Designation: D4177 – 95(Reapproved 2010)

Manual of Petroleum Measurement Standards (MPMS), Chapter 8.2

Standard Practice for Automatic Sampling of Petroleum and Petroleum Products[1]

This standard is issued under the fixed designation D4177; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ε) indicates an editorial change since the last revision or reapproval.

This standard has been approved for use by agencies of the U.S. Department of Defense.

1. Scope

1.1 This practice covers information for the design, installation, testing, and operation of automated equipment for the extraction of representative samples of petroleum and petroleum products from a flowing stream and storing them in a sample receiver. If sampling is for the precise determination of volatility, use Practice D5842 (API *MPMS* Chapter 8.4) in conjunction with this practice. For sample mixing, refer to Practice D5854 (API *MPMS* Chapter 8.3). Petroleum products covered in this practice are considered to be a single phase and exhibit Newtonian characteristics at the point of sampling.

1.2 *Applicable Fluids*—This practice is applicable to petroleum and petroleum products with vapor pressures at sampling and storage temperatures less than or equal to 101 kPa (14.7 psi). Refer to D5842 (API *MPMS* Chapter 8.4) when sampling for Reid vapor pressure (RVP) determination.

1.3 *Non-applicable Fluids*—Petroleum products whose vapor pressure at sampling and sample storage conditions are above 101 kPa (14.7 psi) and liquified gases (that is, LNG, LPG etc.) are not covered by this practice.

1.3.1 While the procedures covered by this practice will produce a representative sample of the flowing liquid into the sample receiver, specialized sample handling may be necessary to maintain sample integrity of more volatile materials at high temperatures or extended residence time in the receiver. Such handling requirements are not within the scope of this practice. Procedures for sampling these fluids are described in Practice D1265, Test Method D1145, and GPA 2166.

1.4 Annex A2 contains theoretical calculations for selecting the sampler probe location. Annex A3 lists acceptance methodologies for sampling systems and components. Annex A4 gives performance criteria for permanent installations, while Annex A5 has the criteria for portable sampling units. Annex A6 provides sampler acceptance test data. Appendix X1 is a design data sheet for automatic sampling systems. Appendix X2 compares the percent sediment and water to unloading time period.

1.5 The values stated in SI units are to be regarded as standard. The values given in parentheses are for information only.

2. Referenced Documents

2.1 *ASTM Standards:*[2]

D923 Practices for Sampling Electrical Insulating Liquids

D1145 Test Method for Sampling Natural Gas (Withdrawn 1986)[3]

D1265 Practice for Sampling Liquefied Petroleum (LP) Gases, Manual Method

D4057 Practice for Manual Sampling of Petroleum and Petroleum Products

D4928 Test Method for Water in Crude Oils by Coulometric Karl Fischer Titration

D5842 Practice for Sampling and Handling of Fuels for Volatility Measurement

D5854 Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products

2.2 *API Standards:*[4]

API Manual of Petroleum Measurement Standards, Chapters 3, 4, 5, 6, and 10

MPMS Chapter 8.1 Practice for Manual Sampling of Petroleum and Petroleum Products (ASTM Practice D4057)

MPMS Chapter 8.3 Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products

[1] This practice is under the jurisdiction of ASTM Committee D02 on Petroleum Products, Liquid Fuels, and Lubricants and the API Committee on Petroleum Measurement, and is the direct responsibility of Subcommittee D02.02 /COMQ the joint ASTM-API Committee on Hydrocarbon Measurement for Custody Transfer (Joint ASTM-API).

Current edition approved May 1, 2010. Published May 2010. Originally approved in 1982. Last previous edition approved in 2005 as D4177–95(2005). DOI: 10.1520/D4177-95R10.

[2] For referenced ASTM standards, visit the ASTM website, www.astm.org, or contact ASTM Customer Service at service@astm.org. For *Annual Book of ASTM Standards* volume information, refer to the standard's Document Summary page on the ASTM website.

[3] The last approved version of this historical standard is referenced on www.astm.org.

[4] Available from American Petroleum Institute (API), 1220 L. St., NW, Washington, DC 20005-4070, http://www.api.org.

(ASTM Practice D5854)

MPMS Chapter 8.4 Practice for Manual Sampling and Handling of Fuels for Volatility Measurement (ASTM Practice D5842)

MPMS Chapter 10.9 Test Method for Water in Crude Oils by Coulometric Karl Fischer Titration (ASTM Test Method D4928)

2.3 *Gas Processors Association Standard:*[5]

GPA 2166 Obtaining Natural Gas Samples for Analysis by Gas Chromatography

2.4 *Institute of Petroleum Standard:*[6]

IP Petroleum Measurement Manual, Part IV, Sampling Section 2, Guide to Automatic Sampling of Liquids from Pipelines, Appendix B, 34th Ed

2.5 *Government Standard:*[7]

CFR 29, Part 1910.1000 Toxic and Hazardous Substances

3. Terminology

3.1 *Definitions of Terms Specific to This Standard:*

3.1.1 *automatic sampler, n*—a device used to extract a representative sample from the liquid flowing in a pipe.

