Department of Petroleum Resources

(DPR)

PROCEDURE GUIDE

FOR THE DETERMINATION OF THE QUANTITY AND QUALITY OF PETROLEUM AND PETROLEUM PRODUCTS IN NIGERIA

TABLE OF CONTENTS

Department of Petroleum Resources

PART 1

PART 1 SECTION 1

PURPOSE, APPLICATION AND GENERAL PROVISIONS

1.0 Purpose

This guide is issued pursuant to the provisions of section 7 (1) (a) of the Petroleum Act of 1969 and Regulation 52 of the Petroleum (Drilling and Production) Regulation of 1969. It describes the method to be used and the standards to be complied with in carrying out the quantity and quality measurements of petroleum and petroleum products at designated facilities; the approved devices and equipment, approved calibration methods, frequency and all other pertinent matters.

1.1 Application

1.1.1 This procedure guide applies to measurement of quantities and qualities of petroleum and petroleum products, at all approved facilities, which include

but not limited to the following:

- All Export Terminals (Onshore and Offshore).
- Special Purpose Vessel storage (SPVs).
- Third party Injection and Supply points.
- Loading and Discharging Jetties.
- Refinery Tank farms / Products Depots.
- Production Facilities and Flow-stations.

1.2 General Provisions

1.2.1 The primary measurement method for determining the fiscal quantities of petroleum and petroleum products at all offshore/onshore facilities and tank farms shall be by dynamic measurement method. Such facilities shall be equipped with functional meters to be installed and maintained in accordance with the relevant section of this guide as issued by the Department of Petroleum Resources. However, manual tank gauging, which in this procedure guide is called static measurement, shall be the secondary method of measurement.

1.2.2 In all other production and custody transfer points (which include third party injection points), the primary measurement device shall be with the use of meters with tank gauging as back up wherever possible and as specified by the Department of Petroleum Resources. All such points shall therefore be equipped with properly certified meters which may include: Positive Displacement meters, Turbine meters, Ultrasonic flow meters, Coriolis meters, Differential Pressure meters and others, as approved by the Director of Petroleum Resources and shall be selected, installed, operated and maintained in accordance with the provisions of the procedure guide on dynamic measurement method as well as the manufacturer's specification.

1.2.3 All custody transfer points from which export of petroleum and petroleum products take place shall have installed, an export line valve with a lock system on the main loading line to be located Downstream the pumps. The valve shall be the main gate of all petroleum and petroleum products leaving the facility.

1.2.4 The design and installation of the lock valve shall be approved and supervised by the Department of Petroleum Resources. After the installation of the lock valve has been found satisfactory by the Director of Petroleum Resources, all the keys to the lock shall be kept in the custody of the Department of Petroleum Resources Official – In – Charge of operations at the facility.

1.3 CLASSES OF MEASUREMENTS.

1.3.1 CLASS A MEASUREMENT

The metering stations used for the delivery of petroleum to offshore customers and where sales contracts are applicable. The DPR officer(s) shall monitor and supervise the systems operations as applicable in the terminals for tax or royalty. The required overall measurement uncertainty shall be less than 1% on a volume basis for gas or as specified in the contract and approved by DPR.

1.3.2 CLASS B MEASUREMENT

The metering stations for the delivery of petroleum in commonly used pipeline systems and where allocation procedures or joint operating contracts apply. This includes production metering for MER allocation. The DPR shall be furnished on a weekly basis the daily measurement record of the meter for accountability. The DPR officer(s) physical involvement in the system operations shall be intermittent, at least fortnightly. The required overall measurement uncertainty shall be less than 1.8% on a volume basis for gas or as specified in the contract.

1.3.3 CLASS C MEASUREMENT

The metering stations for the delivery of fuel gas within the operator's operating facility or to third party facility. The uncertainty limit shall be ± 2 % of standard volume. The DPR involvement is as in CLASS B.

1.4.4 CLASS D MEASUREMENT

The Metering station for flare and injection gas measurement. The uncertainty limit shall be ±5% of standard volume. If the flare gas releases are due to the operational upset, blowdown, purging, or ESD operation the meter readings so recorded shall be forwarded within 24hours to the DPR nearest office with a detailed report on the scenarios of the releases. This report shall form the basis of zero charges on the flare gas releases while charges shall be sustained if the flare releases are operational philosophy. The DPR officer(s) involvement in the metering operations shall comply with CLASS B measurement systems. The uncertainty is given in standard volume, but other units may be requested (project specific) e.g. mass energy, etc.

Note: Any other uncertainty limit may be applicable for fiscal measurement systems if validated by a cost-benefit analysis performed and accepted by the DPR.

1.5 UNCERTAINTY ANALYSIS

An uncertainty analysis shall be developed for gas metering systems within 95% confidence level in accordance with recognized standards. The total gas metering system uncertainty shall, for the operating flow range, be below +/- 1.0% (mass metering). If a deviation on any of the equipment tolerances exists, it should be demonstrated that the metering system is within the limits for total uncertainty given in this section.

PART I SECTION 2

GUIDE FOR STATIC MEASUREMENT (TANK GAUGING) OF PETROLEUM AND PETROLEUM PRODUCTS

2.0 Definition

This procedure applies to the gauging of stabilized petroleum and petroleum products in a storage tank and determination of the volume of its contents from the approved calibration table of the tank.

2.1 Applicable Standards

2.1.1 API MPMS Chapter 3 – Tank Gauging

2.1.2 API MPMS Chapter 7 – Temperature Determination

2.1.3 API MPMS Chapter 8.1/ASTM D 4057 – Manual Sampling of Petroleum and Petroleum Products

2.1.4 API MPMS Chapter 8.2/ASTM D 4177 – Automatic Sampling of Petroleum and Petroleum Products

2.1.5 API MPMS Chapter 9/ASTM D 1298 – Density Determination

2.1.6 API MPMS Chapter 10/ASTM D 4006 – Sediment and Water

2.1.7 API MPMS Chapter 14.3 – Orifice metering of natural gas and other related hydrocarbon fluids

2.1.8 AGA Report No 3 part 2

2.1.9 ISO 5167-2:2003- Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full- part 2: Orifice plates.

2.1.10 AGA Report no 11, API MPMS 14.9 – Measurement of Natural gas by Coriolis meter.

2.1.11 AGA Report 9- Measurement of Natural Gas by Multipath ultrasonic meters.

2.1.12 ISO 10976:2015- Refrigerated light hydrocarbon fluids-measurement of cargoes onboard LNG carriers.

2.2 Essential Equipment and Facilities for Static Measurement

2.2.1 Steel gauging tapes equipped with innage gauging bobs as specified in API MPMS Chapter 3 and the ullage method shall be applicable where necessary.

2.2.2 Approved and valid calibration table for each tank.

2.2.3 Manual sampling cans as specified in ASTM D 4057 (API MPMS Chapter 8 – section 1)

2.2.4 Automatic sampling device designed and installed in accordance with ASTM D 4177 (API MPMS Chapter 8 – section 2).

2.2.5 ASTM type thermometers of suitable range with accuracy of ±0.25˚F and graduation of 0.5˚F (API MPMS Chapter 3).

2.2.6 Tanks shall be equipped with a gauge hatch from the roof to the datum plate.

2.2.7 Gauge hatch reference point on the tank roof to be provided with a covered shelter for adverse weather protection.

2.2.8 Gauge hatch with a well illuminated shelter.

2.2.9 Side gauge to show depth of liquid in tank, or any suitable arrangement for both local and remote reading of tank liquid levels.

2. 3 Procedure for Tank Gauging

2.3.1 Preparation of Tank for Gauging

2.3.1.1 Prior to gauging, the tank should have been allowed to settle for the minimum period specified for that grade of petroleum or petroleum product which in any case shall not be less than 6 hours after filling. Lesser duration can be allowed before draining if it is demonstrated that the tank has settled sufficiently before the officially specified settlement time. Thereafter, the tank is drained until the segregated free water has been completely bled out and a composite sample of the content of the tank taken, to spot check on its BS&W in accordance with the prescribed method for petroleum and petroleum products quality determination. If the BS&W value obtained falls within the limit allowed for that production or custody transfer point, then further gauging exercise is embarked upon preparatory to commencement of loading. Otherwise, the tank is allowed further settling time until this is achieved, subject to a maximum time extension of 3 hours. However, if the desired BS&W value is not achieved after the extended settling period, the DPR Officer – In – Charge should be notified for further directives. The maximum BS&W shall be 0.5% for export.

2.3.2 Tank Gauging

2.3.2.1 This is the measurement of the level of petroleum or petroleum product in a tank. This shall be by Manual Gauging or by Automatic Tank Gauging (ATG).

2.3.3 Manual Gauging Using Steel Tape

2.3.3.1 General Specification for Manual Gauging Using Steel Tape

2.3.3.1.1 Shall be made of high-quality steel (preferably mild or stainless steel) and shall be of a continuous length to cover the total height of the tank.

2.3.3.1.2 Width should be at least 0.5" or 1.27cm.

2.3.3.1.3 Thickness should be about 0.012" (0.03048cm).

2.3.3.1.4 Scale to be graduated in steps of 0.0625" (0.15875cm) and be accurate to 0.125" (0.3175cm) per 100ft (30meters) at 60°F. Tip of the bob when attached should correspond to the zero point of the scale.

2.3.3.1.5 Housing of the tape should be a durable reel and crank mounted in a frame or case.

2.3.3.1.6 Tape should be fitted with a spring snap catch or other safe locking device to which the bob can be securely attached.

2.3.3.1.7 The bob should be made of a corrosion-resistant material, 6 inches (15.24cm) long, 1 inch (2.54cm) diameter and of about 20 oz (0.567 kg) minimum in weight but sufficient to hold the gauging tape taut at full length in accordance with API MPMS Chapter 3.

2.3.3.1.8 Bob's end shall be tapered to a point and not flat.

2.3.4 General Specification for Manual Gauging Using Ullage, Temperature and Interface (UTI)

2.3.4.1 Shall have a valid calibration/recertification certificate which shall be renewed annually.

2.3.4.2 Shall be used according to the equipment manufactures' specification or as specified in API MPMS 3.1A and 17.

2.3.5 Precautions to be Taken Prior to Commencement of Manual Gauging

2.3.5.1 The petroleum or petroleum product's surface in the tank shall be free of foam or waves due to agitation.

2.3.5.2 The tape shall be rubbed with paste to give a good contrast (cut) between the portions wetted by petroleum or petroleum product from the remaining dry portion of the tape on withdrawal.

2.3.5.3 The gauge hatch shall be free of any debris from the roof to the datum plate.

2.3.5.4 To avoid static electricity hazards, it shall be ensured that the bob has contact with the gauge hatch before the bob touches the liquid level. The gauge shall be properly earthed before gauging. Also, gauging of a tank during a rain storm shall not be allowed.

2.3.6 Manual Gauging Sequence

2.3.6.1 The approved gauging procedure shall be by the innage method for floating and fixed roof storage tanks, and ullage method for special purpose vessels. The sequence to follow in carrying out the exercise shall be as outlined below:

2.3.6.2 Innage Method

2.3.6.2.1 The steel tape shall be gradually lowered through the dip hatch situated on the roof of the tank.

2.3.6.2.2 The first dip is usually done for confirming reference height of storage tanks. If the reference height as checked does not agree with that stamped on the tank, then, other things shall be checked e.g. datum plate for debris/sediments, or if gauge hatch has an obstruction along the length.

2.3.6.1.3 The tape is then reeled back on the pulley and the last mark where the petroleum or petroleum product wets the tape is read and taken as the tank dip. It is very essential that care be taken to avoid either the sagging of the tape or its deviation from the vertical plane as this could introduce appreciable errors into the gauge reading. The exercise is repeated until two consecutive identical gauges are obtained. Acceptable readings are illustrated as follows:

Sequence		Gauges Obtained	Remarks
	1st Reading	6m 400mm	
1st Gauging	2nd Reading	6m 399mm	Not Acceptable
	3rd Reading	6m 400mm	
	1st Reading	6m 399mm	
2nd Gauging	2nd Reading	6m 400mm	Acceptable
	3rd Reading	6m 400mm	
	1st Reading	6m 400mm	
3rd Gauging	2nd Reading	6m 400mm	Acceptable
	3rd Reading	6m 399mm	

From the above example, the readings obtained during the 2nd and 3rd gauging are acceptable while 6m 400mm is the tank dip.

2.3.6.1.4 The dip readings are noted in the gauge tickets. This procedure is followed to determine the accurate level of petroleum or petroleum product in a tank before and after cargo off-take from the tank while the procedure outlined under computation and documentation is followed to determine actual quantities.

2.3.6.2 Ullage method

For the ullage method, the gauge reading shall be defined as the measure of the linear distance along a vertical path from the surface of the liquid being gauged to the tank referenced gauge height. When the ullage method is used, the tank reference gauge height for both opening and closing conditions shall be periodically verified to ensure it has not changed.

2.4 Manual Sampling of Tank Contents

2.4.1 Purpose

The purpose of sampling is to obtain a true representative composite sample of the contents of a tank to be used in determining the quality of the petroleum and petroleum product in the storage. The device used for manual tank sampling is called a thief can.

2.4.2 Specification of Manual Sampling Apparatus

2.4.2.1 Sample "thief-can" shall be made of a corrosion- resistant material.

2.4.2.2 The can should have a minimum length of 12" (304.8mm) with inside and outside diameter of 1.75" (44.45mm) minimum and 3.5" (88.9mm) maximum.

2.4.2.4 The can shall neither be of the bomb or core thief-trap type with outside graduations of at least 0.125" (3.175mm)

2.4.2.4 It shall be equipped with a wind shield to be used when taking the temperature of the sample.

2.4.2.5 It shall have attached, a marked cord for samplings at predetermined depths of the tank and a secured hook for hanging the can.

2.4.2.6 It shall be equipped with a mechanical shutter to permit filling and retention of sample at any desired level of the tank.

2.4.3 Guideline for Manual Tank Sampling

2.4.3.1 The number of samples to be withdrawn from petroleum or petroleum products in tank storage shall depend on the depth of the petroleum or petroleum product in storage and shall be in accordance with the ASTM D4057. The general guiding principle for sampling vertical cylindrical tanks is as follows:

2.4.3.2 Only one sample is withdrawn from a tank of petroleum or petroleum product's level of 10ft (3.048m) and below. The single sample is taken from the middle of the oil column.

2.4.3.3 For tank with petroleum and petroleum products content of between 10ft - 15ft (3.048m-4.572m) in depth, two samples are withdrawn as upper and lower samples from which a composite is made.

Upper Sample: this is taken from the middle of the upper third of the level of petroleum or petroleum products that is 1/6th point from the top of the oil level.

Lower Sample: This is taken from the level of the fixed tank outlet or the middle of the lower top portion of the tank for tanks with sump outlets.

2.4.3.4 For tank with petroleum and petroleum products content above 15ft (4.572m) in depth, three samples are withdrawn as upper, middle and lower samples from which a composite is made.

Upper Sample: This is taken from the middle of the upper third of the level of petroleum or petroleum product, that is, 1/6th of the point from the top of the petroleum or petroleum product's level.

Middle Sample: This is taken from the middle of the tank content which is 3/6th of the point from the top of the petroleum or Petroleum product level.

Lower Sample: This is taken from the middle of the lower third portion of the fixed tank which is 5/6th of the point from the top of the petroleum or Petroleum product level. 2.5.3.3 Where the petroleum or petroleum product's level in the tank is above 15ft (or 4.572m) three samples are withdrawn from the following points from which the composite sample is blended.

2.4.4 General Precautions

2.4.4.1 The following precautions shall be taken when carrying out a sampling exercise:

2.4.4.2 The exercise shall be conducted immediately after gauging the tank.

2.4.4.3 The sampling apparatus, including the cord, shall be clean and free of any contaminant; also, the "thief-can" shall be cleaned with standard solvent and thoroughly rinsed with petroleum or petroleum product being sampled before it is lowered into the tank to withdraw the sample.

2.4.4.4 The cord of the "thief-can" shall be made of material that does not accumulate static electricity.

2.4.4.5 The sample container shall be closed immediately it has been withdrawn from the tank to prevent entry of water from external sources (for example, when the exercise is being conducted in a wet weather).

2.4.4.6 It is very essential to ensure that the can is full at the desired depth before withdrawing it to the surface.

2.4.4.7 When samples are required from more than one level in a tank, the order of sampling shall be from the top downwards so that each sample will be obtained before the liquid at that level is disturbed.

2.4.5 Sampling Procedure

2.4.5.1 To conduct the sampling exercise, the "thief-can" to be used is selected and after securing the cork on it properly, it is gently lowered to the desired level through the dip hatch and by counting the number of knots used to graduate the cord or reading directly if a graduated tape is used. On reaching the level, the thief-can is opened by gently jerking the cord to allow oil to flow in. The thief-can is then allowed to stay at this depth for a minimum of fifteen seconds for it to be filled up. Thereafter, it is gently withdrawn to the surface for tank temperature measurement.

2.4.6 Sampling using Portable Manual Sampling Unit (PSU)

2.4.6.1 The portable manual sampling unit (PSU) is designed to obtain samples under closed or restricted system conditions and to be compatible with vapor control valves fitted on vessels. The use of such equipment shall generally conform with provisions of API MPMS Chapters 8.1 and 17.2.

2.4.7 Determination of Tank Temperature

2.4.7.1 Equipment

The approved equipment shall be the mercury-in-glass thermometer of the ASTM type as specified in API MPMS Chapter 7. It shall be either the cup case or flushing case model of a suitable range and an accuracy of ±0.25˚F

2.4.7.2 Tank Temperature Measurement

2.4.7.2.1 The sample can after being filled up at the desired level is gently moved up and down in the petroleum or petroleum product's column for about two (2) minutes to allow its content to reach a temperature equilibrium with the petroleum or petroleum product in storage. Thereafter, the can is withdrawn and held just below the shelter of the gauge hatch and the thermometer is inserted into it. As soon as equilibrium is reached, at which time the thermometer reading becomes constant, the indicated temperature is observed and recorded as the tank temperature at the level of sampling.

2.4.7.2.2 This procedure is followed for the samples withdrawn from other levels of the tank and an average of the temperatures recorded for all the sampled levels shall be noted as the applicable tank liquid temperature to be used for volume correction factor (VCF) determination. For the UTI, the temperature can be read at different levels as describe under section 2.5.3

2.4.7.2.3 Similarly, the reading on the back-up device installed on the tank for measuring tank temperature shall be noted for comparison.

2.4.7.2.4 The back-up device shall either be of mercury-in-glass type of the same range or the electrical resistance type as specified in API MPMS Chapter 7.

2.4.7.2.5 Thereafter, a "cocktail" of the samples withdrawn from the prescribed levels of the tank is formed by transferring all the samples from the can into a sample container which is properly labeled to indicate:

(a) Date of sampling and name of sampler.

(b) The tank number and depth(s) at which sample was obtained.

(c) Grade of oil sampled.

(d) Gross quantity of oil represented by sample.

(e) Name of tanker, if sampling is in respect of a shipment.

(f) Average tank temperature.

2.4.7.2.6 Sample containers shall either be clear or brown bottles or cans which have been properly cleaned in the same manner as specified for sample cans.

2.4.7.2.7 Containers made of plastic materials shall not be used to store petroleum and petroleum product samples. Such containers shall only be acceptable for sample transfers. For every shipment, the facility operator shall obtain four samples of two- liter for the following uses:

(a) One (two-liter) sample, shall be used for laboratory determination of the petroleum or petroleum product cargo qualities at the facility.

(b) One (two –liter) sample shall be retained at the facility for a maximum of 90 days after the departure of the tanker for any later confirmatory test in case of a dispute.

(c) The remaining two (two-liter) samples shall be handed over to the tanker master for any desirable test by the consignee at the port of discharge. Container covers shall be of cork, glass stoppers or screw-cap types only. Rubber stoppers shall not be used.

2.5 Automatic Sampling at Production and Custody Transfer Points

2.5.1 Definition

2.5.1.1 An automatic sampler is a device which, when correctly installed and actuated enables a representative sample of the fluid flowing in a pipeline to be obtained.

2.5.2 Application

2.5.2.1 Automatic sampler shall be the approved device for obtaining samples of petroleum or petroleum product when fiscal quantity is being determined with the use of meters (Dynamic measurement method). It shall also be approved as standard equipment for sampling tanks during fiscal quantity determination by static method.

2.5.3 Design of Automatic Sampling System

2.5.3.1 Design Principle

2.5.3.1.1 Liquid to be sampled is not homogenous, hence there is always a tendency of phase segregation along the pipeline. Also, production/flowstation and especially custody transfer processes are in batches, therefore sample collection shall be proportional to flow quantity.

2.5.3.2 Applicable Standards

2.5.3.2.1 The design, installation, operation and maintenance of the automatic sampling device shall be generally in accordance with ASTM D4177/API MPMS Chapter 8 section 2 (8.2)/ISO 3171.

