the UKCS (the 'bill of lading' figure' as defined in 5.2.1) is therefore the last measurement over which the DTI can exercise direct scrutiny.

The 'bill of lading' measurement is also the last opportunity for the Operator to independently measure the quantity and quality of oil before the cargo is handed over to a third party for sale at an onshore terminal. Comparison between 'bill of lading' figures and the 'terminal outturn' figures (as defined in 5.2.1) could potentially indicate the presence of systematic bias in port-of-discharge measurements. The ability to meaningfully perform such a comparison, however, is critically dependent on the uncertainty of the 'bill of lading' measurement. *It is assumed that* that the 'terminal outturn' measurement is made to Custody Transfer standard, i.e. ±0.25% of dry mass.

5.2.6 Paragraph 1.4.6 of Issue 5 of the Department's Measurement Guidelines (1997) stated that for stand-alone fields loading offshore:

"Provided satisfactory procedures can be developed for initial and periodic verification… the target uncertainty… would be 0.5% to 1.0%."

This was essentially a reflection of the regulatory policy that had been in place since 1994. Under the current (post-1994) regulatory regime the uncertainty in the 'bill of lading' measurement may therefore be as high as ±1.0%. However, it is clear that the ability to detect bias in 'terminal outturn' figures will be further impaired the nearer the uncertainty in the 'bill of lading figure' approaches this upper limit.

In the light of the above considerations one might therefore expect Operators and equity holders to treat the 'bill of lading' measurement as a matter of some importance. In practice, however, this has unfortunately not been the case; most (though not all) Operators have seized the opportunity to reduce cap-ex and op-ex costs by installing measurement systems that perform on the very limit of this target uncertainty, or even beyond it. The prevailing attitude has been as follows: The revenue is generated at the port of discharge, so the 'bill of lading' measurement is of limited interest.

Port of Discharge

5.2.7 The Government, and the Operators and equity holders, are exposed to potential loss of revenue from any or all of the following at the port of discharge:

- Underestimation of the quantity of crude oil offloaded
- Underestimation of the value of the crude oil offloaded
- Overestimation of the water content of the cargo offloaded

5.2.8 The DTI accepts that its financial exposure may be aligned with that of the Operator and any equity holders in the offshore field. In other words, Government revenue will only be lost if the profit from the field is underestimated; it is in the Operators' own best interest to ensure that the profit from the field is maximised, and therefore the Operator can be relied upon to ensure that Government revenue is safeguarded. This argument would be sufficient to fully satisfy the Government's concerns were it not for the following considerations:

a) The Operators or equity holders in the field in question may also be equity holders in the terminal at which the 'point of sale' measurement takes place

b) A degree of scrutiny by the Operators and equity holders in the port-of-discharge measurement systems has been assumed, but never established definitively.

The Department therefore has legitimate and realistic concerns that it is exposed to risk of financial loss through the failure to detect mismeasurement at port-of-discharge measurement stations.

Regulatory Requirements

5.2.9 Operators must be able to demonstrate that their agreed design uncertainties for FPSOs are being met.

5.2.10 It must be borne in mind that the relaxation of the target uncertainty for the ‘bill of lading’ measurement from Custody Transfer levels (±0.25%) to ±0.5-1.0% was dependent on the provision of satisfactory procedures for initial and periodic verification of the measurement system (5.2.6 refers).

5.2.11 Adjustment of the ‘bill of lading’ figure on the basis of comparison with ‘terminal outturn’ figures (as defined in 5.2.1) cannot be regarded as a means of reverification unless figures from several ports of discharge are used. This is to guard against the possibility of an undetected systematic bias in measurement at one port of discharge.

Commercial Considerations

5.2.12 As with other measurement solutions covered by these Guidelines, the quoted target uncertainty of ±0.5-1.0% should be interpreted as a minimum requirement. **Operators are strongly encouraged to review the present arrangements, and to consider whether it is in their interests to accept a situation where their measurement of the ‘bill of lading’ has an uncertainty of more than ±0.5%.** By accepting higher uncertainties they increase their dependence on the measurement systems of third parties (the ports of discharge) over whom they may not necessarily have any control. The consequences of this are explored in 5.2.13 below.

5.2.13 Leaving aside the statistically very unlikely event of the ‘terminal outturn’ figure *exactly* matching that of the ‘bill of lading’, there are two possible scenarios:

a) The bill of lading exceeds the terminal outturn

b) The terminal outturn exceeds the bill of lading

Under scenario (a), the port-of-discharge authorities have apparently received less oil than indicated to them by the shuttle tanker operators; they be expected to raise a ‘letter of protest’ where the discrepancy is greater than 0.5%. We then essentially have a dispute between the two measurement systems. The port-of-discharge figure is likely to have an uncertainty of around ±0.25%. Clearly, the difficulty that the FPSO operator will face in disputing the terminal outturn is proportional to the amount by which the bill-of-lading measurement uncertainty exceeds that of the port-of-discharge. If the bill-of-lading measurement uncertainty is much greater than 0.5%, it becomes very difficult indeed to challenge the port-of-discharge figures.

Under scenario (b), the shuttle tanker operators have apparently exported more oil to the port-of-discharge authorities than they had indicated. Again, there is a disagreement between the figures, but this time in favour of the port-of-discharge. Can the authorities there be depended upon to declare the discrepancy under any circumstances? Shuttle-tanker operators may appoint an independent cargo inspector, charged with highlighting any such discrepancies. Nevertheless, unless the terms of reference of the cargo inspector include a full audit of the port-of-discharge measurement system, systematic under-measurement at the port-of-discharge may well go undetected by the shuttle tanker operators. Let us consider for a moment the consequences of a 0.1% systematic bias in favour of the port of discharge. On a typical load of 500,000 barrels, this is equivalent to 500 barrels; or, at an oil price of $20/barrel, $10,000.

5.3 LIQUID HYDROCARBON MEASUREMENT

5.3.1 Measurement systems used to measure cargo offload to shuttle tankers must be able to demonstrably meet at least the upper uncertainty limit of ±1.0%, and should preferably be able to perform towards the lower limit of ±0.5%.

Possible Measurement Solutions and Reverification Methods

5.3.2 Examples of possible methods of measurement for the 'bill of lading', as defined in 5.3.1, are given in the table below.

In each case a section of the Guidelines is indicated for further reference on installation, operation and possible reverification.

Measurement Principle	Reverification Method	Comments	Guidelines Reference
2 turbine meters in series	• One meter used as a master meter; removed for periodic calibration onshore. • Provision of tie-in point for compact prover connection	Run-down time likely to be higher than with a full-bore meter.	3.8
Multi-path ultrasonic meter	• Built-in meter diagnostics • Provision of tie-in point for compact prover connection	Relatively short run-down time. Relatively low measurement uncertainty. Higher cost than single-path ultrasonic meters.	3.5, 3.9
Single path ultrasonic meter	• Comparison with onshore terminal • Provision of tie-in point for compact prover connection	Relatively short run-down time. Relatively high measurement uncertainty. Lower cost than multi-path ultrasonic meter	See comment in 5.2.11 regarding reverification

5.4 GASEOUS HYDROCARBON MEASUREMENT

5.4.1 As indicated in 5.1.3, in practice gaseous hydrocarbons have not fallen readily into this category, since commercial pipeline agreements invariably prove to be tighter than the uncertainty limits the DTI would be prepared to accept.

5.4.2 Should a situation arise where non-PRT paying gas was not subject to any commercial allocation agreements, or where the uncertainties required by such agreements were comparable with the target uncertainties indicated in 2.2.7 (i.e. 1.0-2.0%), the details of the proposed method of measurement would be agreed in consultation with the DTI on a case-by-case basis.

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MODULE 6

SEPARATOR MEASUREMENT

DESIGN, OPERATING AND REVERIFICATION GUIDELINES

MODULE 6 SEPARATOR MEASUREMENT

CONTENTS

6.1 TERMS OF REFERENCE

6.1.1 Separator measurement is an important aspect of many fiscal measurement systems. Measurement from test separators often forms the basis for many well-test programmes, and the interpretation of these results is routinely used to assess the performance of reservoirs. Nevertheless, this area has received relatively little attention in the past from Regulatory Guidelines or Industry Standards.

Separator metering typically occurs in 'fiscal' measurement applications in one of the following ways:

- as the basis for an Allocation measurement system, where a dedicated separator is used to determine production of oil, gas and water from a particular field
- as the basis for a Well Test system, where a test separator is used to periodically determine oil, gas and water flow rates from a particular well
- for verification purposes, where the output from a (typically test) separator is used to verify the performance of a wet gas or multiphase meter

The incidence of the use of separators in these and other scenarios is increasing as the North Sea matures and 'fiscal' measurement points are moved further and further back towards (and sometimes even beyond) the wellhead.

This Module presents some guidance on how separators and separator metering systems can be designed and operated in order to minimise measurement uncertainty. The guidance offered here can however equally be applied to separator measurement for purely reservoir engineering purposes.

6.1.2 Claimed separator measurement uncertainties are often over-optimistic, for reasons given below, and they may be difficult or impossible to substantiate. This must always be borne in mind when considering measurement systems that incorporate separator metering.

6.1.3 The overall measurement strategy adopted will depend on the agreed Measurement Approach (defined in Module 2 of these Guidelines).

6.2 SYSTEM DESIGN

6.2.1 The need to use separators for 'fiscal' metering applications often arises after the separators have been designed and installed. Nevertheless, there may still exist opportunities for modifications to be made with the aim of enhancing measurement accuracy.

Use of On-Site Proving Facilities

6.2.2 For a measurement system designed at the outset to be based on separator metering, on an installation equipped with a nearby pipe or compact prover, the facility to route the oil flow line from the separator to the prover should be strongly considered. The facility to calibrate the oil meter *in situ* may significantly enhance the effectiveness of the overall measurement system. This strategy has already been adopted on one major North Sea production installation, with positive results.

Alternatively, the separator oil line may be provided with fittings to allow connection to a portable compact prover, in order that the oil meter may be readily calibrated – the calibration could take place, for example, immediately before or after the annual calibration of the installation's pipe prover.

6.2.3 Where fiscal measurement is involved, and there is no facility for *in situ* recalibration of the oil meter, proposals for its recalibration should be discussed with the DTI at the project design stage.

Prevention of Gas Breakout

6.2.4 'Gas breakout' in the oil line will inevitably lead to a degradation of the measurement of oil flow, whichever technology is used. Whenever possible, separators should therefore be designed to minimise the probability of this occurring. For example, use can be made of the fluid head in maintaining the pressure in the oil take-off line.

Flow Rate Range

6.2.5 Test separators should be designed to cover the full range of flow rates from the well(s) under test. They should include a gas, liquid hydrocarbon and water meter, all maintained to provide a level of performance appropriate to the desired class of measurement.

Shrinkage Factors

6.2.6 If wells of significantly different physical properties and process conditions are to be allocated using 'Flow Sampling' techniques, referred to in Module 2 (paragraph 2.8.1) then additional precautions will be necessary to ensure that each well is treated equitably in the allocation process. The pressure and temperature in the main production separators may be significantly different from those in the test separator during different well tests. This will result in the 'test' gas-to-oil ratio differing from the 'production' gas-to-oil ratio.

To compensate for this a process simulation should be run for each well on both the test separator and the main production separator. This will enable a correction or "shrinkage" factor to be determined. The use of such a factor should result in the sum of wellhead production being in closer agreement with the sum of the installation out-turn. Such adjustments have the merit of tending to reduce any systematic differences between wells of significantly different properties when using flow sampling for allocation purposes. This is particularly important if some of the wells are sub-sea completions tied back through long sub-sea flow lines.

Water-in-Oil Measurement

6.2.7 When the oil stream has a significant water content, the use of a water-in-oil meter in the oil take-off line should always be considered, as this may help minimise the error in dry-oil accounting.

Otherwise, the use of a flow-proportional sampler may be an acceptable alternative.

6.3 OIL/CONDENSATE MEASUREMENT

6.3.1 The possibility of gas break-out and the possible presence of liquids other than oil must always be taken into account when considering the most appropriate method of measuring oil flow rate.

6.3.2 Turbine meters are 'traditionally' used for the measurement of oil flow rates from separators. However, assessment of the levels of performance achievable by turbine meters in these applications is not straightforward.

Assuming that the oil output from the separator is always a single-phase liquid, whose flow rate, hydrocarbon composition, water content and dispersion, and operating temperature (and therefore, viscosity) is reasonably constant, a level of uncertainty of perhaps ±5% might be expected.

If the validity of such assumptions cannot be assured, the uncertainty of turbine meter measurement in such service could be in the region of ±5-10% or higher.

6.3.3 The use of ultrasonic meters has been suggested, as these meters are less likely to cause gas breakout.

However, caution should be exercised. Water cuts in excess of 5% in the oil take-off line are likely to cause the failure of ultrasonic meters, and experience has shown that ultrasonic meters used in the measurement of oil are adversely affected by the presence of relatively small amounts of gas. At high (>5 ms^{-1}) velocity meters have been rendered inoperable by the presence of as little as 0.4% (by volume) gas.

6.4 GAS MEASUREMENT

6.4.1 *Separator gas measurement should be treated as a wet gas metering application. Module 7 of these Guidelines should be consulted for more detailed guidance in this area.*

Test Separator

6.4.2 In test separator applications, orifice plates have the advantage that the turndown of the metering system can be enhanced by having available a range of plates with different orifice diameters.

If the separator is fitted with an orifice carrier, plates can be interchanged to effectively measure test separator flows for wells having a wide range of gas flows. Achieving a high degree of turndown can be problematic with other types of meter, unless the total replacement of the meter with another meter of different nominal bore is possible.

In the light of these considerations the use of an orifice plate for test separator measurement can generally be recommended.

6.4.3 When the anticipated turndown requirement of the Test Separator is lower, there may be scope for the deployment of alternative technologies, such as Venturis or V-cone meters.

Production Separators

6.4.4 With the lower turndown requirements on production separators, there is greater flexibility with regard to the choice of measurement technique.

Orifice plates, Venturi meters or V-cones are all potentially suitable for this application.

6.5 WATER MEASUREMENT

6.5.1 Water flow measurement is traditionally achieved using either turbine meters or electromagnetic meters. However, there is scope for the deployment of ultrasonic meters in this area.

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MODULE 7

WET GAS MEASUREMENT

DESIGN, OPERATING AND REVERIFICATION GUIDELINES

MODULE 7 WET GAS PETROLEUM MEASUREMENT

CONTENTS

7.1 TERMS OF REFERENCE

7.1.1 As the North Sea matures, wet gas flow measurement is becoming increasingly important. With the development of an increasing number of marginal fields whose economics do not support single-phase measurement, there has been an increasing emphasis on designing systems whose fiscal measurement point may be, for example

a) On the gas offtake line from a 1st-stage or test separator

b) At the top of a production riser prior to 1st stage separation

c) At the wellhead of a sub-sea tie back to a host installation.

Scenario a), frequently encountered with associated gas from Northern and Central North Sea oilfields, may form part of an ‘Allocation’ or ‘Well Test’ measurement system, as defined in Module 2 of these Guidelines.

Scenarios b) and c) are regularly encountered in Southern North Sea gas fields that are developed and processed as wet gas fields.

The measurement challenges presented by these and similar scenarios are described at some length in this Module. As with other Modules of these Guidelines, particular emphasis is placed on Installation, Verification and Recertification procedures.

7.1.2 For the purpose of these Guidelines, wet gas is taken to mean a two-phase flowing liquid where the liquid volume fraction is in the region of 0-10%.

7.2 FLOW REGIMES

7.2.1 In wet gas flows the following three types of flow regime may occur:

- *Stratified* flow describes the free liquid running along the bottom of the pipe with the gas flowing at the top of the pipe. This is a common regime in horizontal pipes and low gas flow velocities (typically 5 m/s or less).

- *Annular* flow describes the liquid flowing around the pipe wall with the gas flowing through the centre of the pipe. This regime occurs in medium flow velocities in horizontal pipes (typically 5–15 m/s). In horizontal pipes, the annular flow is not uniform; due to gravitational effects the liquid is present in higher quantities around the wall at the bottom of the pipe than higher up the pipe wall.

- *Mist* flow describes liquid in the flow being carried along in small droplet form within the body of gas. This flow regime requires high gas flow velocities (in horizontal pipes) to keep the liquid suspended in the gas (typically 15 m/s or higher).

Other flow regimes can occur intermittently, particularly *slug* flow regimes if liquid has become trapped in the flow line, for example at the bottom of a vertical pipe. It is also worth noting that even in a horizontal pipe, liquid can be ‘held-up’ by gas flows of 1 m/s or less and may remain almost stationary rather than flow with the gas.

7.2.2 In practice, wet gas flows may be a combination of the flow regimes described in 7.2.1. Combinations of line conditions, pipe orientations, gas to liquid ratios, etc., will influence the type of flow regime present.

An appreciation of which, if any, flow regime is likely to prevail may be extremely useful. The application of the same wet gas measurement technique can produce widely different results depending on which flow regime predominates, and knowledge of the likely flow regime can therefore influence on the correct choice of measurement principle to be applied,

7.3 SELECTION OF PRIMARY MEASUREMENT DEVICE

7.3.1 The flow meters that can potentially be used to measure wet gas flows can be divided into two types:

- Differential pressure devices (Venturi, orifice plate, V-cone)
- Ultrasonic flow meters (where the liquid volume fraction is less than 0.5%)

7.3.2 Multiphase meters may be able to handle high gas/liquid ratios, but the use of these meters is outwith the scope of this Module of the Guidelines.

Proposals to use multiphase meters for wet gas measurement will be reviewed by the DTI on a case-by-case basis. Multiphase meters that make use of differential pressure devices are most likely to be configurable as wet-gas meters.

7.3.3 Turbine meters should not be used for wet gas flow measurement. The presence of liquids in even relatively small quantities can lead to meter failure.

7.4 INSTALLATION CONSIDERATIONS

Flow Conditioners

7.4.1 The use of 'thick plate' flow conditioners, designed for use with orifice plates and whose purpose is to correct flow profile, is not recommended in wet gas flow applications. Liquids can easily build up in front of the devices producing a skewed flow profile that will result in measurement error.

In certain conditions hydrates can even form in the flow conditioner, restricting the flow and producing highly distorted exit profiles. Practical experience [e.g. *Stobie*] highlights this and other problems associated with the use of flow conditioners.

However, there may be scope for the use of flow conditioners that are specially designed for use in wet-gas applications – their primary aim being to redistribute liquids evenly across the flow.

Insulation

7.4.2 In order to promote temperature stability, and to ensure that the measured temperature is representative of that at the flow meter, insulation of the meter run from the upstream straight pipe length to the downstream temperature measurement device is recommended.

The use of trace heating may be necessary to prevent the formation of hydrates in extreme conditions. It may help to minimise liquid presence; this may be particularly important in meter applications where liquid correction methods are not being applied.

Pressure Tappings

7.4.3 It is important to recognise that liquid drop-out in pressure impulse lines is likely to occur, as the temperature of the gas will tend towards ambient once it leaves the meter stream. In extreme cases hydrates may even form.

The presence of either liquids or hydrates in impulse lines will introduce errors in the measurement of differential or static pressure.

Pressure impulse lines connecting the flow meter's pressure tappings to a differential or static pressure transmitter should therefore be as short as possible and inclined towards the vertical in order to drain entrained liquids. Liquid or hydrate accumulation can be further countered by the insulation of the impulse lines and the application of trace heating.

To minimise cooling by ambient conditions, Operators should consider placing the pressure transmitters, and even the impulse lines if possible, in a heated, sealed enclosure.

Catchment pots located in the impulse lines may be effective at catching liquids. These should be drained frequently to avoid excessive liquid build-up and therefore they may not be effective in use on un-manned installations that experience significant liquid dropout in impulse lines.

Secondary Instrumentation

7.4.4 Secondary instrumentation may include provision for the measurement of the following parameters

- pressure (static and/or differential)
- temperature

7.4.5 Provision must be made for the routine reverification of this instrumentation. The initial interval between successive recalibrations will be determined by the DTI, in consultation with the Licensee, on a case-by-case basis, and will largely depend on the Measurement Approach (as defined in Module 2 of these Guidelines).

Where wet-gas meters are to be deployed on un-manned installations the recalibration frequency may be predetermined by the frequency of occurrence of maintenance visits. However, for systems operated at lower uncertainties, the associated need for reverification may necessitate the scheduling of visits with the express aim of re-verifying the wet gas measurement system.

As with other routine maintenance programmes, scope may exist for the relaxation of calibration frequencies, subject to satisfactory operation of the instrumentation.

7.4.6 The use of on-line gas chromatographs is obviously problematic in applications where high quantities of liquids are present.

Gas sampling points, if properly designed, should be capable of providing representative gas samples, even where the liquid-to-gas ratio is relatively high.

It is therefore recommended that gas composition in wet gas applications is obtained through the analysis of samples, obtained from an appropriately-designed sample point, in conjunction with an off-line gas chromatograph.

7.4.7 Densitometers should not be used in wet gas applications, even when the liquid volume fraction is relatively low. Contamination will occur, requiring manual intervention.

7.5 VENTURI METERS

7.5.1 Venturi flow meters are widely used for wet gas applications that involve measurement prior to any form of separation or fluid processing. Among their advantages are the following:

- they do not ‘dam’ the flow (unlike orifice plates)
- they can be operated at higher differential pressures than can orifice plates without incurring permanent meter damage (differential pressures up to and above 2 bar can be contemplated)
- they have a relatively high turndown (typically 10:1) when used with re-rangeable differential pressure transmitters

7.5.2 The design requirements for Venturi-type flow meters are contained within the international standard ISO 5167-3. I*t must always be borne in mind that this standard applies only to dry gas applications.*

In general, however, the requirements of ISO 5167 should be adhered to as far as possible. This Module essentially specifies certain key areas where departure from this standard is necessary in order to attempt to minimise measurement uncertainty.

Pressure Tappings

7.5.3 The meter should be supplied with a single tapping at the standard 'pipe' and 'throat' pressure measurement points as described in ISO 5167. These should preferably be at the '12 o'clock' position but other positions between 2 and 10 o'clock may be satisfactory.

In addition, a third pressure tapping may be located downstream of the Venturi conical expander outlet (the 'diffuser') to facilitate the measurement of the fully recovered pressure. The optimum position for this third pressure tapping has not been definitively established, but a distance of 6D from the downstream flange is regarded as reasonable.

Significant variations in this parameter can help indicate when new testing for the Venturi correction parameters (e.g. the liquid/gas mass ratio) is required.