3.1.1.1 *Discussion*—The automatic sampler usually consists of a probe, a sample extractor, an associated controller, a flow measuring device, and a sample receiver.

3.1.2 *automatic sampling system, n*—a system consisting of stream conditioning, an automatic sampler, and sample mixing and handling.

3.1.3 *dissolved water, n*—water in solution in petroleum and petroleum products.

3.1.4 *emulsion, n*—a water in oil mixture, which does not readily separate.

3.1.5 *entrained water, n*—water suspended in the oil.

3.1.5.1 *Discussion*—Entrained water includes emulsions but does not include dissolved water.

3.1.6 *flow proportional sample, n*—flow taken such that the rate is proportional throughout the sampling period to the flow rate of liquid in the pipe.

3.1.7 *free water, n*—water that exists as a separate phase.

3.1.8 *grab, n*—the volume of sample extracted from a pipeline by a single actuation of the sample extractor.

3.1.9 *homogeneous, adj*—when liquid composition is the same at all points in the container, tank, or pipeline cross section.

3.1.10 *isokinetic sampling, n*—sampling in such a manner that the linear velocity through the opening of the sample probe is equal to the linear velocity in the pipeline at the sampling location and is in the same direction as the bulk of the liquid approaching the sampling probe.

3.1.11 *Newtonian fluid, n*—a liquid whose viscosity is unaffected by the order of magnitude or agitation to which it may be subjected as long as the temperature is constant.

3.1.12 *power mixer, n*—a device which uses an external source of power to achieve stream conditioning.

3.1.13 *primary sample receiver/container, n*—a vessel into which all samples are initially collected.

3.1.14 *probe, n*—the portion of the automatic sampler that extends into the pipe and directs a portion of the fluid to the sample extractor.

3.1.15 *profile testing, n*—a procedure for simultaneously sampling at several points across the diameter of a pipe to identify the extent of stratification.

3.1.16 *representative sample, n*—a portion extracted from a total volume that contains the constituents in the same proportions as are present in the total volume.

3.1.17 *sample, n*—a portion extracted from a total volume that may or may not contain the constituents in the same proportions as are present in that total volume.

3.1.18 *sample controller, n*—a device which governs the operation of the sample extractor.

3.1.19 *sample extractor, n*—a device which removes a sample (grab) from a pipeline, sample loop, or tank.

3.1.20 *sample handling and mixing, n*—the conditioning, transferring and transporting of a sample.

3.1.21 *sample loop (fast loop or slip stream), n*—a low volume bypass diverted from the main pipeline.

3.1.22 *sampling, n*—all the steps required to obtain a sample that is representative of the contents of any pipe, tank, or other vessel and to place that sample into a container from which a representative test specimen can be taken for analysis.

3.1.23 *sampling system proving, n*—a procedure used to validate an automatic sampling system.

3.1.24 *sediment and water (S&W), n*—material which coexists with, but is foreign to, a petroleum liquid.

3.1.24.1 *Discussion*—S&W may include dissolved water, free water and sediment, and emulsified and entrained water and sediment.

3.1.25 *static mixer, n*—a device which utilizes the kinetic energy of the flowing fluid to achieve stream conditioning.

3.1.26 *stream condition, n*—the distribution and dispersion of the pipeline contents, upstream of the sampling location.

3.1.27 *stream conditioning, n*—the mixing of a flowing stream so that a representative sample can be extracted.

3.1.28 *time proportional sample, n*—a sample composed of equal volume grabs taken from a pipeline at uniform time intervals during the entire transfer.

3.1.29 *worst case conditions, n*—the operating conditions for the sampler that represent the most uneven and unstable concentration profile at the sampling location.

4. Significance and Use

4.1 Representative samples of petroleum and petroleum products are required for the determination of chemical and

[5] Available from Gas Processors Association (GPA), 6526 E. 60th St., Tulsa, OK 74145, http://www.gasprocessors.com.

[6] Available from Energy Institute, 61 New Cavendish St., London, WIG 7AR, U.K., http://www.energyinst.org.uk.

[7] Available from U.S. Government Printing Office, Superintendent of Documents, 732 N. Capitol St., NW, Mail Stop: SDE, Washington, DC 20401.

physical properties, which are used to establish standard volumes, prices, and compliance with commercial and regulatory specifications.

5. Representative Sampling Criteria

5.1 The following criteria must be satisfied to obtain a representative sample from a flowing stream.

5.1.1 For nonhomogeneous mixtures of oil and water, free and entrained water must be uniformly dispersed at the sample point.

5.1.2 Grabs must be extracted and collected in a flow proportional manner that provides a representative sample of the entire parcel volume.

5.1.3 Grabs must be a consistent volume.

5.1.4 The sample must be maintained in the sample receiver without altering the sample composition. Venting of hydrocarbon vapors during receiver filling and storage must be minimized. Samples must be mixed and handled to ensure a representative test specimen is delivered into the analytical apparatus.