2.5.3.3 Sampler Probe

2.5.3.3.1 The probe shall be the in-line-grab type or any other type as approved by the Director of Petroleum Resources.

2.5.3.3.2 It shall be capable of continuous sampling during operations.

2.5.3.3.3 The probe shall be pneumatically, hydraulically or electrically actuated via a calibrated flow meter which shall serve as the flow signal regulator for sample pacing.

2.5.3.3.4 The flow proportioning meter shall be calibrated with an accuracy of ±5% over the working flow range of the pipeline.

2.5.3.3.5 The sampling aperture of the probe shall have a minimum diameter of 6mm.

2.5.3.4 Sample Receivers

2.5.3.4.1 Shall be of the fixed volume type.

2.5.3.4.2 Shall have its inside made of polished stainless steel to minimize corrosion and water clingage.

2.5.3.4.3 Shall be equipped with a relief valve, set at a pressure slightly less than the line pressure.

2.5.3.4.4 Shall be equipped with a means of monitoring the level of the filling petroleum and petroleum product in the container.

2.5.3.4.5 The bottom shall slope continuously towards the drain to facilitate liquid withdrawal.

2.5.3.5 Other Ancillary devices

2.5.3.5.1 Velocity Profile Improvement Device: This shall either be a powered mixer of rotary or jet type. In addition, the probe shall be installed along the vertical section (rising or descending) of the line segment.

2.5.3.6 Performance Monitoring and Failure Alarms

2.5.3.6.1 These shall be suitable devices to check the functionality of the flow meter such as the proportionality of the collected sample volume with the totalized pipeline flow, loss of flow into the receiver and prevention of liquid high level in the receiver.

2.5.3.6.2 Samples shall be manually taken daily to serve as a back-up in case of eventual failure of the automatic sampler.

2.5.4 Installation of Automatic Sampling System

2.5.4.1 The probe shall be located horizontally within a minimum of 3*pipe diameter (3*internal diameter) and 0.5*pipe diameter (0.5*internal diameter) from any vertical or horizontal bend respectively.

2.5.4.2 The probe orifice shall be offset from the inner center of the pipeline. Alternatively, a profile test should be carried out to select a precise location point in accordance with ASTM D4177.

2.5.4.3 The probe and sample receiver shall be as close as possible to; "dead-sample" volume.

2.5.4.4 The powered mixer shall be located between 7 - 10*internal diameter from the sampling point depending on the pipeline diameter such that the larger the diameter, the nearer the mixer will be to the sampling point.

2.5.4.5 Sampler assembly shall be protected against weather and unauthorized tampering in a suitable enclosure with controlled access.

2.5.5 Operation of Automatic Sampling System

2.5.5.1 Before the commencement of loading, the desired frequency of sample grab shall be calculated for the batch in accordance with the procedure set out in ASTM D4177.

Minimum sample frequency (bbl/grab) = $0.0001233D^2$

D – nominal pipe diameter (mm)

While No. of grabs for the parcel shall be deduced from the relationship

$$\textbf{No. of grabs} = \frac{\textit{Parcel Size}}{\textit{Minimum Sample Frequency}}$$

2.5.5.2 The sampler shall be allowed to operate continuously throughout the loading operation and shall not be removed until fluid flow has ceased in the pipeline after the shutdown of loading pumps, for production purposes the auto sampler or any suitable device approved by the Director Petroleum Resources shall be allowed to run for 24 hours (8am-8am). Thereafter, the sample in the receiver shall be transferred to the laboratory for quality analysis either in the receiver, if it is the removable type, or in a secondary receiver, which shall be a well labeled container made of suitable material after proper mixing within the primary receiver to ensure that the original homogeneity is maintained.

2.5.5.3 The following records should be made after each loading operation:

i. Sample reference number.

ii. Identification of shipment or transfer.

iii. Petroleum and petroleum product type.

iv. Date and time of commencement of sampling.

v. Date and time of completion of sampling.

vi. Nominated expected flow rate.

vii. Maximum expected flow rate.

viii. Sample grab size.

ix. Sample rate.

x. Calculated sample volume.

Time	Total Quantity of Petroleum and petroleum product Transferred	Target sample Quantity	Actual sample Quantity	% of Total Petroleum and petroleum product Transferred	% of Total sample Collected

2.5.5.4 The date logged above shall be used to determine the validity of sample collected and will reflect the performance efficiency of the sampler to ascertain when any equipment failure may have occurred. Appropriate corrective action shall be taken whenever a failure is observed.

2.5.6 Maintenance and Proving of Automatic Sampler

2.5.6.1 The sampling system shall be proved before installation and annually thereafter by injecting known quantity of water into the petroleum and petroleum product's stream passing through the sampler. Alternatively, the grab efficiency of the sampler shall be determined.

2.5.6.2 Analysis of the samples taken from the stream is then compared with the total value of initial BS&W content of the petroleum and petroleum product and the additional water injected.

2.5.6.3 The detailed procedure for carrying out the exercise shall be as outlined in ASTM D4177/API MPMS Chapter 8.

2.5.6.4 An official of the Department of Petroleum Resources shall be present during the proving and shall countersign the official record of the result of the exercise which shall then be sent to the Director of Petroleum Resources for approval. It should however be noted that for water injection method, the acceptance shall conform to ASTM D4177.

2.5.6.5 No new sampling equipment shall be commissioned for operations without the approval of the Department of Petroleum Resources and any existing sampler that fails to be approved after a proving exercise shall be decommissioned immediately and appropriate corrective action taken by the operator.

2.5.6.6 The associated flow meter serving as the pacing device of the sampler shall be calibrated monthly by the normal procedure for proving such measuring devices. All relief valve installed on the sampler receiver shall be checked and cleaned after every six months of operation.

2.5.6.7 For every custody transfer operation, the auto sampler grab performance factor shall be between 1 ± 0.10, which shall be calculated as follows:

$$\text{Performance factor} = \frac{Sample\ Volume\ Collected\ (ml)}{Sample\ Volume\ Calculated\ (ml)}$$

PART I SECTION 3

PROCEDURE GUIDE FOR PETROLEUM AND PETROLEUM PRODUCTS QUALITY DETERMINATION

3.1 Quality parameters for Fiscal Measurement

3.1.1 Relative Density (Specific Gravity)

This is defined as the ratio of the mass of a given volume of liquid at a given temperature to the mass of an equal volume of pure water at the same temperature.

3.1.2 API Gravity

This is a special function of relative density (Specific Gravity) at 60/60˚F represented by API Gravity = (141.5/specific Gravity @60/60˚F) – 131.5.

3.1.3 Base Sediment and Water (BS&W)

This is a measure of the percentage of solid impurities and water content of a petroleum and petroleum product sample. This parameter is used to deduce the quantity of net petroleum and petroleum product in a batch or cargo.

3.1.3.1 The Base Sediment & Water (BS&W) in percentage (%) obtained from automatic sampler as composite samples shall not exceed 0.50% for all export crude oil cargo.

However, when the prescribed parameter of 0.50% BS&W is exceeded consecutively more than three times, outturn verification shall be mandatory, and company shall ensure that the Department witnesses the exercise.

3.1.3.2 If the cause of frequent off-specification cargo of high BS&W% is a characteristic nature of the petroleum and should the abnormal source of the above challenge remain the same, the company shall apply to the Director, Petroleum Resources for an approval for a specific period to continue the export of those cargo enumerating their peculiar situation.

3.2 Procedure for Determining Relative Density (Specific Gravity)

In carrying out the measurement of the specific gravity of a petroleum and petroleum product sample for fiscal measurement purpose, the standards and procedures outlined in ASTM D1298/API MPMS Chapter 9 shall generally be followed.

3.2.1 Equipment Specification

3.2.1.1 Thermometer: Shall conform to the type IP 64F or ASTM E 100 No. 12F and shall be of range -5˚F to 215˚F interval 0.5ºF and a scale error of not more than ±0.25F. Its calibration shall be supported with a certificate issued by an approved authority which is recognized by the Department of Petroleum Resources and shall be periodically calibrated as specified in this guide under part III

3.2.1.2 Hydrometer: Shall be glass type, graduated preferably in units of API gravities. Shall conform to the type BS718: 1960 L50 SP with meniscus correction of ±0.0007, M50 SP with meniscus correction of ±0.0007 to ±0.0014, for hydrometers of the SG type or of type ASTM E100 Nos. 1H or 10H long and plain for API Gravity hydrometers. The accuracy of the instrument shall be confirmed by a certificate issued by a standardizing authority which is recognized by the Department of Petroleum Resources.

3.2.1.3 Constant temperature Bath: This shall be a thermostatically controlled water bath to be maintained at about 60˚F with a maximum temperature fluctuation of ±5˚F.

3.2.2 Procedure

3.2.2.1 Extract a reasonable quantity of the petroleum and petroleum product sample after a thorough mixing into a clean glass cylinder.

3.2.2.2 The hydrometer is then gently lowered into the sample while the thermometer is used to stir the sample until the temperature reading becomes steady. The temperature at this point is read and noted and the gravity of the sample is read from the hydrometer at the meniscus cut on the hydrometer stem while it is stationary and freely floating in the sample. The reading is then adjusted with appropriate meniscus correction applicable to that instrument to give the accurate SG or API Gravity of the sample to the equivalent value at 60/60oF using the appropriate ASTM table.

3.2.3 Precautions

3.2.3.1 Any air bubbles on the surface of the sample in the cylinder should be mopped up with clean filter paper before readings are taken.

3.2.3.2 There should be no air current in the environment in which the test is being carried out.

3.3 Procedure for Determining the Base Sediment and Water Contents (BS&W) of Petroleum and Petroleum Product Sample

3.3.1 Approved Method

3.3.1.1 The approved method for determining the BS&W of petroleum and petroleum product sample shall be with the use of the distillation equipment or any other method as approved by the Director of Petroleum Resources. The steps to follow shall generally conform to those outlined in ASTM D4006 and D95. In crude oil, the amount of water as determined by this method (D4006) shall be used to correct the volume involved in the custody transfer of the petroleum batch under test.

3.3.2 Equipment Specification

3.3.2.1 The apparatus shall be as shown in the figure in Appendix I. It shall consist of a glass distillation flask, a condenser, a graduated glass trap and a heater. Other types of distillation apparatus will be acceptable for this method provided they can be demonstrated to operate within the precision established with the preferred apparatus.

3.3.3 Preparation of Test Samples

3.3.3.1 The sample size shall be selected such that the higher the expected water content of the petroleum batch under test, the smaller the sample quantity. Hence sample sizes will be inversely proportional to the expected water cut. As a general rule, the following proportional sizes shall be adopted:

Expected Water Cut (%)	Approximate Sample Size (ml)
50.1 - 100.0	5
25.1 - 50.0	10
10.1 - 25.0	20
5.1 - 10.0	50
1.1 - 5.0	100
0.5 - 1.0	200
Less than 0.5	200

3.3.3.2 Care shall be taken when pouring the sample into the graduated cylinder to avoid entrapment of air. Also, the level shall be adjusted as closely as possible to the appropriate graduation.

3.3.3.3 The sample contents of the cylinder shall in turn be carefully poured into the distillation flask and the cylinder shall be rinsed, a minimum of five times, with xylene or any other acceptable solvent of a quantity equivalent to one-fifth of the capacity of the graduated cylinder, into the flask, such that the cylinder shall be thoroughly drained into it.

3.3.4 Calibration of the Distillation Assembly

The entire distillation assembly including the trap shall be calibrated prior to use in the following manner:

3.3.4.1 Calibration of Water Trap

3.3.4.1.2 The accuracy of the graduation marks on the trap shall be verified by adding 0.5 milliliter increments of distilled water, at 20°C, from a 5 milliliter micro-burette or micropipette readable to the nearest 0.01 milliliter graduation. If a deviation of more than 0.05 milliliter between the quantity of water added and that observed is recorded, then the trap shall not be used until recalibrated.

3.3.4.2 Calibration of the Apparatus

3.3.4.2.1 The entire apparatus shall be calibrated by using xylene with known water content and to which known quantities of water shall be added and tested in turn as follows:

The quantity of xylene to be used shall be exactly 400 milliliters of known value of water content which shall not be more than 0.02% water volume.

The primary water content of the solvent shall be determined by distillation in the flask and measuring the entrapped water in the trap, which in turn shall be emptied and cleaned preparatory for further calibration test.

3.3.4.2.2 Thereafter, a quantity of 1.00±0.01 milliliter distilled water at 20°C shall with the use of a burette or pipette be added to the xylene in the distillation flask and tested as above. The test shall thereafter be repeated with the addition of 1.00±0.01 milliliter of distilled water at 20°C and the result analyzed. The maximum or minimum permissible water recovery for both tests shall not be more than 1.00±0.025 milliliter in the first case and 4.50 ± 0.025 milliliter in the second case. The apparatus shall not be used if any of these limits is exceeded.

3.3.5 Test Procedure

3.3.5.1 The apparatus shall be chemically cleaned before any test, to remove surface films and debris which may hinder free drainage of water in the test apparatus.

3.3.5.2 Thereafter, test sample quantity shall be selected in accordance with paragraph 3.3.3 above, to which sufficient quantity of xylene shall be added to make the total volume of xylene 400 milliliters. The mixture shall be stirred with the use of a magnetic stirrer to reduce bumping, after which the apparatus shall be assembled as shown in the figure in Appendix I such that it is liquid and vapour tight. A suitable drying tube shall be inserted on the condenser to avoid ingress of atmospheric condensation. Water at 20˚C to 25˚C shall then be circulated through the condenser jacket. The flask shall then be graduated and the water condensation in the trap observed until it has attained a constant level indicating that all the water content in the sample has been boiled off.

3.3.5.2 Thereafter, the trap and contents shall be allowed to cool down to 2ºC. Any water clinging to the walls of the trap shall be dislodged into the water layer with the use of a Teflon Scraper. The volume of water thus collected in the trap shall be read to the nearest 0.025 milliliter after which the percentage water cut of the sample is calculated as illustrated below;

3.3.6 Calculation

The water cut of the sample is deduced from the following equation:

$$\text{Volume \%} = \frac{(\text{Volume of water in Trap,ml}) - (\text{Solvent blank,ml})}{\text{Volume of Test Sample,ml}} * 100$$

This shall be expressed to the nearest 0.025 %.

3.3.7 Precision Requirement

3.3.7.1 Both the repeatability and reproducibility range of this method shall be stipulated in the aforementioned standards. The repeatability and reproducibility of measurement with each apparatus shall be tested at the frequencies specified by the respective manufacturers of the equipment.

PART I SECTION 4

COMPUTATION OF PETROLEUM OR PETROLEUM PRODUCT QUANTITY

4.1 Calculation of Petroleum and Petroleum Products Volume in tank Storage

4.1.1 Parameters

4.1.1.1 All volume correction factors are to be obtained from the Petroleum Tables ASTM D 1250 and API MPMS Chapter 11.1

4.1.1.2 Tank Dip: This is the height of the column of petroleum and petroleum product in the tank as obtained from the gauging exercise.

4.1.1.3 Volume Correction Factor (VCF): For Petroleum, this is obtained by first establishing the API gravity or Specific gravity of the sample at 60˚F from table 5A or 23A, of the measurement tables respectively. The corresponding volume correction factor is then obtained by referring the Specific gravity or API gravity at 60/60˚F to table 24A or 6A of the measurement tables respectively. However, when using density at 15°C, volume correction factor shall be determined using table 54A of the measurement tables.

For Petroleum Products, this is obtained by first establishing the density of the sample at 59˚F (15°C) from table 53B of the measurement tables. The corresponding volume correction factor is then obtained by referring the density at 59˚F to table 54B of the measurement tables.

4.1.1.4 Long Tons per Barrel Factor: This is obtained by referring the API gravity or S.G at 60/60°F to API MPMS Chapter 11.

4.1.2 Calculation for Fixed Roof Tank

The tank dip is referred to the appropriate tank calibration table to obtain the gross quantity of oil in barrels at tank temperature. Thereafter the quantities are calculated as follows:

4.1.2.1 Gross Standard Volume at 60/60°F: This is obtained by multiplying the gross volume at tank temperature by the volume correction factor obtained in paragraph 4.1.1.2.

4.1.2.2 Gross Weight: The gross volume in barrels at 60/60°F is then multiplied by the long ton per barrel factor obtained (in 4.1.1.3) to give the equivalent weight in long ton at 60/60°F.

4.1.2.3 Quantity of Water and Sediment (BS&W) in Petroleum: This is obtained by multiplying the gross volume of petroleum at 60/60˚F by the BS&W percentage to give the volume of water in the petroleum in barrels. Thereafter, multiplying the water volume by a factor of 0.15616 yields the equivalent weight of water in long tons.

4.1.2.4 Net volume and Weight of Petroleum in Tank: The net volume of petroleum in the tank is obtained by subtracting the volume of water from the gross volume of petroleum while the weight of water is subtracted from the gross weight of petroleum in the tank at 60/60˚F to obtain the net weight of petroleum in the tank.

4.1.3 Calculation for Floating Roof Tanks

4.1.3.1 The only difference to note when calculating the quantity in a floating roof tank is that, correction shall be made for the roof displacement which in turn depends on the weight of the roof and specific gravity at tank temperature of the petroleum in storage.

4.1.3.2 For the correction to be valid, however, the roof should be fully floating. In most cases, floating roof displacement charts are either provided along with the calibration tables of the tank or in the alternative is supplied. If neither a table nor a formula is supplied in the tank calibration table, the following steps shall be taken to obtain the appropriate roof displacement.

4.1.3.3 Convert the SG/Density of petroleum and petroleum product at laboratory temperature to that at 60/60^{O}F or 59^{O}F using ASTM table 23A or 53B respectively.

4.1.3.4 Then obtain the SG/Density of petroleum and petroleum product at tank temperature by converting that at 60/60^{o}F or 59^{o}F using ASTM table 23A or 53B respectively.

4.1.3.5 Calculate the roof displacement by using the relationship W/T= Displacement, where W = Weight of roof in long ton as given in the relevant tank table, and T = density at tank temperature obtained from (4.1.2) above.

4.1.3.6 Subtract the roof displacement obtained (i.e. W/T) from the gross volume of tank content at tank temperature to obtain the gross volume of petroleum and petroleum product in storage in barrels/cubic meters. Tank content at tank temperature is obtained by referring the tank dip to the appropriate tank calibration table. Thereafter, proceed with other calculations to obtain the net volume and weight of petroleum and petroleum product in the tank as set out under section 2.0 above.

PART I SECTION 5

PETROLEUM AND PETROLEUM PRODUCT EXPORT DOCUMENTATION PROCESS

5.1 Tanker Movement Information

The following information on tankers nominated to lift petroleum and petroleum product cargoes at facilities, shall be supplied by all operators to the Department of Petroleum Resources office at the Headquarters within the deadlines stipulated hereunder

5.1.1 Advance Tanker Program

This shall contain the schedule of tankers expected to call at the facility in a particular month giving such information as the name and expected time of arrival (ETA), parcel size and the consignor. It shall be furnished within the first week of the month in question and any amendments to the program shall be promptly notified to the respective Department of Petroleum Resources offices not later than 72 hours before the arrival of the tanker.

5.1.2 Tanker Manifest

On arrival of a tanker at the berth, the following information shall be supplied to the Department of Petroleum Resources facility office:

(a) Name of the tanker and its country of registration.

(b) Owner of Tanker.

(c) Summer dead weight of tanker.

(d) Last port of call.

(e) Quantity and type of petroleum and petroleum product to be lifted.

(f) Destination of tanker after loading.

(g) The IMO number of the vessel

(h) The Agent of the vessel

5.1.3 Tanker Loading Schedule

On berthing the tanker preparatory to loading, a schedule shall be prepared for the loading operations and should contain the following information for granting loading clearance:

(a) Name of Berth in use.

(b) Estimated time of commencement of loading.

(c) Quantity and type of cargo on board on arrival.

(d) Tonnage of petroleum and petroleum product to be loaded.

(e) Designated tanks to be used for loading and their BS&W.

(f) Pumping rate and estimated duration of loading.

(g) Consignee and Consignor of the petroleum and petroleum product cargo.

5.1.4 Custom clearances shall be provided before and after loading.

5.2 Official Export Documents

5.2.1 Gauge Ticket

This is a document issued by the Department of Petroleum Resources in which record is made of the tank gauge readings, sample analysis results as obtained before and after loading from the tank (i.e. during opening and closing gauges). It should be completed in quadruplicate and signed by both the officials of the Department of Petroleum Resources and the Company's facility operations supervisor on duty at the material time or any other higher official of the company so designated for the purpose. The original and triplicate copies are handed over to the company while the duplicate copy is forwarded to the Department of Petroleum Resources officer – In – Charge of the area along with the corresponding copy of the calculated net volume ticket.

5.2.2 Calculated Net Volume Ticket

It serves as a mini – certificate of quantity and quality of the cargo. Information to be logged in the document are as follows:

(a) Tank Number

(b) SG/API of the petroleum and petroleum product in the tank before and after loading.

(c) The percentage base sediments and water.