Meter Orientation

7.5.4 For a Venturi meter as described in 7.5.3, the meter should be orientated horizontally such that the two (or three) tappings are located at the 12 o'clock position. In this way the potential for liquid becoming entrained in the tapping or impulse lines is minimised, and the tappings are kept as far as possible from the bulk of the liquid if stratified or annular flow regimes are present.

Meter Construction

7.5.5 The Venturi flow meter should generally conform to the construction requirements of ISO 5167.

However, special attention should be paid to the following:

- The finish of the Venturi internal surface, which should be smooth and free from machining defects including burrs and ridges.
- The pressure tappings, which at the point of entry into the meter internal bore should have sharp edges and be free from burrs and wire edges
- The edge of the conical inlet, which should be sharp and free from manufacturing defects.

A Venturi meter not conforming to these construction practices may experience significant variation in its discharge coefficient, resulting in increased measurement uncertainty.

Upstream and Downstream Pipework

7.5.6 The presence of liquid in the flow line will affect the flow profile as it enters the Venturi meter. This is a source of measurement uncertainty over and above that normally expected for dry gas measurement. In order to minimise this additional uncertainty:

- Upstream pipe work should be designed such that bends immediately upstream of the meter encourage any stratified liquid to flow at the bottom of the pipe away, from the pressure tappings.
- The installation should be designed with the upstream straight lengths requirements of ISO 5167 in mind.

7.5.7 The Venturi flow meter should be installed with suitable 'double block and bleed' isolation valves so that the meter can be removed and inspected as required.

Calibration of Venturi

7.5.8 To minimise measurement uncertainty in wet gas applications, the Venturi meter must be calibrated in 'dry' gas prior to use.

[*Jamieson* et al] have shown that the discharge coefficients of Venturi flow meters can vary significantly with flow rate in gas. To ensure that the best possible measurement uncertainty is obtained, a flow calibration should be performed across the full operating flow range, at temperatures and pressures as close to working conditions as possible. The flow calibration should normally be performed over a minimum of 6 flow rates with a minimum of 3 measurements at each flow rate. Measurements at intermediate flow rates may be required if the calibration curve is particularly unpredictable. Further measurements at individual flow rates may be required to ascertain the degree of repeatability.

Algorithms for Venturi Wet Gas Corrections

7.5.9 When differential pressure type flow meters are operated in wet gas, they will generally *overestimate* the dry gas flow rate. A number of algorithms have been derived in order to account for the over-estimation in flow rate *[Steven]*.

de Leeuw Correlation

7.5.10 The method most applicable to Venturi flow meters used in wet gas applications is the correlation derived by [*de Leeuw*], as the data was generated using Venturi meters.

Full details of the correlation are given in Appendix 7.1.

It should be noted that the De Leeuw correlation is not suitable for wet gas flows where the gas Froude Number, as defined by De Leeuw, is below 0.5.

Chisholm Correlation

7.5.11 The [*Chisholm*] correction algorithm is the direct predecessor of the de Leeuw equation – the de Leeuw equation is effectively a modification of the Chisholm correlation. Essentially the only difference (with reference to the de Leeuw correlation given in Appendix 7.1) is that the parameter C is defined by Chisholm as:

$$C = \left(\frac{\rho_{\text{liquid}}}{\rho_{\text{gas}}}\right)^{0.25} + \left(\frac{\rho_{\text{gas}}}{\rho_{\text{liquid}}}\right)^{0.25}$$

i.e. the parameter n is a constant in all cases and is not a function of the gas Froude number Frg. In addition, the value for the expansibility, ε (in equation (2) of Appendix 7.1) is set to 1.

Murdock Correlation

7.5.12 The [*Murdock*] correction is applied as follows:

$$Q_{\text{gas-corrected}} = \frac{Q_{\text{gas-uncorrected}}}{\sqrt{\left(1 + MX\varepsilon\left(\frac{C_g}{C_l}\right)\right)}}$$

where

X	Lockhart-Martinelli parameter (defined in Appendix 7.1, equation (3))
ε	expansibility of gas in a Venturi meter, as derived from ISO 5167
C_g/C_l	ratio of the discharge coefficient of the Venturi in gas to the discharge coefficient of the Venturi in liquid
M	Murdock constant

7.5.13 The value of the Murdock constant, M, was originally derived as 1.26.

However, following fairly widespread use of the Murdock Correlation, other values of the Murdock constant have been derived, depending on the application. These have been in the range 1.5 to 5.2 [de Leeuw], [Couput]. Variation of this magnitude clearly implies that there is a significant potential for serious mismeasurement caused by use of an inappropriate value of M.

It is therefore recommended that when using this equation in the field, periodic verification against a test separator is performed, in order to determine an appropriate value for the Murdock constant.

Choice of Correlation

7.5.14 Caution should be exercised when using the Chisholm correlation with Venturi meters in wet gas applications. Like the Murdock correlation, the Chisholm correlation was originally derived from data generated with orifice plates. However, unlike the Murdock correlation, it cannot be 'fitted' to individual meters by the method mentioned in 7.5.13 above.

The DTI therefore recommends that the de Leeuw or a 'modified' Murdock correlation is used for Venturi meters in wet gas applications.

Derivation of liquid flow rate

7.5.15 Previous sections of this Module have described methods used to account for the over-estimation of gas flow rate when using a Venturi flow meter in wet gas applications.

There is normally an additional requirement to determine the liquid flow rate and especially the flow rate of condensate passing through the meter. This can be determined by routing the flow line to a test separator, or by the use of tracer techniques (described in 7.5.21 to 7.5.26 below).

Derivation of gas and liquid densities

7.5.16 The density of the gas should be determined from the analysis of representative samples. This value is then input directly into the formula for the uncorrected gas mass flow rate equation (equation (2), Appendix 7.1 for the de Leeuw correlation, or the equation in 6.5.12 for Murdock).

Liquid density should be determined similarly. The value obtained is used in the calculation of the Lockhart-Martinelli parameter.

Upstream Temperature Correction and Pressure Recovery Calculation

7.5.17 Details of the procedure for referring the measured temperature to upstream conditions, and for calculating the fully recovered pressure (if this is not measured directly by a third pressure tapping, as described in 7.5.3. above) are presented in Appendix 7.2.

Verification of Venturi Meter Performance

7.5.18 There are essentially three different methods of verifying a Venturi meter installed for use in a wet gas application. These are:

- The use of a test separator.
- Implementation of tracer techniques.
- Comparison against another meter (e.g. subsea vs. topsides).

It must of course be borne in mind that for the last of these to be meaningful, the second meter will itself require to be verified using one of the first two methods.

The choice of reverification method may be further reduced if the Venturi meter is being employed as part of a Fiscal Well Test measurement system (as defined in Module 2 of these Guidelines). In this case the Venturi meter in question is itself likely to be on the gas outlet of the Test Separator.

These verification methods will now be considered in turn.

Test Separator Method

7.5.19 The test separator should be designed to cover the full range of flow rates from the well(s) under test.

7.5.20 The test separator should include a gas, condensate and water meter all maintained to provide a level of performance appropriate to the agreed Measurement Approach (as referred to in Module 2 of these Guidelines).

Further guidance on separator measurement is contained in a dedicated section (Module 6) of these Guidelines.

Tracer Techniques

7.5.21 Tracer techniques have been developed in order to verify flow meters in wet gas applications [*van Maanen*]. They are especially useful in verifying Venturi flow meters when there is no possible means of routing the flowline to a test separator.

7.5.22 If it is decided at the outset that tracer techniques are to be used for the verification of a wet gas Venturi meter, the installation should be designed and constructed with the needs and requirements of these techniques in mind. Specifically:

- To ensure good mixing of tracer fluids with pipe liquids, it is recommended that there be a length of 150 pipe diameters between the tracer injection and sampling points.
- The injection point should be located such that good mixing will occur between the tracer fluid and line fluids before sampling.
- The sampling point should be located at the bottom of a horizontal pipe to ensure that an adequate amount of liquid can be obtained for analysis purposes - it will generally be necessary to collect at least 50cc.

7.5.23 The tracer technique is used to determine the volumetric flow rate of a liquid within a pipe using the following equation:

$$Q_{liquid} = Q_{injected}\left(\frac{C_{injected}}{C_{sample}}\right)$$

where

$Q_{injected}$	injection volumetric flow rate
$C_{injected}$	concentration of tracer particles in injection fluid
C_{sample}	concentration of tracer particles in sampled fluid

In order to determine condensate and water ratios, hydrophobic and hydrophilic tracers are used.

7.5.24 In order to obtain a significant amount of liquid, sampling to atmosphere may be required. In this instance there will be a requirement to know the flash-factor of the condensate to make corrections to the condensate-to-liquid ratio.

The presence of methanol in the pipeline can mask the real concentration of tracer particles in the sampled fluid. Methanol injection should therefore be suppressed prior to commencing the tracer injection procedure.

Reasonable effort should be made to avoid slug flow in the flow-line since the tracer injection method assumes a constant liquid flow.

7.5.25 Tracer techniques are essentially 'spot checks' and therefore there will be a degree of inherent uncertainty from fluctuations in liquid presence.

7.5.26 Tracer techniques can also be used to directly measure the flow rate of the gas fraction. However, at present the most effective techniques for this purpose involves the use of radioactive tracers, which limits their use in many applications.

However, the gas mass fraction can be indirectly estimated using the techniques described above in combination with the algorithm presented in Appendix 7.3.

Comparison Method

7.5.27 This method can be used to verify meters in remote locations (e.g. sub-sea or on un-manned platforms). Essentially the meter under test is checked against another 'master' meter, which has in turn been verified using either the test separator or tracer-injection methods.

The results of subsea and topsides meters will almost certainly be at variance and therefore flow testing over a considerable time may be necessary in order to clear or cater for liquids and to allow integration over a period of hours (possibly up to 24 hours). It extremely important to clear the subsea flow line and to determine the gas-to-liquid ratio over the flowing period. The gas-to-liquid ratio may be the link to variable flow measurement factors over time (perhaps as much as a few years).

The flow test can also be used to produce a gas sample at the topsides for the subsea meter.

7.5.28 The corrections to be applied to the 'test' meter for gas mass fraction and liquid gas fractions can be determined from the information gained from the 'master' meter. The gas mass fraction and liquid gas fractions may however need to be adjusted owing to flash-off/shrinkage between the fluids at the test meter and those at the master meter. The use of a proprietary process engineering package can be used to calculate the phase fractions at the meter.

The accuracy of this method is dependent on the accuracy of the conversion factors used. As these may not be wholly reliable, the 'comparison' method is unlikely to be an appropriate means of verifying a wet gas Venturi used for Fiscal Allocation purposes (as defined in Module 2 of these Guidelines)

Sub-Sea Applications

7.5.29 Venturi flow meters have been successfully installed in sub-sea applications in a number of producing fields on the UKCS.

In order to operate effectively, the units and subsidiary equipment must be suitably 'marinised'. Secondary metering equipment should be installed with adequate redundancy with a view to continued operation following a unit failure. Dual or even triple redundancy is recommended, with differential pressure transmitters being multi-ranged to cover the expected flow rates.

7.5.30 Since the meters will effectively be treated as 'fit and forget' units, sub-sea Venturi flow meters are unlikely to achieve reasonably low (i.e. better than $\pm$10%) uncertainties unless the flow through the meter can be routed to a test separator or compared against another verified meter. Tracer injection methods are not presently viable in sub-sea applications.

In order to minimise measurement uncertainty, gas and liquid sampling points should be provided on the topsides, since corrections may be required for gas flash-off or condensate shrinkage.

7.6 ORIFICE PLATE METERS

7.6.1 Orifice plate flow meters have been historically used for a wide range of applications including wet gas. However, the limitations of orifice meters must always be borne in mind when they are used in 'non-ideal' applications. Wet gas metering is one such application.

Primarily, orifice plate meters are significantly affected by liquid. As with other flow meters based on the measurement of differential pressure, orifice plates generally over-estimate the gas flow rate when significant quantities of liquid are present. Murdock and Chisholm both derived their corrections for liquid with orifice plate flow meters and these corrections should be applied if the liquid throughput is substantial. However, in separator applications, any liquid carry-over is often intermittent and so correction for liquid can be difficult to perform accurately. Separators should therefore be designed and operated optimally to avoid significant liquid carry-over. In most cases orifice plates are operated to measure the dry gas flow rate only.

Application of Standards

7.6.2 The design requirements for orifice plate type flow meters in terms of their construction and installation are contained within the international standard ISO 5167.

In general, the requirements of ISO 5167 should be adhered to as far as possible. This Module will however specify certain areas where departure from this standard is necessary in order to minimise measurement uncertainty.

Use of Orifice Plates Fitted with Drain Holes

7.6.3 Where orifice plates are to be used to measure wet gas flows the Operator is strongly advised to install orifice plates fitted with drain holes.

The use of orifice plates fitted with drain holes is covered by the standard ISO TR 15377. Any additional uncertainty incurred as a result of the use of drain holes is likely to be insignificant compared to that which would result from the continued presence of a liquid build-up on the upstream side of the plate.

The Operator should ensure that the drain hole is located at the bottom of the orifice plate (corresponding to the 6 o'clock position).

Orifice Fittings

7.6.4 To minimise measurement uncertainty the orifice plate should be housed within a standard orifice fitting, as used in 'Fiscal-Quality' measurement systems.

Pressure Tappings

7.6.5 The meter should be supplied with two tappings at the standard 'flange' pressure measurement points as described in ISO 5167.

Meter Orientation

7.6.6 The orifice fitting should be orientated in such a manner that the two tappings are located at the 12 o'clock position. In this way the potential for liquid becoming entrained in the tapping or impulse lines is minimised, and the tappings are kept as far as possible from the bulk of the liquid if stratified or annular flow regimes are present.

Upstream and Downstream Pipework

7.6.7 The presence of liquid in the flow line will affect the velocity flow profile as it impinges on the orifice plate meter. This is a source of measurement uncertainty over and above that normally expected for dry gas measurement.

For this reason it is not recommended that the reduced straight lengths outlined in ISO 5167 are used. Where possible, the 'standard' lengths should be used in order to minimise measurement uncertainty.

It has already been stated (7.4.1, above) that the use of flow conditioners in wet gas applications is not recommended.

7.6.8 The orifice assembly should be installed with suitable 'double block and bleed' isolation valves so that the plate can be removed and inspected as required.

Algorithms for Wet Gas Corrections

7.6.9 The [*Chisholm*] and [*Murdock*] correction factors can be applied. These have been covered in 7.5.11 and 7.5.12 above.

Operating Procedures

7.6.10 In general, the Operating Procedures should be similar to those described for 'Fiscal-Quality' orifice plate metering stations.

Verification of Meter Performance

7.6.11 In any orifice plate metering system, plate inspection forms a critical part of the verification procedure and particular attention should be paid to this area. In general, the required frequency of plate inspection will depend on the Measurement Approach of the system as a whole.

Irrespective of this consideration, a plate found to be damaged on inspection should *always* be replaced.

7.7 ULTRASONIC METERS

7.7.1 Ultrasonic-type flow meters may be used in wet gas applications with a relatively low liquid volume fraction (LVF < 0.5%). They have the significant advantage of being a 'full bore' meter without any restrictions to the flow.

Ultrasonic flow meters, in common with other types of wet gas meter, will over-estimate gas flow rate. However, unlike some other types of wet gas meter (Venturi, orifice plate) there is as yet no satisfactory correction method to account for this. Ultrasonic meters therefore provide an uncorrected gas flow rate and do not measure liquid flow rate.

7.7.2 A number of researchers [*Zanker*, *Stobie*, *Beecroft*] have attempted to use ultrasonic flow meters in wet gas conditions. The installations where this has been most successful have been those where the presence of liquids is relatively low.

Owing to large (uncorrectable) errors obtained from flows with Liquid Volume Fractions greater than approximately 0.5%, ultrasonic flow meters should generally not be installed in flowlines prior to separation other than for testing or comparison purposes.

Application of Standards

7.7.3 Ultrasonic flow meter installations in wet gas should generally conform to the requirements of the standard BS 7965. The following guidelines are additional to this Standard.

Meter Installation

7.7.4 Ultrasonic flow meters should be installed horizontally, in order that any stratified liquid flow will be at the bottom of the pipe. This will minimise the risk of liquid being trapped in transducer ports for those meters featuring 'horizontal' paths. Meters featuring 'bounce' paths usually feature transducers located near the top of the meter, which will be distant from stratified liquid anyway.

However, care should be taken to ensure that liquid at the bottom of the pipe does not interfere with the ultrasound beams and cause dispersion. The Operator should consider slightly offsetting the bounce paths to avoid any liquid running along the bottom of the pipe.

7.7.5 Temperature transmitters should not be located more than 15 pipe diameters downstream of the ultrasonic meter downstream flange.

Meter Location

7.7.6 Wet gas ultrasonic flow meters should be located in a position where liquids do not naturally form and in general, the meter should therefore be located at a high point in the flow-line. A small decline in the downstream direction will aid liquid drainage away from the meter. The upstream pipework should be designed so that liquids cannot build-up and produce slugging flow, which can stop the meter from performing altogether unless the transducer ports drain the liquid.

Meter Transducers

7.7.7 It is recommended that the transducers are located with their faces close in to the meter spool wall to encourage the removal of liquids by gas turbulence. The transducer ports should be designed to allow the draining of any entrained liquids over a short period of time (2 minutes maximum). The design of the transducer ports may be modified to feature drainage holes that will encourage the automatic removal of liquids.

7.7.8 The transducer capsules are sensitive instruments and can be damaged by a variety of typical operating conditions.

It is recommended that liquid presence in the flowline is minimised, as some transducer types can be adversely affected by liquids, especially condensate, causing the face to become damaged. Transducers may also have to routinely deal with the presence of additional process liquids (e.g. methanol).

7.7.9 Ultrasonic flow meters should be designed to cope with the sudden shutdown conditions that are likely to occur a number of times per year.

However, there have been practical cases where transducers have been damaged by the rapid de-pressurisation of the flow-line. Where possible, flowlines containing Ultrasonic meters should not be depressurised at a rate exceeding 5 bar per minute.

Particular care should be taken during hydro-testing to ensure that the meter is not de-pressurised too quickly and also to ensure that left-over hydro-test water does not affect the meter performance following start-up.

Flow Conditions

7.7.10 Ultrasonic flow meters should be operated at as high a flow rate as possible without affecting measurement integrity, since [*Wilson*] has shown that the measurement error reduces as the flow velocity increases. This is apparently due to the fact that as the flow velocity increases, more and more of the liquid becomes entrained as a mist type flow. As this occurs, the total measurement error tends towards the percentage LVF.

If this effect was predictable, the ultrasonic meter's suitability as a wet gas meter capable of determining both gas and liquid flow rates would improve dramatically. However, [*Zanker*] has shown that predicting flow regimes in wet gas is not easy and stratified or annular flows, which result in much greater errors, are more commonly acquired.

It has also been shown by Zanker that increased line pressure reduces measurement error, as the increased gas density encourages more liquid to become entrained as mist flow.

Flow Profile Correction

7.7.11 It has already been stated (7.4.1, above) that the use of flow conditioners in wet gas applications is not recommended, unless hydrate formation can be avoided.

For Ultrasonic meters there is the additional problem that at high flow velocities (approximately $18ms^{-1}$ and above), the flow conditioners can be the source of ultrasonic noise which causes the meter to malfunction. BS 7965 states that 10 pipe diameters of straight pipe is satisfactory for Fiscal Quality meters, but flow disturbance caused by valves and bends may cause significant measurement error even with installations complying with this standard. If the proposed installation is downstream of a number of flow-influencing installations, further pipe diameters should be added to the upstream length (those indicated in ISO-5167 could be used as an indication, for example).

Verification of Meter Performance

7.7.12 For increased measurement accuracy, Ultrasonic flow meters intended for use in wet gas conditions should be calibrated in gas at a recognised accredited facility. The procedures to be followed in this case will be the same as those applied to Fiscal Quality gas measurement using Ultrasonic Meters (covered in Module 4 of these Guidelines).

Routine reverification intervals have already been discussed in 7.4.5 above.

7.8 ALLOCATION WET GAS METERING

7.8.1 *This class of measurement, as defined in Module 2 of these Guidelines, is the best that can realistically be expected of a wet gas metering system.*

This section sets out certain general criteria that should be met by a wet gas metering station that is to form part of an Allocation measurement system. The specific cases of Venturi, orifice plate meters and ultrasonic meters are covered.

Failure to meet any or all of these specifications may mean that the measurement system will necessarily be regarded as being of 'Well Test' rather than 'Allocation' quality.

Venturi Meter

7.8.2 Venturi meters must be designed and installed broadly in accordance with ISO 5167.

All reasonable measures should be taken in order to minimise measurement uncertainty. The following specific considerations will apply to Custody Transfer measurement systems (reference is made to other paragraphs or Appendices of this Module):

- The meter should have standard pipe and throat pressure tappings at the 12 o'clock position. (7.5.3, 7.5.4)
- If a third pressure tapping is not used, then the fully recovered pressure should be calculated.
- The meter should be installed horizontally. (7.5.4)
- Particular care must be taken in the manufacture of the meter and its associated upstream and downstream pipework. (7.5.5, 7.5.6)
- The meter must be calibrated on dry gas, across the full operating range, prior to use. (7.5.8)
- A liquid correction algorithm should be applied. (7.5.9 to 7.5.14). Where the Murdock correlation is used, it is recommended that a value of M is derived for the specific application by the method referred to in 7.5.13.
- The Venturi meter should be periodically reverified by one of the methods described in 7.5.18 through 7.5.28.
- There should be an adequate provision of sampling facilities for all correlation and reverification purposes

- Where a subsea Venturi meter is used, there should be the means to carry out periodic reverification by comparison with a test separator.

Orifice Plate

7.8.3 The orifice plate should be designed and installed broadly in accordance with ISO 5167.

In general, the operational procedures will be similar to those applicable to Fiscal Quality dry gas measurement systems (covered in Module 4). All reasonable measures to minimise measurement uncertainty should be followed. The following specific considerations will apply to Allocation measurement systems (reference is made to other paragraphs or Appendices of this Module):

- Standard orifice fittings, typical of those used in Custody Transfer applications, should be used. (7.6.4)

- Particular care should be taken with the manufacture of the upstream and downstream pipework. (7.6.7, 7.6.8)

- The use of orifice plates fitted with drain holes should be seriously considered (7.6.3); otherwise the Chisholm or Murdock correlations should be used to correct for the presence of liquids. (7.5.11, 7.5.12,)

- Reverification of the metering system will depend critically on the inspection of the orifice plate; this and calibrations of secondary instrumentation should initially take place at monthly intervals, with subsequent relaxation of the inspection frequency subject to satisfactory results.