6. Automatic Sampling Systems

6.1 An automatic sampling system consists of stream conditioning upstream of the sampling location, a device to physically extract a grab from the flowing stream, a flow measurement device for flow proportioning, a means to control the total volume of sample extracted, a sample receiver to collect and store the grabs and, depending on the system, a sample receiver/mixing system. Unique properties of the petroleum or petroleum product(s) being sampled may require the individual components or the entire system be insulated or heated, or both. Appendix X1 references many of the design consideration that should be taken into account.

6.2 Grabs must be taken in proportion to flow. However, if the flow rate, during the total parcel delivery (week, month, etc.) varies less than ±10 % from the average flow rate, a representative sample may be obtained by the time proportional control of the grabs.

6.3 There are two types of automatic sampling systems (see Fig. 1). Both systems can produce representative samples if properly designed and operated. One system locates the extracting device directly in the main line, whereas the other system locates the extracting device in a sample loop.

6.4 In a sample loop type system, a probe is located in the main pipeline and directs a portion of the fluid flow into the sample loop. This probe may be a 90° elbow or a 45° level facing upstream (see 10.2). The average flow velocity through the sample loop shall be near the maximum average velocity expected in the main pipeline, but not less than 2.5 m/s (8 ft/s).

6.5 The controller which operates the sample extractor in the sample loop receives its flow proportional signal from the flow meter(s) in the main line. For sample loop installations, a flow indicator must also be installed in the sample loop.

6.6 If circulation in the sample loop stops and sampling continues, a non-representative sample will result. A low-flow alarm should be installed to alert the operator of a loss of flow. In no case shall a filter be installed in a sample loop, upstream of the sample extractor, as it may alter the representativeness of the sample.

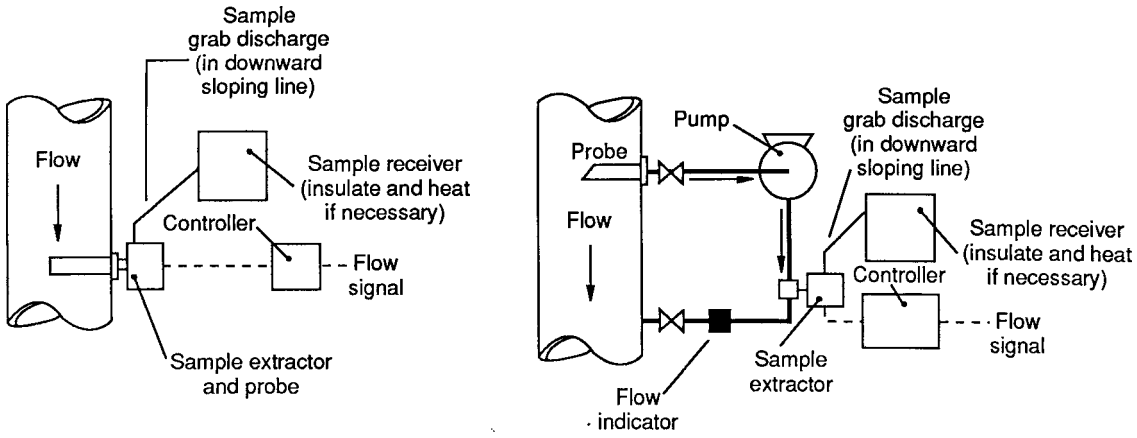
7. Sampling Frequency

7.1 Guidelines for sampling frequency can be given in terms of "grab per lineal distance of pipeline volume." For marine and pipeline service this minimum guideline can be related to barrels per grab using the following equation:

$$\text{BBL/grab} = 0.0001233 \times D^2 \text{ or } 0.079548 \times d^2 \quad (1)$$

where:

D = nominal pipe diameter, mm and
d = nominal pipe diameter, in.



NOTE 1—Arrow does not indicate piping orientation.

FIG. 1 Typical Automatic Sampling Systems

7.2 This formula equates to one grab for every 25 lineal metres (approximately 80 ft) of pipeline volume.

7.3 Sampling frequency should be based on maximizing grabs for the available receiver size. Typically, Lease Automatic Custody Transfer (LACT) or Automatic Custody Transfer (ACT) units are paced at one grab per one to ten barrels.

7.4 The optimum sampling frequency is the maximum number of grabs which may be obtained from any parcel operating within the grab frequency and grab volume limitations of the equipment. The completed sample should be of sufficient volume to mix and properly analyze while not over filling the sample receiver.

8. Stream Conditioning

8.1 The sampler probe must be located at a point in the pipe where the flowing stream is properly conditioned. This conditioning may be accomplished with adequate flow velocity through the piping system or mixing elements may be added to supplement mixing provided by the basic piping. Petroleum that contains free or entrained sediment and water (S&W) requires adequate mixing energy to create a homogeneous mixture at the sample point.

8.2 Petroleum products are generally homogeneous and usually require no special stream conditioning. Exceptions to this may occur if free water is present or if a product is exiting a blending system.