(d) The gross and net quantity of the petroleum and petroleum product in barrels and long tons.

(e) Metered quantity in barrels.

5.2.2.1 The ticket is completed in duplicate by the Department of Petroleum Resources official on duty after all parties have agreed on the fiscalized quantity of the cargo. The original copy of the ticket should be sent along with the other export returns to the Department of Petroleum Resources Divisional office under which the facility falls.

5.2.3 Certificate of Quantity

This is a document solely prepared and issued in quadruplicate by the Department of Petroleum Resources office at the facility to reflect the official quantity and quality of the cargo. After preparation by the Department of Petroleum Resources officer on duty, it shall be signed by the official of the Department of Petroleum Resources in charge of the facility, a very senior official of the operating facility and the representative of the consignor to the cargo.

5.2.3.1 The information contained in this document shall be identical in all respects with the records entered to the bill of lading in respect of that shipment. A certificate of quantity shall be issued for each parcel lifted and for the total cargo lifted by the tanker in the case of joint lifting by two or more consignors. The data to be logged in this document are as follows:

a) Tank number and gauge readings / Meter Readings.

b) Average tank temperature / Average Line Temperature.

c) Basic Sediments and water contents in percentage.

d) Average line pressure.

e) Average specific gravity of the crude at 60°F / density of product at 59°F.

f) Equivalent API Gravity / SG of the cargo.

g) Volume correction factors.

h) Gross and net quantities of the cargo in barrels, long tons, cubic meters and metric tons as obtained from the tank dips/Meter Readings.

i) Absolute values of BS&W in barrels and long tons.

j) Meter Factor

5.2.3.2 The Average BS&W for the whole cargo in a case where loading has taken place from more than one tank shall be obtained by dividing the total BS&W value by total gross volume at 60°F of the cargo and expressed in percentage.

5.2.3.3 The Equivalent API Gravity of the cargo in a case where loading has taken place from more than one tank shall be obtained as follows:

5.2.3.3.1 Calculate the long tons per barrel factor of the cargo by dividing the net weight in long tons by its net volume in barrels.

5.2.3.3.2 The factor thus obtained is referred to table 29 of the ASTM table of standards to obtain the corresponding dry specific gravity, which is in turn referred to table 21 of the ASTM tables to determine the equivalent API gravity of the cargo.

5.2.3.4 In case of auto-sampler failure, pre-export BS&W shall be used for determining the quality of petroleum and petroleum product exported.

5.2.3.5 After all the necessary values are determined and entries have been made in the relevant document, it is distributed in the following manner:

Original Copy - To the consignor or his authorized representative.

Duplicate Copy - To the Department of Petroleum Resources Divisional office in the area.

Triplicate Copy - To the facility operator.

Quadruplicate Copy - To be retained among the records of the Department of Petroleum Resources facility office.

5.3 Export Permits

Requirements for granting Crude Oil/Condensate/GTL/Gas Export Permits is as follows:

5.3.1 New Application

Companies making a foremost application for export permits must have a concession (Oil field) or a partnership in the concession with a consent letter from DPR conveying the approval of the Honourable Minister for the ownership of such. In addition, a consent letter from DPR conveying the assignment of interest to participating company(s) shall be included for first application.

5.3.1.1 A written application shall also be submitted to The Director of Petroleum Resources with the following documentation:

a. A layout of the oil field/export facilities (terminals) in relation to other facilities.

b. Provide evidence of DPR approval to commence production/well-test from the field.

c. Evidence of ownership of the operating facility (where applicable).

d. Provide a copy of the Crude Handling Agreement (CHA) with the operating companies/third-party injectors (for companies that do not have Crude Oil Terminals).

e. Companies making foremost application for export permit shall include two (2) copies each of Certificate of Incorporation, Memorandum and Article of Association as well as current Tax Clearance.

f. Copy of current monthly/quarterly NNPC commercial allowable rate of production covering the period of application (where applicable).

g. DPR Certificate of conformity for the fiscal meters, gauges and all custody transfer weighing and measuring instruments at the terminal(s) to be used for export.

h. A copy of DPR'S technical allowable of the operating field.

i. Three-year tax clearance.

For companies in partnership, applying for export permit(s), volumes requested must be commensurate with the percentage share in DPR approved Technical Allowable for wells in the concession.

5.4 Ship/shore Differences

The shore figures shall continue to be regarded as the official fiscalized figures for any lifting, however occasions do arise when the figure recorded on board a tanker varies remarkably from that recorded on shore or at the loading point.

In such cases the limit of tolerance allowed for these variations shall depend on the cargo quantity expressed in long tons and the allowance that shall apply are as follows:

5.4.1 For Petroleum and Petroleum Products of up to 100,000 long tons, a limit of 0.50% difference, shall be allowed.

5.4.2 For Petroleum and Petroleum Products cargo of above 100,000 long tons, the allowable tolerance limit shall be 0.30%.

5.4.3 However, in cases where the ship/shore difference recorded exceeds the above stipulated limits, the tanker shall not be cleared to sail until a firm undertaking has been given by the tanker Captain or the facility operator to arrange for DPR officers to verify the outturn discharge of the vessel at port of discharge.

On conclusion of the outturn verification process, a new Certificate of Quantity shall be issued if the tolerance limits referred to in 5.4.1 and 5.4.2 above are exceeded.

5.5 Sanction Measures on Tankers

After lifting, any facility owner/tanker that fails to comply with the above when demanded, within sixty days, shall be sanctioned and not allowed to lift petroleum or petroleum product from any Nigerian facility until the owners have complied. Also, any tanker that records ship/shore differences more than the allowed limit during three consecutive lifting, shall not be allowed to lift cargo from any facility in Nigeria until satisfactory evidence has been provided to show that the ships measurement device has been recalibrated afterwards.

PART I SECTION 6

DAILY, MID-MONTH, MONTHLY AND ANNUAL FISCALISATION OF PETROLEUM AND PETROLEUM PRODUCT STOCK AT PRODUCTION AND CUSTODY TRANSFER POINTS

6.1 Purpose

6.1.1 The purpose of this exercise is to compute the monthly production of petroleum and petroleum product into the facility and establish the stock of petroleum and petroleum product in storage at the end of the month by material balancing. All facilities shall apply static measurement procedure for daily, mid-month, monthly, and annual fiscalization.

6.1.2 For petroleum, the exercise shall be carried out at:

8.00am for daily fiscalization

8.00am on the sixteenth day of every month for mid-month fiscalization

8.00am on the first day of every month for monthly fiscalization.

8.00am on the first day of every year for annual fiscalization

6.1.3 For petroleum products, the exercise shall be carried out at:

6.00am for daily fiscalization.

6.00am on the sixteenth day of every month for mid-month fiscalization.

6.00am on the first day of every month for monthly fiscalization.

6.00am on the first day of every year for annual fiscalization.

6.1.4. The National Production Monitoring System (NPMS) platform shall be complied with by all Operators for submission of daily production, stock and export volumes.

6.2 Procedure for Stock Measurement

The step to follow in conducting facility receipts and stock measurement shall be as outlined hereunder:

6.2.1 The tank shall be drained after which it is gauged for stock taking. However, if the tank has just been filled, it is allowed to settle for at least one hour before it is drained. In a case like this, the gauging for stock taking could be carried out later than the stipulated 8. 00 am/6 .00 am, as applicable.

6.2.2 If a tank is discharging into a tanker at 8.00 am the practice to follow is to allow it to continue discharging rather than halting the operation purposely for the stock taking exercise. However, for such a tank, the opening gauge before the commencement of loading is recorded as the stock at 8.00 am and NOT the gauge after the loading operation. This thus implies that the quantity of petroleum and petroleum product already discharged into the tanker is theoretically brought back to the tank farm. The corollary to this is that the shipment in question is treated as having taken place during the new month.

6.2.3 Where a tank is receiving production on the first day of the month, the filling of such a tank is stopped at 8.00 am and the filling is immediately switched to another tank which has already been gauged. It is an ERROR to switch the filling to an unfiscalized tank for the simple reason that the stock in that tank had been known at 8.00am. Such a step only succeeds in confusing the exercise the more.

6.2.4 In rare cases where a tanker has completed loading from two tanks prior to 8.00am and the same tanker is still receiving cargo from the third tank, then the total shipments from the three tanks is regarded as export for the new month while the opening gauge before pumping from the three tanks concerned are taken as the stock at 8.00 am on the first day of the new month. However, for bill of lading purpose, the date and time that loading is completed shall be documented on the bill of lading document unless otherwise requested by the exporter and approved by the Director of Petroleum Resources.

6.2.5 Calculation: The petroleum and petroleum product produced for any particular month is calculated by a simple material balance equation.

6.2.6 Example

Production for January = Export (including local delivery) for January + Closing stock for January – opening stock for January.

Export for January = Summation of exports between 8.00am on 1st of January to 8.00am on 1st of February.

6.2.7: - DETERMINATION OF PRODUCTION/TERMINAL ADJUSTMENT (ERRORS) Definition: Terminal adjustment is referred to as volumes which represent the difference in production obtained from material balance and that derived from production receipt into terminal. Production/Terminal Adjustment (Errors) = Total Production (Obtained by Material/Mass Balance) – Total Cumulative Production (Obtained by Summation of Total Receipt into Terminal).

6.2.7.1: Terminal adjustment or losses should be determined and the report on Reconciled Monthly Stock Inventory Production Mass Balance shall be signed -off jointly by the operator, NNPC and DPR Representatives in the approved format shown below in Appendix 1.

6.3 Procedure for Special Purpose Vessel Storage (SPV)

6.3.1 All such installations shall be adequately equipped with meters to measure receipts into and off-takes from the vessel. Meter selection, sizing, installation, operation and maintenance shall be in accordance with the procedure guide on dynamic measurement contained in Part II of this document. Meter tickets shall be taken at 8.00am daily from the production meter bank and at the end of the batch pumping for the off-taker meter bank.

6.3.2 Production in a particular month shall in this case be the sum of meter records over the month while the stock shall be deduced from the total production and off-takes during the month.

6.4 Procedure for Reporting and Allocating Crude Oil Loss/Theft Volume

6.4.1 All production/injection figures for both terminal operators and third party injectors shall comply with the provisions of this procedure guide.

6.4.2 No deduction (losses, theft, etc.) shall be made from any third party injector's volume without approval from the DPR.

6.4.3. The DPR Methodology for Determination and Allocation of Crude Oil Production and losses (as revised from time to time) shall be used by terminal operators and Injectors for computation.

6.5 Crude oil Transportation and Handling Agreements (CTA/CHA)

6.4.1 Where two or more companies intend to enter into CTA/CHA, the agreement shall be transparent, fair and in conformity with oil and gas transportation and handling international best practices. The Department shall also be notified for guidance.

6.4.2 Methodologies for determination of Production/Injection/Allocation included in any CHA/CTA shall comply with the provisions of this procedure guide and/or as approved by the Director of Petroleum Resources.

PART II

PROCEDURE GUIDE FOR DETERMINATION OF THE VOLUME OF PETROLEUM AND PETROLEUM PRODUCTS BY DYNAMIC FLOW MEASUREMENT – LIQUID METERING

1.1 Approved Devices

1.1.1 The metering devices approved for installation at custody transfer points for dynamic flow measurement are:

i. Positive displacement meters

ii. Turbine meters

iii. Ultrasonic Flow meters

iv. Coriolis Flow meters

1.1.2 All meters, including those not listed above, may be used upon satisfactory demonstration of its accuracy, reliability, recertification method and approval by the Director of Petroleum Resources.

1.2 Essential Accessories

1.2.1 Strainers and filters to remove solid particles in the flowing liquid.

1.2.2 Automatic sampling device to be selected and installed as prescribed in Part 1, Section 2.7 of this Procedure Guide.

1.2.3 Meter proving facilities of any of the type prescribed in this guide.

1.2.4 Check valves and back pressure valves, and air eliminators.

1.2.5 Flow conditioning sections for meters, where applicable.

1.2.6 Meter counters of the non – resettable totalizer type with auxiliary reset able counter for use during proving.

1.2.7 Ticket printers of either the mechanical or digital type.

1.2.8 Means of manually sealing the housing of the flow registration mechanism – (for meters used for fiscalization only).

1.2.9 Temperature, pressure gauges and transmitters located down-stream the meter.

1.2.10 A security seal to prevent unauthorized tampering with the meter. Meters at all custody transfer points shall be equipped with level-A security system.

1.3 General Conditions

1.3.1 The design of the metering arrangement shall be based on the "Lease Automatic Custody Transfer (LACT) System."

1.3.2 The design drawings of the pipelines and meter arrangement shall be furnished to the Department of Petroleum Resources together with the design parameters for installation approval. The same kind of diagrams for the proposed proving device shall be simultaneously submitted for review and approval. Any future alteration to the installation shall undergo the same process of review and approval before being carried out.

1.3.3 Both factory and field construction program of the metering system and associated prover shall be submitted for appropriate monitoring of progress of construction by the Department of Petroleum Resources.

1.3.4 The date of in-factory test and calibrations of the meters and the prover shall be notified to the Director of petroleum Resources one month ahead while the date of all subsequent calibrations and proving of the meters and prover shall be notified to the Department of Petroleum Resources two weeks ahead of time.

1.3.5 A representative of the Department of Petroleum Resources shall be present to witness all tests and calibrations of meters and prover in satisfaction of the specific provisions of the Petroleum (Drilling and Production) Regulation 52 (3) of 1969.

1.3.6 The allowable metering devices shall be of the same type for all the meters in a bank and for the meters at interfaces along the same pipeline.

1.3.7 No by-pass of the meter bank or provision for reverse flow through the bank shall be allowed for any system. For existing installations, all by-pass shall be suitably blanked off at the inception of this guide.

1.3.8 A file shall be maintained for each meter which will contain all information relevant to the design and maintenance of the meter throughout its operational life.

1.3.9 It shall be mandatory that no PD meter in a bank shall be operated at more than 80% of its maximum name plate capacity. Consequently, the number of meters required for a given service shall be obtained from the following empirical relationship, rounded-off to the next whole number:

$$\text{No. of Meters} = \frac{Meter\ station's\ Flowrate}{0.80 * Maximum\ Capacity\ of\ each\ meter}$$

1.3.10 An extra meter shall be provided in each bank, as back-up, to allow for uninterrupted operations.

1.3.11 Control procedure shall be worked out for the witnessing and approval by the Department of Petroleum Resources of the metering system, and its functional acceptance test before leaving the factory and on the completion of installation on site before commissioning. This shall follow the lodgment of construction and installation Program with the Department of Petroleum Resources.

1.3.12 Accessory equipment which may include filters, temperature, pressure gauges and transmitters as well as protective valves shall be installed as indicated in the Department of Petroleum Resources approved Detailed Engineering Design (DED).

1.3.13 During meter selection, the meter linearity, accuracy and turn-down ratio of the meter shall be considered.

1.3.14 The linearity of a custody transfer flow meter shall be ±0.15% or lower. Meters shall be operated and proved within this linearity limit.

1.3.15 The LACT system must be located within a clear visibility range to the injection point.

1.3.16 This point shall be agreed by both parties and approved by DPR.

1.4 Applicable Standards for Design, Installation, Operation and Maintenance of Meters

The applicable standards for Design, Installation, Operation and Maintenance of Metering system shall be American Petroleum Institute Manual of Petroleum Measurement Standards (API MPMS) Chapters 4, 5, 6, 11, 12 and 13.

1.5 Positive Displacement Meters - PD Meters

1.5.1 Description

This is basically a piece of equipment designed to measure a volume of liquid by separating it into measured quantities (displaced volume) and counting these quantities. Meters of this type can only measure in one direction; hence it is impossible to reverse flow through such meters.

1.5.2 Design and Selection

1.5.2.1 Principle

The design shall be based on the Lease Automatic Custody Transfer System (LACT). The metering assembly shall therefore generally follow the guideline specified in the API Manual of Petroleum Measurement Standard Chapter 6 of LACT Systems.

1.5.2.2 Selection Criteria

In selecting the meters, consideration shall be given to the viscosity and density of liquid, solid contents, expected flow rates and operational conditions.

1.5.3 Operation and Maintenance

Flow rate through the bank shall be maintained at between 60% and 80% of the maximum name plate capacity of each meter. It shall be more acceptable to shut down some of the meters in the bank to maintain this optimum flow rate than to operate any of the meters below the 60% capacity.

1.6 Turbine Meters

1.6.1 Description

This is a flow rate measuring device which works on the principle of a sensing rotor moving with a tangential velocity which is proportional to the volumetric flow rate. The corresponding volume of liquid passing through the meter is indicated on a pre-calibrated readout device. Meters of this type can measure reverse flows but for the purpose of this guide, no reversal of flow shall be allowed.

1.6.2 Design and Selection

1.6.2.1 These shall generally be carried out in accordance with the procedure outlined in API Manual of Petroleum Measurement Standards Chapter 5 Section 3 and other reference standards in section 1.4 above.

1.6.2.2 Adequate consideration shall be given to the required maximum and minimum flow rates, maximum operating pressure and temperature as well as solid particles in the liquid and the liquid properties.

1.6.2.3 Turbine meters shall not be considered for use at flow rates less than 1,500 barrels per hour because of the short span of linearity of such meters in this flow regime. However, meters shall be selected such that they operate always within the linear portion of their characteristic curves.

1.6.3 Operation and Maintenance

1.6.3.1 Turbine meters shall be operated and maintained in accordance with the guidelines of the manufacturer and those stipulated in the appropriate reference standards.

1.6.3.2 The meter linearity is to be proved at a minimum of six points over the manufacturer's specified range to include the minimum flow rate, the maximum flowrate and four equally spaced points between the minimum and the maximum flow rate.

1.7 Coriolis Meters

1.7.1 Description

1.7.1.1 Coriolis meters measure mass flow rate and density. A Coriolis meter consists of a sensor and a transmitter. A typical Coriolis sensor has one or two tubes through which the fluid flows.

1.7.1.2 A Coriolis meter may also be configured to indicate volumetric flow rate. The volumetric flow rate may be determined by dividing the mass flow rate by the measured density at flowing conditions.

1.7.2 Design and Selection

1.7.2.1 Coriolis meters for custody transfer meter purposes shall satisfy that its application, proving facilities can reliably and consistently meet the accuracy criteria of all parties engaged in the transaction and shall generally be carried out in accordance with API MPMS Chapter 5.6 and other relevant standards.

1.7.3 Operation and Maintenance

1.7.3.1 Coriolis meters shall be operated and maintained in accordance with the guidelines of the manufacturer and those stipulated in the appropriate reference standards.

1.7.3.2 Changes in fluid temperature as well as pressure shall be monitored and shall be compensated to minimize its influence on the accuracy the meter.

1.8 Multipath Ultrasonic Flow meters

1.8.1 Description

Ultrasonic meters are inferential meters that derive the liquid flow rate by measuring the transit times of high- frequency sound pulses. They also measure flow rate using ultrasound, which can either be by "Doppler Method" or "Transit time differential method.

1.8.2 Design and Selection

1.8.2.1 Consideration shall be given to the following items in designing and selecting

Ultrasonic flow meters:

1.8.2.2 The class, type of piping connections, materials and the dimensions of the equipment to be used; minimum and maximum operating flow rates; space required for the installation of the metering and proving system; acceptable pressure drop across the meter and minimum and maximum ambient and process temperatures shall generally be in accordance with API MPMS Chapter 5.8 and other relevant standards.

1.8.3 Operation

1.8.3.1 After an Ultrasonic flow meter is calibrated to determine one or more calibration coefficients, these coefficients shall be entered to the Ultrasonic flow meter Signal Processing Unit (SPU) in the presence of representative of the Department of

Petroleum Resources and shall remain unchanged. However, for factors that can affect the quantities measured by the meter that must be changed, an approval shall be granted by the Director of Petroleum, and adjustments must be retained in the audit trail.

1.8.3.2 Meter factors shall be determined over a range of flow rates. The various meter factors can then be used to linearize the output from the Ultrasonic flowmeter at varying flow rates. If the meter is used to measure bidirectional flow, a meter factor should be developed for each direction.

1.9 General Regulation

1.9.1 All meters at facilities shall be proved during every loading operation or at other frequencies approved by the Department of Petroleum Resources while those at other custody transfer points shall be proved fortnightly in accordance with the procedure outlined in this guide. Production meters shall be proved monthly.

1.9.2 Meters shall be proved under their normal operating conditions with the same type of liquid being measured by them.

1.9.3 Meter Linearity test shall be conducted annually during annual recertification exercise or when the need arises and a performance (linearity) table and curve shall be established for each meter as outlined in this guide.

1.9.4 All meters shall be proved before being put to use and also after maintenance.

1.9.5 Continued acceptance of a meter for use shall depend on its maintenance of satisfactory performance during successive meter proving (or linearity) as adjudged within the set down tolerance limits.

1.9.6 Each meter in the bank shall be equipped with adequate protection devices such as valves, air eliminators, flow conditioning vanes and other measuring instruments as indicated on the approved Detailed Engineering Design (DED).