Ultrasonic Meter

7.8.4 The ultrasonic meter should be designed and installed broadly in accordance with BS 7965.

In general, the operational procedures will be similar to those applicable to Custody Transfer dry gas measurement systems (covered in Module 4). All reasonable measures should be taken in order to minimise measurement uncertainty. The following specific considerations will apply to Allocation measurement systems.

- All reasonable measures should be taken to minimise the presence of liquids in the flow line.

- Particular consideration should be paid to the manufacture and installation of the meter and its associated pipework.

- The meter should be flow calibrated at a recognised onshore facility prior to its installation offshore, recalibration of the meter should then take place at 12-month intervals; this recalibration frequency may subsequently be relaxed subject to the meter demonstrating a satisfactory degree of stability.

7.9 SAMPLING

7.9.1 Sampling is a potentially critical part of any wet gas measurement system. This is especially so in situations where a test separator is not provided for verifying wet gas flow meter performance and tracer techniques are used instead.

This section presents some guidance that may help to minimise mismeasurement resulting from poor design and/or operation of sampling systems.

Sampling Points

7.9.2 If sampling is to be carried out from the flow line itself, where significant amounts of liquid may be present, two sample points should be installed; one each for gas and liquid.

In this case sampling probes are not advisable in view of the high risk of sample contamination. Instead the sample points should be constructed to allow the removal of gas from the top of the pipe and liquid from the bottom of the pipe. Correct installation of these sample points is vital if tracer flow techniques are to be successful.

Test Separators

7.9.3 Test separators should be provided with suitable sampling points, with sampling probes installed on the condensate and gas take-off lines.

The provision of a sampling point on the water take-off line should also be considered in order that the salinity, and also the validity of any water density constants.

Gas Sampling

7.9.4 For gas sampling the standard IP 345/80 should generally be adhered to. The sample probe should be installed with the 'scoop' facing downstream to reduce the risk of any liquid carry-over entering the sample vessel. The sample vessel should be pre-charged with argon or another suitable gas.

7.9.5 Spot sampling is only effective provided the sample is representative of the flowing gas, and the gas composition does not vary unduly.

During comparison of a wet gas meter with a test separator, in order to ensure that the sample is reasonably representative, flowing conditions should be established for as long as it takes to ensure that representative fluids are passing through the test separator and that the flow conditions have settled.

Condensate Sampling

7.9.6 For Condensate sampling and analysis due attention should be given to the recommendations of the standard GPA 2165-95.

7.9.7 Steps should be taken to minimise the potential for gas break-out in the line. For example:

- The flow line containing the sample point should be located at a lower level than the test separator.
- The sample point should be located upstream of a turbine meter run where flash-off may occur across a filter basket or turbine rotor.
- The number of bends in the flow line should be minimised.

Some pressure drop may result from the use of a static mixer, which should nevertheless be used to ensure a good mix of condensate and water.

Pressurised sampling should be performed to ensure that representative ratios for water and condensate are derived and are not in error from flash-off to atmospheric conditions.

7.9.8 The sampling analysis should provide:

- The base density of the condensate.
- The ratio of condensate to water in the liquid (and methanol if applicable).
- Information on the water (or water/methanol mix) so that the validity of any density constants may be determined.

APPENDIX 7.1 DE LEEUW WET GAS VENTURI CORRELATION

The corrected gas *volume* flow rate can be derived from the following equations: (all equations are based on S.I. units)

$$Q_{\text{gas-corrected}} = \frac{Q_{\text{gas-uncorrected}}}{\sqrt{(1 + CX + X^2)}} \qquad (1)$$

where:

$Q_{\text{gas-corrected}}$	corrected volume flow rate (the best estimate of the 'true' gas flow rate)
$Q_{\text{gas-uncorrected}}$	uncorrected gas volume flow rate, as indicated by the Venturi meter using the following equation:

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

where:

C_{gas}	discharge coefficient of the Venturi flow meter in dry gas as determined through calibration
ε	expansibility of gas in Venturi as defined by ISO 5167
d	throat diameter of the Venturi flow meter (corrected for temperature)
ρ_{gas}	gas density at upstream conditions
ΔP	raw differential pressure as measured by the transmitter
β	ratio of d to D, the pipe diameter

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

$$X = \frac{Q_{liquid}}{Q_{gas}}\sqrt{\frac{\rho_{liquid}}{\rho_{gas}}} \qquad (3)$$

where:

Q_{liquid}	combined liquid flow rate through the Venturi flow meter
ρ_{liquid}	combined liquid density

C is given by the following equation:

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

where:

$n = 0.606(1 - e^{-0.746Frg})$	for	$Frg \geq 1.5$	
$n = 0.41$	for	$0.5 \leq Frg \leq 1.5$	(5)

where F_{rg} is the gas Froude number and is given by the following equation:

$$F_{rg} = \left(\frac{V_{gas}}{\sqrt{gd}}\right) + \left(\frac{\sqrt{\rho_{gas}}}{\sqrt{(\rho_{liquid} - \rho_{gas})}}\right) \qquad (6)$$

where:

V_{gas}	superficial gas pipe velocity
g	local acceleration due to gravity

V_{gas} can be derived by using an iterative method and 'seeding' a velocity based on the uncorrected mass flow rate. It can be calculated as follows:

$$V_{gas} = \frac{Q_{gas\text{-}uncorrected}}{\rho_{gas}\left(\frac{\pi d^2}{4}\right)} \tag{7}$$

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

APPENDIX 7.2 UPSTREAM TEMPERATURE CORRECTION AND PRESSURE RECOVERY

The correction for downstream measured temperature to upstream temperature (in ºC) at the inlet can be estimated by the following equation:

$$t = (t_m + 273.15)\left(\frac{P_3}{P_1}\right)^{K_3} - 273.15$$

where

t_m	measured downstream temperature, in ºC
P_3	fully recovered downstream pressure
P_1	pressure measured at the upstream tapping
K_3	downstream–to-upstream temperature correction exponent

It is accepted that the value of K_3 is derived from dry gas thermodynamics, and may not therefore be wholly applicable. However, in the absence of any alternative method this is presently regarded as the best means of estimating the upstream temperature.

P_3 can be measured using a third pressure tapping or calculated (in bar) from the following empirical equation (from *[Miller]*).

$$P_3 = P_1 - \frac{\Delta\omega}{10^3}$$

where

$$\Delta\omega = (A\beta^2 - B\beta + C)\Delta P$$

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

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

APPENDIX 7.3 GAS MASS FRACTION ESTIMATION USING TRACER TECHNIQUES

The gas mass fraction can be estimated as follows:

1 Perform tracer flow technique to determine condensate and water flow rates and mass ratios.

2 Analyse condensate to determine base density.

3 Sample gas to determine gas density.

4 Record total uncorrected gas flow from Venturi during tracer flow technique.

5 Determine dry 'first pass' gas mass fraction and liquid-to-gas ratio based on the recorded uncorrected gas flow and tracer flow results (corrections for methanol injection after completion of tracer technique may be required)

6 'Seed' values from the last stage into the wet gas Venturi flow calculation to determine a 'first pass' corrected gas flow rate.

7 'Re-seed' this value into the calculation, correcting gas mass ratio and liquid-to-gas ratio.

8 Iterate process until corrected gas flow rate converges

APPENDIX 7.4 REFERENCES/TECHNICAL PAPERS

The following papers are of particular technical interest:

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DEPARTMENT OF
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LICENSING AND CONSENTS UNIT

GUIDANCE NOTES FOR PETROLEUM MEASUREMENT

UNDER THE PETROLEUM (PRODUCTION) REGULATIONS

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MODULE 8

MULTIPHASE PETROLEUM MEASUREMENT

APPLICATION, OPERATION AND REVERIFICATION GUIDELINES

MODULE 8 MULTIPHASE PETROLEUM MEASUREMENT

CONTENTS

8.1 TERMS OF REFERENCE

8.1.1 The ability to meter to a satisfactory degree of uncertainty oil, gas and water in multiphase mixtures without recourse to expensive separation is perhaps the greatest challenge facing the oil and gas measurement industry.

This Module is intended to provide Operators with guidance on the relevant considerations regarding the potential application, selection, operation and reverification of multiphase meters for 'fiscal' measurement.

Unfortunately the achievable levels of uncertainty, even under laboratory conditions, remain such that multiphase metering is essentially an option of 'last resort' in fiscal measurement applications, when fields and resources are so marginal that even 'Flow Sampling' is ruled out. The *in-situ* reverification of these meters, once in service, to demonstrate that even these levels of uncertainty are being met, is difficult if not impossible.

Since these meters are being used more and more in fiscal service, there is a pressing need to improve both their accuracy and their reverification methods.

8.1.2 Any operator contemplating the use of multiphase metering for systems within the scope of these Guidelines should make contact with the DTI at as early a stage as possible in the system design.

The acceptability of a multiphase meter for a particular development will depend in large measure on the match between the instrument's operating characteristics and the anticipated 'in-service' process conditions. It may in some circumstances be necessary to implement an evaluation programme to assess the suitability of a meter for a particular set of process conditions. The DTI should be involved in designing the scope of such an evaluation programme. Inspectors from the DTI may, at their discretion, witness the testing of a meter under evaluation.

8.2 STANDARDS

8.2.1 No independent standards exist as yet to assist engineers in designing multiphase metering systems.

Reporting Meter Performance

8.2.2. The difficulty is compounded by the fact that there is not even an accepted standard format for quoting the performance and accuracy characteristics of multiphase meters. It is essential when considering a manufacturer's performance and accuracy statements to understand the implications of accuracies quoted in different ways. There are three common ways in which multiphase meter accuracies are presented:

i) % phase volume flow rate.

ii) % total multiphase flow rate.

iii) % gas and liquid flow rate plus absolute uncertainty of water cut in liquid phase.

Method i) is favoured by metrologists and clearly represents performance as stated. This method may not be the most practical for extreme cases of phase fractionation. Methods ii) and iii), while quoting relatively small numbers of the order of 5% to 10% for gas/liquid phase uncertainties and 2% or 3% for percentage water cut may nevertheless exhibit very large individual phase errors of 100% or more depending on the absolute value of the percentage water.

8.3 MULTIPHASE MEASUREMENT TECHNOLOGIES

8.3.1 All existing multiphase measurement systems are comprised of a combination of sensors, each of which provide specific information about the flow. On their own these measurements are insufficient to provide a unique determination of the phase flow rates, but when these measurements are considered along with conservation laws such as continuity, it becomes possible to uniquely determine the individual flow rates of the oil, water and gas.

8.3.2 Typically sensors within multiphase flow meters seek to measure parameters such as the water content in the liquid and the multiphase density. Technologies used for this purpose vary, but to date there has been a heavy emphasis on the use of radiation techniques to measure density and to quantify the amount of water in the liquid. The measurement of the electrical characteristics of the fluid mixture is also commonly employed to determine the water content within the liquid phase.

Phase Velocity Determination

8.3.3 Once the phase fractions have been determined, the individual flow rates can then be determined if the velocity of each phase is known. Commonly, each phase will travel at a different velocity, an effect known as slippage. Presently no practical technology exists that can be used to determine three individual velocities simultaneously, so the problem is often overcome by measuring one velocity and then applying flow models to obtain correction factors. These flow models are often based on knowledge or estimation of the multiphase flow patterns. Methodologies for velocity measurement vary, but two are very common:

- Differential pressure using a Venturi.
- Cross-correlation of flow features over a known axial spacing along the pipe.

8.4 APPLICATION OF MULTIPHASE METERS

8.4.1 The starting point for any potential multiphase metering application is to clearly identify issues surrounding the location, pressure, temperature, and the likely mode of operation. Sub-sea aspects and HP/HT conditions need very specific advice from multiphase meter manufacturers.

Modes of Operation

8.4.2 Possible applications of multiphase meters include, but are not restricted to, the following scenarios:

Scenario	Measurement Challenge
Continuous measurement from a single well	The most straightforward measurement scenario as the measured fluids would be well defined in terms of their physical properties.
Batch testing of a group of wells using a single meter and an appropriate pipework manifold arrangement	This would require the ability to modify the calibration parameters of the multiphase meter to match each well fluid - a potentially difficult, but not unachievable process
Continuous measurement of a number of wells after commingling	A very difficult measurement challenge because the properties of the fluid within the flow meter are unlikely to be well specified at any given time. Measurement error is inevitable because of the critical dependence of multiphase flow meter performance on the physical properties of the flowing fluids. The degree of error will depend on the degree of change in the characteristics of the multiphase fluid, and the degree of sensitivity of the multiphase meter to such changes.

8.5 SELECTION OF APPROPRIATE METER

Precision of Measurement of Each Phase

8.5.1 If the application under assessment is appropriate for deployment of an in-line multiphase meter, the next issue is to decide which of the phases require the highest degree of measurement precision. It is sensible at this stage to consider the through-life variations that are expected in the production. In some applications it may only be important to measure the gas or oil accurately, but in other situations all three phases may need to have a low measurement uncertainty.

8.5.2 The upper bound of acceptable measurement uncertainty for each phase flow rate should be agreed with the DTI. While there may be good reasons to compromise on these initial requirements at some future point, it is a useful starting position. There are numerous methods for specifying uncertainty, but in order to avoid ambiguities it is recommended that each phase flow rate uncertainty is always expressed as a percentage of the actual phase flow rate – method (i) in 8.2.2 above.

8.5.3 After consideration of the issues raised above, an assessment of metering technologies appropriate to the measurement scenario should then be undertaken. The aim is to match the multiphase measurement technology to the fluid properties in order to achieve the desired level of measurement uncertainty for each phase.

Relative Phase Fractions

8.5.4 In this assessment, it is important to always bear in mind that the achievable uncertainties with current multiphase measurement systems are very closely linked to the relative phase fractions.

For example, attempting to measure oil flow rate accurately when the gas volume fraction (GVF) is very high is an exceptionally challenging measurement task. This is a situation analogous to the measurement of two commingled single-phase flows, the smaller of which is measured by difference. It is well known that in such situations relatively high uncertainty in the measurement of the smaller flow rate will result, irrespective of the accuracy of the measurement of the larger flow rate and of the commingled flow.

Partial separation multiphase metering systems have been developed specifically to deal with very high GVF flows. These meters essentially split the metering challenge to that of a wet gas stream and a low GVF multiphase stream.

Fluid Properties

8.5.5 In assessing the suitability of a multiphase meter to a suitable development, knowledge of the properties, as well as the proportions, of each fluid is critical.

For example, for high-water-content wells the use of capacitance measurement to infer water content is unwise as the flow must exhibit non-conducting properties (it is then normally referred to as ‘oil-continuous’) for this technology to operate successfully.

Similarly, if the produced oil is heavy then its properties in terms of ionising radiation can approach those of water. This creates difficulty in discriminating between the oil and water using dual-energy radiation techniques. Other technologies may therefore be more appropriate.

Meter Sizing

8.5.6 The multiphase meter must be sized to match the total flow rate to factors such as pressure loss and the multiphase flow pattern envelope. Generally, extremely high or extremely low velocities are to be avoided.

8.6 METER INSTALLATION

Vertical Installation

8.6.1 Where multiphase meters are to be installed in a vertical orientation with the flow in an upward direction, care must be taken to consider the nature of the multiphase flow regime. Under certain circumstances, normally at medium-to-high Gas Volume Fractions, it is possible for the flowing fluid to have insufficient energy to continuously sweep all of the liquid through the meter, and a situation of liquid back-flow under gravity can occur. Maintaining a sufficiently high gas velocity will alleviate this potential problem, but no firm guidance can be given in terms of a velocity threshold because of the complex nature of multiphase flow patterns within piping systems. Each application must be considered individually.

Horizontal Installation

8.6.2 Multiphase meters operating in a horizontal orientation are likely to have a much less uniform cross-sectional distribution of the oil, water and gas. The gas will have a strong tendency to flow at the top of the pipe, while the water and oil will preferentially occupy the lower part of the pipe. Segregation within the liquid is also possible, and triple stratified flows have been observed in laboratory tests using crude oil. Distribution effects may impact on the meter performance, but these can normally be reduced by increasing the flow velocity. Again, each application should be considered separately.

Installation in Self-Contained Skid

8.6.3 Multiphase meters are often supplied in a self-contained skid that takes care of the physical installation aspects close to the meter. Where this is not the case, multiphase meters should be installed as specified by the manufacturer, as no standards presently exist governing this issue.

Upstream and Downstream Pipework

8.6.4 In all cases it is desirable to avoid installation of the metering package immediately downstream of piping configurations or components that will cause significant flow disturbance over and above the transient nature of the majority of multiphase flow patterns.

8.7 ACHIEVABLE PERFORMANCE

8.7.1 There is now a considerable amount of performance data on multiphase meters, most of which has been generated in laboratory test programmes. From this data the following general conclusions can be drawn (expressing flow rates as in 8.2.2 (i) above):

(i) There is no currently-available multiphase meter that will give measurement uncertainties on each phase to within ±10% over the full range of gas volume fractions (GVFs) and water contents.

(ii) Over certain parts of the envelope of GVF and water content, most multiphase meters will achieve a level of uncertainty of ±10% or less, for all three phases.

(iii) The best performance consistently achieved on one of the phases is typically ±5%, but this is normally over a very restricted envelope of GVF and water content.

The above comments are broad generalisations, but they represent a fair assessment of multiphase metering technology in 2001.

8.8 FACTORS AFFECTING PERFORMANCE

Unsteady Local Conditions

8.8.1 Probably the single most important cause of uncertainty in multiphase flow measurement is related to the unsteady nature of the majority of flow conditions. The instantaneous flow patterns and the interfaces between liquid and gas phases can be continually varying in a multiphase flow. This is most extreme in slug flow, where the liquid fraction can vary between almost zero in the film region after liquid slugs, to almost 100% liquid in the slug body. However significant fluctuations will also be present in annular and churn flow patterns.

The impact of fluctuating local gas fraction is linearly related to the density; but for other parameters, particularly differential pressure it exhibits non-linearity. The pressure drop of a liquid slug passing through a Venturi meter can be 5 times higher than the average pressure drop for the flow; the minimum pressure drop in the same flow, corresponding to the ‘film’ region can be 20% of the average. A Venturi meter would experience pressure drops over a range of 25:1 at a nominally steady multiphase production condition. A fundamental principle of single-phase flow measurement - that readings should be taken under steady state conditions - clearly has to be abandoned in such circumstances.

In order to reduce the uncertainty associated with measurement of a parameter that fluctuates over such a wide range, many samples are required over a relatively long measuring period. The measuring period will be unique to each application, so a good knowledge of the flow regime at the multiphase meter is important.

Unsteady Global Conditions

8.8.2 In laboratory evaluations, it is usually possible to ensure relatively steady input conditions to the multiphase flow line, so that the average oil, water and gas flow rates are stable over a period longer than that required by the multiphase meter to make its measurement.

However, in ‘real’ operating systems, steady flow is much less likely over longer time scales. Flow through a multiphase pipeline is influenced by the flow into the line (which may be combined from several wells), the flow patterns developing along the line, the topography of the line (the terrain it passes), the outlet pressure and other fluctuations caused by the downstream processing requirements.

These effects increase the measurement uncertainty of a multiphase meter in the field when compared to the uncertainties of measurement achievable in laboratory tests.

Incorrect Identification of Flow Regime

8.8.3 Most multiphase flow meters will use some empirical modelling of the flow in order to derive the individual phase flow rates from the measurements taken. This modelling has its greatest influence on the method of interpreting the pressure drop from a differential pressure device or the velocity obtained from a cross-correlation device.

If the flow conditions differ in practice from those assumed in the empirical models, then there will be an additional uncertainty in the measurements.

There are many ways in which this could occur. For example, the flow pattern may be affected by unexpected changes in the physical properties of the fluids or the operating pressure. In other situations the slug frequency or velocity may be different to that expected - this will have a similar effect to the factors described in 8.8.1 above.

To illustrate the potential for incorrect flow regime identification, it may be pointed out that it is not uncommon for differences such as those described above to occur in comparisons of the same meter in different laboratory test facilities. Very significant variations can therefore be expected in field conditions.

Uncertainty in Physical Properties of Fluids

8.8.4 To obtain the best achievable performance of a multiphase flow meter the initial calibration process must include filling the meter with each of the single phases in turn, and measurements made of relevant parameters such as the dielectric constants or gamma attenuation coefficients. This end-point information can then be entered into the meter set-up software. Most meters also require that the density of the individual phases are known, at least as a function of temperature, and for gas as a function of pressure as well. A good PVT model is therefore essential.

Under laboratory conditions it is usually a straightforward task to calibrate a multiphase flow meter with respect to the fluid properties, and to be confident that the properties of the fluids are constant over the course of a test. However, in the field, considerable thought needs to be given as to how this basic calibration is performed.

Typically, physical property calculations are performed by multiphase meters on the basis of the analysis of samples, and clearly there is considerable scope for error in this process. Methodologies for *in-situ* determination of the physical properties need careful consideration, and clearly there are many challenges to be overcome, not least of which is guaranteeing clean single phase flow for each end-point calibration. Small amounts of contamination will bias the results significantly and this will feed through in all subsequent multiphase measurements.

In circumstances where fluid properties will change appreciably with time, a methodology is required to allow the new physical property data to be downloaded to the multiphase meter. Alternatively, some form of back-calculation routine may need to be applied to correct the measured data.

8.9 OPERATION OF METERS

8.9.1 Due to the absence of any ‘standard’ design of multiphase meters, it is difficult to give general guidance on their operation. Their in-service operation is largely governed by the recommendations of the individual manufacturers. The issues highlighted in the previous sections need to be addressed prior to installation, but once installed there are no standards currently in existence that specify particular operating methodologies.

Flow Rate Data

For example, most commercially-available meters provide local data processing and can provide either rolling average flow rate data, or instantaneous flow rate data. A decision as to the most appropriate data for each application is required. Generally the rolling average technique over a reasonably short time period (15 minutes to 1 hour) is to be preferred as the instantaneous data can fluctuate wildly and make sensible decision making impossible.

Maintenance of Fluid Property Data

8.9.2 Maintaining correct fluid property data is by far the greatest issue concerning the on-going operation of a multiphase meter. It would be wise to assume that the technicians responsible for operating the multiphase meter will not be multiphase metering experts, so a heavy emphasis should be placed on developing a detailed procedure concerning the fluid property set-up data. A record of changes to the set-up configuration is absolutely essential, as this not only provides measurement traceability, but would allow the metering data to be reprocessed should the need arise.