8.3 *Velocities and Mixing Elements:*

8.3.1 Fig. 2, based on tests, provides a guideline for minimum velocities versus mixing elements for pipes 50 mm (2 in.) in diameter and larger. Stream conditioning can be accomplished with pressure reducing valves, metering manifolds, lengths of reduced diameter piping, or piping elements (valves, elbows, tees, piping, or expansion loops).

8.3.2 Where the flow velocity at the automatic sampler probe location falls below the minimum levels detailed in Fig. 2, additional means will be required to provide adequate stream conditioning such as power mixers or static mixers. The effect of viscosity, density, water content, as well as the relative position of the mixing element(s) and sample probe should also be considered.

8.3.3 Specific calculation procedures for estimating the acceptability of a proposed or existing sampling location are detailed in Annex A2.

8.3.4 Again it should be remembered that petroleum products are assumed to be homogeneous at the point of sampling and require no additional stream conditioning unless specifically sampling for water content, or where the sampler is downstream of a blending manifold.

9. Special Considerations for Marine Applications

9.1 When pumping from a shore tank or from a vessel, a significant amount of free water may be transferred during a short period of time (see Appendix X2). This may occur when the pumping rate is low and the oil/water mixture is stratified. The stream conditioning may not be adequate to provide a representative sample. To help minimize this condition, a tank that does not contain free water should be utilized first. Tanks containing free water can be discharged when the pumping rate is normal.

9.2 If the sampler is located some distance from the point of load/discharge, operating procedures should account for the line fill between those two points.

10. Probes

10.1 *Probe Location and Installation:*

10.1.1 The recommended sampling area is approximately the center one-third of the pipeline cross-section area as shown in Fig. 3.

10.1.2 The probe opening must face upstream and the external body of the probe should be marked with the direction of flow to verify that the probe is installed correctly.

10.1.3 The probe must be located in a zone where sufficient mixing results in adequate stream conditioning. This zone is generally from 3 to 10 diameters downstream of piping elements, 0.5 to 4 diameters from static mixers, and 3 to 10 diameters from power mixers. When static or power mixers are used, the manufacturer of the device should be consulted for the probe's optimum location.

10.1.4 The line from the outlet of the extractor to the sample receiver must continuously slope downward from the extractor to the receiver and contain no dead space.

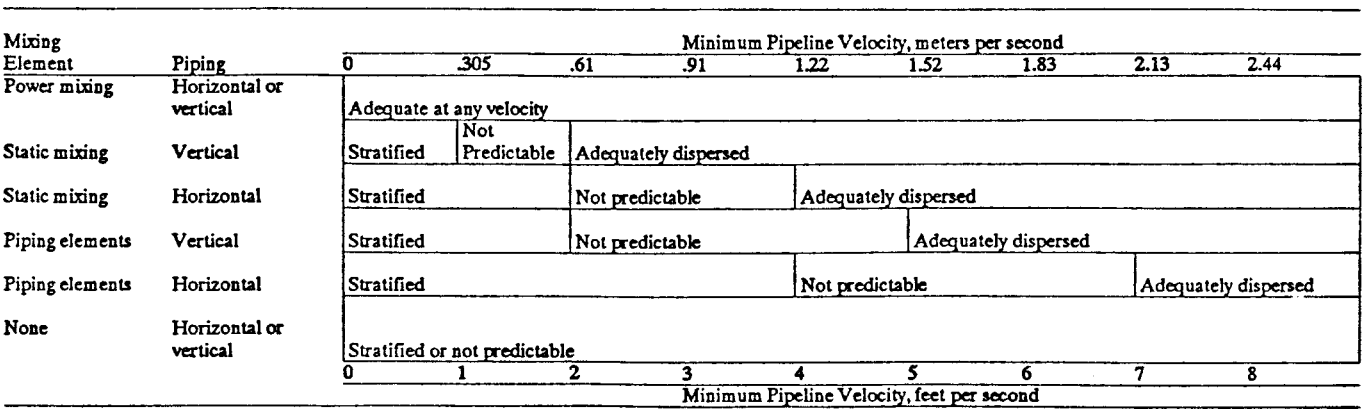


FIG. 2 General Guidelines for Minimum Velocities Versus Mixing Elements

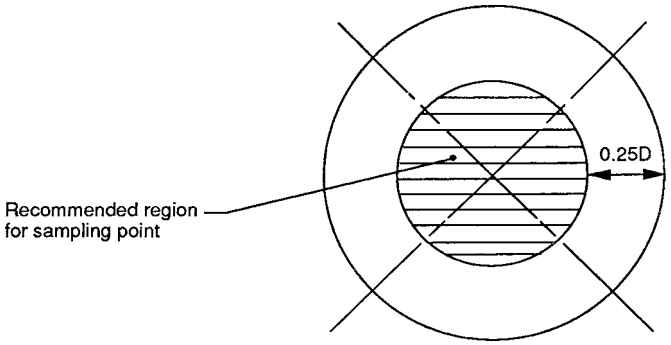


FIG. 3 Recommended Sampling Area

10.1.5 The preferred installation of a combined probe-extractor is in the horizontal plane.

10.1.6 If a vertical piping loop is used for stream conditioning, locate the probe in the downflow section of the loop to obtain the benefit of the additional stream conditioning provided by the three 90° elbows. Locate the probe a minimum of three pipe diameters downstream of the top 90° elbow and not closer than one-half pipe diameter upstream of the final exiting elbow (see Fig. 4).