1.9.7 The flow conditioning vanes shall be installed within a distance of 5D (5*internal diameter) of the pipe upstream the meter where applicable.

1.9.8 The meter shall be in the same horizontal plane with the pipeline.

1.9.9 The meter bank shall be equipped with a dedicated prover preferably the pipe prover type. Provisions shall be made for proving meters at other measurement points by any of the methods specified in this guide.

1.9.10 Installation and commissioning shall follow appropriate reviews and approvals by the Department of Petroleum Resources of factory calibration and on-site control proving.

1.9.11 A control chart shall be established and maintained for each flow meter.

1.9.12 Results of all proving shall be carefully interpreted to identify the maintenance requirements that are due. Determination of when to repair or inspect a meter shall be by keeping a control chart of its meter factor values for each product or grade of petroleum and petroleum products. Small random changes in meter factor will naturally occur in normal operation, but if the value of such a change in meter factor exceeds ±2 standard deviation (±2σ) on the control chart the cause of the change should be sought and maintenance provided.

For this purpose, the procedure outlined in Section 3.2.3 of this guide shall be followed in proving all the meters in the bank for performance monitoring.

1.9.13 In a case where the counter of a meter is found stuck, the volume/quantity of petroleum and petroleum product that has passed through shall be established by the material balance between the estimated quantity based on the pumping rate and the gross receipt at the tank farm downstream the meter, or for cases where the meter is installed between two tankages, the material balance of petroleum and petroleum product quantities in the two tankages over the period concerned.

1.9.14 In a case where the meter fails during measurement operations, average meter factors established during the three preceding proving shall be used to estimate the quantity of petroleum and petroleum product passed through during the operations. However, if the meter failure persists after 30 days, the Department's approval shall be sought for further guidance.

1.9.15 In the case where critical instrument/part of the metering system such as four-way valve, flow computer etc. fails to function, Part II Section 1.9.14 shall apply for four (4) export liftings only. Thereafter, static measurement shall be used, and outturn of such export shall be verified by DPR.

PART II SECTION 2

PROVING SYSTEMS

2.1 Approved Proving Systems

Pipe prover of the bi-directional or uni-directional type shall generally be the approved meter proving device at all custody transfer and production Monitoring points. However, the use of a master meter or any other prover shall be allowed in special cases and on specific request to and approval by the Director of Petroleum Resources.

Exceptional case should be when the pipe prover is out for maintenance. However, Coriolis and ultrasonic meters of the same type with that in the meter bank shall be used.

2.2 General Specifications

2.2.1 Meter proving systems and procedures shall generally conform to the specifications stipulated in the API Manual of Petroleum Measurement Standards (MPMS) Chapters 4 and 12.

2.2.2 The bi-directional prover shall be equipped with a wall sealing four-way valve for flow reversal.

2.2.3 Provers Shall be capable of continuous proving operation without interrupting any on-going loading operation.

2.2.4 The minimum distance between detector switches (calibrated prover volume) shall be 15m (where detector's resolution is less than or equal to 0.03". When greater than 0.03", distance may be reduced).

2.2.5 The maximum sphere velocity in the loop shall be 1.5m/s or 5ft/s (Bi-directional) and 3m/s or 10ft/s (uni-directional).

2.2.5.1 For piston displacers, a maximum of velocity of 3ft/s -- 5ft/s (1-1.5ft/s).

2.2.6 The repeatability of the bi-directional prover when the base volume is calibrated shall be within 0.020% for forward, reverse and roundtrip; while for uni-directional prover, the repeatability shall be within 0.020%.

2.2.7 The volume between the detectors shall be sized to enable at least 10,000 pulses to be generated by the meter and collected in the totalizer during the proving run.

2.2.8 All the valves in the system shall be made bubble-tight.

2.2.9 The Automatic Temperature Compensator (ATC) set point of any meter shall fall within ±20°F of the prevailing average field API gravity at 60°F.

2.2.10 Detection devices must be rugged and reliable as any major replacement/maintenance shall lead to Prover loop revalidation.

2.2.11 All Custody transfer loops shall be thermally insulated to enable thermal stability to be achieved in good time during proving.

2.2.12 The insulation material shall be as specified in ASTM C-547.

2.3 Installation

The layout shall basically be as illustrated in the DPR approved Detailed Engineering Design (DED). However, other devices to improve the quality and performance of the Prover may be included.

2.4 Applicable Standards for Design, Installation, Operation and Maintenance of Proving Systems

The applicable standards for Design, Installation, Operation and Maintenance of proving systems shall be American Petroleum Institute Manual of Petroleum Measurement Standards (API MPMS) Chapters 4, 12 and 13.

2.5 Calibration of the Prover Loop

2.5.1 Accreditation

This shall be on job by job basis and any corporate body wishing to carry out a prover calibration shall be pre-qualified for the job by the Department of Petroleum Resources.

2.5.2 Frequency

2.5.2.1 All new pipe provers shall be calibrated in the presence of representative(s) of The Department of Petroleum Resources at the site of manufacturer and thereafter annually for prover loops used for Custody transfer, and every three (3) years for prover loops used for production monitoring.

2.5.2.2 All calibration exercises shall be witnessed, and the result countersigned, by representative(s) of the Department of Petroleum Resources.

2.5.2.3 It is mandatory for in-factory calibration of the loop to be by waterdraw method.

2.5.2.4 All other measuring equipment associated with the Prover such as thermometers, temperature gauges and transmitters, temperature compensators, pressure gauges and transmitters, auto samplers, densitometers, etc. shall equally be calibrated according to the relevant sections of this guide.

2.5.3 Procedure

Although only waterdraw method is acceptable for calibrating new Provers, the master meter method shall be allowed for subsequent calibration of the Prover while in operation. The field standard test measure to be used for water draw calibration shall be traceable to a primary standard established at standard condition. All the steps outlined in the reference standard shall be followed in carrying out the calibration exercise. The base volume to be established shall be the sum of the volume displaced between the two detectors for a round trip of the displacer and this shall fall within 0.020% repeatability.

2.5.3.1 Do five or more out of a maximum of ten consecutive runs which shall agree within a range of 0.020% or less for pre and post meter factor.

2.5.3.2 Do three or more out of a maximum of six consecutive runs which shall agree within a range of 0.020% or less for calibrated prover volume.

2.5.3.3 The flow rate during a calibration run shall be maintained within a range of ±2.5%.

2.5.3.5 The delta % of pre and post meter factor shall agree within 0.020%

$$\text{Delta \%} = (\text{Pre-meter factor} - \text{Post-meter factor}) * 100$$

2.5.3.6 During annual recalibration exercise, the difference between the established Base Prover Volumes and the previous year's Base Prover Volume shall not exceed 0.02%.

2.5.3.7 A minimum of three (3) flow rates at minimum of 25% interval shall be used during prover loop certifications. The volumes so derived from each flow rates shall check within 0.020% repeatability.

2.5.4 Presentation of Results

2.5.4.1 The result of the calibration shall be presented in a standard form and will contain the following information:

a) Prover serial number, type, dimensions and the proving location.

b) Field Standard (test measure) – Nominal capacity identification and certifications.

c) Observed values – pressure, temperature, density and volumes.

d) Corrections for temperature, pressures, Prover materials and proving liquid.

e) Base Prover Volume calculation.

2.5.4.2 Results of calibration by master meter method shall be in the standard form giving information on the Prover, master meter and how its meter factor was established on site and the Base Prover volume calculation.

2.5.4.3 For Prover calibration using a Master meter, the master meter calibration flow rate shall agree with the flow rate at which the Prover is to be calibrated.

2.5.4.4 The calibration result shall be endorsed by representative of Department of Petroleum Resources and approved by the Director of Petroleum Resources if found satisfactory and this shall constitute approval for the continued use of the Prover concerned.

2.5.4.5 Input or change of Base Prover Volume and other parameters shall ONLY be in the presence of an officer of the Department of Petroleum Resources.

2.5.4.6 For conduct of linearity test after a prover loop certification exercise, a newly generated BPV shall be used and immediately replaced with the old approved BPV pending the approval of the new BPV by the Department.

2.6 Meter Proving Operations

2.6.1 Definition

This is the procedure used to determine the relationship between the true volume of a liquid measured by a meter and the volume indicated by the meter. This relationship is generally called the meter factor which is expressed as the ratio of the actual volume of a liquid passed through the meter to the volume registered by the meter.

2.6.2 General Consideration

2.6.2.1 Meters shall be proved as close to their normal operational conditions as possible.

2.6.2.2 Meters shall be proved with liquid to be metered, or if not practicable such as the case of in-factory tests, with a liquid whose density and viscosity are very close to those of the liquid to be measured.

2.6.2.3 Five consecutive proving runs must check to 0.020% repeatability, else the meter shall be taken out for inspection and repair before being put back into service.

2.6.3 Approved Meter Proving Procedure

2.6.3.1 The standard device approved for meter proving shall be the bi-directional or uni-directional pipe Prover. However, tank provers and master meters shall be accepted on case basis.

2.6.3.2 A representative of the Department of Petroleum Resources shall always be present during any proving exercise. In conducting a proving run for pipe Prover, master meter or tank Prover, all steps outlined in API MPMS 4 and 12 or its equivalent standards shall be followed, and the results shall be presented as indicated by the example in Appendix V for a pipe Prover proving run.

2.6.3.3 In case where proving has been by tank Prover or master meter method, the procedure outlined in the reference standard shall be closely followed in carrying out the proving and presenting the results.

2.6.3.4 The following requisite steps must be adhered to before Meter Proving:

a) The entire fluid stream from the meter to be proved is diverted to flow through the prover, care being taken to ensure that there are no leakages from the valve assembly as this may lead to erroneous results. Flow is maintained through the meter and the prover section until stable conditions of temperature and pressure are reached.

b) Entrained air or vapour shall be removed from the pipeline connections and the prover by venting at suitable points (usually the highest points of the Prover pipe).

c) The two detector switches which demarcate the calibrated section of the Prover loop are also connected to the electronic counter by means of an electric cable.

d) The electronic counter is then plugged to a power source.

e) The electronic counter shall be tested for its repeatability which must not exceed a difference of ±0.0002. This test is achieved by switching on the "TEST" button of the electronic counter. When the button/switch is on, the counter should intermittently register 1,000 counts (pulses). These counts should check to within ±2.

f) Calibrated pressure gauges and thermometers of appropriate types shall be mounted at both the inlet and outlet sections of the Prover loop.

g) Flow rate shall be noted to be constant and within the designed range. This is achieved using a stop watch to repeatedly time the liquid flow through the meter.

h) The back pressure down-stream of the meter shall be maintained at the manufacturer's recommended figure to ensure that there is no cavitation or excessive swirling in the vicinity of the meter.

i) Trial proving run shall thereafter be conducted as a final check before the commencement of a recorded meter proving.

2.6.3.5 Proving Run

a) The ball is launched by operating the appropriate Prover valves. The ball should move into the flowing stream from the housing tee, and be swept into the Prover loop section

b) After the ball has passed the second micro-switch, it moves into rest within the housing tee. The ball has now completed a proving trip. This trip is equivalent to a proving run if the uni-directional Prover loop is used. With the bi-directional type, the ball is again launched, and the movement of fluid is reversed in order to obtain a complete run.

c) The duration of each run is obtained in seconds by using a stop watch. The electronic counter registration and the duration for the complete run are recorded.

d) Proving inlet and outlet pressure and temperature readings are recorded as each proving run is in progress. Upon completion of each complete run and when all the data obtained have been recorded, the electronic counter is reset to zero and additional proving runs are made.

e) Sufficient runs shall be made to verify the repeatability of the system. However, a set of five consecutive runs, which checks within 0.020% (2 counts per 10,000 counts), should be obtained before a proving exercise is regarded as successful and acceptable. The gravity of the fluid flow during proving must also be determined.

f) When proving manifolds are not equipped with automatic samplers, it is desirable that samples be collected from a sampling point located on the prover loop until such a time that automatic samplers are installed on such metering manifolds. Sampling should be done when a set of five acceptable runs have been made. Ambient temperature reading for each sample shall also recorded.

2.6.4 Meter Proving Report

A Standard Meter Proving Report Sheet is divided into "Meter Volume Data" and "Prover Volume Data". All the data obtained during meter proving shall be properly entered in the Meter Proving Report Sheet and this shall form the basis for Meter Factor calculation.

2.6.4.1 Meter Factor Calculation

The known volume of Prover was calibrated at 60°F at atmospheric pressure. The Prover and metered volumes shall be corrected to the same standard using the under listed correction factors. When calculating meter factors or measurement tickets for the effect of temperature and pressure, use valid tables of values. When two or more correction factors enter a calculation, multiply them together in a set sequence.

a) Temperature Correction Factor for Steel (CTS)

This shall be computed from the following formula:

CTS =$\{1 + (T - 60°F) * G_C\}$

Where T = observed temperature in °F

G_C = mean coefficient of cubical expansion per °F for the material of which the container is made between T and 60°F.

b) Temperature Correction Factor for Liquid (CTL)

This is the volume correction factor obtained from API MPMS Chapters 11.1 and 12.

CTL = exp $\{-\alpha\Delta t[1 + 0.8\alpha(\Delta t + \delta)\}$

c) *Pressure Correction Factor for Steel (CPS)*

This shall be computed from the following formula:

CPS = 1 + $\{\frac{(P*D)}{(E*t)}\}$

Where P = observed pressure, psi

D = internal diameter of prover, inches

t = wall thickness of prover, inches

E = Modulus of Elasticity

d) *Pressure Corrections Factor for Liquid, i.e. Compressibility, (CPL)*

This shall be computed from the following formula:

CPL = $\frac{1}{\{1-(P*F)\}}$

Where P = observed pressure, psi

F = Compressibility factor of the medium of calibration

F = exp $\{A+Bt+\frac{C+Dt}{\rho^2}\}$

2.6.4.2 Proving Reports

2.6.4.2.1 Department of Petroleum Resources representative(s) shall witness prover/meter calibrations and endorse field data generated there from.

2.6.4.2.2 Final calibration certificate/report for the newly generated base prover volume (BPV) shall be approved by the Director DPR. Calibration for subsequent year shall commence on site at least three (3) months before the expiration of the current base volume(s). Pending the approval of the new base volume(s), previous base volume(s) shall be used. Validity of all base volumes shall be 12 months.

2.6.5 Rules Governing Meter Proving

2.6.5.1 A meter shall be proved to obtain an initial meter factor as soon as the meter is installed for use in a facility.

2.6.5.2 Thereafter, if the meter is in use as the only means of determining the fiscalized production of a company in a given area it should be proved fortnightly but if installed on an export facility it should be proved during every loading exercise.

2.6.5.3 If the meter is installed in any other type of facility it shall be proved once every month.

2.6.5.4 If a meter is removed for service/maintenance, it shall be proved before it is put back into operation.

2.6.5.5 During export meter proving, the repeatability of each set of five (5) proving runs shall check within 0.040% repeatability while for production, allocation and custody transfer meters, repeatability shall be 0.050%.

2.6.5.5.1 During the certification of Master meters, repeatability shall check to 0.020%.

2.6.5.6 Oil producing Companies shall on a monthly or quarterly basis, submit to the appropriate field office of the Department of Petroleum Resources, an acceptable schedule for the proving of all meters in use at their facilities.

2.6.6 Rules Governing Meter Factors

2.6.6.1 The difference between the meter factors calculated from each of the series of complete runs made for a meter in a proving operation should not exceed ±0.0015. Where this limit is exceeded, the proving should be regarded as unsuccessful, and the meter serviced. During servicing, the clearances are checked and wax or any foreign deposit is removed before the meter is re-assembled, ensuring minimum change in the set point (s) of the meter's inner mechanism components/ accessories. A second proving is then carried out to establish a meter factor which would be regarded as base factor (as there could occur a change in the inner mechanism accessory). Thereafter, if subsequent meter proving yield meter factor which are out of tolerance, with other conditions remaining within acceptable range, the inner mechanism (including any other major accessory) is changed in the presence of a representative of the Department of Petroleum Resources.

2.6.6.2 An initial meter factor shall be re-established for the meter before it is put back to use.

2.6.6.3 The difference between the meter factors obtained for any two successive proving for a meter should not exceed ±0.0025.

2.6.6.4 A meter performance chart (see attached specimen "Appendix V") shall be kept for each meter in use in all facilities.

2.6.6.5 The repeatability of five (5) consecutive proving runs of meter factor or K factor out of maximum of ten runs made for a meter proving operation should not exceed ±0.020% (0.040%).

$$\text{Repeatability} = \frac{Maximum\ Meter\ Factor - Minimum\ Meter\ Factor}{Minimum\ Meter\ Factor} * 100$$

$$\text{Or} \quad = \frac{Maximum\ K\ Factor - Minimum\ K\ Factor}{Minimum\ K\ Factor} * 100$$

2.6.7 Quality Control Chart

A quality control chart shall be established for each meter during the initial proving of the meter before it is put to use. The quality control chart shall be reviewed and revalidated after five consecutive operational proving of the flow meter. The quality control chart shall be re-established after every comprehensive overhaul or maintenance of a meter in which the inner mechanism set points or essential references have been altered.

PART III

PROCEDURE GUIDE FOR THE CALIBRATION AND CERTIFICATION OF MEASURING EQUIPMENT

1.1 Application

This procedure applies to all equipment used in the process of determining the quantity and quality of bulk petroleum and petroleum products at all facilities.

Specifically, the following equipment and devices shall be covered by the procedure:

i) Thermometers

ii) Hydrometers/Densitometers

iii) Steel Tapes

iv) Storage Tanks (upright cylindrical types)

v) Storage Tanks (horizontal cylindrical types)

vi) Storage vessels (Barges/FPSO/FSO)

vii) Trailer Mounted Tanks (Tank Cars)

viii) Pressure measuring instruments

1.2 General Guidelines

1.2.1 All these equipment shall be calibrated by an approved authority or accredited corporate body and in accordance with the procedure specified for each equipment and shall be witnessed by representative(s) of the Department of Petroleum Resources. Field Data/results generated shall also be reviewed and endorsed by the representative(s). Where data is to be inputted for tank tables computation, representative(s) of Department of Petroleum Resources shall participate.

1.2.2 In all cases, calibration companies shall be pre-qualified by the Director of Petroleum Resources. The validity period of a calibration certificate or table shall be as stated for each equipment and no equipment shall be accepted for use for measurement at any facility outside the validity period of its calibration certificate.

1.2.3 All equipment calibration shall be done locally except in cases where the facilities are not available locally in which case appropriate approval shall be obtained from the Director of Petroleum Resources for offshore calibration of such equipment.

1.2.4 Conditions for accrediting Corporate Bodies and Agencies to carry out equipment calibration shall be set out for each equipment type and shall form the basis of approval by the petroleum Resources of the certificate or table issued after a calibration exercise.

PART III Section 2

Calibration

2.1 Calibration of Mercury in Glass Thermometers

2.1.1 Accreditation

Only corporate bodies with current permits to render such specialized services to the oil industry by the Department of Petroleum Resources shall be eligible to carry out calibration of thermometers used in taking measurements at custody transfer points with participation of representative(s) of The Department of Petroleum Resources.

2.1.2 Principle

Thermometers used generally for measurement of liquid temperatures are always under partial immersion conditions, hence calibration shall be as specified for instruments of this type. Temperatures shall be referred to ice points and other fixed points on a secondary standard thermometer.

2.1.3 Frequency of Calibration

2.1.3.1 All new thermometers shall be deemed calibrated and an attestation to this fact by the manufacturer shall be sufficient.

2.1.3.2 All thermometers in service shall be calibrated annually. All calibration operations for facility instruments shall be witnessed and certified by representative(s) of the Department of Petroleum Resources.

2.1.4 Applicable Standard

This shall be the latest ASTM Standard under title "Standard Method for Verification of liquid- In –Glass Thermometers".

2.1.5 Calibration Equipment

2.1.5.1 Comparators as specified in the reference standard shall be used.

2.1.5.2 Secondary Thermometers which shall be calibrated annually against a primary standard thermometer of the platinum resistance type which has been certified by recognized bureau of standards.

2.1.5.3 Other ancillary equipment as outlined in the reference standard.

2.1.6 Verification and Calibration

2.1.6.1 The thermometer shall be inspected for entrapped gas, bubbles found shall be eliminated by the process outlined in the reference standard.

2.1.6.2 Similarly, inspection shall be carried out for the presence of liquid globules, any foreign matter, entrapped air and glass faults. Any of these defects that could not be rectified shall constitute enough reason to reject such defective thermometers.

2.1.6.3 Linear dimensions of the stem with regards to diameter, length and uniformity of graduation spacing, shall be checked in accordance with the procedure outlined in the Standard. Also, it shall be tested for bulb stability and for this purpose, the 24-hour heating period in the test bath shall be sufficient.

2.1.6.4 Thereafter, the thermometer shall be calibrated at ice point and at a minimum of two (2) other fixed points in accordance with the prescribed method for total immersion thermometers in an appropriate comparator device equipped with a certified secondary standard thermometer.