8.10 REVERIFICATION OF METERS

Initial Calibration

8.10.1 Before installation a multiphase meter should always be calibrated over a range of Gas Volume Fractions, water contents and flow velocities similar to those likely to be encountered in its 'in-service' application. This process will check the functionality of the meter, and will give an indication of the level of accuracy that may be obtained in the field, albeit with different fluid properties.

Periodic Reverification

8.10.2 It is essential to consider the methodology and procedure for periodic re-calibration at the design stage of any new multiphase meter installation.

Once installed, periodic re-calibration of a multiphase meter by 'traditional' methods may be very difficult, if not impossible.

Quite apart from the inherent technical difficulties, the use of multiphase meters for 'fiscal' measurement will generally be a solution of 'last resort' in an extremely marginal application. In such cases, suitable infrastructure for the calibration of the meter (for example, a nearby test separator) may not exist.

8.10.3 Where it is practical to remove a multiphase meter, the most appropriate option is to repeat the initial calibration at a suitable test laboratory. In view of the concerns expressed in 8.8.3, it is recommended that the same calibration facility is used in each case.

8.10.4 Where this is not possible, a periodic comparison against a test separator is likely to be the next best option, but careful consideration of the uncertainty associated with test separator measurements should be made. Practical experience over many years has shown that test separators often do not provide the anticipated measurement accuracy. Module 5 of these Guidelines suggests ways in which separator measurement may be enhanced.

This method is at the very least likely to provide a reasonable verification of the meter's repeatability.

8.10.5 In Norway, a subsea template and dual flowline system has been developed, allowing production to continue whilst one well is routed to a platform-based test separator. When well-testing is not ongoing, two production lines are available to maximise flow.

8.10.6 In situations where removal of the meter or comparison with a test separator is not possible, there are essentially two remaining means of demonstrating that at least some measurement integrity is being maintained.

The first is to rely on static (zero flow) calibration of instruments such as gamma densitometers, and the second is to use some form of in-situ calibration technique. While static calibrations provide a useful check on sensor performances, it must be remembered that this process will not identify any changes that may have taken place within the meter that are only manifested under dynamic conditions. To avoid this drawback, radioactive tracer technology has been developed recently that allows a verification process in-situ and under dynamic flow conditions.

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MODULE 9

FLARE GAS MEASUREMENT

MODULE 9 FLARE GAS MEASUREMENT

CONTENTS

9.1 TERMS OF REFERENCE

Background

9.1.1 The Department's Guidance Note on "Procedures for Regulating Offshore Oil and Gas Field Development" (available online at http://www.og.dti.gov.uk/regulation/guidance/index.htm) states in the section on Policy that:

"It is recognised that during the appraisal, commissioning and production phases of a development, the flaring and venting of some gas is unavoidable. The Department requires that this flaring should be kept to the minimum that is technically and economically justified. Flaring and venting is also undesirable on environmental grounds."

The Department controls gas flaring on the UKCS through the requirement for Licensees to apply for consent to flare gas. The main purpose of this requirement is to ensure that gas is conserved where possible by avoiding unnecessary wastage during the production of hydrocarbons.

Legislation

9.1.2 Model Clause 21, Section (3) of the Petroleum Model Clauses Order (1999) (available online at http://www.og.dti.gov.uk/regulation/legislation/index.htm) states that:

"…the Licensee shall not flare any gas from the licensed area, except with the consent in writing of the Minister and in accordance with the conditions, if any, of the consent."

i.e. all flaring is technically prohibited, unless it is governed by a consent agreed with the Department for the relevant License. One of the conditions referred to is the amount of gas that may legally be flared over a given period of time.

During the commissioning of a field, when flaring is generally at its highest and most volatile levels, consents are generally renewed every 30 days. Once flaring levels have stabilised, annual consents may be agreed with the Department. In line with the Government's overall aim of reducing CO_2 emissions, successive annual flare consents will normally be reduced.

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9.1.4 Further information on the above legislation, and on the Department's flaring policy, can be obtained from the DTI's Head of Consents.

Measurement of Flare

9.1.5 The Guidance and regulations referred to in 9.1.1 and 9.1.2 above do not specifically refer to measurement of flare. However, for the Licensee to be able to demonstrate that the flare consent referred to in 9.1.2 above has not been exceeded, some form of measurement of flare is clearly necessary.

9.1.6 As indicated in 1.3.2 of these Guidelines, the measurement of flare can in some cases also be 'fiscal' (as defined by 2.2.6). Under these circumstances, there is clearly an additional need to account for flare as accurately as possible.

9.1.7 If the Operator intends to enter into an emissions trading scheme including flare measurement, the method of measurement may be subject to the scrutiny of the Regulator, and a method of periodic reverification may also have to be proposed.

Units of Measurement

9.1.8 The present flare consent system requires flared quantities to be reported in standard volume units (15°C, 1.01325 bar abs).

The DTI plans to introduce a mass-based consent system, probably in 2004. Since no direct mass measurement technique exists, in practice this will simply mean an additional requirement to measure and report the flare gas density.

Where direct measurement techniques (as defined in 9.1.9) are employed, density determination is relatively straightforward; meters typically indicate the molecular weight of the flare gas, from which the density can be determined.

Where flare gas is not measured directly, the density value can be determined either by:

- The laboratory analysis of representative samples of flare gas.
- Process modelling techniques.

Definitions

9.1.9 These Guidelines will make use of the following definitions:

- ***Direct measurement***, where a meter is used to determine flared quantities
- ***Indirect measurement***, where the amount flared is estimated on the basis of process modelling (for example, 'by difference' calculation)

9.2 DIRECT MEASUREMENT

Measurement Challenges

9.2.1 In a typical flare system, there may well be formidable technical challenges to any direct measurement of flare gas. Principally:

- The flare line may operate over a very wide range of flow rates. Under normal operations, flow rates may be as low as 0.1m/s, while at times of plant upset or maintenance they may be as high as 30m/s. During safety-critical events such as installation blowdown, line velocities may reach 100m/s, depending on the gas inventory and flare line diameter.
- Flare gas typically comes from a variety of sources; fugitive emissions from valves, water vapour, purge gas (normally Nitrogen), and produced gas will all find their way to the flare header. The presence of liquids, caused either by process carry-over or by condensation (especially during periods of high flow), can also be expected. In extreme cases (such as the very high flow rates experienced in blowdown situations), solids may even be carried over from separators and process pipework.

Meter Selection

9.2.2 In view of the points highlighted in 9.2.1, the use of non full-bore meters (such as orifice plates and turbine meters) in the main flare line is discouraged. These meters will be more susceptible to contamination, with consequent degradation of performance.

The use of a non full-bore meter in the main flare line may also be undesirable on safety grounds; any blockage in the flare line will increase the length of time necessary to evacuate the installation's gas inventory in an emergency blowdown situation.

9.2.3 It follows from 9.2.1 and 9.2.2 that flare meters must be physically robust, should preferably be full-bore, and they should offer the potential for very high turndown.

The vast majority of practical applications make use of ultrasonic measurement technologies. These Guidelines have therefore been written principally for ultrasonic flowmeters, although the basic principles may be applicable to other technologies.

Installation Effects

9.2.4 The meter manufacturer should *always* be consulted prior to the installation of a flare meter.

9.2.5 If a single meter is used for reporting purposes, it must be located where it will measure the total flow entering the flare header, i.e. downstream of the last branch-line into the flare header itself. However, satisfying this basic pre-requisite can lead to difficulty in meeting other installation criteria for the meter.

9.2.6 If, for example, the last feeder joins the main flare line at a point which leaves less than the required number of upstream straight lengths for the flare meter at its point of installation, the performance of the meter will be adversely affected. Flow profile asymmetries are unfortunately relatively persistent in the low-pressure gas flows typical of flare lines.

9.2.7 If an ultrasonic meter is used, the meter should be located as far as possible from any source of gas-borne ultrasonic noise, such as flow-control and pressure-regulating valves. Despite the advanced signal processing capability of gas ultrasonic meters, these features may degrade the signal-to-noise ratio to the extent that measurement integrity is compromised.

9.2.8 It is recognised that the choice of locations for the flare meter on the main flare line may be limited. However, the meter location should, as far as possible, be selected so as to minimise installation effects referred to in 9.2.5 and 9.2.6 above.

'Spool-Piece' v 'Hot Tap'

9.2.9 Two types of ultrasonic meter installation are possible:

- *Spool-Piece*, where the ultrasonic meter transducers are mounted in a pre-fabricated meter spool
- *'Hot Tap'*, where the ultrasonic transducers are retrofitted to the 'parent' pipe in the flare line

9.2.10 For 'new build' flare systems, a 'spool-piece arrangement' is preferred, since it allows greater precision in the positioning and alignment of the transducers, and allows meter dimensions to be determined more precisely. It may however be possible to install 'spool-pieces' during plant shutdowns, if these are of sufficient duration.

It may be the case that the incremental improvement in measurement accuracy due to a 'spool-piece' installation is relatively small when compared with the significant sources of uncertainty inherent in any 'real' flare measurement application.

Instrumentation

9.2.11 Where the meter's output is in the form of an analogue 4-20mA signal, the following points should be considered:

- Although the flare meter may have a very wide turndown, it is likely to operate predominantly at the very bottom of this range. It is therefore advisable to scale the meter's output across the lower range of predicted flow rates, in order to benefit from improved sensitivity under normal operating conditions. At the highest (e.g. 'blowdown') flow rates, it may be undesirable to use the flare meter's output; this may in any case become unreliable under these circumstances.

- It may be possible to use more than one output channel for the flare meter; in this case one channel may be scaled at, say, 0-25% of range, with the remaining channel scaled for 25-100%. Where this possibility exists it is likely to be the optimum solution.

9.2.12 In view of the relatively low operating pressure of flare gas systems, absolute pressure measurement is required, as undetected variations in atmospheric pressure can otherwise have a significant adverse impact on measurement accuracy.

Therefore, either:

- Pressure gauges should be of the absolute type, or

- The barometric pressure should be measured separately, with the value added to the gauge pressure reading by the meter's associated software

Initial calibration

9.2.13 The use of a 'spool-piece meter' offers the Operator the possibility of meter calibration prior to installation. However, in the absence of a test facility that is able to replicate the 'in-service' conditions likely to be experienced by the meter, flow calibration may be of limited benefit.

Periodic reverification

9.2.14 Periodic meter reverification is not automatically required under current legislation, but it may be a condition of entry into an emissions trading scheme (9.1.7 refers).

Clearly, where the flare measurement is 'fiscal' (as defined in 2.2.6), periodic reverification of the flare gas meter is desirable.

9.2.15 There are a number of possibilities for meter reverification, for example:

a) It may be possible to remove the transducer heads in order to test their response in a dedicated 'flow cell' provided by the meter manufacturers for this purpose.

b) Flare gas meters typically provide information on the molecular weight of the flare gas. The molecular weight of the gas can be predicted independently from the flare gas density (determined, for example, from the flare gas composition, together with measurements of its pressure and temperature). An on-line comparison of these figures for molecular weight can then be used to demonstrate continued confidence in the flare gas meter's operation.

c) A nucleonic tracer can be injected into the flare line at a suitable point (allowing for satisfactory mixing with the flare gas); its measured rate of progress along the flare line provides an indication of average flare gas velocity. This figure can be integrated across the cross-sectional area of the flare line (using an assumed flow profile) to give an independent indication of flare gas flow rate.

9.2.16 Meter reverification is a specialist activity. The meter manufacturer should be always consulted for advice.

9.3 INDIRECT MEASUREMENT

9.3.1 When there is no direct measurement of flare gas, or where the metered figures cannot be used (as may occur, for example, during 'blowdown' situations), is necessary to determine flared quantities indirectly.

'By Difference' Measurement

9.3.2 The most commonly used indirect measurement is the 'by difference' technique. Essentially, this works as follows:

1. The total amount of gas produced by all wells is calculated. This can be estimated either directly from well-test measurement (the sum of gas production from each well), or by taking the product of the gas-to-oil ratio (GOR) of each well and the measured liquid export rate from the facility.

2. The quantity of gas *not flared* is established from the direct measurement of gas:
   - exported
   - used for fuel
   - re-injected or used for gas lift (if applicable)

3. The gas flared is inferred from the difference between these figures determined in stages 1 and 2 above.

9.3.3 The 'by difference technique' has a number of obvious shortcomings. The principal objections to its use are the following:

a) The uncertainty in the exported quantity, while very low (typically less than 1%) in relative terms, can be very high compared to the flared quantity itself. As a result the estimate of flared quantity can be subject to very high measurement uncertainty.

b) There is no facility for a true mass balance calculation across any installation using a 'by difference' technique to determine flare gas quantities.

c) Any undetected leaks into the flare line are unaccounted for by the 'by difference' technique; this can lead to systematic underestimation of flared quantities.

9.3.4 In view of the difficulty highlighted in 9.3.3 a), it is necessary to perform by-difference calculations repeatedly, in steady-state conditions, over a long period of time in order to reduce the uncertainty in flare gas determination to an acceptable level. Instantaneous by-difference calculations can even indicate *negative* flare values.

Inventory Calculations

9.3.5 When plant upsets occur, significant quantities of gas may be passed through the flare line at very high velocity. This may present a challenge to any direct measurement technique. Where pipeline or vessel inventories are known, the indirect measurement technique may be modified to include these figures. This point will be explored further in section 9.4.

9.4 FLARE MEASUREMENT STRATEGY

9.4.1 In view of the considerations outlined in section 9.3 above, it is worth considering an overall strategy for effective flare gas measurement. This is particularly so where flare meters are used, as a combination of direct and indirect measurement techniques may in fact provide the optimum means to determine flared gas quantities.

9.4.2 On any installation there are likely to be three typical flaring 'regimes':

a) Quiescent operation.

b) Higher-than-normal flaring levels due to temporary plant upset (e.g. compressor failure).

c) Blowdown or depressurisation of the processing facility with as part of safety (e.g. emergency shutdown) event.

Direct measurement techniques are perfectly feasible in the first two scenarios. However, flare metering in blowdown situations can be problematic. In this event, the use of indirect techniques (such as Inventory Calculations as referred to in 9.3.5) is recommended.

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MODULE 10

FLOW COMPUTERS

GUIDELINES FOR MANUFACTURERS AND OPERATORS

MODULE 10 FLOW COMPUTERS – Guidelines for Manufacturers and Operators

CONTENTS

10.1 TERMS OF REFERENCE

This Module is intended to provide manufacturers and Operators with some guidance on points to consider in the design and operation of flow computers for use with high-quality oil and gas measurement systems.

These features are generally common to oil and gas systems. Where items are specific to either oil or gas this is indicated.

This is not intended to be an exhaustive list, as this would be beyond the scope of this document.

10.2 DESIGN CONSIDERATIONS

Redundancy

10.2.1 Either of the following scenarios are regarded as satisfactorily addressing redundancy concerns in connection with high-quality metering systems:

- a dedicated flow computer may be provided for each meter run;
- multiple meter runs may be computed by one central flow computer, in which case a standby instrument should be provided so that maintenance or replacement may be carried out without interruption of flow.

Storage of Constants

10.2.2 All computer and compensating functions, other than data input conversions, should be made by digital methods. All calculation constants should be securely stored within the computer and should also be easily available for inspection at the appropriate resolution.

10.2.3 Computer equipment should be designed such that constants can be adjusted only by authorised personnel. Where it is necessary to use manual data inputs within the computer, for such functions as defaults, establishing fallback values and setting alarm limits, the use of this data should be automatically logged.

10.2.4 Flow computers and databases should be designed so that measurement accuracy is not compromised by inadequate resolution on the display of critical constants.

Lack of resolution on the computers' displays can create difficulties in establishing whether the correct values of constants have been entered.

Totalisers

10.2.5 Totalisers on individual and station summators should have sufficient digits to prevent rollover more frequently than once every two months. The resolution of the totalisers should be such as to comply with this rollover criterion. Totalisers should provide resolution sufficient to permit totalisation checks to be completed within a reasonably short time frame.

10.2.6 Totalisers and summators should be non-resettable and should be provided with battery-driven back-up or non-volatile memories where they are of the non-mechanical type.

10.2.7 Where external totalisers or summators are not installed, the resolution of the flow computer totalisers should be such as to comply not only with this rollover criterion, but also allow totalisation tests to be performed to the required tolerance. These totalisers should also be non-resettable. If the resolution of the totalisers cannot meet both the rollover and totalisation test requirements, consideration should be given to the provision of a totalisation test function within the flow or database computer.

10.2.8 Flow computer manufacturers should consider the provision of a separate ‘maintenance’ totalisation register for use during totalisation checks.

Remote Access

10.2.9 The facility for remote access to a database and flow computers is becoming common. *This is a potentially extremely useful feature and its use is strongly encouraged.*

Correction Algorithms

10.2.10 Where multiple meter factors are used in conjunction with approved algorithms to calculate instantaneous flow correction factors, the calculations should be performed by the flow computer and not within the meter electronics unit.

This applies particularly to the use of calibration ‘offsets’ applied to ultrasonic meters.

Software Changes

10.2.11 The DTI must be informed of any proposed changes to the flow computer or database software.

A software version number or configuration certificate should be accessible to enable changes in software to be identified.

10.2.12 A full set of calculations and input tests should be carried out when the software is installed in the flow computer.

Alarms

10.2.13 Any alarms used within the flow computer must be accessible to suitably authorised persons and not ‘hard-coded’ within the operating software. This will allow appropriate alarms to be enabled or disabled for use and suitable values to be set for their initiation.

10.2.14 The use of alarms should be carefully controlled. They provide an important means of drawing attention to potential mismeasurements, especially on systems where metering personnel are not present full-time.

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MODULE 11

MEASUREMENT STATIONS

SUPPORTING DOCUMENTATION

MODULE 11 MEASUREMENT STATIONS - SUPPORTING DOCUMENTATION

CONTENTS

11.1 TERMS OF REFERENCE

11.1.1 This Module is intended to provide Operators with guidance as to the documentation that the DTI expects to be maintained in connection with Fiscal Quality Measurement Stations, both oil and gas, as defined in Module 2 of the Guidelines.

11.1.2 The same principles apply to lower-quality measurement systems, though there will be less stringent requirements in these cases.

11.1.3 This list is not intended to be exhaustive but rather to provide guidance on the maintenance of a satisfactory degree of traceability in measurement stations. This is to satisfy the interests of Regulators, both Government and Commercial, and the Operators themselves. For example, the ability to calculate the magnitude of a mismeasured quantity, and potentially recover revenue that would otherwise be lost, may depend critically on the ability to identify exactly when a problem arose.

11.1.4 These guidelines have been formulated with the need to avoid duplication in recording data in mind. Proposals to further reduce duplication will be viewed sympathetically by the DTI provided they do not unduly jeopardise traceability.

11.2 SYSTEM DESIGN AND OPERATIONAL DOCUMENTATION

11.2.1 The following documentation should be maintained at the measurement station:

(i) The latest version of the system's Functional Design Specification

(ii) A full set of up-to-date Operation and Reverification Procedures

11.3 DTI LOGBOOKS

11.3.1 Logbooks must be maintained at the measurement station.

Use of Electronic Logbooks

11.3.2 Logbooks have traditionally been of the 'hard copy' type, in a dedicated notebook with numbered pages to demonstrate that no entries have been destroyed. While the DTI has no objection to the continued use of such logbooks, operators are strongly urged to consider the use of 'electronic' logbooks, provided that these are suitably secure. This offers a number of advantages – principally, it allows the logbooks to be reviewed onshore. A well-designed electronic logbook would allow a 'filter' to be applied to entries to allow the reviewer to search by category.

Logbook Format

11.3.3 Entries should be clear and concise at all times, and should be signed, timed and dated.

11.3.4 The operator must maintain a separate logbook for each meter stream.

11.3.5 The operator should consider the use of a 'common equipment' logbook in which to maintain records of work done on equipment or instrumentation that is not specific to any one stream – for example, the sampling system.

11.3.6 For liquid measurement systems using a prover loop, a prover log must be maintained. This should contain details of all prover calibrations, sphere detector serial numbers and any maintenance work carried out on the prover and its associated instrumentation.

Meter proving records should also be maintained. The important parameters that should be recorded are given in Module 3 (Section 3.6.10) of these Guidelines.

Significant Events

11.3.7 These logbooks should contain details of all significant events in the operation of the measurement station. A well-maintained logbook should permit the precise timing of any mismeasurement to be identified retrospectively. It should allow the observer, e.g. an independent auditor, to establish to what extent the measurement station is able to run ‘smoothly’, without upset.

Examples of ‘significant’ events include:

- Any removal of the flow meter, for whatever reason.
- The totaliser readings at the removal from, or introduction of, the stream into service.
- Any ‘non-routine’ events, such as the failure of any items of instrumentation and any remedial action taken.

Note that this list is not intended to be exhaustive – the Operator is expected to be able to decide what constitutes a ‘significant’ event in the operation of a measurement station.

11.3.8 A list of currently-operating dispensations should be readily available for inspection at all times.

11.3.9 Operators should notify the DTI prior to any major maintenance or recalibration work on the metering system. The operator must seek dispensation from the DTI if they cannot comply with the agreed calibration schedule of a primary element, or in the event of the failure of a flow computer or database.

11.4 MISMEASUREMENT REPORTS

Reporting to DTI

11.4.1 The DTI should be notified, preferably by E-mail, when any abnormal situation or measurement error occurs which could require significant adjustments to the totalised meter throughputs.

11.4.2 When corrections to meter totalised figures are required due to known metering errors, a formal report should be prepared. This report should be sent, preferably by E-mail, to the DTI, and should contain the following details of the mismeasurement:

- Its start and finish time.
- Totaliser readings at its start and finish.
- The method used to determine its magnitude.
- The reasons for its occurrence.

Records to be Maintained

11.4.3 Records should also be maintained, 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) Any change in meter pulse comparator register readings.

A set of these 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 %BS&W content, should be recorded at agreed intervals if not already included in the automatic log.

All above records should be available at all reasonable times for inspection by the DTI. Electronic or hard copies are acceptable. Records for the preceding 12 months should be retained at the metering station.

11.5 FLOW COMPUTER CONFIGURATION RECORDS

11.5.1 Configuration listings for each stream flow computer must be maintained at the measurement station. These listings may be of critical importance in the retrospective calculation of any mismeasurement. Any manual change of a normally-fixed parameter should be recorded in a Controlled Document, giving details of:

- The date and time of the change.
- The previous value of the parameter.
- The new value of the parameter.
- The reason for the change.

An example of a change in flow computer configuration that would need to be reflected in the configuration listing is the change in calibration constants following the annual recalibration of a densitometer.