10.1.7 According to tests sponsored by the American Petroleum Institute (API), locating a sample probe downstream of a single 90° bend is not recommended because of inadequate stream conditioning.

10.2 *Probe Design:*

10.2.1 The mechanical design of the probe should be compatible with the operating conditions of the pipeline and the fluid being sampled. There are three basic designs shown in Fig. 5. Probe openings should be in the center third of the cross sectional area of the pipe.

10.2.2 Probe designs commonly used are described as follows:

10.2.2.1 A closed end probe equipped with an open orifice (see Fig. 5A).

10.2.2.2 A short-radius elbow or pipe bend facing upstream. The end of the probe should be chamfered on the inside diameter to give a sharp entrance (see Fig. 5B).

10.2.2.3 A tube cut at a 45° angle with the angle facing upstream (see Fig. 5C).

11. Automatic Sampling Components

11.1 *Extractor*—An automatic sample extractor is a device that extracts a sample (grab) from the flowing medium. The extractor may or may not be an integral part of the probe. The sample extractor should extract a consistent volume that is repeatable within ±5 % over the range of operating conditions and sampling rates.

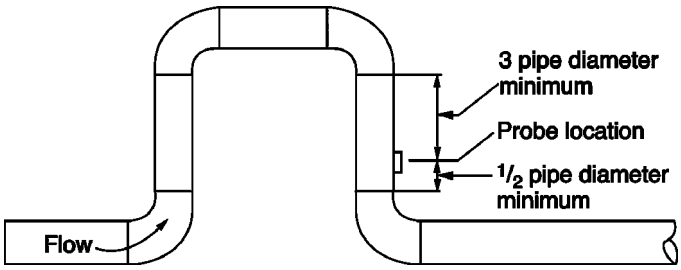


FIG. 4 General Vertical Piping Loop Configuration

11.2 *Controller*—A sample controller is a device which governs the operation of the sample extractor. The sample controller should permit the selection of the sampling frequency.

12. Sampler Pacing

12.1 *Custody Transfer Meters*—Custody transfer meters should be used to pace the sampler where available. When flow is measured by multiple meters, the sampler should be paced by the combined total flow signal. Alternatively, a separate sampler may be installed in each meter run. The sample from each meter run must be considered a part of the total sample and in the same proportion as that meter's volume is to the total volume.

12.2 *Special Flow Meters*—When custody transfer is by tank measurements, a flow signal must be provided to the sample controller. This signal may be provided by an add-on flow metering device. These devices should have an accuracy of ±10 % or better, over the total volume of the parcel.

12.3 *Time Proportional Sampling*—An automatic sampler should preferably operate in proportion to flow. However, sampling in a time proportional mode is acceptable if the flow rate variation is less than ±10 % of the average rate over the entire parcel.

13. Primary Sample Receivers

13.1 A sample receiver/container is required to hold and maintain the composition of the sample in liquid form. This includes both stationary and portable receivers, either of which may be of variable or fixed volume design. If the loss of vapors will significantly affect the analysis of the sample, a variable volume type receiver should be considered. Materials of construction should be compatible with the petroleum or petroleum product sampled.

13.2 *Stationary Receivers:*

13.2.1 *General Design Features*—These features may not be applicable to some types of receivers, that is, variable volume receivers.

13.2.1.1 Receiver design must allow for preparation of a homogeneous mixture of the sample.

13.2.1.2 The bottom of the receiver must be continuously sloped downward toward the drain to facilitate complete liquid withdrawal. There should be no internal pockets or dead spots.

13.2.1.3 Internal surfaces of the receiver should be designed to minimize corrosion, encrustation, and clingage.

13.2.1.4 A means should be provided to monitor filling of the receiver. If a sight glass is used, it must be easy to clean and not be a water trap.

13.2.1.5 A relief valve should be provided and set at a pressure that does not exceed the design pressure of the receiver.