2.1.6.5 The data obtained by comparing the reading on the thermometer with the corresponding ones on the standard instrument of the comparator shall be collated and plotted to generate a calibration curve for the instrument.

2.1.7 Presentation of Results

2.1.7.1 A report of the calibration of each thermometer shall be submitted to the Department of Petroleum Resources for appropriate review and approval. The report shall provide information on the certifying Agency for the primary standard thermometer and that for the secondary standard thermometer used during the exercise. The respective dates of the last calibration as well as the next calibration of the primary and secondary thermometers shall be furnished in the report. Also, a summary of the steps followed in calibrating the thermometer under test and any observations made during the exercise shall be contained in the report.

2.1.7.2 The report shall also include the calibration data and the curve established for the instrument after the exercise which must then be approved by the Department of Petroleum Resources before the thermometer is allowed for use.

2.1.7.3 Where the thermometer error exceeds the maximum allowable temperature measurement accuracy, error correction shall be made using the accuracy curve or table whenever the thermometer is used.

2.2 Calibration of Hydrometers and Densitometers

2.2.1 Accreditation

Only companies or Institutions that possesses a current Petroleum Resources registration permit as an equipment calibrator shall be eligible to carry out hydrometer calibration with participation of representative(s) of The Department of Petroleum Resources.

2.2.2 Principle

Hydrometers and Densitometers shall be calibrated by comparing the specific gravity, API gravity and density readings of the test liquids as given by the hydrometer/densitometer with those simultaneously observed on the secondary standard hydrometer/densitometer in a standard comparator device.

2.2.3 Frequency of Calibration

All new hydrometers/densitometers shall be deemed calibrated before use and annually thereafter. Certificate of calibration issued by the manufacturer shall be acceptable as evidence of calibration of new hydrometers/densitometers.

2.2.4 Applicable Standard

Calibration method shall be as outlined in latest ASTM E126 "Standard Test Method for Inspection, Calibration, and Verification of ASTM Hydrometers", American Petroleum Institute Manual of Petroleum Measurement Standard (API MPMS) Chapter 9.1. For densitometers, American Petroleum Institute Manual of Petroleum Measurement Standard (API MPMS) Chapter 14.6 shall be followed.

2.2.5 Verification and Calibration

The hydrometer/densitometer shall be inspected for linear dimensional accuracy as described in the reference standard after which its reading shall be standardized in accordance with the prescribed procedure in the standard for liquid with low surface tension. As much as practicable, samples of petroleum or petroleum product of similar characteristics with those whose gravity will be measured during the operational life of the hydrometer/densitometer shall be used as the test liquid. The secondary standard hydrometer/densitometer to be used in the exercise shall have a valid certificate of its prior calibration against a primary standard hydrometer/densitometer which shall be issued by a recognized bureau of standard.

2.2.6 Presentation of Results

A report of the calibration exercise shall be submitted to the Department of Petroleum Resources for approval before the hydrometer/densitometer can be used.

This report shall be accompanied by a copy of the certificate of the calibration of the secondary standard hydrometer/densitometer that has been used as reference during the exercise.

2.3 Calibration of Pressure and Differential Pressure Measuring Devices

2.3.1 Accreditation

Only companies or Institutions that possesses a current Petroleum Resources registration permit as an equipment calibrator shall be eligible to carry out Pressure and Differential Pressure Measuring instrument calibration with participation of representative(s) of The Department of Petroleum Resources.

2.3.2 Principle

Pressure and Differential Pressure Measuring devices shall be calibrated by a pressure calibrator that is certified as intrinsically safe. The Pressure Calibrator shall have the ability to apply pressure to a pressure transmitter or pressure switch while simultaneously measuring the mA signal or switch contacts.

2.3.3 Frequency of Calibration

All Pressure and Differential Pressure Measuring devices shall be calibrated and certified in the presence of DPR official before being put to use and thereafter annually.

2.3.4 Applicable Standard

Calibration method shall be as outlined in latest applicable ASTM and American Petroleum Institute Manual of Petroleum Measurement Standard (API MPMS).

2.3.5 Verification and Calibration

2.3.5.1 All new Pressure and Differential Pressure Measuring devices shall be deemed calibrated before use and annually thereafter. Certificate of calibration issued by the manufacturer shall be acceptable as evidence of calibration.

2.3.5.2 If a Pressure and Differential Pressure Measuring device calibration error exceeds one-half of the scale division, error correction shall be applied whenever the instrument is used.

2.3.6 Presentation of Results

A report of the calibration exercise shall be submitted to the Department of Petroleum Resources for approval before the Pressure and Differential Pressure Measuring device can be used.

This report shall be accompanied by a copy of the certificate of the calibration of the secondary standard Pressure and Differential Pressure Measuring device that has been used as reference during the exercise.

2.4 Calibration of Metal Tapes

2.4.1 Accreditation

Only companies or Institutions that possesses a current Petroleum Resources registration permit as an equipment calibrator shall be eligible to carry out metal tape calibration with participation of representative(s) of The Department of Petroleum Resources.

2.4.2 Principle

Calibration shall be based on comparison of the horizontal length of tape with that of a valid Master Tape calibrated in a recognized laboratory under the same tension at a reference temperature of 68°F (20°C).

2.4.3 Frequency of Calibration

All new tapes shall be deemed calibrated and an attestation to this effect by the manufacturer shall be recognized as evidence of this calibration. Annually thereafter throughout the operational life of the tape.

2.4.4 Applicable Standard

This shall be the API MPMS 2.2A or its latest ASTM equivalent standard.

2.4.5 Verification and Calibration

2.4.5.1 The tape shall be calibrated against the length of a secondary standard tape both under a tensile force of 1lb or 0.45kgf with both tapes being supported on a horizontal plane along their entire length.

2.4.5.2 The Master Tape shall be covered by a current certificate issued by a recognized bureau of standards as evidence of a recent calibration against a primary standard-length measure.

2.4.5.3 Both tapes (Master Tape and Working Tape) shall be inspected for kink before calibration.

2.4.6 Presentation of Results

A report of calibration exercise shall be submitted to the Department of Petroleum Resources office for review and approval. However, the allowable tolerance limit of variation in total length of the steel tape shall be 0.005ft (0.0015m) for every 100ft (30.48m) of tape length.

2.5 Calibration of Vertical Cylindrical Tanks

2.5.1 Accreditation

This shall be on job basis. Any corporate body proposed by an operator to carry out a tank calibration exercise shall formally apply to the Department of petroleum Resources for accreditation. Such application shall be considered in the light of the expertise and previous performance of the applying company, the proposed programme of calibration and chart computation, and other applicable conditions as specified by The Department of Petroleum Resources and shall be with participation of its representative(s).

2.5.2 Principle

Calibration of vertical cylindrical tanks is a process of accurately measuring such parameters of a vertical storage tank like circumferences at specific locations, vertical height, plate thickness, weights and volume of internal and external fixtures and bottom plate with the purpose of drawing up a calibration chart for the tank to show quantity of petroleum and petroleum products at any given depth.

2.5.3 Frequency of Calibration

2.5.3.1 All new tanks shall be calibrated before commissioned to service and mandatorily after every five years of its operational life.

2.5.3.2 A tank shall also be automatically due for recalibration, if the circumferential reading shows a difference of 0.015% and above, at a reference point, over the reading of the last calibration of the tank.

2.5.3.3 A tank shall be recalibrated whenever the deadwood has changed in configuration or arrangement.

2.5.3.4 A tank shall be recalibrated on relocation of the tank to another position.

2.5.3.5 A tank shall be recalibrated after any major repair or maintenance of the tank

2.5.4 Applicable Standard

Calibration method shall be as outlined in latest American Petroleum Institute Manual of Petroleum Measurement Standard (API MPMS) Chapters 2.2A, 2.2B, 2.2D, 2.2F, API Standard 2555 (Method of Calibration by Liquid Calibration) as well as ISO 7507-5.

2.5.5 General Practices

2.5.5.1 Before a tank is calibrated, it shall be ascertained that the tank has been filled at least once with a liquid of a density equal to or greater than the normal service liquid.

2.5.5.2 All tanks in service shall be cleaned out and checked for bottom alignment every five years.

2.5.5.3 Any maintenance or repair job that involves replacement of plate sections or alteration of the "Deadwood" of the tank shall automatically invalidate the existing tank capacity tables and a new calibration of the tank shall be carried out before re-commissioning.

2.5.5.4 Any modification to the tank changes its capacity by more than 0.015% of the original shall invalidate the existing tank table.

2.5.5.5 There shall be no movement of petroleum or petroleum products into or out of the tank during calibration.

2.5.5.6 Before a tank shall be deemed ready for calibration, it shall be thoroughly cleaned and degassed.

2.5.6 Manual Tank Strapping

2.5.6.1 Calibration Equipment

These shall be as stated in the reference standards and shall comply with appropriate specifications. The essential equipment shall be the same with those for taking measurements of tank shells above ground and shall always be maintained in good condition. Both the tape for height measurement and that for circumference measurement shall themselves have been calibrated in accordance with the Part III Section 2.4 or possess a current certificate of recent calibration at 68ºF (20ºC) in accordance with a recognized National Bureau of Standard. Also, the equipment for determining temperature and gravity shall be as follows: -

2.5.6.2 Presentation of Results

2.5.6.2.1 The calibration chart shall bear the full name and address of the calibration company, the tank number, name of operator, location of tank farm and other parameters indicated in the format shown in 2.5.8.2.2 below.

2.5.6.2.2 The tank table/chart shall also contain a column in which the approval of the Director of Petroleum Resources to the use of the tank table shall be endorsed.

2.5.6.3 General Consideration

Serious attention shall be paid to the following factors which shall be adequately compensated for in the tank table:

2.5.6.3.1 Expansion and contraction of the tank shell under liquid head and temperature.

2.5.6.3.2 Effect of tilt on cylindrical portion of the tank.

2.5.6.3.3 Alignment of the tank bottom

The actual strapping and measurement shall generally follow the procedure described in the reference standard to obtain the necessary parameter of circumference, shell plate thickness, height, temperature and gravity of the oil in the tank during strapping.

2.5.6.3.4 Deadwood

The size and locations of the "Deadwood" in the tank shall be accurately determined and reflected in the field report.

2.5.6.3.5 Floating Roof Adjustment (Correction) Factor

Tanks fitted with floating roofs shall have proper provisions made in the tank table for computing float roof effect.

The weight of the roof and all its appurtenances shall be separately determined and reflected in the tank table.

2.5.6.3.6 Critical Zone

All tanks with floating roofs shall have their "critical zones" calibrated with liquid in accordance with API 2555 or ASTM –D1406. A separate calibration chart for the critical zone shall be prepared for each tank of this type.

2.5.7 Electro-Optical Distance-Ranging method

2.5.7.1 Calibration Equipment/instrument

These shall be as stated in the reference standards and instrument to be used shall comply with appropriate specifications including 5.1 of ISO 7507-4.

The tank bottom shall also be calibrated by the liquid method in accordance with API Standard 2.2A by use of the electro-optical ranging instrument, a surveyor's level, or by use of water-filled tubes.

2.5.7.2 Calibration Procedure

Target points shall be sighted along the horizontal plane at each course location, and measure the slope distance, horizontal angle and vertical angle to each of the reference target points. After all measurements on a course are completed, repeat the measurements to the reference target points. Once the internal radii are calculated, the development of the capacity table shall be carried out in accordance with API MPMS Chapter 2.2A.

2.5.7.3 General Consideration

The following corrections shall be applied in the development of the capacity tables:

a) Correction for hydrostatic head effect.

b) Correction to the certified tank shell temperature.

c) Correction for deadwood and correction for tilt.

2.5.8 Presentation of Result

2.5.8.1 Field Data

These shall include all data collected during strapping as illustrated below:

Location:

Date:

Name of Calibrating Company:

Name of Operator:

Tank No:

Date of Last Calibration:

Shell Height:

Gauging Height:

Type of Roof:

Weight of Floating Roof:

Tank Contents (deadwoods):

Average Liquid Temperature (°F):

Temperature at which the capacity table is generated:

Gauge:

Tank Service:

API gravity:

Shell Circumferences -

A: Descriptions of Shell plates and Joints:

Ring No.	Thickness	Type of Vertical Joint	Set in/out	Thickness of Lap or Strap	No. of Joints

Deadwood Records:

Description	Number	Size	Elevation	
			From	To

Type of bottom:
Height of Crown:
Other Details:
Calibration Company:
Measurements by:
DPR official witnessing:

2.5.8.2 Calibration Chart

2.5.8.2.1 This shall contain information on the nominal dimensions of the tank, the weight of floating roof where applicable, the critical zone and any other special conditions.

2.5.8.2.2 In addition to the main calibration table for the whole height of the tank (except the critical zone) which shall be in volume at 60°F, floating roof displacement table and the calibration table for the critical zone of the tank shall be included in the main chart. Calibration chart shall conform generally with the format sketched below:

Location:
Date of Calibration:
Name/ Address of Calibration Company:
Name of Operator:
Tank No:
Nominal Dimensions:
Nominal Capacity:
Weight of Floating Roof:
Table Volume at Standard Temperature of 60^{O}F:
Other Special Conditions:
Production Depth:
Cumulative U.S. Barrels:

Prepared By: Approved By:

……………………… ……………………….

Calibration Company Rep *Director of Petroleum Resources*

2.5.8.2.3 Both the chart and the field data shall be submitted to the Department of Petroleum Resources for appropriate review and approval before the tank table becomes valid for official measurement.

2.5.8.2.4 Representative of the Department of Petroleum Resources shall participate during the tank charts/table generation.

2.5.9 Optical Reference Line Method (ORLM)

Other methods for calibration of storage tanks include: Optical Reference Line Method (ORLM): This method employs a mobile magnet trolley or similar device which carries the measuring rule, up and down the tank height. Applicable standards: API 2.2B, ISO 7507 -2 or any of its recent revisions.

2.5.10 Optical Triangulation Method:

This type accomplishes calibration through optical methods and the tank profile is established by triangulation. Applicable standards: API Chapter 2.2C or ISO 7570-3 or its latest revisions.

2.5.11: General Consideration

2.5.11.1 No false-bottom, capillary, inflatable devices, unapproved deadwoods or similar design is allowed in storage tanks.

2.5.11.2: For all tank farms, all back-loading lines connected to storage tanks or metering systems and/or stations shall be flanged off and locked via one-way valve, the key of the padlock shall be kept in custody of Officer In charge (herein referred to as the Officer of the Department).

2.5.11.3: Conversely, all petroleum inter-tank transfers, circulation, recirculation, redistribution, diversion or any similar movement of petroleum or petroleum products shall be with prior written approval of the Department's Representative or Officer In-Charge at the facility. However, for activities that will affect the Non-resettable totalizer, an approval shall be granted by the Director Petroleum Resources.

2.6 Calibration of Horizontal Storage Tanks

2.6.1 Accreditation

Any corporate body or institution proposed by an operator to carry out the calibration of this group of tanks shall be accredited on job by job basis by the Department of Petroleum Resources. The procedure for securing such accreditation shall be as enumerated in Part III Section 2.5.1 of this guide.

2.6.2 Principle

The underlining principle for calibrating horizontal tanks is that of computing its incremental volume from geometric dimensions of the cylindrical main body of the tank and those of the two heads. Other factor like the deadwood contents of the tank, elasticity of the shells due to liquid pressure and inclination of the tank to the horizontal are also taken into consideration.

2.6.3 Frequency of Calibration

The frequency of calibration of Horizontal tanks shall be as outlined in Part III Section 2.5.3 above.

2.6.4 Applicable Standard

Calibration method shall be as outlined in latest American Petroleum Institute Manual of Petroleum Measurement Standard (API MPMS) Chapters 2.2E, API Standard 2551 or ASTM D-1410 captioned "Standard Method for Measurement and Calibration of Horizontal Tanks.

2.6.5 Calibration Equipment

These shall be as enumerated in the reference standards and shall comply in all respects with the specifications stipulated in the standard.

2.6.6 Calibration Procedure

The tank shall be thoroughly cleaned, degassed, and completely filled with water prior to calibration to ensure that the shells are stretched to the maximum level that they could reach during operational life. Therefore, the procedure outlined in the reference standard is followed to obtain the necessary parameters for preparing a calibration chart for the tanks. Parameters to be obtained shall be those for critical measurements in the tank such as shell plate thickness, circumferential perimeters of each ring along the cylindrical portion, geometric dimensions of the deadwood, inclination of the tank to the horizontal plane if it is off-level and other parameters applicable to the mode of construction of the tank.

2.6.6.1: Every tank after calibration and approval of usage shall display conspicuously on the surface: ''Tank number'', ''Tank Service'', ''Date of Calibration'' and ''Due date for next Calibration''. Frequency of storage tank inspection and calibration shall be every 5 years.

2.6.6.2: For all new and repaired or rehabilitated aboveground floating roof storage tanks, there shall be lightning protection for unintended upsurge in static electricity and lightening arrestors as safeguard against possible rain storm or thunder installed within approved specifications in line with API Recommended Practice 545 or NFPA 780 (Lightning Protection Code) or any other approved international standards or recommended practice.

2.6.7 Presentation of Results

The field data shall show a diagrammatic representation of the tank with the geometric dimensions of each shell ring and the tank heads indicated. Other necessary data to be reflected are the liquid type and its level in the tank during strapping, cylinder shell thickness and that of the heads, and the horizontal inclination of the tank. Tank calibration report shall also include the calculations of the volumes of the main cylinder and that of the two heads, the spread diameter and the partial volumes of the tank. The appropriate K factor of the circular segments of the tank and those of the segments of the heads shall be obtained from the standard tables of the reference standard to produce the required calibration chart for the tank to be presented in the format shown below:

Location:

Date:

Name/Address of Calibrating Company:

Name of Operator:

Tank Identification:

Height	M/D	K_c of Cylinder	K_c * Vol of Cylinder	K_n of Head	K_n*Vol Head	Partial Vol.	Interv. Vol.

Where,

Height = Incremental height of the tank.

M/D = Ratio of incremental height to the spread diameter.

K_c = Ratio of area of the full circle of the cylinder to that of the segment given by standard table.

K_n = Co-efficient of the ratio of the volume portion of the head to the total volume of head at the respective incremental height given by the standard table.

Prepared By: Approved By:

……………………… …………………………….

Calibration Company Rep *Director of Petroleum Resources*

2.7 Calibration of Storage Vessels (Barges/FPSO/FSO/Coastal Vessels)

2.7.1 Application

This procedure and that for the calibration of Tank Cars shall be followed in fulfilling the requirement for the certification of receptacles used for transportation of liquid petroleum products in accordance with Part II of the Petroleum Regulations of 1967.

2.7.2 Accreditation

This shall be on annual basis and in accordance with the procedure outlined by the Department of Petroleum Resources for registering Oil Industry Service Companies. Calibrating Companies, before accreditation, shall always be required to show evidence of expertise and equipment with which to conduct such exercises up to the standards specified herein.

2.7.3 Principle

The underlining principle for this procedure is to obtain the linear incremental volume of each tank in the storage vessels taking into consideration their design and construction features. Appropriate correction shall be made for the chamber, expansion hatches and all the deadwood in the form of stiffeners, pipelines, valves etc. The recommended method shall be to dry-dock the storage vessels on even keel and inject measured known quantity of water into the barge tank being calibrated and recording the height of the liquid above datum in the tank or any other method as approved by Director of Petroleum Resources.

2.7.4 Frequency of Calibration

All storage vessels/tanks shall be calibrated before being put into operation and subsequently after five operational years or after any maintenance work necessitating changes to the deadwood of the tanks in the form of size, number and arrangement.

2.7.5 Applicable Standard

This shall be API MPMS 2.8A, API Standard 2553 or ASTM –D1407 under title "Measurement and Calibration of Barges".

2.7.6 Calibration Equipment

The basic and accessory equipment shall be as specified in the reference standards and shall comply with the specifications stipulated therein.

2.7.7 Calibration Procedure

2.7.7.1 Each tank shall be thoroughly cleaned prior to calibration and water shall be used as the calibrating liquid. The shore tank containing the calibrating liquid shall itself must have been calibrated in accordance with Part III Section 2.5 of this guide and in which details of the approved procedure for calibrating vertical cylindrical tanks has been outlined.

2.7.7.2 Liquid draw from the shore tank shall be by gravity drive. However, if the storage vessels are to be calibrated using meters, then the measurement procedure shall be as stipulated in API Standard 2555, ASTM D-1406 and API MPMS Chapter 5.2. The procedure outlined in reference standard shall be generally followed to obtain the internal tank measurements, temperature and gravity parameters, linear deck measurements and deadwood measurements.

2.7.7.3 Calculation of the barge tank capacity and incremental volume shall be made in accordance with the steps outlined in the reference standard.