11.6 CALIBRATION CERTIFICATES

11.6.1 The Operator must have readily available at the metering station calibration certificates for the following

- All current test equipment – the DTI expects test equipment to have been calibrated at a laboratory accredited by UKAS, or an equivalent overseas authority, whenever possible.
- Elements of the metering system that have been calibrated remotely (for example, orifice plate/meter tubes, differential pressure cells, densitometers).

11.6.2 These certificates can either be maintained in ‘hard-copy’ or electronic (i.e. scanned) form.

11.7 ROUTINE CALIBRATION RECORDS

11.7.1 Routine calibration records must be maintained at a metering station. These records should allow the auditor to *readily* establish:

- that planned maintenance routines have been carried out at the agreed frequency
- the degree of reliability of the secondary test equipment under calibration

For offshore systems, the Operator is encouraged to make these records available onshore. Copies for at least the last 2 years should be retained. The procedure of reviewing them can be time-consuming and this activity can be profitably pursued prior to any offshore inspection.

11.7.2 Operators are strongly encouraged to use an electronic means of maintaining routine calibration records. This may be in the form of one of several commercially-available packages, or it may be developed ‘in-house’. However, it should have the facility to readily summarise the details required by 11.7.1.

As well as helping to reduce the time spent on these tasks by auditors, a well-designed system can also be of significant help to the Operator as it significantly facilitates the task of collation of calibration records prior to their submission to the DTI in application for the extension of agreed calibration intervals.

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MODULE 12

NEW SYSTEMS

DESIGN CONSIDERATIONS

MODULE 12 NEW SYSTEMS – DESIGN CONSIDERATIONS

CONTENTS

12.1 TERMS OF REFERENCE

12.1.1 This section is intended to provide a 'high-level' overview of important points that must be considered by Licensees when reviewing potential solutions to measurement challenges.

12.1.2 Attention is drawn to the requirements of the Petroleum Operations Notice (PON) 6, available on the DTI Oil and Gas Division website (http://www.og.dti.gov.uk/regulation/pons/pon_06.htm) and reproduced in Appendix 1.2 of these Guidelines.

12.2 APPLICATION OF SUITABLE TECHNOLOGY

12.2.1 It is the responsibility of the Licensee to ensure that the chosen measurement technology is appropriate to the desired application.

This is not a trivial point. On more than one occasion, meters totally inappropriate to the in-service flow conditions have been commissioned and installed in UKCS applications. The costs involved in retro-fitting new meters are likely to be very high – not to mention the potential cost to the Operator of systematic under-measurement resulting from the use of the meter in conditions for which it was not designed.

Discussion with the DTI is recommended at as early a stage as possible in the field development. Guidance in this area is also available in BS7405.

Nature of Fluids

12.2.2 Careful consideration must always be given to the likely nature of the fluid or fluids being measured. In particular:

- Is the fluid likely to be single phase, two-phase (e.g. wet gas), or multiphase?
- If dealing with gas, is the fluid likely to be at or near its dew-point?
- If dealing with liquid, is gas break out likely to occur?
- Are contaminants such as scale or wax likely to occur?

The answers to these and other questions can have a critical bearing on the appropriate choice of meter for a given application.

Flow rates to be Measured

12.2.3 Certain types of meter have higher flow rate capacities than others for the same bore of meter tube. The choice of a meter may therefore impact on the required number of meter runs.

12.2.4 Operators should consider the expected flow rates that are likely to occur throughout the life of a field. Some meters have higher turn-down characteristics than others.

12.3 LIFE-OF-FIELD COSTS

12.3.1 While the DTI recognises the demands on many projects to minimise Cap-ex costs, the life-of-field cost of a measurement station must always be at the forefront of the Operator's mind.

Selection of high-quality primary and secondary instrumentation can have a critical role to play in reducing life-of-field costs.

Reliability of Instrumentation

12.3.2 The DTI has seen many examples of the use of inferior quality, but nevertheless nominally 'fit-for purpose' elements of measurement systems.

The use of high-quality instrumentation is likely to reduce Op-ex costs associated with the failure in service of critical elements of the measurement station.

Maintenance Costs

12.3.3 High-quality instrumentation, though more expensive, is likely to be more stable than its lower-cost counterpart. However, this Cap-ex cost is likely to be more than offset through reduced Op-ex maintenance costs. The DTI is always ready to agree to reductions in the required calibration frequencies of instrumentation, subject to the demonstration of satisfactory performance and stability.

Reverification Procedures

12.3.4 The cost of reverification of a system should be considered at the design stage.

12.3.5 Any proposal for the reverification of a measurement system that involves shutting in production from a well, or even a field, will potentially be very costly for the Operator.

As a rule, this means of reverification will not be acceptable to the DTI.

There have been many cases in the past where Operators, after themselves proposing such a means of reverification, have subsequently used the cost involved as a justification for not carrying it through – often with little or no discussion with the DTI.

12.4 PHYSICAL LOCATION OF METERING SKID

12.4.1 Operators are asked to consider the physical location of the overall metering skid. This has the potential to affect the quality of measurement, and can have safety implications.

Process Pipework

13.4.2 The piping arrangement before and after the metering skid should be given careful consideration as this can have a considerable impact on the operation of the system components.

The siting of a metering station at the bottom of a 'U' in the process pipework is not conducive to effective measurement in the long term, particularly in wet gas applications.

12.4.3 The type and location of control valves also requires careful consideration, particularly where ultrasonic meters are to be used. If in doubt, the meter manufacturers should be consulted for advice.

Effect of Ambient Conditions

12.4.4 The DTI has experience of metering skids being sited in some of the most exposed locations possible on offshore installations. These have occasionally been in open, rather than closed modules.

While the DTI accepts that there may be safety considerations involved in the use of open, rather than closed, modules, Operators are reminded that extremes in ambient conditions *can* have a practical effect on measurement integrity, particularly in areas where assumed values of temperature are used , e.g. gas density measurement.

Operators should consider the siting of metering skids, where possible, so that their exposure to ambient conditions is minimised. Lagging and insulation requirements will thereby be minimised.

Safety Considerations

12.4.5 Operators must consider the ease of access to metering skids, particularly to those areas that require routine maintenance and calibration.

In one recent case on a major North Sea producing installation, the Health and Safety Executive (HSE) ordered elements of a skid to be redesigned in order to improve access to an acceptable level. The costs involved could have been avoided by appropriate consideration at the design stage.

Operators should consult the HSE for guidance on their requirements with regard to access.

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MODULE 13

STANDARDS AND TECHNICAL PAPERS

STANDARDS

Operators are encouraged to make use of the Industry Standards listed below when considering the design, construction and operation of measurement systems.

TECHNICAL PAPERS

Technical papers are referred to in the text by the first-named author, e.g. [*Smith*]. The paper details are presented at the end of each Module.

Institute of Petroleum,
61 New Cavendish Street,
London W1M 8AR,
United Kingdom.

www.petroleum.co.uk

Petroleum Measurement Manual

Part	Content
VI	Sampling.
VII	Density
X	Meter Proving
XIII	Fidelity and Security of Measurement Data Systems
XV	Metering System. Section 1 A Guide to Liquid Metering Systems
X	Background, Development and Computer Documentation

IP 200 (API 2540; AST D1250) Petroleum Measurement Tables

Publication	Content
Vol. VII Table 54A	Generalised Crude Oil, Correction of Volume to 15°C Against Density at 15°C
Vol. IX Table 54C	Volume Correction Factors for Individual and Special Applications, Volume correction to 15°C Against Thermal Expansion Coefficients at 15°C
Petroleum Measurement Paper No. 2	Guidelines for Users of the Petroleum Measurement Tables (API Std 2540; (IP200); ANSI/ASTM D 1250)

American Petroleum Institute
1220 L Street, Northwest,
Washington D.C. 20005,
U.S.A.
www.api.org

Manual of Petroleum Measurement Standards	
Chapter	**Content**
4	Proving Systems.
5	Liquid Metering.
6	Metering Assemblies.
8	Sampling.
9	Density Determination
10	Sediment and Water.
11.2.1	Compressibility Factors for Hydrocarbons, 600 to 1074 Kgm^{-3}
11.2.1M	Compressibility Factors for Hydrocarbons 350 to 637 Kgm^{-3}
12	Calculation of Petroleum Quantities.

Report	Content
345/80	Composition of Associated Natural Gas – Determination of oxygen, carbon dioxide and C1-C5 hydrocarbons as a group

ISO (International Organisation for Standardisation)
Case Postale 56
CH-1211 Genève 20
Switzerland
www.iso.org

ISO	Content
1000	SI units and recommendations for the use of their multiples and of certain other units.
10790	Measurement of fluid flow In closed conduits – Guidance to the selection, installation and use of Coriolis meters (mass flow, density and volume flow measurements)
2714	Liquid Hydrocarbons - Volumetric measurement by displacement meter systems other than dispensing pumps.
2715	Liquid Hydrocarbons - Volumetric measurement by turbine meter systems.
3170	Petroleum Liquids - Manual sampling.
3171	Petroleum Liquids - Automatic pipeline sampling.
3675	Crude Petroleum and Liquid Petroleum Products -Laboratory determination of density or relative density Hydrometer method.
3735	Crude Petroleum and Fuel Oils - Determination of sediment extraction method.
4006	Measurement of Fluid Flow in Closed Conduits - Vocabulary and symbols.
4124	Liquid Hydrocarbons - Dynamic measurement; Statistical control of volumetric metering systems.
5167-1	Measurement of Fluid Flow by Means of Pressure Differential Devices; Orifice Plates, Nozzles and Venturi Tubes Inserted in Circular Cross-section Conduits Running Full. *(Current Revision)*
6551	Petroleum Liquids and Gases - Fidelity and security of dynamic measurement cabled transmission of electric and/or electronic pulsed data.
6976	Natural Gas - Calculation of calorific values, density, relative density and Wobbe index from composition.
7278	Liquid Hydrocarbons - Dynamic measurement; Proving systems for volumetric meters.
9951	Natural Gas -Turbine meters used for the measurement of gas flow in closed circuits.
10723	Natural Gas – Performance evaluation for on-line analytical systems.
12213	Natural Gas - Calculation of compression factor.
13443	Natural Gas - Standard reference conditions.
GUM 1	Guide to the Expression of Uncertainty in Measurement.
TR 12765:1998	Measurement of fluid flow in closed conduits – Methods using transit-time ultrasonic flow meters
TR 15377: 1998	Measurement of fluid flow by pressure-differential devices – Guidelines to the effect of departure from the specifications and operating conditions given in ISO-5167-1
TR 3313: 1998	Measurement of fluid flow in closed conduits – Guidelines on the effect of flow pulsations on flow measurement instruments.

A number of relevant international standards are currently at the Draft International Standard (DIS) stage. When these documents are adopted as full ISO standards they should be included in any list of standards to which reference would routinely be made in arriving at the design of a metering system.

British Standards Institute
389 Chiswick High Road,
London W4 4AL,
United Kingdom
www.bsi-global.com
http://bsonline.techindex.co.uk

Many British Standards are now uniform with international standards and where this is the case are issued by the British Standards Institute as dual-numbered standards. BS 1042 is one such standard. However only part one of the British standard is uniform with the ISO equivalent, ISO 5167. The other parts of the British standard give guidance on the use of orifice plates with drain holes and the effect on discharge coefficients of non-ideal installation. The additional parts of the British standard are a useful source of practical guidance.

BS	Content
1042	Measurement of fluid flow in closed conduits; pressure differential devices.
1904	Industrial Platinum Resistance Elements. (adopted as dual or triple numbered CEN and national standards with identical text)
7405	Guide to the selection and application of flowmeters for measurement of fluid flow in closed conduits
7965	The selection, installation, operation and calibration of diagonal path transit time ultrasonic flow meters for industrial gas measurement

American Gas Association
400 N. Capitol Street, N.W.
Washington, DC 20001
U.S.A.
www.aga.org

Report	Content
No. 8	Compressibility and supercompressibility for natural gas and other hydrocarbon gases.
No. 9	Measurement of Gas by Multipath Ultrasonic Meters
No.10	Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases

Gas Processors Association
6526 E 60th Street
Tulsa, OK 74145
U.S.A.
www.gasprocessors.com

Report	Content
GPA 2165, 1995	Standard for analysis of natural gas liquids mixtures by gas chromatography.

APPENDIX II

Petroleum Production Reporting System

Oil and Gas Directorate

Department of Trade and Industry

Submission Guidance

"PPRS 2000"

Revision 0: August 2000

Table of Contents

1.0 Introduction

This Submission Guidance describes the data requirements and format for the reporting of hydrocarbon production from Fields and Terminals in the UK (both offshore and onshore). The "PPRS 2000" supersedes and replaces the previous guidance ("Blue Book" – Issue 4 dated January 1990).

The DTI was ready to accept PPRS Returns in the new XML format on 1st July 2000 as email attachments. After the 1st October 2000, it is planned to have a fully automated web based 'file upload' Internet solution and an update to the documentation will be issued at that time.

1.1 Reporting Unit Categories

For convenience, Operators are requested to use six dedicated input formats as appropriate. The primary division for the PPRS returns is into two groups, Fields and Terminals, but each of these two groups is then further sub-divided to give six categories of PPRS reports. This will enable Operators to more easily relate their facility to the data required by the DTI.

Fields

Type		Figure	Table
"P"	Oil Field Exporting to Pipeline	1	1
"T"	Onshore Oil Field or Offshore Tanker Loader	2	2
"G"	Dry Gas Fields	3	3

Terminals

Type		Figure	Table
"O"	Oil Pipeline Terminal	4	4
"A"	Associated Gas Terminal	5	5
"D"	Dry Gas Terminal	6	6

Attached to this Submission Guidance are six corresponding simplified Figures and Tables to illustrate each of the six categories. This division into six categories simplifies the data requirements even though many of the discrete data elements are common across both Field and Terminal Types.

1.2 Distinguishing Dry Gas Fields from Oil Fields

Some of the terms used within the Oil and Gas industry carry a range of interpretations, which if not precisely defined can cause confusion. The definitions in this PPRS may not conform precisely to that stated in other publications, either by DTI or other industry bodies, and are only intended for application within the PPRS.

An 'Oil Field' is defined for the purposes of the PPRS as a Field that produces oil into a pipeline or Tanker, whether Marine, Road or Rail. The Associated Gas can be disposed of by flaring, venting, utilisation, and re-injection or shipped via pipeline to an Associated Gas Terminal in a pipeline that is different from the oil pipeline. [Fields referred to as 'Gas Condensate' Fields will fall into this category.]

The objective for Field data is to satisfy the reservoir engineers and for this purpose the PPRS 2000 seeks to reduce "Inter Field Transfers" to as few as possible by attributing back to an individual Field wherever possible. Note that Inter Field Oil and Associated Gas Transfers may not necessarily go to the same other Field Unit. The convention is for the donor to report a positive quantity and the recipient a negative value.

A ‘Dry Gas’ Field is defined as one where any NGLs in the well head stream i.e.: ‘Dry Gas Condensate’ are spiked/ co-mingled back into the pipeline gas and then transported to a ‘Dry Gas’ Terminal in the same pipeline.

1.3 Distinguishing between Associated and Dry Gas Terminals

In most cases, there will be no difficulty in the distinction. However, the DTI will assist Operators to ensure that the PPRS 2000 submissions are appropriate to their facilities.

The ‘Dry Gas’ Terminals are typically taking delivery of Dry Gas from the UKCS Southern Basin and Irish Sea areas. Similarly, onshore Dry Gas Fields may transport to a Central Gas Gathering Facility that would then in most instances be a Dry Gas Terminal. Onshore oilfields will have, or be deemed to have, an Associated Gas Terminal attached if gas is to be exported for sales.

Terminal Data is gathered for a group that monitors Hydrocarbon stocks and disposals and therefore the data requested is now designed just to fulfil this aim.

1.4 Measurement Specification

All hydrocarbons are to be reported on a water dry basis at Standard Conditions (15 ^{o}C and 1.01325 bara) and in the following Units throughout, unless otherwise specified. The primary distinction is Volume for Offshore and Mass for Onshore.

Property	**Units**	**Description**
Mass	Tonnes	
Density - Liquids	Kg/m^3	Kilograms per Cubic Metre
Density - Gases	Kg/sm^3	Kilograms per Standard Cubic Metre
Volume - Liquids	m^3	Cubic Metre
Volume - Gases	Ksm^3	Thousands of Standard Cubic Metre (1000 m^3)
Gross Calorific Value	Mj/m^3	Mega Joules per Standard Cubic Metre

1.5 File Transmission to DTI

This replacement PPRS 2000 assumes that the ‘Hydrocarbon Accountants’ in the Operators’ organisation are familiar with the stream descriptions used. Explanatory Notes have been inserted in to the overall Manual where DTI feels that additional clarifications are appropriate. **It is emphasised that, under the new PPRS 2000 format, the Streams have been given numbers as well as names simply to assist identification. All communication now between Operators and DTI on the PPRS data items should only reference the XML name and not the stream number.**

The Monthly Returns should be supplied to the DTI via Internet transfer in XML format. The appropriate monthly XML file should be created separately for each individual Field or Terminal Reporting Unit. The XML file should be e-mailed as a text attachment to the following address: PPRS2000@dti.gsi.gov.uk.

However, it is planned by 1st October 2000 to provide an improved, alternative method ‘file upload’ of sending data via the DTI Oil and Gas Directorate web site. This will provide a faster method of sending data as well as provide confirmation that it has been received and automatically identify to the DTI any errors in the XML file.

There will then be two options for XML file transmission,

- Via Email as a plain text attachment
- File upload via a web screen

It is envisaged that many of the larger companies with automated production allocation systems will prefer email attachment as it can be made fully automated. On receipt at the DTI, the attachment will be removed and processed – with success or failure resulting in an email acknowledgement being returned to a nominated list of company email addressees. If errors are encountered, the file will be returned via e-mail to correct and re-submit as a new XML file. The emphasis is on the Operators' internal QC procedures to get the files in a format to load directly onto the DTI computers.

"Upload File" will provide an instantaneous Validation and loading. Any errors will be reported at the time of the operation. This option will be available on the above website reference (see above).

1.6 Notification of New Reporting Units and Cessation of Production

When a new Reporting Unit is coming up, the Operator will need to contact the Data Management Team in London to request confirmation of the Name of the Reporting Unit and it's Identifier. The co-ordination of receipt of the first PPRS return will be by the Data Management Team, who will also need to know the return email address (es) to acknowledge successful loads or transmit error messages in Validation.

In the case of Field Abandonment, the PPRS return must continue to be submitted until the Cessation of Production is officially confirmed by the DTI.

1.7 DTI Contacts

The single point contact for clarifications to this PPRS 2000 Manual, technical procedures and PPRS processes at the DTI is,

Single Point	Michael Pye	020 7215-5087	michael.pye @ dti.gov.uk

For specialist queries, alternative contacts are

XML/ IT	Mark Sanders	020-7215-5236	mark.sanders@dti.gov.uk
Data Records	Russell Hornzee	020 7215-5128	russell.hornzee @ dti.gov.uk

2.0 Explanatory Notes - Fields

2.1 Oil Field Exporting to Pipeline

See Figure 1 and Table 1.

Stream 1 'Oil Production'. Oil produced from an offshore Field. It will usually contain a few percent of NGLs but the revised PPRS does not seek separate values for SCO and NGLs here, only the 'Oil Production' by volume and density.

Stream 2 'Inter Field Transfer of Oil'. The PPRS 2000 seeks to attribute production back to individual Fields and this mechanism in the 'Blue Book' will be little used now.

Stream 3 'Oil Production to Pipeline'. Oil pipelined to an onshore Terminal.

Stream 4 'Associated Gas Production'. The 'Associated Gas Production' is defined as the 'Total Field Wellhead Hydrocarbon Production' less the oil that has been produced (Stream 1). Under this definition of 'Associated Gas Production', NGLs that will be measured with the oil in the pipeline will therefore not be included in this gas stream calculation.

Stream 5 'Inter Field Transfer of Associated Gas'. Inter Field transfers should be only be used now typically when gas from one Field reservoir is injected into another Field reservoir.

Stream 6 'Associated Gas to Pipeline'. If 'NGL/ Condensate' drops out of the 'Associated Gas to Pipeline' during transportation to the Terminal, it should be reported in the PPRS as if it were all still a single phase Gas. (This is different from how Dry Gas Fields are reported).

Stream 27 'Gas Flared at Field'. Gas flared, calculated on same basis as Flare Consent.

Stream 28 'Gas Vented at Field'. Any hydrocarbon gas cold vented.

Stream 29 'Gas Utilised in Field'. Most gas utilisation in operations is Fuel Gas. If gas is used for other process purposes, such as stripping, check no double counting as flare etc.

Stream 30 'Gas Injected'. The Gas Injected into the Field can originate both from the Field reservoir and/or from another Field after Inter-Field Transfer.

Stream 34 'Produced Water'. Water produced from each Field but there is no distinction here between native reservoir water and previously injected water.

Stream 35 'Produced Water to Sea'. Does not necessarily have to be reported per Field; it can be from several Fields serviced from the same Installation and reported from there.

Stream 36 'Injected Water'. In most instances this will be treated seawater, but exceptionally could be water obtained from another source.

Stream 37 'Re Injected Produced Water'. The Re Injected Produced Water may not necessarily originate from the Field receiving the water.

Stream 50 'Stock of Oil in Field' at Month End**.** Although offshore storage with pipeline export is not typical, there are some Fields with such storage tanks.

2.2. Onshore Oil Fields or Offshore Tanker Loader

See Figure 2 and Table 2. The common feature of Onshore Oil and Offshore Loader is that the production can be stored on-site prior to lifting.

Stream 1. 'Oil Production'. Oil produced from a Field.

Stream 2 'Inter Field Transfer of Oil'. An example of Inter Field Transfer of Oil occurs when a FPSO vessel receives production from another Field for storage and disposal.

Stream 4 'Associated Gas Production'. The 'Associated Gas Production' is defined as the 'Total Field Wellhead Hydrocarbon Production' less the oil that has been produced (Stream 1). Under this definition of 'Associated Gas Production', NGLs that will be measured with the oil in the pipeline will therefore not be included in this gas stream calculation.

Stream 5 'Inter Field Transfer of Associated Gas'. Inter Field transfers should be only be used now typically when gas from one Field reservoir is injected into another Field reservoir.

Stream 6. 'Associated Gas to Pipeline'. If 'NGL/Condensate' drops out of the 'Associated Gas to Pipeline' during transportation to the Terminal, it should be reported in the PPRS as if it were all still a single phase Gas. (This is different from how Dry Gas Fields are reported).

Stream 27 'Gas Flared at Field'. Gas flared, calculated on the same basis as Flare Consent.

Stream 28 'Gas Vented at Field'. Any hydrocarbon gas cold vented.