13.2.1.6 A means to break vacuum should be provided to permit sample withdrawal from the receiver.

13.2.1.7 A pressure gauge should be provided.

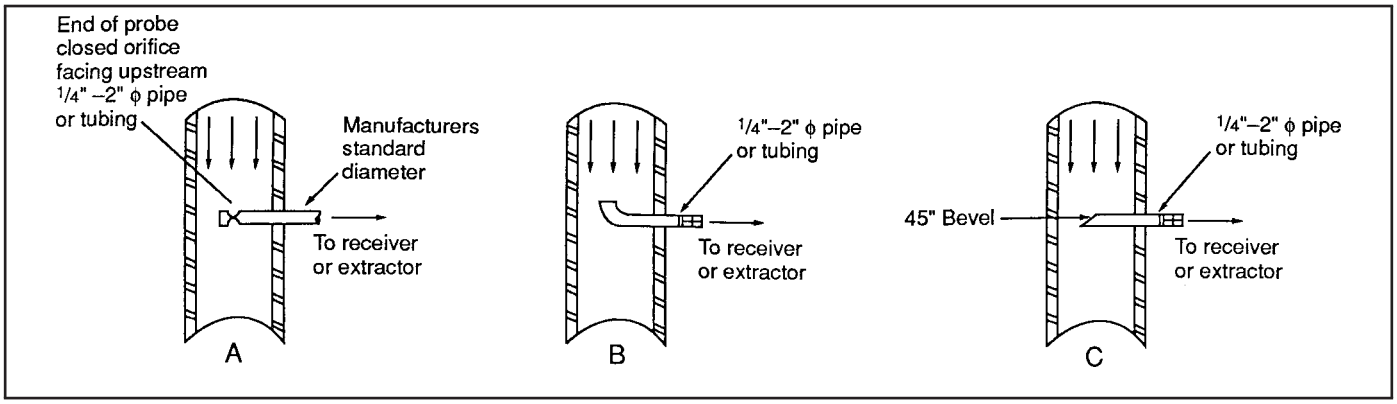


FIG. 5 Probe Designs

13.2.1.8 Receivers should be sheltered from adverse ambient conditions when in use.

13.2.1.9 Receivers may need to be heat traced or insulated, or both, when high pour point or high viscosity petroleum or petroleum products are sampled. Alternatively, they may be housed in heated and insulated housing. Exercise caution to ensure added heating does not affect the sample.

13.2.1.10 Use of multiple sample receivers should be considered to allow flexibility in sampling sequential parcels and line displacements. Exercise care in the piping design to prevent contamination between samples of different parcels. See Fig. 6.

13.2.1.11 Receivers should have an inspection cover or closure of sufficient size to facilitate easy inspection and cleaning.

13.2.1.12 Facilities for security sealing should be provided.

13.2.1.13 The system must be capable of completely draining the receiver, mixing pump, and associated piping.

13.2.1.14 The circulating system shall not contain any dead legs.

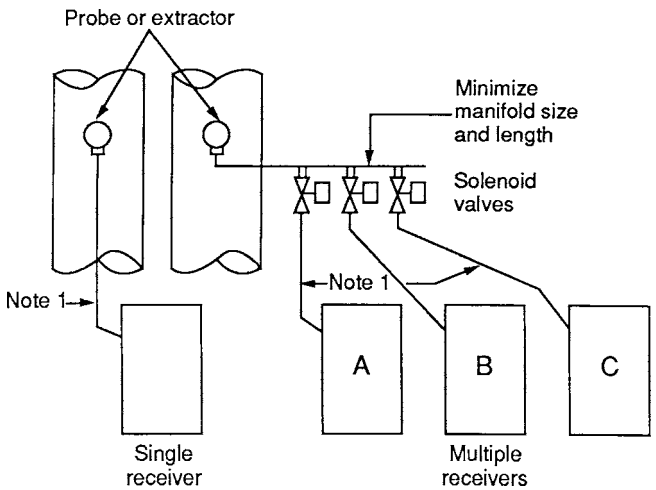
13.3 *Portable Receivers*—In addition to considerations outlined in 13.2, portable receivers may include the following additional features:

13.3.1 Light weight,

13.3.2 Quick release connections for easy connection/disconnect to the probe/extractor and the laboratory mixer (see Fig. 7), and

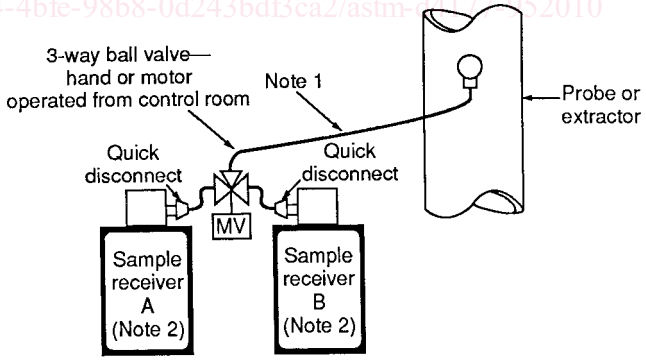
13.3.3 Carrying handles.

13.4 *Receiver Size*—The receiver should be sized to match its intended use and operating conditions. The size of the receiver is determined by the total volume of sample required, the number of grabs required, the volume of each grab and, transportability of the receiver if portable. Typical sample receiver sizes are shown in Table 1.



NOTE 1—6.4 or 9.5 mm (¼ or ⅜ in.) tubing, as short as possible and sloping continuously toward the sample receiver, should be used. 9.5 mm (⅜ in.) tubing should be used where long sampling lines cannot be avoided or in crude oil service. Heat trace and insulate these lines when necessary.