2.7.8 Presentation of Results

2.7.8.1 The field data to be submitted along with the calibration chart of each tank in the storage vessels shall contain the following information:

a) Name of storage vessel.
b) Name and address of operating Company.
c) Name and address of calibrating company.
d) Name of builders of the storage vessel, the date of construction and date of last calibration of tank.
e) Nominal capacity.
f) Compartment or tank number.
g) Total height.
h) Linear measurements.
i) Deadwood description.
j) Gross Volumes.

2.7.8.2 The calibration chart shall be prepared showing the incremental net volumes at 60°F with appropriate indication of the total under deck cargo capacity.

2.8 Calibration of Tank Cars-Vehicle Mounted Petroleum Bulk Carriers

2.8.1 Application

This shall be as is the case for barges in Part III Section 2.7. This procedure shall be used to calibrate the tank compartments of all vehicle mounted liquid Petroleum and Petroleum Products bulk carriers operating under the provisions of Part II of the Petroleum Regulations 1967.

2.8.2 Accreditation

All corporate bodies and agencies wishing to be accredited as authorized calibrators shall lodge appropriate applications for registration as Oil industry Service Companies with the Department of petroleum Resources. Such registration shall be annual and constitute the accreditation of the agency concerned.

2.8.3 Principle

The underlining principles for this procedure shall be to determine the capacity of each tank compartment of non-pressure type tank cars by using standard volume measure or weighing on properly calibrated scales.

2.8.4 Frequency of Calibration

After the pre-operational calibration of a tank car, a re-calibration shall become due whenever the tank car is modified or damaged with visible dents on the tank body. Besides these operational situations, all tank cars shall be recalibrated after every three years of service.

2.8.5 Applicable Standard

In the conduct of calibration of cargo compartment of tank cars, the general outline specified in the API standard 2554 or ASTM D-1409-65 shall be followed.

2.8.6 Calibration Equipment

These shall consist of a primary volume measurement which has been certified for accuracy by an agency recognized by the Department of petroleum Resources, calibrated gauge tanks and weighing apparatus all to the specifications stipulated in the reference standard API 2554.

2.8.7 Calibration Procedure

2.8.7.1 Water Gauge Method: The arrangement of the water gauge plant shall be as described in the standard. The primary volume measure to be used in calibrating the gauge tanks shall be of a nominal capacity of between 5 gallons and shall be certified by a bureau of standards recognized by the Department of Petroleum Resources.

2.8.7.2 The gauge plant shall be covered to shield the tank car from weather effect during calibration while the track of the car at the calibration bay shall be concreted and level.

2.8.7.3 The gauge tanks and finishing tanks shall be calibrated in accordance with the procedure outlined in the reference standards before being mounted on the water gauge plant.

2.8.7.4 Each cargo compartment of the tank car shall be calibrated in turn with water from the gauge tanks while the volume and corresponding liquid levels in each compartment shall be noted and recorded. A capacity chart of the tank car shall then be drawn up containing the calibrated capacities of each of the compartments.

2.8.7.5 Water weighing Procedures: A weighing device which has been certified for accuracy by a body or Agency recognized by the Department of Petroleum Resources shall be used for this exercise.

2.8.7.6 The net weight of water in each compartment of the tank car shall be obtained in turn and in accordance with the procedure outlined in the referenced standards. Based on this measurement, a calibrated capacity chart of each of the cargo compartments for the whole tank car shall be prepared.

2.8.8 Presentation of Results

2.8.8.1 A capacity chart shall be drawn up as described in the foregoing and it shall contain the ambient conditions during calibration, the references temperature of the stated capacities with each compartment properly identified. The chart shall also contain information on the certifying body for the primary volume measure or the weighing scale with a photocopy of the certificate of accuracy of the primary volume measurement available for inspection on request.

2.8.8.2 The chart shall show the capacity of each compartment according to incremental depth. The date of calibration, description of the tanker trailer and the name of the calibrating company shall be conspicuously displayed on the chart. In cases where calibration is by water weighing, Table Viii of API 2554 shall be used to establish the appropriate correction factor for the temperature effect on relative density.

2.9 Field-Standard Test Measure

2.9.1 Principle

The Test Measure so calibrated shall be the basis for calibrating all Proving Systems. The Field-Standard Test Measure is a vessel fabricated to meet specific design criteria and calibrated by an accredited international agent of a recognized standardization body.

The Field-Standard Test Measure shall be calibrated by a competent Laboratory that can provide traceability of its equipment to the US National Bureau of Standards or any other similar internationally recognized body.

2.9.2 Frequency of Calibration

The Field –Standard Test Measure shall be calibrated every three years and shall be automatically rendered invalid by damage or dent to the body.

2.9.3 Calibration Procedure

2.9.3.1 Field –Standard Test Measure shall be calibrated by the accredited laboratory or agency in accordance with the provisions of API Manual of Petroleum Measurement Standard Chapter 4.7.

2.9.3.2 Calibration shall be made using water as calibration medium. Certified laboratory graduates may be used to measure, partial volumes of a test measure. Actual capacity of the test measure shall be used as Official capacity rather than the nominal capacity of the measure. Calibrations shall be maintained at +0.02 percent minimum.

2.9.3.3 Visual inspection of Field-Standard Test Measure shall be made before each use to ascertain that constant capacity has not been altered by dents or corrosion.

2.9.3.4 Field-Standard Test Measure shall be calibrated either to deliver or contain. Calibration and subsequent certification must include the affixing of a tamper proof seal on the adjustable scale by the calibrating agency.

2.9.4 Presentation of Results

The Field-Standard Test Measure Calibration Report shall contain but not limited to the following:

Nominal Measure Capacity:

Manufacturer:

Material:

Assumed Cubical Coefficient of expansion:

Scale reading:

Volume delivered or contained at 60ºF:

Estimated margin of error in (m3):

2.10 Calibration stickers or tags shall be attached on all instruments showing the date of calibration or verification, party or person performing the inspection, and the due date of the next certification.

PART IV

PROCEDURE GUIDE FOR DETERMINATION OF THE VOLUME OF PETROLEUM AND PETROLEUM PRODUCTS BY DYNAMIC FLOW MEASUREMENT –GAS METERING

1.1 ORIFICE PLATE INSTALLATION REQUIREMENT

1.2 INTRODUCTION

An orifice plate is a thin square-edged plate with a machined circular bore, concentric with the meter tube ID, when installed.

1.3 General

The orifice meter shall consist of the following elements:

1.3.1 A thin, concentric, square-edged orifice plate – the faces of the plate shall always be flat and parallel.

1.3.2 An orifice plate holder consisting of a set of orifice flanges (or an orifice fitting) equipped with the appropriate differential pressure sensing taps;

1.3.3 A meter tube consisting of the adjacent piping sections (with flow conditioners).

1.4 Flange taps

1.4.1 The upstream tap center shall be located 1 inch. (25.4 mm) upstream of the nearest plate face.

1.4.2 The downstream tap center shall be located 1 inch. (25.4 mm) downstream of the nearest plate face

1.4.3 The upstream and downstream taps shall be in the same radial direction

1.5 Temperature measurement

The flowing fluid temperature (Tf) shall be measured at the designated downstream location (as specified in API MPMS Ch. 14.3, Part 2/AGA Report No. 3, Part 2. by placing a temperature sensing device in the middle of the flowing stream to obtain the flowing temperature in deg. Celsius. The thermowells shall be placed on the downstream side of the orifice and neither closer to the plate than dimension DL and farther from the plate than dimension 4DL as shown in table 7, 8a and 8b in API MPMS 14.3.2/AGA report No.3 Part 2. Adequate sections of the meter run upstream and downstream of the thermowell should be thermally isolated to ensure that indicated temperature readings reflect the temperature of the flowing fluid and not the effects of the ambient conditions of the pipe surrounding the thermowell.

Thermowell length shall not be longer than the length obtained by the formula below and not shorter than 1/3 of the pipe ID.

$$L = \left\{ \frac{F_m . 4.38\ X\ OD\ X\ 10}{S\ X\ V} \sqrt{\left[\frac{E}{\rho} (OD^2 + ID^2) \right]} \right\}^{\frac{1}{2}}$$

Where

L = Probe length in mm

F_m = virtual mass factor; a constant to take account of the extra mass of the cylinder due to the fluid surrounding it and vibrating with it, for gas, F_m=1.0, for water and other liquids, F_m=0.9

OD = Outside diameter of the probe in mm

ID = Inside diameter of the probe in mm

S = Strouhal number, dependent on the Reynolds number and shape of the cylinder, but can be taken as 0.4 for worst case or 0.2 as suggested by API MPMS Chapter 8

V = velocity of the fluid in m/sec

E = modulus of elasticity in kg/cm2

ρ = density of probe material in kg/cm3

1.6 Pressure measurement

Differential Pressure (ΔP) is the static pressure difference measured between the upstream and downstream flange taps. The static pressure shall be the absolute pressure measured at the flange tap holes

1.7 Flow measurement

The Orifice Flow Rate is the mass flow rate (q_m) or volumetric flow rate (q_v) through an orifice meter per unit of time. (AGA 3.1.1990)

$$q_m = C_d E_v Y (\frac{\pi}{4}) d^2 \sqrt{2 g_c \rho_{t,p} \Delta P}$$

Where:

C_d	is the orifice plate coefficient of discharge
E_v	is the velocity of approach factor
Y	is the expansion factor
π	is the numerical constant 3.142
d	is the orifice bore diameter calculated at flowing temperature, T_f
g_c	is the dimensional conversion constant
$\rho_{t,p}$	is the density of the fluid at flowing conditions T_f, P_f
T_f	is the temperature of the flowing fluid
P_f	is the pressure of the flowing fluid
ΔP	is the orifice differential pressure
q_m	is the mass flow rate

And q_v, the volumetric flowrate is given as

$$q_v = \frac{q_m}{\rho_{t,p}}$$

1.8 Orifice Plate Installation Straight Run Requirement with Flow conditioners

Minimum straight run lengths for orifice runs and other flow elements shall be in accordance with ISO 5167-2 and installation of flow conditioners as recommended in API MPMS 14.3.2/AGA report No.3 Part 2.

1.9 Inspection and Maintenance

The orifice meter shall be validated at least on quarterly basis and the exercise shall be witnessed by a DPR representative. The validation exercise shall involve the following:

i. Orifice plate visual inspection – measurement of the orifice bore diameter (dm), pipe inside diameter (Dm), Orifice outside diameter (D), orifice thickness and the departure from flatness. The maximum allowable departure from flatness shall be 0.005(Dm – dm)

ii. Calibration of field instruments -flow transmitters, pressure transmitters, temperature sensors, Gas chromatograph, densitometers, flow computers in line with their footprint certificate

iii. The physical instruments – temperature probe, resistors, voltmeters, pressure gauge, used in the calibration exercise must be tagged with details of the calibration date and due date, and the certificates must be valid and made available for sighting by the DPR representative.

A	HEADER	DETAILS	STATUS
1	Company name		
2	Date of Inspection		
3	Name of Inspector(s)		
B	**GENERAL INFORMATION**		
1	Serial number		
2	Nominal Pipe diameter		
3	Fluid measured (gas/liquid)		
4	β ratio limit		
C	**METER TUBE**		
1	Type of orifice holder (flange/fitting)		
2	manufacturer		
3	Serial number		
4	Flow conditioner (Yes/No)		
5	Type of flow conditioner		
6	How fastened? (welded/flanged/pinned)		
7	Dimensions	Length:	
		Upstream diameter:	
		Downstream diameter:	
		First pipe connection:	
		Second pipe connection:	
		Upstream pressure tap:	
		Downstream pressure tap:	
8	Meter run type		
9	Meter tube temperature		

D	PRESSURE TAPS		
1	Orientation		
2	Location of static pressure transducer (upstream/downstream)		
3	No. of differential pressure connection		
4	Pressure tap size		
5	Condition of tap hole edge		
6	Gauge line length		
7	Temperature probe type		
8	Densitometer (manufacturer, type, insertion, size, location)		
9	Sampler (manufacturer, type, sample line size, location)		
E	ORIFICE PLATE		
1	Orifice plate type		
2	Orifice fitting leak test		
3	Bore diameter		
4	Orifice outside diameter		
5	Orifice plate thickness		

1.10 Orifice plate specifications

1.10.1 Diameter – the diameter d shall in all cases be greater than or equal to 12.5mm. the diameter ratio, $\beta = d_m/D$ shall always be greater than or equal to 0.10 and less than or equal to 0.75.

1.10.2 Thickness E and e – the thickness e of the orifice shall be between 0.005D and 0.02D while the thickness E of the plate shall be between e and 0.05D. However, when $50mm \leq D \leq 64mm$, a thickness E of up to 3.2mm is acceptable.

1.10.3 Bevel angle – if the thickness E of the plate exceeds the thickness e of the orifice, the plate shall be bevelled on the downstream side. The angle of bevel α, shall be $45^{o} \pm 15^{o}$.

1.11 CORIOLIS METER INSTALLATION REQUIREMENT

1.12 Introduction

A Coriolis meter is a device consisting of a flow sensor (primary device) and a transmitter (secondary device) which measures mass flow and density by means of the interaction between a flowing fluid and the oscillation of a tube or tubes.

The flow sensor consists of an oscillating tube(s), drive system, measurement sensors, supporting structure and housing (ISO 10790:2015)

1.12.1 General Requirements

1.12.1.1 Gas quality

The meter shall as a minimum requirement, operate with any of the normal range natural gas composition mixtures specified in AGA Report No.8, this includes relative density between 0.554 (pure methane) and 0.87.

1.12.1.2Temperature measurement

Coriolis flow meters should operate over a temperature range of –40 to 200°F (-40 to 93°C). However, in extreme ambient environment, appropriate measures such as providing shade to reduce impact of direct sunlight to the meter should be considered. A thermowell should be installed upstream of the Coriolis sensor for temperature verification purposes

1.12.1.3 Pressure measurement

The location of the pressure measurement should be made near the sensor. The pressure tap can be located either upstream of the sensor.

1.12.1.4 Vibration and Electrical noise

Coriolis meter package should be installed far away from vibration sources like compressors, pumps, generators and electrical noise such as electromagnetic interference.

1.12.1.5 Piping Configuration

The following components should be provided in the piping design: Isolation block valves, Pressure, blow down port and thermowell port. The pipe-works must be aligned and properly supported to minimize stress due to pressure, weight and temperature.

1.12.1.6 Mounting

a. The sensor should be properly mounted, supported and aligned with the inlet and outlet flanges. A spool piece should be used in place of the meter to align pipe-work during the construction phase.

b. The Coriolis transmitter shall be mounted to ensure easy access to communication equipment, displays and keypads. The Coriolis meter may have the transmitter mounted to the sensor or mounted remotely.

1.12.2 Orientation

The sensor tubes should be positioned in such a way that the possibility of heavier components, such as condensate, settling in the vibrating portion of the sensor is minimized.

1.12.3 Minimum Performance Requirements

The following minimum performance requirements shall be met by the meter, as supplied directly from the manufacturer, prior to making any calibration factor adjustments based on an independent third-party flow calibration of the meter.

Repeatability:

+ 0.35% of reading for $Q_t < Q_i < Q_{max}$

+ 1.0% of reading for $Q_{min} < Q_i < Q_t$

Where

Q_t is the transitional mass flow rate.

Q_i is the actual measured mass flow rate passing through a meter under a specific set of test or operating conditions

Q_{min} is the minimum allowable mass flow rate through the meter, as specified by the meter manufacturer

Q_{max} is the maximum allowable mass flow rate through the meter, as specified by the meter manufacturer

1.12.4 Field Meter Validation

The following general meter verification procedures shall be performed on quarterly basis during the meter validation exercise:

1.12.5 Meter Transmitter Verification

The meter transmitter verification should coincide with the meter zero check. It should include the following procedures:

- Verify the sensor calibration and correction factors in the configuration of the transmitter to be unchanged from most recent calibration.
- Verify all transmitter diagnostic indicators to be in the normal state.

1.12.4.2 Coriolis Sensor Verification

Sensor diagnostics may be available that continuously, on-command or procedurally verify the performance of the sensor and/or infer change in measurement performance. Meter manufacturer should be consulted for the availability of these types of diagnostics.

1.12.4.3 Temperature Verification

Spot checks shall be conducted by placing a temperature probe through the thermowell to verify the reading of the Coriolis temperature transmitter which monitors the temperature element bonded to the flow tubes of the Coriolis sensor.

1.12.4.4 Density verification

The density verification shall be carried out by passing a gas of known density and components (calibration gas) through the densitometer and/or Gas chromatograph.

The Densitometer shall be the primary means of density measurements at custody transfer points.

1.12.4.5 Meter Zero Verification

A change in the meter zero value can be used as an indicator of change in the metering conditions.

The meter zero should be checked at flowing pressure and temperature within 1 to 4 weeks of installation and quarterly during its field service years. The meter zero verification should include the following procedures:

i. Ensure thermal stability
ii. Record the as-found zero
iii. Verify the indicated meter zero value to be within manufacturer specification limits

- If meter zero is within specification,
- record the as-left meter zero value, and
- return the meter to service.

- If meter zero is out of specification,

iv. Verify isolation valves are not leaking and check for other potential leak sources. If leaks are present, zero verification cannot be performed correctly,

v. Record current zero value,

vi. Re-zero the meter and record the new zero value:

- open upstream and downstream block valves placing meter back into service and,
- evaluate indicated meter zero value against its history to identify the long-term performance of the meter zero and potential influences (consult manufacturer).

1.13 Factory Calibration

The Coriolis meter shall be calibrated annually and witnessed by DPR officer(s).

1.13.1 Flow Computer Calculations

The equations for measuring a gas with a Coriolis meter are summarized with the following expressions.

$$Q_{m(compensated)} = Q_{m(uncompensated)}(F_p)$$

Where:

$Q_{m\,(compensated)}$ = Mass flow rate of gas compensated for flow pressure effect

$Q_{m\,(uncompensated)}$ = Mass flow rate of gas uncompensated for flow pressure effect

F_p = Flow pressure effect compensation factor

And F_p is given as

$$F_p = \frac{1}{1 + \left(\left(\frac{P_{effect}}{100}\right) * (P_f - P_{cal})\right)}$$

where

P_{Effect} = Flow pressure effect in percent of rate per psig

P_f = Measurement fluid static pressure in psig

P_{Cal} = Calibration static pressure in psig

1.14 Pre-commissioning checklist

A	HEADER	DETAILS	STATUS
1	Company name		
2	Date of Inspection		
3	Name of Inspector(s)		
B	**GENERAL INFORMATION**		
1	Serial number		
2	Nominal Pipe diameter		

3	Fluid measured (gas/liquid)		
4	Meter type		
C	**METER TUBE**		
1	Flow conditioner (Yes/No)		
2	Type of flow conditioner		
3	How fastened? (welded/flanged/pinned)		
4	Dimensions	Length:	
		Upstream diameter:	
		Downstream diameter:	
		First pipe connection:	
		Second pipe connection:	
		Upstream pressure tap:	
		Downstream pressure tap:	
5	Thermowell (Location, length, condition)		
6	Pipe alignment (Yes/No)		
D	PRESSURE TAPS		
1	Orientation		
2	Location of static pressure transducer (upstream/downstream)		
3	No. of pressure taps		
4	Pressure tap size		
5	Condition of tap hole edge		
6	Temperature probe type		
E	METER PARAMETERS		
1	Minimum flow rate		
2	Maximum flow rate		
3	Meter factor		

1.15 MEASUREMENT OF GAS BY MULTIPATH ULTRASONIC METERS

1.15.1 Introduction

Ultrasonic meters are inferential meters that derive the gas flow rate by measuring the transit times of high-frequency sound pulses. Transit times are measured for sound pulses transmitted and received between pairs of transducers positioned on or in the pipe. Pulses transmitted downstream with the gas flow are accelerated by the flow and pulses transmitted upstream against the gas flow along the identical acoustic path are decelerated. The difference in these transit times along the acoustic paths is related to the average gas flow velocity.

1.15.2 Design requirements:

The design shall be done in accordance with AGA 9 and other relevant standards and should be done in such a way not to allow for settlement of liquids and sediments.

1.15.3 Gas quality

The meter shall as a minimum requirement, operate with any of the normal range natural gas composition mixtures specified in AGA Report No.8, this includes relative density between 0.554 (pure methane) and 0.87.

1.15.4 Pressure

The minimum and maximum operating pressure shall be as specified by the manufacturer. The maximum operating pressure of the meter must be the lowest of the maximum design operating pressure of the meter body, flanges, transducer connections and transducer assemblies.

1.15.5 Temperature

The UM ambient and operating temperature range shall be between –40°F and 140°F (-40°C and 60°C) except specified otherwise by the manufacturer.

1.15.6 Meter performance requirement

General flow measurement performance requirement for all UMs shall be as follows before any calibration factor adjustment.