Stream 29 'Gas Utilised in Field'. Most gas utilisation in operations is Fuel Gas. If gas is used for other process purposes, such as stripping, check no double counting as flare etc.

Stream 30 'Gas Injected'. The Gas Injected into the Field can originate both from the Field reservoir and/or from another Field after Inter-Field Transfer.

Stream 34 'Produced Water'. Water produced from each Field but there is no distinction here between native reservoir water and previously injected water.

Stream 35 'Produced Water to Sea'. Does not necessarily have to be reported per Field; it can be from several Fields serviced from the same Installation and reported from there.

Stream 36 'Injected Water'. In most instances this will be treated seawater, but exceptionally could be water obtained from another source.

Stream 37 'Re Injected Produced Water'. The Re Injected Produced Water may not necessarily originate from the Field receiving the water.

Stream 51 'Stock of Oil in Tanker' at Month End. Oil stocks in partially loaded tanks and Tankers. If the Tanker breaks moorings/ connection, the cargo is reported as a disposal.

Stream 52 'Stock in Pipeline' at Month End. Stocks in pipeline attached to storage.

Stream 60 'Total Oil Tanker Disposals' during the Month.

Stream 61 'Individual Oil Tanker Disposal' during the Month**.** For Marine Tankers, the number of entries equals the number of individual cargoes loaded and detached from moorings. For onshore disposal, the entries will equal the number of different destinations.

2.3. Dry Gas Fields

See Figure 3 and Table 3. This category covers both offshore and onshore Dry Gas Fields.

Stream 7 'Dry Gas Field Production'. Total Field Wellhead Gas Production. Historically, the convention is for 'Dry Gas' here to be reported as a separate Stream from the 'Condensate', which is reported separately as Stream 17.

Stream 8 'Inter Field Transfer of Dry Gas'. The convention is for the donor to report a positive quantity and the recipient a negative value. Possibly redundant in the future.

Stream 9 'Dry Gas to Pipeline'. Dry Gas pipelined to an onshore Terminal.

Stream 17 'Dry Gas Field Condensate Production'. Condensate production that is measured after separation but will then be co-mingled back into the pipeline to Terminal gas.

Stream 18 'Inter Field Transfer of Dry Gas Condensate'. In practice, the exceptional case where Dry Gas Fields and Oil Fields might co-exist on the same Installation.

Stream 27 'Gas Flared at Field'. Gas flared, calculated on same basis as Flare Consent.

Stream 28 'Gas Vented at Field'. Any hydrocarbon gas cold vented.

Stream 29 'Gas Utilised in Field'. Most gas utilisation in operations is Fuel Gas. If gas is used for other process purposes, such as stripping, check no double counting as flare etc.

Stream 30 'Gas Injected'. The Gas Injected can originate from either the Field and/or from Inter-Field Transfer. The "Injected Gas CV" data item is only required on those Fields that inject sales gas for storage.

Stream 31 'Gas Utilised from Inter Field Transfer'. A special case when gas has been injected into a partially depleted gas reservoir for storage. There would then be two sources of gas for utilisation, native reservoir gas and gas imported through Inter Field Transfer.

Stream 34 'Produced Water'. Water produced from each Field

Stream 35 'Produced Water to Sea'. Produced Water may be recovered from the Dry Gas offshore but, more typically, is sent onshore with the pipeline gas and no offshore discharge.

Stream 78 'Sales Gas to NTS'. This is for onshore Dry Gas Fields only, and not necessarily always applicable. If a number of onshore Fields transport to a gathering station, then 'Stream 9' to a Dry Gas Terminal may be the more applicable model.

Stream 79 'Individual Sales Gas Non NTS'. Only applies to onshore Fields and is the direct Gas Sales through dedicated pipelines to power stations, refineries or other end users. The number of entries will equal the number of different destinations.

3.0 Explanatory Notes - Terminals

3.1 Oil Pipeline Terminal

See Figure 4 and Table 4.

Stream 10 'Pipeline Oil Entering Terminal'. Pipeline Oil from offshore or onshore Fields.

Stream 12 'NGLs Condensate Entering Terminal'. Where one Terminal provides process, storage and despatch facilities for NGLs and/or Condensate produced from another Terminal.

Stream 13 'SCO Receipts'. A calculation for DTI purposes resulting from when all the liquids entering the Terminal are designated as either SCO Receipts or NGL Receipts. (Data is required by 16th of the Month but can still be revised in End of Month FULL Return.)

Stream 14 'NGL Receipts'. Calculated as for 'SCO Receipts' above. (Data also required by 16th of the Month but can still be revised in End of Month FULL Return.)

Stream 23 'SCO Losses'. Accounting and metering losses of SCO across the Terminal system. Essentially, the difference between 'SCO Receipts' and oil to storage/ disposal with the losses expressed in terms of final SCO product rather than pipeline entry conditions.

Stream 24 'Condensate and NGL Losses'. Similarly, accounting losses of NGLs.

Stream 40 'SCO Stock' at Month End**.** Stocks in Tanks, pipelines and partially loaded Tankers still moored at the Terminal.

Stream 41 'Gas Flared at Terminal'. Gas flared, calculated on same basis as Flare Consent.

Stream 42 'Gas Vented at Terminal'. Any gas cold vented, including inert gases.

Stream 43 'Gas Utilised in Terminal'. . Most gas utilisation is Fuel Gas. If gas is used for other process purposes, such as stripping, check no double counting as flare etc.

> **Notes for Stock:** If the NGL product is delivered directly into a pipeline for disposal, without intermediate storage at the Terminal, a zero stock should be reported.

Stream 44 'NGL Production' during the Month. The sum of the Ethane, Propane, Butane, and C5+ Condensate to storage or directly exported.

Stream 45 'Ethane Stock' at Month End.

Stream 46 'Propane Stock' at Month End. Refers to both liquefied refrigerated storage and pressure storage.

Stream 47 'Butane Stock' at Month End. Refers to liquefied refrigerated storage and pressure storage.

Stream 48 'C5 Condensate Stock' at Month End.

Notes for Disposal of the individual cargoes of both SCO and NGL.

For Marine Tankers leaving the Terminal during the Month, the number of entries equals the number of individual cargoes loaded and detached from moorings during the Month. For Road Tanker, Rail Tanker and other pipeline disposals, the number of entries will equal the number of different destinations.

Stream 62 'Total SCO Disposal' leaving the Terminal during the Month.

Stream 63 'Individual SCO Disposal' during the Month.

Stream 64 'Total Ethane Disposal' during the Month

Stream 65 'Total Propane Disposal' during the Month

Stream 66 'Total Butane Disposal' during the Month

Stream 67 'Total C5 Condensate Disposal' during the Month

Stream 68 'Individual Ethane Disposal'

Stream 69 'Individual Propane Disposal'

Stream 70 'Individual Butane Disposal'

Stream 71 'Individual C5 Condensate Disposal'

3.2 Associated Gas Terminals

See Figure 5 and Table 5.

If an Onshore Oil Field has surplus gas available after utilisation and flare, such gas will be deemed to then enter an Associated Gas Terminal.

Stream 12 'NGLs Condensate Entering Terminal'. Where one Terminal provides process, storage and despatch facilities for NGLs and/or Condensate produced from another Terminal.

Stream 15 'Associated Gas Entering Terminal'. Pipeline Gas entering Terminal.

Stream 24 'Condensate and NGL Losses'. Accounting and metering losses of Condensate and NGL across the Terminal system.

Stream 25 'Gas Losses'. Accounting and metering losses across the Terminal system.

Stream 41 'Gas Flared at Terminal'. Gas flared, calculated on same basis as Flare Consent.

Stream 42 'Gas Vented at Terminal'. Any gas cold vented, including inert gases.

Stream 43 'Gas Utilised in Terminal'. . Most gas utilisation is Fuel Gas. If gas is used for other process purposes, such as stripping, check no double counting as flare etc.

> **Notes for Stock:** If the NGL product is delivered directly into a pipeline for disposal, without intermediate storage at the Terminal, a zero stock should be reported.

Stream 44 'NGL Production' during the Month. The sum of the Ethane, Propane, Butane, and C5+ Condensate to storage or directly exported.

Stream 45 'Ethane Stock' at Month End.

Stream 46 'Propane Stock' at Month End. Refers to both liquefied refrigerated storage and pressure storage.

Stream 47 'Butane Stock' at Month End. Refers to liquefied refrigerated storage and pressure storage.

Stream 48 'C5 Condensate Stock' at Month End.

> **Notes for Disposal of the individual cargoes of both SCO and NGL.**
>
> For Marine Tankers leaving the Terminal during the Month, the number of entries equals the number of individual cargoes loaded and detached from moorings during the Month. For Road Tanker, Rail Tanker and other pipeline disposals, the number of entries will equal the number of different destinations.

Stream 64 'Total Ethane Disposal' during the Month

Stream 65 'Total Propane Disposal' during the Month

Stream 66 'Total Butane Disposal' during the Month

Stream 67 'Total C5 Condensate Disposal' during the Month

Stream 68 'Individual Ethane Disposal'

Stream 69 'Individual Propane Disposal'

Stream 70 'Individual Butane Disposal'

Stream 71 'Individual C5 Condensate Disposal'

Stream 72 'Total Mixed Condensate Disposal' during the Month. This mixed Condensate is typically sent by pipeline from one Terminal that is not equipped to produce specification NGL products, to another Terminal that is. DTI need to take care over double counting.

Stream 73 'Individual Mixed Condensate Disposal' during the Month. The number of entries will equal the number of different destinations, if more than one.

Stream 75 'Sales Gas from UK Production' during the Month**.** Gas originating from UKCS or UK onshore production delivered to UK customers.

Stream 76 'Sales Gas from Non UK Production' during the Month. Gas originating from Non UK supply delivered to UK customers.

Stream 78 'Sales Gas to NTS' during the Month. Sales Gas irrespective of origin.

Stream 79 'Individual Sales Gas Non NTS' during the Month. Sales Gas through dedicated pipelines directly to power stations, refinery, or other users. The number of entries will equal the number of different destinations.

3.3 Dry Gas Terminals

All Dry Gas Terminals handling offshore gas have to provide a PPRS return in order that there is a clear segregation of Field and Terminal reporting. One possible exception may be made for onshore Dry Gas Fields.

Stream 19 '**Pipeline Dry Gas Entering Terminal'**. The pipeline fluids entering the Terminal but excluding the quantity of 'Condensate', a convention for Dry Gas Fields.

Stream 20 '**Dry Gas Condensate Entering Terminal'.** Condensate that is carried in the Pipeline Stream co-mingled with the Dry Gas (cf.: Figure 3, Table 3).

Stream 25 'Gas Losses'. Accounting losses across the Terminal system.

Stream 26 'Dry Gas Condensate Losses'. Accounting losses across Terminal System.

Stream 41 'Gas Flared at Terminal'. Gas flared, calculated on same basis as Flare Consent.

Stream 42 'Gas Vented at Terminal'. Any gas cold vented, including inert gases.

Stream 43 'Gas Utilised in Terminal'. . Most gas utilisation is Fuel Gas. If gas is used for other process purposes, such as stripping, check no double counting as flare etc.

Stream 49 'Dry Gas Condensate Stock' at Month End. If the Dry Gas Condensate product is delivered directly into a pipeline for disposal, without intermediate storage at the Terminal, a zero stock should be reported.

Stream 75 'Sales Gas from UK Production' during the Month**.** Gas originating from UKCS or UK onshore production delivered to UK customers.

Stream 76 'Sales Gas from Non UK Production' during the Month. Gas originating from Non UK supply delivered to UK customers.

Stream 78 'Sales Gas to NTS' during the Month. Sales Gas irrespective of origin.

Stream 79 'Individual Sales Gas Non NTS' during the Month. Sales Gas through dedicated pipelines directly to power stations, refinery, or other users. The number of entries will equal the number of different destinations.

Stream 81 'Dry Gas Condensate Disposal' during the Month. Total Dry Gas Condensate leaving the Terminal.

Stream 82 'Individual Dry Gas Condensate Disposal' during the Month. For Marine Tankers, the number of entries equals the number of individual cargoes loaded and detached from moorings. For Road, Rail Tanker and pipeline disposal, the number of entries will equal the number of different destinations.

4.0 Submission Requirements

The ANNEX gives a much more detailed description to assist the IT programmers to write their XML software files. The text below is just to give the non-IT specialist an overview of the new method of working.

4.1 Computing Background

The format of data files to be sent to the DTI is based on an Internet compliant standard called "XML", (Extensible Mark up Language), which defines a method of exchanging structured data. The structure of an XML file is defined by another file called a Document Type Definition or "DTD" for short. The XML file includes actual data reported and the DTD defines the structure of the data expected.

Each monthly PPRS return for a Reporting Unit must be sent to the DTI as a single XML text file and this must comply with a DTD shown in the Annex.

The DTDs, and a more comprehensive selection of sample XML files than in the Annex, are available at(http://www.og.dti.gov.uk/upstream/field_reporting/pprs2000/xmlfiles/index.htm) for downloading from the DTI Oil and Gas Web site and further information on XML is available on (www.w3.org/xml).

4.2 Timing of Submission to DTI

For control purposes, there are two types of PPRS Returns, a "PARTIAL" return required by the 16th day of the following Month and a "FULL" Return required by the 30th day of the following Month. The Tables 1 to 6 clearly identify those few data items that are required by the 16th of the Month as well as those by the 30th of the Month.

The PARTIAL returns report only selected data items, leaving the rest as zeros. The FULL returns report all the data due, including that sent earlier in a PARTIAL, and will overwrite the PARTIAL data submission. If there is additional data sent in a PARTIAL return, although not required, it will nonetheless be loaded by DTI and overwritten by the FULL return. For the avoidance of doubt, a Company may send a FULL return at any time before the 30th of the Month.

4.3 Error Handling

When the DTI receives an XML PPRS Return, the Oil and Gas Data Administration Team will attempt to load it onto the main DTI Oil and Gas database.

If errors are encountered, the file in error and error messages will be returned via the Internet to the originator [nominated email addressees] to correct and re-submit as a new XML file. The emphasis is on the Operator's internal Quality Control procedures to avoid files with errors due to the Validation Rules.

FIGURES

(6 Pages)

APPENDIX III

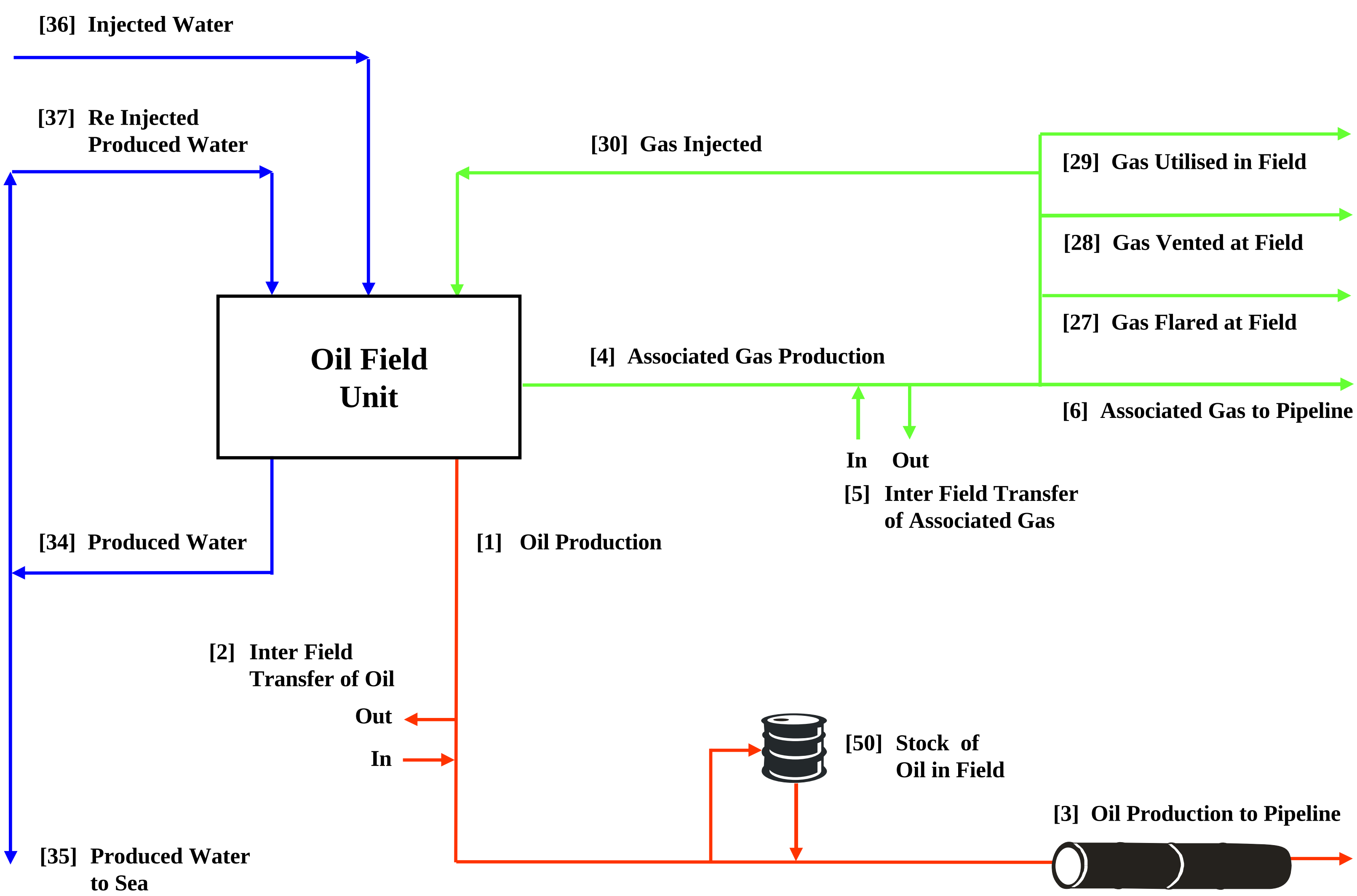

Figure 1. Oil Field Exporting to Pipeline (Data Type P)

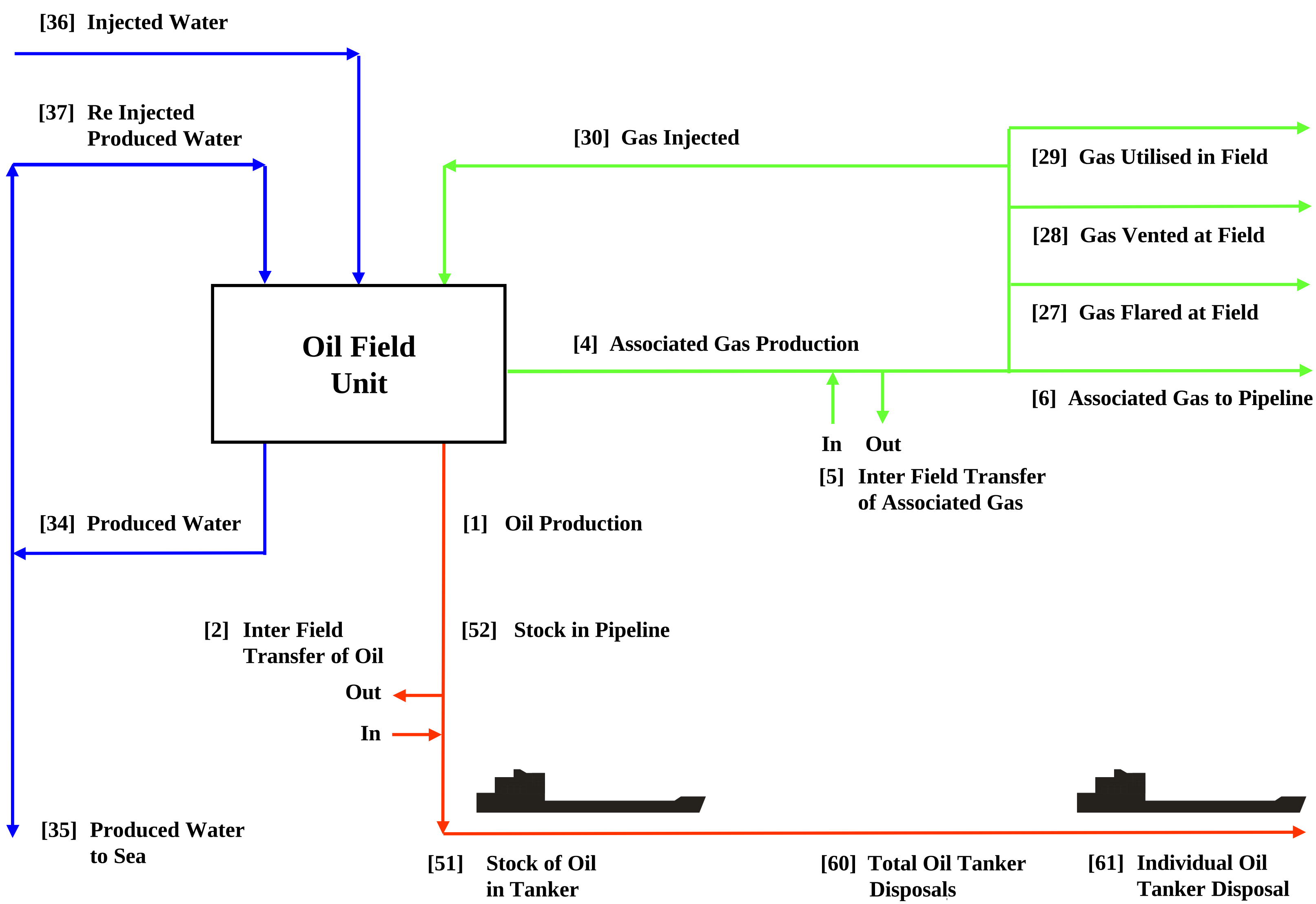

Figure 2. Onshore Oil Field or Offshore Tanker Loading (Data Type T)