FIG. 6 Receiver(s) Installation



Installation Showing Portable Receivers

NOTE 1—6.4 or 9.5 mm (⅜ in.) tubing, as short as possible and sloping continuously toward the sample receiver should be used. Three-eighths inch tubing should be considered where long sampling lines cannot be avoided or the crude oil is viscous. Heat trace and insulate these lines when necessary.

NOTE 2—Sample should flow into a connection at the top of the container.

NOTE 3—In warm climates, a sun shield should be provided to avoid excessive temperature changes in sample receivers.

NOTE 4—In cold climates, consider placing sample receivers in a heated housing or heat trace and insulate the receivers and sample lines.

FIG. 7 Portable Receiver(s) Installation

TABLE 1 Typical Receiver Sizes

Lease automatic custody transfer	10–60 L (3–15 gal)
Pipelines (crude petroleum)	20–60 L (5–15 gal)
Pipelines (products)	4–20 L (1–5 gal)
Portable sampler	1–20 L (1 qt–5 gal)
Tanker loading/unloading	20–75 L (5–20 gal)

14. Sample Mixing and Handling

14.1 Sample in the receiver must be properly mixed to ensure a homogenous sample. Transfer of samples from the receiver to another container or the analytical glassware in which they will be analyzed requires special care to maintain their representative nature. See Practice D5854 (API *MPMS* Chapter 8.3) for detailed procedures.

15. Portable Samplers

15.1 A typical application of a portable sampling system is on board a marine vessel. There are also occasional applications on shore. The same criteria for representative sampling applies to both portable and stationary sampling systems. Exercise caution when using portable samplers on marine vessels due to the difficulty in verifying stream conditioning during actual operations. An example of a marine application is shown in Fig. 8.

15.2 *Design Features*—Special features and installation requirements for a portable sampler are:

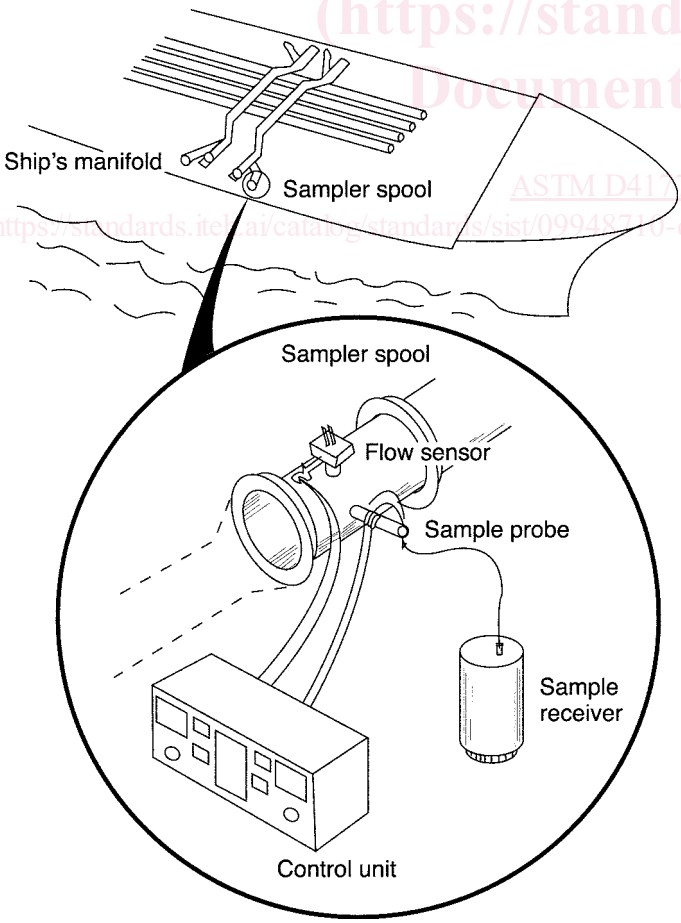


FIG. 8 Typical Portable Marine Installation

15.2.1 A spool assembly fitted with a sample probe/extractor and flow sensor is inserted between the ship's manifold and each loading/unloading arm or hose. If the grab size of each sampler is equal, a common receiver can be used.

15.2.2 A controller is required for each extractor. The controller must be able to record total number of grabs and total volume.

15.2.3 Piping arrangement at the ship's manifold will often distort the flow profile. The flow sensor, when operated under the piping and flow conditions at the ship's manifold, must meet the accuracy criteria in 12.2.

15.2.4 Stream conditioning is accomplished by velocity of the fluid and the piping elements ahead of the probe. The number of hoses, arms, and lines in service at any one time may need to be limited to maintain sufficiently high velocity.

15.2.5 The controller may be placed on the ship's deck, which is usually classified as a hazardous zoned area. If the controller is electronic, it should meet the requirements of the hazardous area.

15.2.6 Air supply must meet the requirements of the equipment.

15.2.7 For high pour or viscous fluids, particularly in cold climates, the line from the extractor to the receiver may require a thermally insulated high pressure hose or tubing. The receiver should be placed as close to the extractor as possible to minimize the hose length. The hose or tubing should have an internal diameter of 9.5 mm (⅜ in.) or more and slope continuously downward from the extractor to the receiver. The line from the extractor to the receiver may have to be heat traced.