Repeatability: ±0.2% for $q_t \leq q_i \leq q_{max}$

±0.4% for $q_{min} \leq q_i < q_t$

Resolution: 0.001m/s

Velocity sampling interval: ≤ 1 second

SOS deviation: ±2.0%

Maximum SOS path spread: 0.5m/s

1.15.7 Meter accuracy

The UM shall meet the following flow measurement accuracy requirement before any calibration factor adjustments;

For UMs of 12" (nominal) diameter or larger

Maximum error: ±0.7% for $q_t \leq q_i \leq q_{max}$

±1.4% for $q_{min} \leq q_i < q_t$

Maximum Peak to Peak Error: ±0.7% for $qt \leq q_i \leq q_{max}$

±1 .4% for $q_{min} \leq q_i \leq q_t$

For UM meters 4" to 10" nominal diameter:

Maximum Error: ±1 .0% for $q_t \leq q_i \leq q_{max}$

±1 .4% for $q_{min} \leq q_i \leq q_t$

Maximum Peak to Peak Error: ±1 .0% for $q_t \leq q_i \leq q_{max}$

±1 .4% for $q_{min} \leq q_i \leq q_t$

For meters less than 4" nominal diameter:

Maximum Error: ±2.0% for $q_t \leq q_i \leq q_{max}$

±3 .0% for $q_{min} \leq q_i \leq q_t$

Maximum Peak to Peak Error: ±1 .0% for $q_t \leq q_i \leq q_{max}$

±1 .4% for $q_{min} \leq q_i \leq q_t$

q_t is the transition gas flow rate below which the expanded error limit is applicable

q_i is the actual gas flow rate passing through a UM under a specific set of test conditions

q_{min} is the minimum gas flow rate through the UM that can be measured within the expanded error limit

q_{max} is the maximum gas flow rate through the UM that can be measured within the expanded error limit.

1.15.8 ULTRASONIC METER INSTALLATION REQUIREMENT

1.15.8.1 Pressure taps

At least one pressure tap shall be provided for measuring the static pressure in the meter. Each pressure tap hole should be between 1/8" and 3/8" nominal in diameter and cylindrical over a length at least 2.5 times the diameter of the tapping, measured from the inner wall of the meter body. The tap hole edges at the internal wall of the meter body should be free of burrs and wire edges and have minimum rounding. For a meter body with a wall thickness less than 5/16", the hole should be 1/8" nominal in diameter. Pressure taps may be located at the top, left side and/or right side of the meter body.

1.15.8.2 Piping installation

Both the upstream and downstream piping configuration (with or without flow conditioners) shall be installed in such a way that the additional flow rate measurement error shall not be more than ±0.3% due to the installation configuration.

1.15.8.3 Protrusions

No part of the upstream gasket or flange face edge shall protrude into the flow stream more than 1% of the internal diameter to minimize flow disturbances especially at the upstream flange. However, thermowells are excluded from the protrusion limit.

1.15.8.4 Meter body length and bores

The UM bore and the adjacent upstream pipe along with the flanges should have the same inside diameter to within 1% of each other.

1.15.8.5 Thermowells

For unidirectional flow, the thermowell should be installed downstream of the meter. The thermowell should be located at least 6 inches from the flange weld or 2 ND whichever is larger, and no farther than 5 ND from the downstream USM flange face.

The recommended insertion length for thermowells and sample probes is between 1 /3 ND to 1 /2 ND for line sizes NPS 2 to NPS 1 0 and 1 /5 ND to 1 /3 ND for line sizes NPS 12 and larger. Special thermowell design may be required for insertion lengths greater than 1 /3 ND.

1.15.8 Environmental consideration

Factors such as temperature, vibration and electrical noise shall be taken into consideration. Appropriate measures should be taken to mitigate extreme temperatures and excessive/ unnecessary vibration and electrical noise should be avoided

1.15.9 Associated flow computer

The associated flow computer must be installed to correct the volume rate and accumulated volume for pressure, temperature and compressibility, and to provide necessary data retention for audit trail.

1.15.10 Density measurement

A densitometer/ Gas chromatograph should be installed downstream of the UM to take density measurements.

1.15.11 Orientation of Meters

The metering package should be oriented during flow calibration to match the field installation.

1.15.12 Meter Tube Inspection and Cleaning Ports

Meter tube inspection ports should be located a minimum of 3 ND downstream and/or upstream of the ultrasonic flow-meter body flanges. Inspection ports for the flow conditioner should be located 3 ND upstream of the flow conditioner. The port diameter should not exceed 6% of the pipe diameter for meters larger than 1 2" and 0 .750" for meters 12" and smaller.

1.15.13 Flow conditioner

Installation of flow conditioners shall be as recommended in AGA Report No.9 2017 – Measurement of Gas by Multipath Ultrasonic Meters.

1.15.14 Flow Computer Calculations

The necessary calculations are summarized in the following expressions

$$Q_b = Q_f({}^{P_f}/_{P_b})({}^{T_b}/_{T_f})({}^{Z_b}/_{Z_f})$$

$$V_b = \int Q_b dt$$

Where Q_b = flow rate at base conditions

Q_f = flow rate at flowing conditions

P_f = absolute static pressure of gas at flowing conditions

P_b = base pressure, typically atmospheric pressure (101.325Kpa)

T_b = base temperature

T_f = absolute temperature of gas at flowing conditions

Z_b = compressibility factor of gas at base conditions

Z_f = compressibility factor of gas at flowing conditions

V_b = accumulated volume at base conditions

dt = integration increments of time (per second)

1.15.15 Field Meter validation

The following verification procedure shall be carried out on quarterly basis and witnessed by DPR. It includes but not limited to the following:

1. Zero-flow verification test shall be carried out as follows;
   - If zero-flow verification is performed at elevated pressure, blind flanges shall be attached to the ends of the flow meter body.
   - The acoustic properties of the reference gas shall be well known and documented.
   - The gas pressure and temperature shall be allowed to stabilize at the outset of the test.
   - The gas velocities for each acoustic path shall be recorded for at least 30 seconds. The mean gas velocity and standard deviation for each acoustic path shall then be calculated.
   - Adjustments to the meter shall be made as necessary to bring the meter performance into compliance with the specifications stated in this guideline.
   - The measured speed-of-sound values shall be compared with the theoretical value computed using a complete compositional analysis of the reference gas
   - The zero-flow verification test shall meet the following:
     a. The individual path gas velocity no greater than ±0.02 ft/sec (0.006 m/s)
     b. The speed of sound per path within ±0.2% of the theoretical value
     c. Percentage of accepted pulses for each acoustic path are 100%
     d. All gain levels are within the nominal limits provided by the manufacturer
     e. Maximum Speed of Sound path spread not greater than 1 .5 ft/s (0.5 m/s)
2. Speed of sound measurement analysis
3. Individual path measurement analysis
4. Internal inspection
5. Dimensional verification
6. Other mechanical and electrical tests

During the validation if the meter did not pass Zero check and verification of sound, the meter should be taken out for service.

1.15.16 Pre-commissioning checklist

A	HEADER	DETAILS	STATUS
1	Company name		
2	Date of Inspection		
3	Name of Inspector(s)		
B	**GENERAL INFORMATION**		
1	Serial number		
2	Nominal Pipe diameter		
3	Fluid measured (gas/liquid)		
4	Meter type		
C	**METER TUBE**		
1	Flow conditioner (Yes/No)		
2	Type of flow conditioner		
3	How fastened? (welded/flanged/pinned)		

4	Dimensions	Length:	
		Upstream diameter:	
		Downstream diameter:	
		First pipe connection:	
		Second pipe connection:	
		Upstream pressure tap:	
		Downstream pressure tap:	
D	PRESSURE TAPS		
1	Orientation		
2	Location of static pressure transducer (upstream/downstream)		
3	No. of pressure taps		
4	Pressure tap size		
5	Condition of tap hole edge		
6	Temperature probe type		
E	METER PARAMETERS		
1	Minimum flow rate		
2	Maximum flow rate		
3	Meter factor		

1.16 LNG OPERATIONS

The LNG loaded at the loading points shall be measured in cubic meters by gauging LNG loaded in tanks of the LNG tanker vessel in accordance with ISO 10976:2015.

1. Each tanker should be equipped with level measuring device of different types capable of determining the LNG level to within accuracy equal to or better than ±7.5mm. The level of the liquid in the tank shall be determined by main primary capacitance measuring devices which give automatic readouts in the cargo control room, but if there is a failure, the level of liquid shall be determined by using the Auxiliary liquid level gauging device for the relevant cargo tank(s). For volume calculations, the gauging table shall convert the level of the liquid in tanks to the volume of that cargo tank using one (1) millimeter as the smallest unit of dimension.

1.16.1 QUALITY OF LNG FOR TRUCKING IN NIGERIA

Quality of LNG loaded should:

i. have a Gross calorific value (Volumetric) between 39.90 and 42.70 MJ/SCF on a dry basis
ii. Not contain more than 1 (one) mol% of nitrogen

Hydrogen Sulphide	5.0 mg/SCF
Mercaptan sulphur	2.3 mg per standard cubic feet
Mercury	50 mg per standard cubic feet
Carbon Dioxide	0.1 mol per cent
Carbonyl Sulphide plus Hydrogen	15.0 mg per standard cubic metre

iii. Have the constituent elements varying between the following percentage limits (in molecular percentages)

Methane (C1)	Between 87.0 and 96.0
Ethane (C2)	Equal to or Lower than 9.0
Propane (C3)	Equal to or Lower than 4.0
Isobutane (C4)	Equal to or Lower than 1.0
Normal butane (nC4)	Equal to or Lowe than 1.5
Pentanes (C5+)	Equal to or Lower than 0.1
Molar sum of propane (3) And heavier hydrocarbon components	Equal to or Lower than 5.3

1.16.2 CERTIFICATE OF QUANTITY

The following information should form the basis for certificate of quantity;

PARAMETER	UNITS
Volume Loaded (Net)	M^3
MASS LOADED (Net)	MT
GROSS ENERGY LOADED	KWh
Gross energy loaded	MMBTU
VAPOUR RETURNS	MMBTU
WOBBE INDEX	MJ/Sm^3
DENSITY (at 15°C)	Kg/m^3
GROSS CALORIFIC VALUE (Volumetric)	MJ/Sm^3
GROSS CALORIFIC VALUE (Mass)	MJ/kg
NET CALORIFIC VALUE	MJ/Sm^3
GAS CONSUMED	MMBTU
COOL DOWN	MMBTU
GAS UP	MMBTU

Opening custody transfer survey
Closing custody transfer survey
SIGNATURES AND NAMES
DPR REP:
TERMINAL OPERATOR'S REP:
CONSIGNOR'S REP:
DATED AT
VESSEL NAME:
CONSIGNOR:
CONSIGNEE:
CARGO ID:
PRODUCT:
TERMINAL:
COMMENCED LOADING (DATE/TIME):
COMPLETED LOADING (DATE/TIME):

1.16.3 Determination of Density

There are three ways of determining density:

- Measuring its average value directly in the LNG carrier's tank by means of densitometers.
- Calculated based on an average composition of LNG in accordance with ISO 6578 and the revised KLOSEK-McKINLEY method.
- Using gas chromatograph.

1.17 DETERMINATION OF TEMPERATURE AND PRESSURE

1.17.1 PRESSURE

At the time of gauging, the pressure in the cargo tanks shall be arithmetic average of the absolute pressure indicating device for each tank. One absolute pressure indicating device shall be fitted to the vapor space of each tanks and shall be accurate to ±5 mbars or a range 800mbars to 1,400mbars absolute for purpose of calculation.

1.17.2 Temperature

At the times of gauging, the liquid temperature of the cargo shall be determined by calculating the arithmetic average of temperature indicated by the temperature resisting devices immersed in the LNG in all the tanks. Each tank has a minimum of 5 devices distributed over the entire height of the tanks and shall be accurate to ±0.2 °C above the range of -145°C to -165°C. (±1.5°C outside the range). The vapour temperature shall be the arithmetic average of the temperatures indicated by the temperature devices which at the time of gauging are in the vapor space above the surface of the LNG. These temperatures shall be printed before and after the loading and unloading operations for calculating average temperature of LNG liquid and LNG vapor and shall be rounded to one decimal place in degree Celsius.

1.17.3 Sampling determination of composition of LNG in accordance with ISO 8943.

1.17.3.1 Sampling and vaporization of LNG shall be taken at both loading and unloading in the presence of DPR representatives.

1.17.3.2 LNG samples shall be taken at different time intervals between the duration of the loading. Samples can be taken automatically or manually.

1.17.3.4 The calibration of the chromatograph utilized during sampling shall be done in accordance with ISO 1411.

1.17.3.5 Each set of samples obtained during loading or unloading shall be distributed as follows:

i. First cylinder - for use of seller at loading or buyer at unloading establishing the LNG composition for custody transfer by chromatographic analysis.

ii. Second cylinder - for retention by seller at loading or buyer unloading for a period of twenty (20) days after the analysis of the first portion has been reported to the other party during which period any question as to the accuracy of any analysis shall be raised. In such case, the portion shall be used as buyer and seller may mutually agree; and

iii. Third cylinder - for the use by an independent surveyor.

1.17.4 Definitions and Notations

The density ("d") of LNG loaded or notations unloaded at the prevailing composition and temperature T, in kg/m[1], shall be rounded to 2 (two) decimal places and calculated as follows:

$$d = \frac{\sum(X_i * M_i)}{\sum(X_i * V_i) - \left[K_1 + \frac{(K_2 - K_1)}{0.0425} * X_n\right] * X_m}$$

H_i = Gross Calorific Value (Molar Based) of individual LNG components at 15°C (fifteen degrees Celsius) and 1,013.25 millibars, in MJ/kg as specified in ISO 6976 (1995) and ISO 6578;

H_m = Gross Calorific Value (Mass Based) of the liquid cargo loaded or unloaded in its gaseous state in MJ/m^3(st), rounded to 2 (two) decimal places, calculated in accordance with the formula:

$$H_m = \frac{\sum(X_i * M_i * H_i)}{\sum(X_i * M_i)}$$

H_v = Gross Calorific Value (Volumetric) of the liquid cargo loaded or unloaded in its gaseous state in MJ/m^3(st) rounded to 2 (two) decimal places, calculated in accordance with the formula:

$$H_v = \frac{\sum(X_i * M_i * H_i)}{23.6449}$$

Where 23.6449 is the volume occupied by a kmol of ideal gas at 15°C (fifteen degrees Celsius) and an absolute pressure of 1.01325 bar;

K_1 = volume correction factor at temperature T, in m^3/kmol, rounded to 6 (six) decimal places, obtained by linear interpolation;

K_2 = volume correction factor at temperature T, in m^3/kmol rounded to 6 (six) decimal places, obtained by linear interpolation from Part III of Attachment 4;

M_i = molecular mass of individual LNG components in Kg/kmol rounded to 3 (three) decimal places and specified in ISO 6976 (1995);

Q_r = quantity of Natural Gas in Megajoules returned to the LNG Tanker during the unloading process calculated in accordance with the formula:

$$Q_r = V * \frac{288.15}{(273.15 + T_v)} * P * \frac{1}{1013.25} * 37.0$$

Where: the figure of 37.0 represents the gross heating value in MJ/m³(st) of the vapour returned to the LNG Tanker at 15°C (Fifteen degrees Celsius) and 1013.25 millibars. The figure 1013.25 represents standard atmospheric pressure expressed in millibars. The figures 273.15 and 288.15 represent 0°C and 15°C (zero degrees Celsius and fifteen degrees Celsius) respectively as expressed in K (Kelvin);

P = average absolute pressure of vapour in the LNG Tanker immediately before loading and after unloading, expressed in millibars, rounded to a whole millibar

T = average temperature of the LNG in an LNG Tanker before and after loading or before unloading, expressed in degrees Celsius rounded to 1 (one) decimal place

T_v = average temperature of the LNG in an LNG Tanker before and after loading or before unloading, in degrees Celsius rounded to 1 (one) decimal place

V = the total volume of the liquid cargo loaded or unloaded, in cubic metres rounded to 1 (one) cubic metre

V_i = molar volume of individual LNG components at temperature T, in m^3/kmol rounded to 6 (six) decimal places, obtained by linear interpolation.

X_i = molar fraction of individual LNG components of sample taken from the receiving lines, determined by gas chromatographic analysis as specified in Clause 12.4;

X_m = the value of X_i for methane; and

X_n = the value of X_i for nitrogen; and

W = Wobbe Index of Regasified LNG in MJ/m^3(st) calculated in accordance with the formula:

$$W = \frac{H_v}{\sqrt{d_r}}$$

Where:

d_r= relative density of Regasified LNG compared with air calculated in accordance with the formula:

$$d_r = \frac{\sum(X_i * M_i)}{28.9625}$$

1.18 FUEL GAS MEASUREMENT

1.18.1 Special consideration for fuel gas system

For single meter run configuration, it shall be possible to route the gas stream through a bypass line for inspection and maintenance of the fuel meter run. When the system is in this bypass mode, flow calculations shall continue based on average flow rate in a user selectable time periods (that is from one minute to one hour) prior to opening to by-pass.

Orifice meter should be preferred to gas turbine meter unless the cost of long upstream meter run lengths for the orifice meter outweighs the cost of annual flow calibrations at operating conditions of the gas turbine meter, and the cost of one spare gas turbine meter (in stores).
Also, a gas turbine meter should be preferred if the flow range of the fuel stream requires frequent changes of orifice plates during regular operation.

For every small fuel gas stream, in particular non-fuel streams withdrawn from the fuel distribution system downstream of the main fuel metering system, the following methods should be considered:

- For streams smaller than specified by ISO 5167 and AGA 7, one of the following methods shall be used:

- Small, full bore, gas turbine meters, designed to manufacturer's standard (minimum 6 mm).
- Integral orifice meters (smaller than 12 mm).
- Other suitable type of small flow meter with equivalent accuracy.

1.19 FLARE GAS MEASUREMENT

1.19.1 Functional requirements

1.19.1.1 General

The system shall measure flow rate and accumulate quantities of flare gas, in accordance with the following guides. The calculation can either be done in a dedicated flow computer or in SAS. If the flare gas releases are due to the operational upset, blowdown, purging, or ESD operation the meter readings so recorded shall be forwarded within 24hours to the DPR nearest office with a detailed report on the scenarios of releases. This report shall form the basis of no charge on the flare gas releases. If the flare releases are operational philosophy the meter reading shall comply with fuel gas measurement systems and all the conditions attached thereof.

1.20 GAS SAMPLER SYSTEMS

1.20.1 Functional requirements

1.20.1.1 General

The system shall collect and store a representative gas sample at line conditions, allowing it to be transported to the laboratory for analysis. The system shall be mounted as close as possible to the pipeline to collect samples over a sample period, unattended. The system shall be in accordance with ISO 10715. The distance to the nearest upstream disturbance, shall be at least 20 ID. The measurement system shall control an automatic gas sampler system, i.e.

- provide a flow proportional by mass pacing signal (and a fall-back signal)
- monitor the sample volume collected and status of the sampling system.

In addition, there shall be a manual sample point, where the manual sampling probe shall be installed such that a representative sample of the gas can be collected. The distance to the nearest upstream disturbance, shall be at least 20 ID. However, if an auto-sampler or OGC sampling probe is included in the measurement system the manual sampling may be taken from the same probe.

1.20.2 Equipment/Schematic

The system consists of a probe, a by-pass loop, two separating devices (sample collection pumps), an instrumentation supply system, a timing system and two sample receivers (collection cylinders) for sample transportation.
The sample equipment shall be contained in a cabinet with exception for:

- the probe,
- tubing to/from the mainline and
- the back-pressure system.

The manual sample point shall be equipped with flushing facilities and a cabinet/enclosure with required valves and quick connectors in addition to an arrangement where the sample cylinder can be placed during spot sampling.

1.20.3 Performance

1.20.3.1 General

ISO 10715 describes the performance requirements for a fiscal sampling system.

1.20.3.2 Operational Requirements

The control function shall be done from a dedicated controller, SAS or a measurement system. There shall be monitoring of maximum filling with adjustable alarm setting. In addition, the measurement system shall provide a flow proportional pacing signal and monitor the sample volume collected and status of the sampling system.

1.20.3.2.1 Isolating and Sectioning

It shall be possible to isolate the system from the main process.

1.20.3.2.2 Layout Requirements

ISO 10715 describes the layout requirements for a fiscal sampling system.

1.20.3.2.3 Interface Requirements

The system shall be controlled and monitored from the measurement computer or SAS.

1.20.3.3 Technical requirements

1.20.3.3.1 Initial selection of automatic probe location

The sample point shall be chosen to provide a representative sample of the flowing gas in the pipe.

The sampling point shall be installed at least 20 diameters downstream of the nearest bend or restriction on a horizontal pipe. The probe shall be installed in a 10 - 2 o'clock position.

1.20.3.3.2 Probe design

The probe shall be a pilot tube type extending into the centre one-third of the pipeline diameter. In addition, the sampling probe should be possible to retract under operating pressure by method accepted by the operator.

1.20.3.3.3 Sample collection pump

There shall be two parallel sample collection pumps, which shall be self-purging and can operate under line conditions. The grab size volume shall be adjustable in the range 0.5 – 1.5 ml.

The sample collection pumps shall be located above and as close to the probe as is practically possible. Filters, drip pots, screens, regulators and such conditioning equipment shall not be placed between the probe and the sampler.