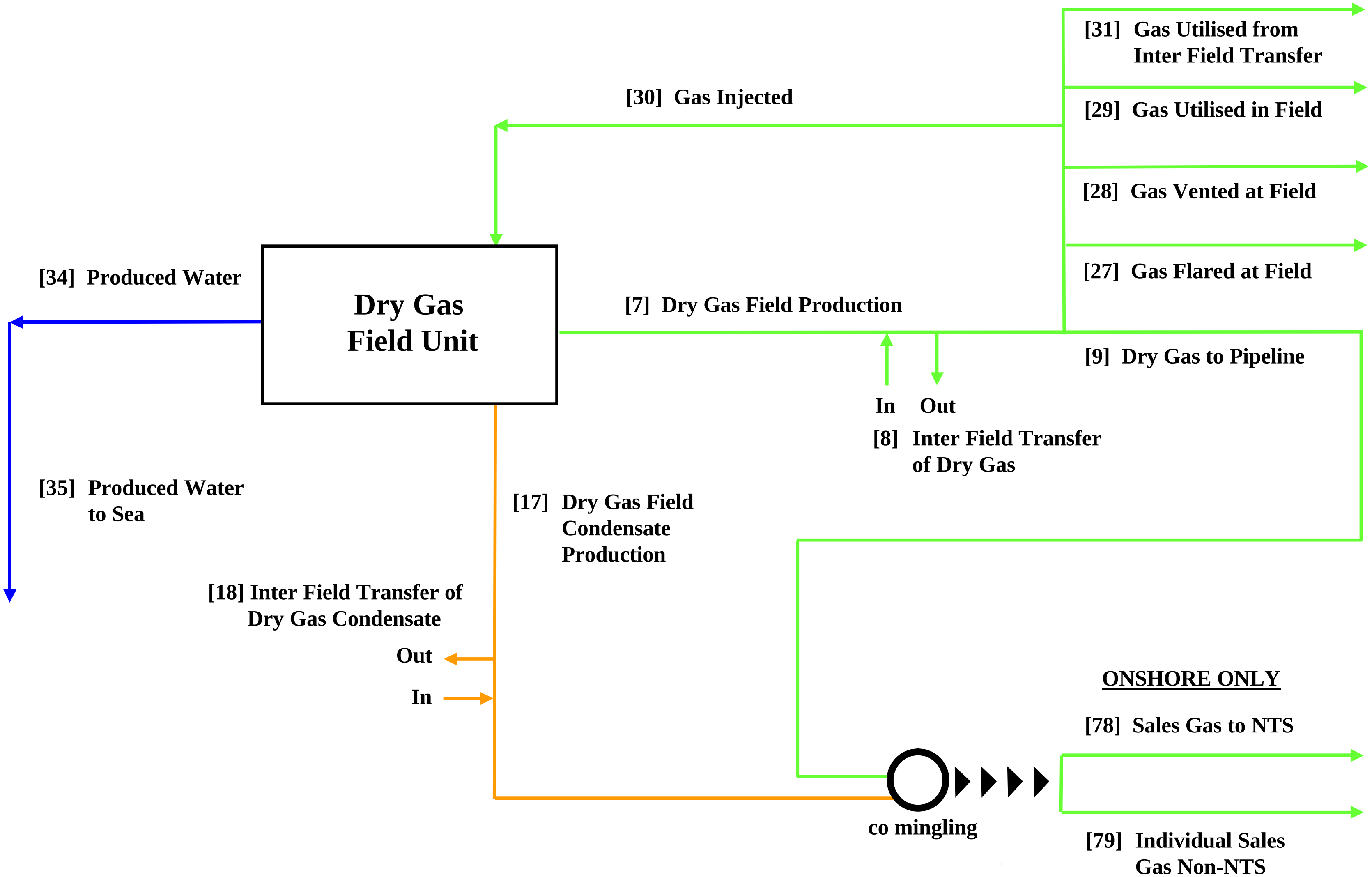

Figure 3. Offshore and Onshore Dry Gas Field (Data Type G)

PD/rh0700.ppt

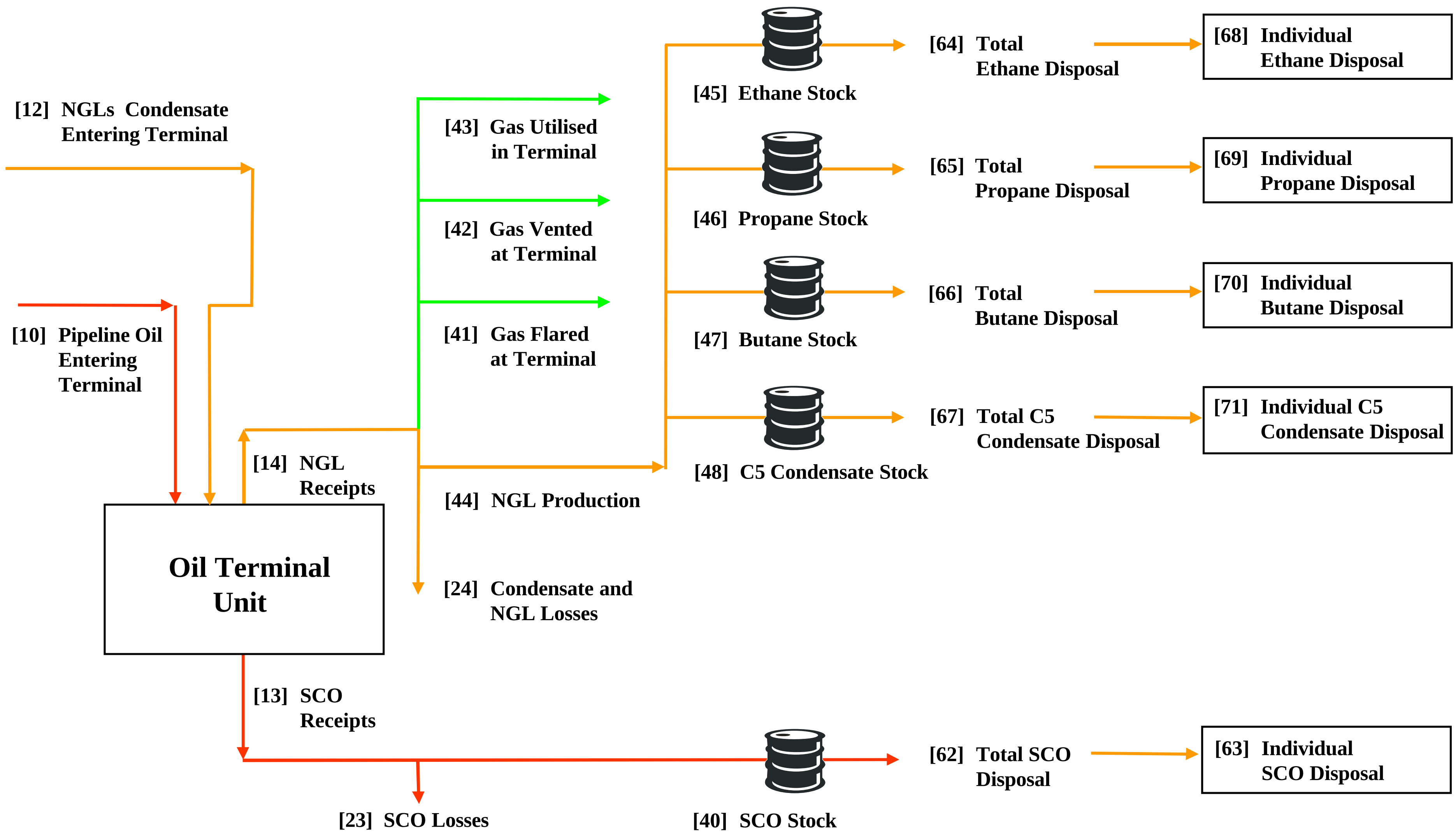

Figure 4. Oil Pipeline Terminal (DataType O)

PD/rh0700.ppt

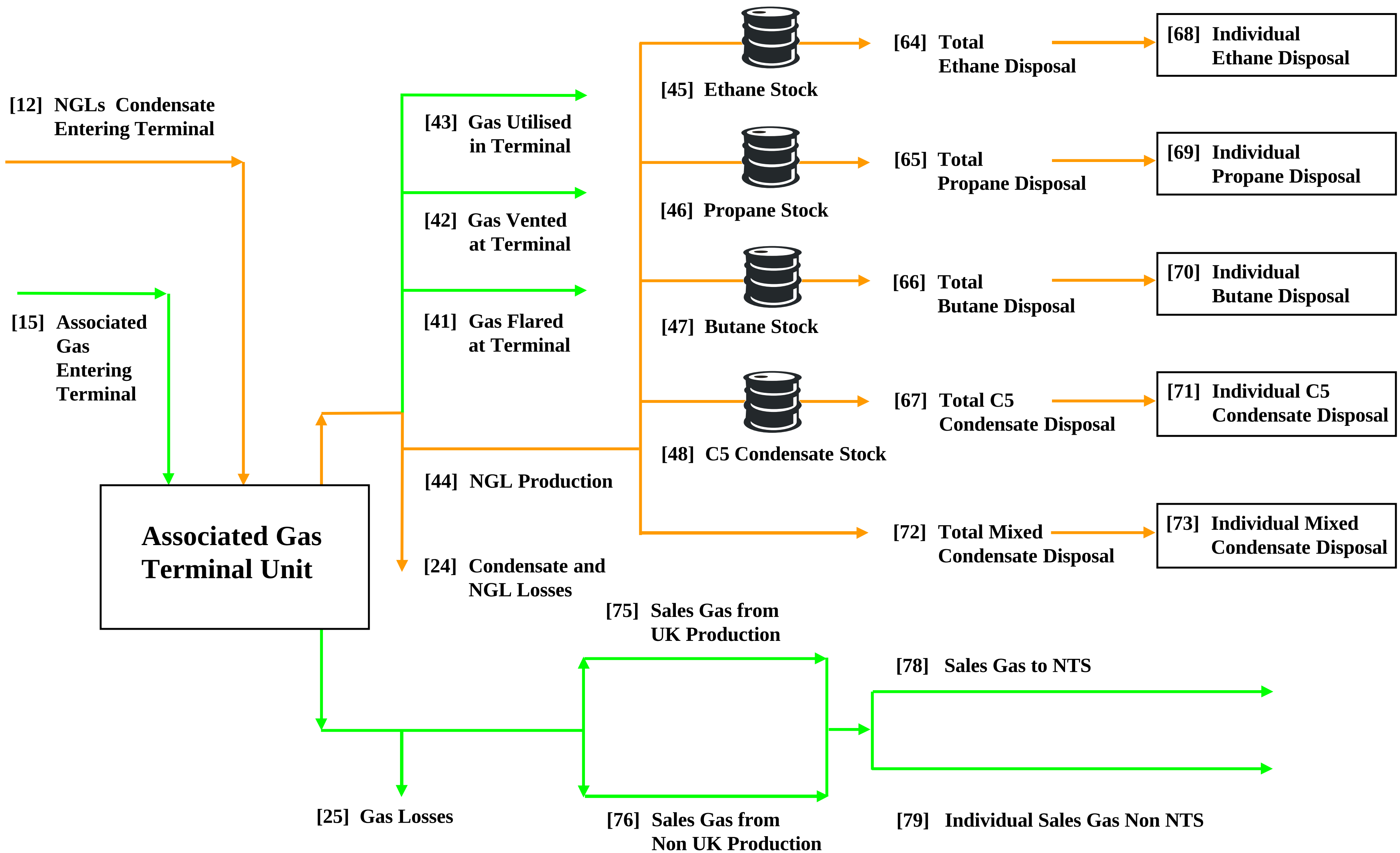

Figure 5. Associated Gas Terminal (Data Type A)

PD/rh0700.ppt

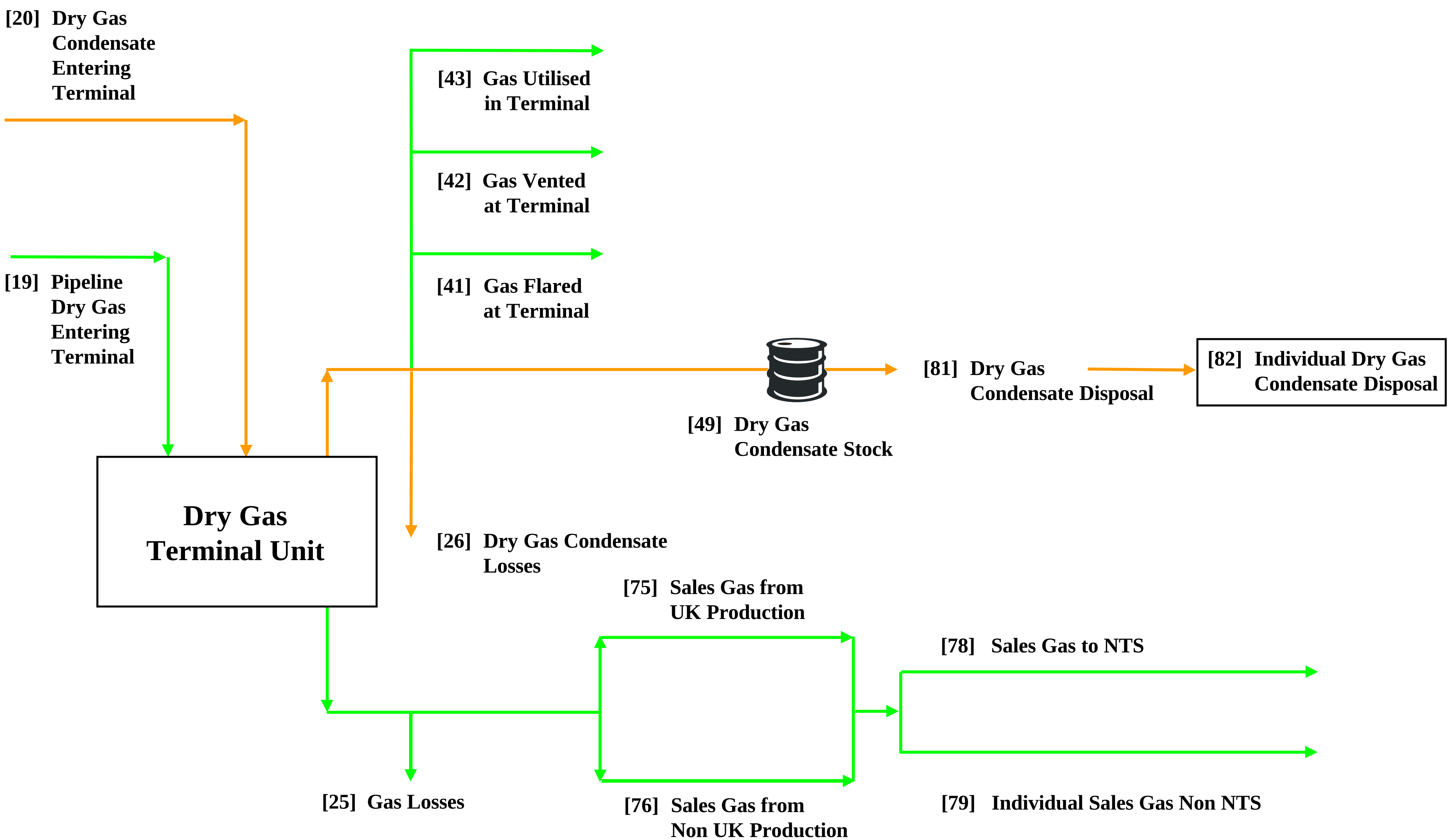

Figure 6. Dry Gas Terminal (Data Type D)

APPENDIX III

REGULATIONS RELATING TO MEASUREMENT OF PETROLEUM FOR FISCAL PURPOSES AND FOR CALCULATION OF CO_2-TAX (THE MEASUREMENT REGULATIONS)

1 November 2001

The Norwegian Petroleum Directorate (NPD)

CONTENTS

PREFACE

The purpose of these regulations is to ensure that accurate measurements form the basis of the calculation of taxes, royalties and fees etc. to the Norwegian state, including the CO_2 tax, and the income of the licensees. The regulations contain supplementary provisions to the requirements of the Petroleum Act and the CO_2 Tax Act relating to measurement of petroleum and stipulate framework requirements concerning the organisation, planning and implementation of the activity as referred to in the Petroleum Act and the CO_2 Tax Act. It defines functional and specific requirements to the design and operation of the metering equipment, elaborates on the responsibility of the individual participant to comply with requirements laid down in or pursuant to applicable law and shall contribute to ensuring that the metering equipment and method at all times comply with the requirements of these regulations relating to accumulated measuring uncertainty. The regulations stipulate requirements with regard to how the quantities of fuel and flare gas are to be reported and documented. Furthermore the regulations provide for suitable supervision of the activities.

These regulations replace the previous Regulations for fiscal measurement of oil and gas etc. and the previous Regulations relating to measurement of fuel and flare gas for calculation of CO_2 tax in the petroleum activities. Particular points relating to CO_2 tax measurement are dealt with in comments re. Section 14. If provisions contained in these regulations apply to either fuel gas or flare gas this will appear from the text.

The regulations provide for a practice whereby not all documentation needs to be submitted to the Norwegian Petroleum Directorate, but may instead be available from the operator and be submitted to the Norwegian Petroleum Directorate on request. Furthermore provision is made for transfer of information electronically.

Comments have been prepared to the individual provisions of these regulations. The comments provide explanation and guidance in relation to the provisions of the regulations. Examples are given to show how the requirements of regulations can be complied with, or reference is made to recognised standards, including industry standards, as one way in which the requirements of the authorities may be complied with. Trading in petroleum takes place across national borders with international actors. Technical standards should therefore be internationally accepted. Reference is further made to comments re. Section 4.

Guidelines to Plan for development and operation of a petroleum deposit, PDO, and Plan for installation and operation of facilities for transport and utilisation of petroleum, PIO, of 18 May 2000 contain details on the information which should be contained in a PDO/PIO with regard to fiscal measurement systems.

REGULATIONS RELATING TO MEASUREMENT OF PETROLEUM FOR FISCAL PURPOSES AND FOR CALCULATION OF CO_2 TAX (THE MEASUREMENT REGULATIONS)

Regulations relating to measurement of petroleum for fiscal purposes and for calculation of CO_2 tax, issued by the Norwegian Petroleum Directorate 1 November 2001 pursuant to Section 86 of Regulations to Act relating to petroleum activities issued by Royal Decree 27 June 1997 No. 653, cf. Act of 29 November 1996 No. 72 relating to petroleum activities, Section 4-9 and Section 5 of Act of 21 December 1990 No.72 relating to tax on discharge of CO_2 in connection with petroleum activities on the continental shelf, cf. Decision on delegation issued by the Ministry of Petroleum and Energy 28 June 1985 and 27 December 1990. Last amended 5 December 2003.

CHAPTER 1
INTRODUCTORY PROVISIONS

Section 1
Scope

These regulations are applicable to the petroleum activities in areas comprised by Section 1-4 of the Act of 29 November 1996 No. 72 relating to petroleum activities and Section 2 of the Act of 21 December 1990 No. 72 relating to tax on discharge of CO_2 in connection with petroleum activities on the continental shelf, specifically:

a) in planning, design, construction and operation of metering systems for measuring produced, transported and sold quantities of oil and gas (fiscal measurement systems)
b) in planning, design, construction and operation of metering systems and metering equipment for determination and reporting of quantities used for fuel and flare gas in petroleum activities.

Comments

Section 2
Definitions

For the purpose of these regulations, the following definitions shall apply:

Accreditation:
An official recognition to the effect that an organisation is operating in accordance with a documented quality assurance system and that it has demonstrated is competency to carry out specified tasks.

Allocation:
Apportionment of petroleum between various owner groups and owner companies.

Recognised standard:
Standards, guidelines and similar which within a technical sphere are internationally and/or nationally recognised. Acts or regulations which are not directly applicable but which regulate corresponding or neighbouring areas may equally be recognised standard.

Fuel:
Natural gas, oil, condensate or diesel used for operation of combustion machinery such as turbines and similar.

Place of operation:
Facility or terminal where the metering system is in service.

Place of manufacture:
Place where fabrication, assembly and testing of one or more of the metering system's main components takes place.

Computer part:
That part of the metering system which consists of computers and receives metering signals from A/D converters or from digital instrument loops.

Flare gas:
Natural gas burnt off or vented to the atmosphere.

Fiscal metering:
Metering carried out in connection with purchase and sale and the calculation of taxes and royalties.

Sensing element:
A device that responds to the condition which is to be measured, so that the device produces a signal proportional to this condition.

Instrument:
An assembly consisting of a transducer and one or more sensing elements. The signal from an instrument represents a physical condition.
A technical device used to measure a physical parameter.

Instrument part:
Part of the metering system from and including the instrument to the digital input of the computer part.

Calibration:
Establishment of relationship between measured value and reference value with known uncertainty.

Calibration factor, K-factor:
Relationship between the measured value coming from a meter and the measured value from a reference measurement system.

Calibration factor for flow meter:
Designated or non-designated value which indicates the relationship between the recording of the flow meter and actual flow volume. In these regulations this term is intended to cover the international terms 'meter factor' and 'K-factor'.

Calibration mode:
Selectable condition of the computer part to carry out verification whilst the associated meter tubes are closed.

Control:
Monitoring, supervision, inspection and similar of conditions, processes, products etc. to ensure that they comply with specifications.

Linearity:

1) Deviation between a calibration curve for a device and a straight line.
2) Correlation between variables where a change in one causes a precise and proportional change for the other.

Mechanical part:
All mechanical equipment included in an oil or gas metering system.

Meter tube:
Straight pipe section where a flow meter is installed.

Instrument loop:
Assembly of all equipment and computer links etc. from sensor input to the visual representation in the computer part.

Metering station:
Assembly of metering equipment dedicated to the determination of measured quantities.

Measurement uncertainty:
An expression of the result of a measured value which characterises the range within which true value is expected to lie.

Metering system:
Consists of a mechanical part, an instrument part and a computer part, as well as appurtenant documentation and procedures.

Resolution:
Indicates the least variation in signal level which produces a noticeable change in the displayed value.

Petroleum products:
Marketable products fractionated from crude oil or natural gas. Examples are: Ethane, propane, petrol, paraffin.

Prover:
Device for calibration of dynamic flow meter, based on displacement of a body through a calibrated tube.

Flow meter:
Equipment located in or clamped to a pipe with associated signal transformer providing a primary signal proportional to the amount of flow through the pipe.

Transducer:
Technical device which changes the nature of the measured signal. Used in these regulations solely in respect of ultrasonic meters.

Comments

Section 3
Responsibility according to these regulations

The licensee and other parties participating in petroleum activities comprised by these regulations are responsible according to the regulations and individual administrative decisions issued by virtue of the regulations.

In addition the licensee has a duty to see to it that anyone carrying out work for him, either personally, by employees, contractors or sub-contractors, complies with these regulations and individual administrative decisions issued by virtue of the regulations.

Comments

Section 4
Requirements to the petroleum activities in general

Activities as mentioned in Section 1 of the present regulations shall be carried out in accordance with requirements stipulated by or pursuant to these regulations, and in accordance with recognised standards for such activities.

When technology or methods not described in recognised standards are used, criteria for development, testing and operation are required to be produced.

Comments

CHAPTER II
REQUIREMENTS RELATING TO MANAGEMENT CONTROL SYSTEM ETC.

Section 5
Management control system

The licensee and others participating in the petroleum activities shall establish, follow up and assure the development of a management control system which shall include organisation, processes, procedures and resources necessary to ensure compliance with the requirements of the present regulations.

A management control system for metering shall be prepared and maintained in a systematic and controlled manner. Update and revision shall be announced within the organisation itself, to the Norwegian Petroleum Directorate and other parties concerned. The management control system shall ensure that relevant experience and information is conveyed from one shift of personnel to the next and from the construction phase to the operational phase.

Executive responsibility for, and supervision of, the management control system shall be placed with the unit responsible for the other management control systems of the enterprise.

A quality assurance manual for the operation of metering systems shall be prepared.

Comments

Section 6
Organisation and competence

The functional scope and areas of responsibility of personnel who carry out supervision of or tasks in connection with the metering system shall be documented in the organisation chart of the licensee. The duties, responsibilities and authority of the personnel shall be described.

The licensee shall nominate the person responsible for the metering system. The nominated person shall be responsible to see that procedures relating to operation, maintenance, calibration and control are followed.

All personnel carrying out tasks related to the metering systems shall possess documented qualifications within the relevant technical sphere. A system shall be established to show that updating and skills/competence advancement is ensured.

Comments

Section 7
Verification

When planning, designing, purchasing, building and operating fiscal measurement systems as mentioned in these regulations, the licensee shall be able to verify that the provisions of the regulations or individual administrative decisions have been complied with. Independent verification of critical parameters may be required.

The licensee shall see to verification of fiscal figures and calibration reports for equipment comprised by these regulations.

Comments

CHAPTER III
GENERAL REQUIREMENTS RELATING TO MEASURING AND THE MEASUREMENT SYSTEM

Section 8
Allowable measuring uncertainty

Measurement system	**Uncertainty limit at 95 percent (%) confidence level** *(expanded uncertainty with coverage factor k=2)*
Oil metering for sale and allocation purposes	± 0.30 % of standard volume
Gas metering for sale and allocation purposes	± 1.0 % of mass
Fuel gas metering	± 1.8 % of standard volume
Flare gas metering	± 5.0 % of standard volume

It shall be possible to document the total uncertainty of the measurement system. An uncertainty analysis shall be prepared for the measurement system within a 95 percent confidence level. In the present regulations a confidence interval equal to ± 2 σ, i.e. coverage factor k=2, is used. This gives a confidence level slightly higher than 95 percent.

In respect of the measurement system's individual components the following maximum limits apply:

Component	***Circuit uncertainty limits***	***Linearity limits (band)***	***Uncertainty limits component***	***Repeatability limits (band)***
Meter prover oil	NA	NA	± 0,04 % for all 4 volumes	0,02 % for all 4 volumes
Turbin meter oil	1 puls of 100000, 0,001 %	0,50 % in working range (10:1) 0,30 % in working range (5:1)	± 0,25 % in working range(10:1)	0,04 % in working range (10:1)

Component	***Circuit uncertainty limits***	***Linearity limits (band)***	***Uncertainty limits component***	***Repeatability limits (band)***
Ultrasonic flow meter oil	1 puls of 100000, 0,001 %, at puls transmission of signal	0,30 % in working range (10:1)	± 0,20 % in working range (10:1)	0,07 % in working range (10:1)
Turbine meter gas (sales – allocation)	1 puls of 100 000	1,0 % in working range (10:1)	± 0,70 % in working range (10:1)	0,28 % in working range (10:1)
Ultrasonic flow meter gas (sales – allocation)	1 puls of 100 000, 0,001 %, at puls transmission of signal	1,0 % in working range (20:1). Deviation from reference in calibration shall be less than ± 1,50 % in working range (20:1) before use of calibration factor	± 0,70 % in working range (20:1) after zero point control	0,50 % in working range (20:1) after zero point control
Pressure measuring	± 0,30 % of measured value in working range	NA	± 0,10 % of measured value in working range	NA
Pressure measuring fuel gas, flare gas	± 0,50 % of measured value in working range	NA	± 0,20 % of measured value in working range	NA
Temperature measuring oil, gas	± 0,30°C	NA	± 0,20°C	NA
Temperature measuring fuel gas, flare gas	± 0,50°C	NA	± 0,30°C	NA
Density measuring oil	± 0,50 kg/m^3	NA	± 0,30 kg/m^3	NA
Density measuring gas	± 0,25 % of measured value	NA	± 0,20 % of measured value	NA
Differential pressure measuring	± 0,30 % of measured value in working range	NA	± 0,10 % of measured value in working range	NA
Water in oil measuring		NA	± 0,05volum% absolute for 0 to 1,0 volum% water content, ± 5,0% of measured value over 1,0 volum% water content	0,50 % of measured value at water content over 0,01volum%
Online GC	NA	NA	± 0,15% of caloric value	NA
Calorific value gas	NA	NA	± 0,15% of calorific value	NA

Component	*Circuit uncertainty limits*	*Linearity limits (band)*	*Uncertainty limits component*	*Repeatability limits (band)*
Uncertainty computer part for oil and gas	NA	NA	± 0,001%	NA
Uncertainty computer part for fuel and flare gas	NA	NA	± 0,1%	NA
With regard to fuel gas: cf. comment re. Section 14.				

Comments

Section 9
Units of measurement

The measuring system shall give readings in SI units. Reporting of fiscal figures to the Norwegian Petroleum Directorate shall be in SI units.

Reporting of fuel and flare gas to the Norwegian Petroleum Directorate shall be in standard cubic meters in respect of natural gas and liters in respect of diesel or other hydrocarbons in liquid phase.

Determination of the critical parameters of the measuring system by measurements shall be in SI units.

Comments

Section 10
Reference conditions

Standard reference conditions for pressure and temperature shall in measuring oil and gas be 101.325 kPa and 15°C. In the measuring of petroleum products other reference pressure may be used.

Comments

Section 11
Determination of energy content etc.

Gas composition from continuous flow proportional gas chromatography or from automatic flow proportional sampling shall be used for determination of energy content.

With regard to sales gas metering stations two independent systems shall be installed.

When oil or gas is analysed to determine physical and/or chemical properties and the analysis results are used for sale or allocation purposes, this shall be carried out by a competent laboratory.

Comments

Section 12
Bypassing the metering system

Bypassing of the metering system is not permitted.

Comments

CHAPTER IV
REQUIREMENTS TO DESIGN OF THE METERING SYSTEM

Section 13
Requirements to the metering system in general

The metering system shall be planned and built according to the requirements of the present regulations and in accordance with recognised standards for metering systems.

The metering system shall be capable of metering the full range of planned hydrocarbon flows without any component involved operating outside its working range.

On sales metering stations the number of parallel meter runs shall be such that the maximum flow of hydrocarbons can be measured with one meter run out of service, whilst the rest of the meter runs operate within their specified operating range.

The metering system shall be suitable for the relevant type of measuring, the given fluid properties and the hydrocarbon volumes to be measured.

If necessary, flow straighteners shall be installed.

In areas where inspection and calibration takes place there shall be adequate protection against the outside climate and vibration.

The metering tube and associated equipment shall be insulated upstream and downstream for a distance sufficient to prevent temperature changes affecting the instruments that provide input signals for the fiscal calculations.

Shutoff valves shall be of the block and bleed type. All valves of significance to the integrity of the metering station shall be accessible for inspection to secure against leakage.

All parts of the metering system shall be easily accessible for maintenance, inspection and calibration.

Comments

Section 14
The mechanical part of the metering system

The mechanical part of the metering system shall be designed so that representative measurements are achieved as input signals for the fiscal calculations (cf. Section 8).

Provision shall be made for necessary redundancy and the possibility of verification of the gas and liquid metering devices.

When turbine meters are used for liquid metering, a permanent prover shall be available for calibration of the metering devices.

It shall be possible to calibrate the prover at the place of operation.

If other types of flow meters are used for liquid metering, permanent equipment for calibration of the metering device shall be available.
It shall be documented that surrounding equipment will not affect the measured signals.

Comments

Section 15
The instrument part of the metering system

Pressure, temperature density and composition analysis shall be measured in such way that representative measurements are achieved as input signals for the fiscal calculations (cf. Section 8).

Comments

Section 16
The computer part of the metering system

The computer part of the metering system shall be designed in such way that the fiscal calculations may be carried out within the stipulated uncertainty range (cf. Section 8).

The computer part of the metering system shall be equipped with various security functions to ensure that the fiscal values cannot be changed as a result of incidents of a technical nature or as a result of a manual fault.

With regard to reports the computer part shall be capable of documenting the various fiscal parameters and the fiscal volumes calculated.

The computer part shall have uninterruptible power supply. It shall be ensured that faults are detected as an alarm and that a back-up system is activated. A power failure shall not be able to cause measured fiscal data to be deleted from the storing unit of the computer.

Comments

Section 17
Requirements relating to sampling

Sampling shall be carried out in a manner which ensures that representative amounts are sampled.

Sampling shall be automatic and flow proportional. In addition it shall be possible to carry out manual sampling.

With regard to oil and condensate the necessary mixing equipment shall be installed upstream of the sampling probe.

Comments

CHAPTER V
REQUIREMENTS RELATING TO CALIBRATION AND VERIFICATION ETC. PRIOR TO STARTUP OF THE METERING SYSTEM

Section 18
Application for consent

The licensee shall obtain consent from the Norwegian Petroleum Directorate prior to startup of the metering system.

Consent for carrying out major rebuilding or change in the purpose for use for the metering system shall also be obtained.

If the basis for consents granted in accordance with the first paragraph of this section is significantly changed, the Norwegian Petroleum Directorate may require the licensee to obtain a new consent before the activities are continued.

Prior to startup of the metering system, procedures shall be prepared for operation, maintenance, calibration and verification. The procedures shall ensure that the metering system is maintained to the standard to which it is designed.

Procedures for calibrations and verifications to be carried out in order to prepare the metering station for startup, shall be forwarded to the Norwegian Petroleum Directorate enclosed with the application.

Comments

Section 19
General

Calibrations and verifications as described in this Chapter shall be carried out prior to startup of the metering system at the place of operation.

The Norwegian Petroleum Directorate shall have the opportunity of being present when the activities are carried out.

Comments

Section 20
Calibration of mechanical part

The prover volume shall be calibrated:
a) before the metering system is delivered from the place of manufacture
b) prior to startup at the place of operation.

The mechanical parts critical to measurement uncertainty shall be measured or subjected to flow calibration in order to document calibration curve.

The assembled fluid metering system shall be flow tested at the place of manufacture and flow meter calibration shall be carried out.

Statistical methods to provide documentation for repeatability requirements may be used.

Comments

Section 21
Calibration of instrument part

The instrument loops shall be calibrated and the calibration results shall be accessible.

The instrument loops shall be calibrated at a number of values necessary to detect any non linearity errors within its working range. Calibration of the instrument loops shall be carried out using the display reading of the visual signal from the computer part.

Comments

Section 22

Verification of computer part

Verification of the computer part shall be carried out for each metering tube to confirm that all functions are operational.

Each independent program routine shall be verified to show that calculations are carried out with requirements equal to or better than those mentioned in Section 8 of the present regulations. Integration shall be verified with at least three values in the flow range.

The calculations for calibrations as mentioned in Section 20 of these regulations shall be verified. This includes K-factor in respect of the individual calibration and the average value within the predetermined range of variation.

Comments

CHAPTER VI
REQUIREMENTS RELATING TO OPERATION OF THE METERING SYSTEM

Section 23
Maintenance

The metering system shall be maintained to the standard according to which it is designed.

The equipment which is an integral part of the metering system, and which is of significant importance to the measuring uncertainty, shall be calibrated using traceable equipment before start of operation, and subsequently be maintained to that standard.

Control to ensure that equipment mentioned in the first paragraph of this section is within given limit values shall be carried out regularly by qualified personnel. If during calibration equipment is shown to be outside the given limit values, correction shall be carried out by qualified personnel or by calibration and associated correction in a competent laboratory. Traceable calibration of test instruments shall be carried out regularly by competent laboratories.

Comments

Section 24
Operating requirements for the prover

The meter prover volume shall be calibrated annually
Calibration shall also be carried out if the volume may have changed as a result of equipment failure.

Comments

Section 25
Operating requirements for flow meters

Turbine meters for oil shall be calibrated against the permanent meter prover with a repeatability such that 5 consecutive single calibrations in sequence fall within a range of 0.05 % of the average calibration factor.

The calibration factor for the flow meters shall be within the control limits according to recognised standard. Flow meters installed after workover, modification or replacement shall immediately be calibrated to verify that they meet the requirements to linearity and repeatability.

After startup of the metering system, calibration of flow meters shall be carried out in order to verify requirements to repeatability and linearity. It shall furthermore be verified to what extent the calibration factor is affected by flow volume, temperature, pressure and crude composition when these vary within their normal operating range.

The calibration of flow meters shall satisfy the following requirements:

a) If there is a correlation between calibration factor and flow rate, temperature, pressure, density, viscosity or composition, calibration factor limits shall be established.
A new calibration shall be carried out if the limits are exceeded.

b) The time interval between calibration of the flow meters shall not exceed four days. Calibration factor for flow meters in use shall be established for each tanker loading.

Statistical methods may be used to document requirements to repeatability.

The orifice plates shall be inspected with regard to edge sharpness, surface roughness and flatness. An inspection shall be carried out at startup and then once a month during the first six months. Subsequently the intervals may be extended, however if at a later time damage or wear-and-tear is detected, the interval between inspections of the orifice plates shall be reduced. The orifice plate shall also be inspected after incidents which may have affected the fiscal measuring quality. The orifice plates shall be certified prior to installation in meter tubes and subsequently if visible damage is detected.

In the case of ultrasonic flow measurement of gas the condition parameters shall be verified.

During orifice plate gas measuring or ultrasonic gas measuring the meter tubes shall be checked if there is indication of change in internal surface.

Comments

Section 26
Operating requirements for instrument part

All sensors shall be monitored continually and/or shall be regularly calibrated in accordance with the requirements of Section 8. Calibration shall comprise several values in the sensor's operating range. If the outlet signals from the sensors deviate from the preset limits, necessary maintenance and subsequent new calibration shall be undertaken.

The calibration methods shall be such that systematic measurement errors are avoided or are compensated for.

Gas densitometers shall be verified against calculated density or other relevant method.

When continuous gas chromatography is used, corrective maintenance and new calibration shall be undertaken.

Comments

Section 27
Operating requirements for computer part

Critical data shall be filed regularly. Procedures shall be established for handling of fault messages from the computer part or faults otherwise discovered.

Transmission of signals from sensors to the computer part shall be checked in connection with calibration of the sensors.

In the case of software changes and replacement of computer parts an independent verification shall be carried out of the calculation requirements of the computer part, cf. Section 22 of the present regulations.

Comments

CHAPTER VII
REQUIREMENTS RELATING TO DOCUMENTATION

Section 28
Documentation prior to start-up of the metering system

After the Plan for development and operation of petroleum deposits (PDO) and Plan for installation and operation of facilities for transport and utilisation of petroleum (PIO) have been approved and prior to start-up of the metering system, the operator shall have the following documents available,

a) technical description of the metering system;
b) an overview showing the location of the metering system in the process and transportation system;
c) drawings and description of equipment included in the metering system;
d) list of documentation for the metering system;
e) progress plan for the project up to the time of application for consent to use;
f) description of the operator's and the supplier's management control system for follow-up of the metering system;
g) uncertainty analysis.

The Norwegian Petroleum Directorate shall on request receive documentation as mentioned in the first paragraph of this Section.

Comments

Section 29
Documentation relating to the metering system in operation

An archive shall be established and maintained which shall contain documentation in respect of the metering system. It shall be possible to document that the quality of measurements are as described in the present regulations and that there is accordance between reported and measured quantities.

Fixed parameters shall be easy to verify.

Correction shall be made for documented measurement errors. Correction shall be carried out if the deviation is larger than 0.02 % of the total volume. If measurement errors have a lower percentage value, correction shall nevertheless be carried out when the total value of the error is considered to be significant.

If there is doubt as to the time at which a measurement error arose, correction shall apply for half of the maximum possible time span since it could have occurred.

Reporting of CO_2 tax meterings for payment of the CO_2 tax shall take place every six months as stated in Section 4 of the CO_2 Tax Act and in accordance with the form issued by the Norwegian Petroleum Directorate.

In the event that measured figures are not available for technical reasons, it must be possible to document the reported figures in a manner which is acceptable from a calculation point of view.

Quantities of diesel delivered to the facility during the tax period in question shall be reported as taxable basis for calculation of CO_2 tax. Deduction in respect of diesel which has not been used as fuel shall be documented and reported to the Norwegian Petroleum Directorate as mentioned in the fourth paragraph of this Section.

All measured data comprised by these regulations shall be reported in the PetroBank system.

Comments

Section 30
Information

When the PDO has been approved, the licensee shall inform the Norwegian Petroleum Directorate about all significant changes that affect the quality of fiscal measurements or figures reported from them

The Norwegian Petroleum Directorate shall be informed about
a) annual plan for activities within the technical field in question;
b) measurement errors;
c) when fiscal measurement data have beencorrected based upon calculations;
d) change in calibration interval;
e) change in calculation software;
f) changes affecting the basis of the consent;
g) cargo claims procedures applicable for sale of hydrocarbons in liquid phase.

Comments

Section 31
Calibration documents

Description of procedure during calibration and inspection, as well as an overview of results where measurement deviation before and after calibration is shown, shall be documented. The documentation shall be available for verification at the place of operation.

Comments

CHAPTER VIII
GENERAL PROVISIONS

Section 32
Supervisory authorities - authority to make individual administrative decisions etc

The Norwegian Petroleum Directorate shall supervise compliance with provisions laid down in or decisions made pursuant to the present regulations. The Norwegian Petroleum Directorate may make such individual administrative decisions as are necessary to implement provisions contained in the present regulations.

Comments

Section 33
Exemption

The Norwegian Petroleum Directorate may in particular cases grant exemption from provisions contained in the present regulations.

Comments

Section 34

Penal provision

Violation of these regulations or of decisions made pursuant to these regulations shall be punishable as stated in the Petroleum Act Section 10-17 and the CO_2 Tax Act Section 7, cf. the Criminal Code Chapter 3a.

Comments

Section 35

Entry into force and transitional provisions.

1. These regulations enter into force 1 January 2002.

2 As from the same date, the following amendments shall be made:

a) Regulation for fiscal measurement of oil and gas etc. issued by the Norwegian Petroleum Directorate 3 July 1991, No. 532, shall be repealed.
b) Regulations relating to measurement of fuel and flare gas for calculation of CO_2 tax in the petroleum activities, issued by the Norwegian Petroleum Directorate 12 August 1993, No. 806, shall be repealed.

3 Decisions made pursuant to the regulations mentioned in this section item 2 shall remain in force until such time as they may be repealed or altered by the Norwegian Petroleum Directorate.

4 a) The general requirements of these regulations and requirements relating to testing and operation of measuring equipment (Chapters I, II, III, V, VI, VII and VIII) are applicable to all metering systems.
b) Requirements to design (Chapter IV) apply only to metering systems where the design was commenced after 1 January 2002. The Norwegian Petroleum Directorate may by individual administrative decisions directed at the individual operator make requirements to design fully or partly applicable to measuring equipment or metering systems designed prior to the time mentioned in the preceding sentence, cf. Section 32 of the present regulations.

Comments

LIST OF REFERENCES

- AGA, American Gas Association
  - AGA Report No 8, Natural Gas density and compressibility factor executable program and Fortran Code
  - AGA Report No 9, Measurement of gas by multipath ultrasonic meters
- ASTM 1945, Standard test method for analysis of natural gas by gas chromatography (1991)
- API, MPMS, American Petroleum Institute, Manual of Petroleum Measurement Standards
- Håndbok for usikkerhetsberegning CMR/NFOGM/OD (1999)
- ISO/OIML The guide to the expression of uncertainty in measurement (1995)
- OIML R 117 Measuring systems for liquids other than water, Annex A (1995)
- ISO 3171 Petroleum liquids - Automatic pipeline sampling (1988)
- ISO 5024 Petroleum liquids and liquefied petroleum gases. Measurement Standard reference conditions (1976)
- ISO 5167-1 Measurement of fluid flow by means of orifice plates, nozzles and venturi tubes inserted in circular cross section conduits running full (1998)
- ISO 6551 Petroleum Liquids and Gases - Fidelity and Security of Dynamic (1982)
- ISO 6976. Natural gas – Calculations of calorific values, density, relative density and Wobbe index from composition (1995)
- ISO 7278 Liquid hydrocarbons - Dynamic measurement - Proving system for volumetric meters.
- ISO 9002 Quality systems, Model for quality assurance in production, installation and servicing (1994)
- ISO 9951 Measurement of gas flow in closed conduits - Turbine meters (1993)
- ISO 1000 (1981), SI units and recommendations for the use of their multiples and certain other units
- ISO/IEC 17025 General requirements for the competence of testing and calibration laboratories
- ISO/CD 10715 Natural Gas - Sampling Guidelines
- NORSOK I-104, Fiscal measurement system for hydrocarbon gas (Rev 2, 2. June 1998)
- NORSOK I-105, Fiscal measurement system for hydrocarbon liquid (Rev 2, 2. June 1998)
- NORSOK P-100, Prosess system
- NS 4900 (1979)
- NS 1024 (1982)
- Standards relating to measurement of petroleum for fiscal purposes and for calculation of CO2-tax

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APPENDIX 1: FORM 1, CO_2-TAX, HALF-YEARLY PAYMENT
APPENDIX 2: FORM 2, CO_2-TAX, TAX ASSESSMENT PER PRODUCT

FORM 1 - CO_2 TAX
HALF-YEARLY PAYMENT

Half-year period:

Company:

Field/installation	Tax amount Gas	Tax amount Oil/cond.	Tax amount Sum
Total this period			
Total corrections			
Total interest			
	Half-yearly payment		

Date/sign:

For NPD internal use

Account	Debit	Credit
Total		

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FORM 2 - CO_2 TAX
TAX ASSESSMENT PER PRODUCT

Half-year period:

Field/install:

Norwegian share:

Product:

Month	Fuel ($Sm^3/1$)	Flare ($Sm^3/1$)	Vent ($Sm^3/1$)	Total ($Sm^3/1$)	Tax rate	Tax amount (NOK)
1						
2						
3						
4						
5						
6						
Sum						
				Prior payment(s)		
				Difference		
				Interest		
				Total		

Date/sign:

____

Revised FORM 2 to be completed when correcting prior accounts.
Specification of accrued interest to be enclosed.

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