1.20.3.4 Sample receiver

- There shall be two parallel sample receivers.
- The filling of the two sample receivers shall have a maximum deviation of ± 5 %.
- Heat tracing and insulation shall be provided to keep the temperature minimum 10 ° C above the condensation temperature.
- The receivers shall be of the floating piston type with back-pressure of an inert gas.
- The receivers shall be equipped with a local piston position indicator and a limit switch for maximum filling.

1.20.3.5 Tubing and valves

- The temperature in all parts of the sample lines/tubing and sample receivers shall be kept at a temperature minimum 10 ° C above the hydrocarbon dew point temperature.
- The valves for the sampling system shall be of type full-bore ball valves.
- The sample tubing from/to the main pipe should have a slope of at least 1:12 to avoid liquid traps.

1.20.3.6 Back-pressure system

There shall be a back-pressure system with inert gas (argon or helium). This shall include a booster facility. The back-pressure volume shall be at least five times larger than the receiver volume and of a size so that the pressure increase caused by 100% sample filling is less than 10 bar.

1.20.4 GAS CHROMATOGRAPH

1.20.5 Functional requirements

1.20.5.1 General

The purpose of an on-line gas chromatograph (OGC) is to give continuous quantitative composition analysis of natural gas from a process stream.

i. The ranges shall be restricted to the operational needs for each project.
ii. The OGC shall quantify the concentrations of the main components in the gas composition, for gas accounting, calculation of calorific value and reference density in fiscal applications. The gas composition shall also be used for checking of gas quality conformity with gas quality specifications defined by commercial gas agreements, and as a base for calculation of the operating density. The calculation of the operating density will normally be handled by the flow computers using live input values of the gas composition from the gas chromatograph.
iii. Calculation of flow weighted average composition will normally be handled by the fiscal measurement computer system. The concentration given in mole % shall be converted to mass % for such calculations.
iv. The analytical results shall be traceable regarding sample point, time and date, calibration gas cylinder, calibration table, and time of last calibration.

1.20.6 Computer unit

i. The computer unit shall control the chromatograph. Program software, interfaces and protocol should be robust with special consideration concerning automatic regeneration of all control and communicational functions after the event of a general power failure.
ii. Criteria for accepting the results from the calibration sequence shall be implemented.
iii. The computer unit shall have the option of selecting an automatic calibration performed between a certain number of analysis, or executed at selected calendar dates or weekdays, or at a specified time during the day.
iv. The computer system shall be capable of calculating the following figures based on the compositional data normalized values Xi: in accordance with ISO 6976.
   - Compressibility factor at reference condition.
   - Gross calorific value.
   - Wobbe-index.
   - Relative density (real / ideal)
   - Density at reference condition.

v. Algorithm and truncated/rounding errors for computations in the computer unit shall be less than ± 0.001 %.

1.20.7 Calibration equipment.

The calibrated gas shall be permanently connected to the analytical unit. The system shall have a valve arrangement that provides the possibility of automatically selecting gas samples from the WGMs. Selection of WGMs shall be possible from the central control unit.

Each of the components in the calibrated gases (WGM) used for either acceptance tests, commissioning or during operation shall have the following documented uncertainty limits (extended uncertainty with a coverage factor k=2):

Component range (mole %)	Uncertainty (%)
0.1 – 0.25	5.00
0.25 - 1	1.00
1 - 10	0.5
10 - 100	0.2

1.20.8 Performance

1.20.8.1 Uncertainty and repeatability

The repeatability of the OGC shall be within the following limits:

Component range (mole %)	Standard deviation (mole %)
0 - 25	0.02
25 - 100	0.05

Control procedure shall be worked out for the witnessing and approval by the Department of Petroleum Resources of the metering system, and its functional acceptance test before leaving the factory and on the completion of installation on site before commissioning. This shall follow the lodgement of construction and installation Program with the Department of Petroleum Resources.

PART V

FEES AND ADMININISTRATIVE FINES FOR NON-COMPLIANCE WITH THE PROVISIONS OF THIS PROCEDURE GUIDE

FEES

S/N	APPLICATION	UNIT	AMOUNT
1.	Processing fee for Export Permit Application.	Per application and Export form/ Permit	$1,000. (One Thousand USD)
2.	Processing Fee for LACT System Calibration / Recertification at Export Terminal / Injection Points.	Per LACT Unit	$1,000 (One Thousand USD)
3.	Processing Fee for Calibration / Recertification of Storage Tank Land / Offshore Terminal.	Per Tank	$1,000 (Land Tanks) / $500 (Offshore FPSO, FSO and Barges)
4.	Recertification/recalibration of third party/service companies primary measures/master provers (pipe prover, tank prover, compact prover, master meter etc)	Per unit	$1,000. (One Thousand USD)
5.	Processing Fee for Approvals of Barging and Trucking of Crude Oil.	Per Approval	$1,000 (One Thousand USD) for Barging. $500 (Five Hundred USD) for Trucking
6.	Annual License Fee to operate a crude oil Terminal /Renewal to operate an export Terminal.	Per Terminal (Land/FPSO/FSO)	$100,000 (One Hundred Thousand USD)
7.	Operational license fee for LACT/accounting meters	Per LACT system/accounting meters renewable every 5 years	$10,000 (Ten Thousand USD)
8.	Processing fee for Approval of Terminals Establishment Order	Per Terminal (Land/FPSO/FSO)	$50,000 (Fifty Thousand USD)

ADMINISTRATIVE FINES FOR NON-COMPLIANCE

S/N	OFFENCE DESCRIPTION	UNIT	AMOUNT
1.	Employment / engagement of non-accredited DPR Contractors for fabrication, construction, calibration, testing etc. of any critical equipment or facility.	Per facility	$5,000. (Five Thousand USD) In addition to suspension of not less than 3 months
2.	Using unapproved tank for storage or changing tank product/ pipeline product service without approval.	Per tank/per pipeline 10-meter length	$5,000. (Five Thousand USD)
3.	Measuring Petroleum or Petroleum Products with faulty (kinked) measuring equipment or Ullage Transmitting Instrument (UTI) – static measurement method.	Per tape or steel measure or UTI	Outright confiscation of faulty measuring instrument and

			payment of fine of $10,000. (Ten Thousand USD)
4.	Conducting inspection FAT/SAT of any critical equipment without approval and without witnessing by Representative of the Department.	Per equipment	$50,000. (Fifty Thousand USD)
5.	Modification, Alteration, upgrade, etc. of LACT Metering System (Export) without DPR approval.	Per LACT System	$250,000. (Two Hundred and Fifty Thousand USD)
6.	Modification, Repair, Alteration of surface or underground storage tanks without approval. Introduction of dead woods, capillary Tube or false-bottom, etc. attract the same fine.	Per storage greater than or equal to 500 barrels.	$25,000. (Twenty-Five Thousand USD) for crude oil tanks
7.	Non-compliance in ensuring DPR Representatives witness out turn verification at the port of discharge.	Per loaded Vessel or shipment	$50,000. (Fifty Thousand USD)
8.	Tampering or Bye-pass of pipeline, back-loading line (depots), lines for export at terminal or discharge at Jetties/Depots, etc. without approval.	Per loading or shipment	$200,000. (Two Hundred Thousand USD)
9.	Exporting/Importing Petroleum or Petroleum Products without approval.	Per loading or shipment	Outright forfeiture and payment of total cost in USD to DPR
10.	For any Petroleum or Petroleum Product handling facility, the set-back shall not be less than 25km from any border country and lack of adherence or the construction of the facility by operator or owner without approval by DPR, shall attract sanctions, thus:	Per facility	Forfeiture of petroleum product and DPR shall report to Security Agency, Town Planning Authority for outright demolition.

11.	Failure to apply the DPR Methodology for Determination and Allocation of crude Oil Losses.	Per facility	Monetary equivalent of 30% of the total loss volume allocated at the prevailing oil price in USD
12.	National Production Monitoring System (NPMS) non-compliance by operating company.	Per Week Per Month Per Quarter	$10,000. (Ten Thousand USD) $30,000. (Thirty Thousand USD) $100,000. (One Hundred Thousand USD)
13.	Late submission of export permit application. Deadline Definition: Tenth (10th) day of the second month of the previous quarter of the same year.	Per quarter	$1,000. (One Thousand USD)
14.	Non-compliance with applying approved new base volume and meter factor from proving.	Per loading	$250,000. (Two Hundred and Fifty Thousand USD)
15.	Non-compliance with installation/tampering with DPR Locking Device (sea line Valves) on export pipeline.	Per Terminal	$100,000. (One Hundred Thousand USD)
16.	Tampering with Metering Systems or its ancillary equipment without approval.	Per Meter	$100,000. (One Hundred Thousand USD)
17.	Commissioning any critical equipment or facility e.g. valve, compressor, pump, sampler, etc. without approval.	Per equipment	$50,000. (Fifty Thousand USD)
18.	None display on operational tank in service “Tank Service”, “Date of Calibration” and “Next Due Date of Calibration.	Per tank in service or operation	$100,000. (One Hundred Thousand USD) Per Tank

19.	Installation of LACT System at Export terminals or Custody transfer point without approval.	Per month	$750,000. (seven Hundred and Fifty Thousand USD)
20.	Non-compliance to five (5) yearly inspection of storage tanks at export terminals	Per year	$150,000. (One Hundred and Fifty Thousand USD)
21.	Non-compliance to five (5) yearly calibration of storage tanks at export terminals.	Per year	$150,000. (One Hundred and Fifty Thousand USD)
22.	Shutting down of operators/third party production facility without DPR approval. Exception: For emergency situations, the nearest DPR office shall be notified within 24hrs and a formal report shall be submitted to the Director, Petroleum Resources within 48hours.	Shut-down operation per day	$500,000. (Five Hundred Thousand USD) and in addition to sanction as may be directed by Director, Petroleum Resources.
23.	Evacuation and discharging of petroleum, petroleum product or gas without approval from Director, Petroleum Resources.	Per operation	Payment of monetary equivalent of the total cargo at the prevailing market price in USD to the DPR in addition to sanction as may be approved by Director, Petroleum Resources.
24.	submission of Misleading report by any company on quantity and/or quality of petroleum or petroleum products.	Per Operation	Payment of monetary equivalent of the total cargo at the

			prevailing market price in USD to the DPR
25.	Lack of proper accounting, reporting, intentional/wrongful allocation of losses to any injector, equity holder or stakeholder.	Per barrel	Refund of allocated volume to rightful owner and payment of equivalent of 30% of total volume involved to the DPR at prevailing prices in USD.
26.	Introduction of hydrocarbon, Comingling/Spiking without approval from the Director, Petroleum Resources.	Operation or for every violation	$100,000. (One Hundred Thousand USD)
27.	Decommissioning of facility without approval from the Director, Petroleum Resources.	Per Action	$50.000 (Fifty Thousand USD)
28.	All "Agreement" between companies, operators, and injectors in any form shall be carried out in line with the Petroleum Acts and a copy submitted to the Department.	Per Company	Appropriate Sanction may be imposed by Director, as may be applicable.
29.	Tampering or breakage of security seal on flow meters used for custody transfer without approval.	Per Flow Meter	$5,000 (Five Thousand USD)
30.	Non- Compliance with frequency of calibration of measurement dipping tape, UTI, Temperature/Pressure Gauges & Transmitters.	Per Equipment	$5,000 (Five Thousand USD)
31.	Collection of crude oil samples without DPR approval.	Per Litre	$500 (Five Hundred USD)
32.	For all DPR approved flow meters, flow rate shall be maintained at specified station flow range.	Per Failure of station to inform DPR of changes in station flow rates	$10,000 (Ten Thousand USD)

33.	Falsification of Proving System Calibration/Meter Proving reports.	Per Prover/Meter	$30,000 (Thirty Thousand USD)
34.	Unavailability of up to date Metering station log book	Per facility	$5,000 (Five Thousand USD)
35.	Modification, Alteration, upgrade, etc. of LACT Metering System at operator/Third Party Custody Transfer Point / Third-Party Injection Points without DPR Approval.	Per LACT System	$150,000. (One Hundred and Fifty Thousand USD)
36.	False Declaration of Production Figures	Per Barrel or part thereof	$100
37.	Submission of Production/Lifting Figures, Reports within 21 days	First Week	$10,000
		Second Week and thereon	$5,000
38.	Failure to Calibrate/Recertify metering system Ancillary Equipment (Temperature & Pressure Gauges, Transmitters etc.)	Per Equipment	$5,000
39.	Failure to calibrate FPSOs/FSO/Barges storage tanks as at when due.	Per Vessel/Barge	$200,000
40.	Prover Loop Installation/Commissioning of Prover Loop without Approval		$500,000
41.	Failure to Recertify Prover Loop when due		$175,000 Per Annum
42.	Installation/Commissioning of Auto sampler without Approval		$25,000
43.	Failure to Recertify Auto sampler when due		$25,000 Per Annum
44.	Install/Commission of Meter(s) without Approval	Per Meter	$50,000
45.	Failure to Recertify Meter(s) or carry out statutory meter proving when due	Per Meter	$20,000 per proving frequency in addition to Any other sanctions by the Department.
46.	Installation/Commissioning of Storage Tank without Approval	Per < 100,000 Bbls Tank	$250,000
		Per > 100,000 Bbls Tank	$500,000

Note: 1- All fees in USD shall be paid to DPR in Naira equivalent based on the CBN prevailing rate at the time of infraction/application.

2- Payment of above-mentioned fines/fees shall be in addition to other necessary directives by the Director, DPR.

NOMENCLATURES, ABBREVIATIONS AND DEFINITIONS

- Petroleum and Petroleum Products means crude oil, refined products, natural gas liquid, LNG, LPG, natural gas, condensate, hydrocarbon liquid, renewable hydrocarbon liquid/sources and all their derivatives.
- LPG and Condensates shall be measured using liquid metering systems.
- Losses of Petroleum in plant installations, pipelines or installations may be caused or the result of corrosion, aged equipment, sabotage, willful damage or acts of nature, crisis, crimes or war etc.
- Licensee or lessee or operator – owner of facility or Oil Mining Lease (OML)
- DPR – Department of Petroleum Resources
- EGASPIN – Environmental Guideline and Standards for Petroleum Industries in Nigeria
- NNPC – Nigerian National Petroleum Corporation
- USD – United States Dollar
- FGN – Federal Government of Nigeria
- CBN – Central Bank of Nigeria
- MOSR – Mineral Oil (Safety) Regulations
- NPMS – National Production Monitoring System
- NSCDC – Nigerian Security and Civil Defence Corp
- NERC – Nigerian Electricity Regulatory Commission
- TPA – Town Planning Authority
- API – MPMS American Petroleum Institute – Manual for Petroleum Measurement Standards
- FAT – Factory Acceptance Test. Test of critical equipment at manufacturer's premises or workshop.
- SAT – Site Acceptance Test. Test of critical equipment at locations of installation, normally in country.
- LACT – Lease Automatic Custody Transfer.
- OTM – Optical Triangulation Method for tank calibration.
- ORLM – Optical Reference Line Method.
- EODRM – Electro-Optical Distance Ranging Method
- NFPA – National Fire Protection Association
- LFN – Laws of the Federation of Nigeria
- BPV - Base Prover Volume
- ISO: International Standard Organization.
- MMBTU: One-million British thermal units

- UTI- Ullage, Temperature and Interface
- GCV- Gross calorific value
- INJECTOR – Any producer of crude oil/condensate that pumps into a trunk pipeline/terminal (Both operators and the third party)
- PRODUCTION METERS – Any DPR approved meters used for production accounting.
- ALLOCATION METER – Any DPR approved meter used for accounting of volumes pumped into a trunk pipeline/terminal.
- CUSTODY TRANSFER METER – Any DPR approved meter that is used for the transfer of ownership for handling/safe keeping.
- GCV (Volumetric) – The quantity of heat measured in Joules produced by complete combustion in air of one cubic metre of anhydrous ideal gas taken at a 15°c and at an absolute pressure of 101.325 pascals.
- GCV (Mass) – The quantity of heat measured in joules produced by complete combustion in air of one kilogram of anyhydrous ideal gas taken at 15°C and in absolute pressure of 101.325 pascals.
- WOBBE INDEX – The gross calorific value (Volumetric) of the Degasified LNG divided by the square root of the molecular weight of the degasified LNG compare with air.
- Xi – is the concentration of component i.

- **Recognized standard:**

Guidelines, Standards or similar documents that within a technical field, are international or nationally recognised. Also, Acts or regulations, that are not directly applicable but which, regulate corresponding or neighbouring areas of activity.

- **Area of application:**

Any installation, a subsea installation or a terminal owned by Oil and/or Gas Operator where Gas metering system is in operation.

- **Place of Manufacture:**

Factory or a workshop where one or more of the measurement system's main parts are fabricated or constructed.

- **Datafile:**

Groups of data stored in an electronic unit

- **Computer part:**

The part of the measurement system, which comprises of digital computers and receives digital metering signals from A/D converters or from digital instrument loops.

- **Computer for administrative routines:**

Computer connected to one or more flow calculation computers. Information from the flow calculation computers may be further processed for reporting purposes. Information may be transferred from the administrative computer to the flow calculation device. The administrative unit may include long and short-term data storage facilities.

- **Flow computer:**

A computer performing flow calculations connected to one or more instruments and/or devices for collecting and distribution of signals. The storage unit (memory), which is providing long and short-term retention of data, is regarded as an integral part of the flow computer.

- **Devices and equipment error:**

Quantifiable amount incorrectly measured, since the accepted procedures for operation or calibration are not followed.

- **Fiscal metering station:**

Assembly of metering equipment dedicated to the determination of fiscal quantities, including MER values.

- **Technical Metering:**

Metering for the purposes of determining the essential parameters (formation volume factors, solution gas, etc) required for effective reservoir management.

- **Gas:**

Hydrocarbons in gaseous state at measurement conditions

- **Sensing element:**

A device, which acts directly on the condition it is measuring and produces a signal proportional to a physical condition.

- **Instrument part:**

The part of the metering system which is located between the mechanical part and the computer part i.e. from sensing element to digital input of the computer part inclusive.

- **Calibration:**

Establish relationship between the input and output signal for a device.

- **Calibration factor:**

Relationship between measured value coming from a flow meter and the measured value from a reference measurement system

- **Calibration mode:**

Selectable condition within the flow computer where routine checks and calibrations can be carried out, whilst the associated meter tubes are closed.

- **Linearity**

A relation between conditions where a change in one causes a proportional change for the other

- **Mechanical part:**

Meter tube, turbine meter, meter prover and all mechanical devices that are included in gas metering system

- **Metering tube**

Straight pipe sections where a flow meter is installed

- **Instrument Loop:**

The assembly of all devices and data links from the sensing element to the visual indication in the computer part of the metering system.

- **Metering system:**

Includes mechanical part, instrument part and computer part, including the auto-sampling system

- **Transmitter:**

Technical device, which changes the nature of the measured signal and transports the signal to from one equipment to another

- **Resolution:**

The least variation in signal level, which produces a noticeable change in the displayed value

- **Flow meter:**

Equipment located in or clamped to a pipe and its signal transformer, to provide a primary signal proportional to the amount of flow through the pipe.

- **Thermowell:**

A well in the meter tube for installation of a thermometer

- **Calibration factor for turbine meter:**

This is a number that indicates the ratio between volume throughput and readings of the turbine meter. The term is used to cover both the terms "meter factor" and the "K-factor".

- **Uncertainty in measurement:**

An estimate characterising the range within which the measured value will be found. In these guides this is at 95 percent confidence level, c = 2.

- **Inferential meters**

These are meters with no measurement compartments to trap and then release the gas. These meters are categorised as inferential meters in that the volume passed through them is "inferred" by something else observed or measured.

APPENDIX 1

Department of Petroleum Resources

DPR

RECONCILED MONTHLY STOCK / PRODUCTION (INVENTORY) MASS BALANCE REPORT

MONTH / YEAR: ....
NAME OF OPERATING COMPANY: ....
NAME OF TERMINAL: ....
AVERAGE API AT 60^{0}F: ....

S/NO:	**DESCRIPTION (ALL UNITS @ 60^{U}F)**	**GROSS US BARRELS**	**NETT US BARRELS**
A	CLOSING STOCK		
B	LIFTING (EXPORT + REFINERY)		
C	OPENING STOCK		
D	PRODUCTION BY MATERIAL BALANCE (A + B –C)		
E	PRODUCTION RECEIPT INTO TERMINAL		
F	TERMINAL ADJUSTMENT/LOSSES (D - E)		

PARTICIPANTS (NAMES IN FULL)

DPR REPRESENTATIVE:	SIGN:	DATE:
NNPC REPRSENTATIVE:	SIGN:	DATE:
OPERATING COMPANY:	SIGN:	DATE:

REMARK(S): The above are reconciled figures and accepted by all the parties. Refinery Supply may be applied for terminals that are linked with refineries or similar approved plant installations. ....

Department of Petroleum Resources

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