15.2.8 Filling of receivers should be monitored to ensure that each sampler is operating properly. Frequent visual inspection, level indicators, and weighing have proven to be acceptable monitoring methods.

15.2.9 The portable sampler is used intermittently; therefore the sample probe, extractor, and flow sensor should be cleaned after every use to prevent plugging.

15.2.10 All components and installation must meet applicable regulations, such as those of the U.S. Coast Guard.

15.3 *Operating Considerations*—The portable sampler operator must maintain operating conditions which provide adequate mixing and produce a representative sample. Performance criteria is given in Annex A5. To meet the criteria requires cooperation of the vessel crew and shore personnel. Special operating requirements are:

15.3.1 The portable sampler operator should keep the flow rate at each flow sensing device within its design range by limiting the number of loading lines or hoses in service during periods of low flow rates, for example, start-up, topping off, stripping, etc.

15.3.2 For discharge operations, the vessel compartment discharge sequence must be controlled so that the amount of free water being discharged during the start-up operation is less than 10 % of the total amount of water in the cargo.

15.3.3 For loadings, a shore tank with no free water is preferred for the initial pumping. Water drawing the tank or pumping a small portion of the tank to another shore tank prior to the opening tank gauge, or both, are suggested.

16. Acceptance Tests

16.1 Testing is recommended to confirm that a sampling system is performing accurately. Annex A3 outlines methods for testing samplers that are used for the collection of S&W or free water samples. The test methods fall in two general categories; Total System Testing and Component Testing.

16.2 *Total System Testing*—This test method is a volume balance test where tests are conducted for known amounts of water. It is designed to test the total system including the laboratory handling and mixing of sample. Two procedures are outlined. One involves only the sampler under test, the other utilizes an additional sampler to measure the baseline water.

16.3 *Component Testing*—This test method involves testing individually the components that comprise a sampling system. Where applicable, some of the component tests may be conducted prior to installation of the total system. Components to be tested include:

16.3.1 Probe/extractor,

16.3.2 Profile (for stream conditioning),

16.3.3 Special flow meter, and

16.3.4 Primary sample receiver and mixer.

16.3.5 If a system design has been proven by testing, subsequent systems of the same design (for example, LACT units), including piping configuration and operated under the same or less criterial conditions (that is, higher flow rate, higher viscosity, lower water content, etc.) need not be tested. Once a system or system design has been proven, the following checks can be used to confirm system reliability:

Component	Check
Stream conditioning	Flow rate or pressure drop if equipped with power or static mixer.
	Profile test for systems with only piping elements.
Pacing device	Compare recorded batch volume to known volume.
	Compare actual sample volume to expected volume.
Extractor	Compare actual sample volume to expected volume.
	Compare actual grab size to expected grab size.

16.3.6 Portable sampling systems can be tested by the component testing method except for proper stream conditioning. To compensate for this, the performance test for each operation has been designed to evaluate the operation of the sampler. This is shown in Annex A5.

16.4 *Requirements for Acceptability*—Testing by either the component or total system method requires that two out of three consecutive sets of test data repeat within the limits shown in Annex A3.

17. Operational Performance Checks/Reports

17.1 Monitoring of sampler performance is a necessary part of every sampling operation. Monitoring is required to make sure that the sample extractor is extracting a uniform grab in a flow proportional manner. This is normally accomplished by assessing the sample volume collected to ensure that it meets expectations for the equipment and transfer volume involved.

17.2 Several procedures may be used to accomplish this requirement, that is, sight glasses, gages, or weigh cells. Selection of a procedure should be based on (*1*) volume of transfer, (*2*) type of installation, (*3*) time interval of transfer, (*4*) whether the sampling facility is manned, (*5*) receiver type, (*6*) purpose of the sample, and (*7*) equipment used.

17.3 For LACT and ACT units, monitoring may consist of comparison between sample volume collected and expected sample volume. For very large transfers including marine transferee, more information may be desired as outlined in Annex A4 and Annex A5.

18. Keywords

18.1 acceptance tests; automatic petroleum sampling; controllers; extractor; intermediate sampling receiver; isokinetic sampling; mixing elements; portable samplers; primary sample receiver; probe; representative sampling; representative sampling criteria; sample loop; sample mixing; sampling handling; stream conditioning

ANNEXES

(Mandatory Information)

A1. PRECAUTIONARY INFORMATION

A1.1 Physical Characteristics and Fire Considerations

A1.1.1 Personnel involved in the handling of petroleum-related substances (and other chemical materials) should be familiar with their physical and chemical characteristics, including potential for fire, explosion, and reactivity, and appropriate emergency procedures. These procedures should comply with the individual company's safe operating practices and local, state, and federal regulations, including those covering the use of proper protective clothing and equipment. Personnel should be alert to avoid potential sources of ignition and should keep the materials' containers closed when not in use.

A1.1.2 API Publication 2217 and Publication 2026[4] and any applicable regulations should be consulted when sampling requires entry to confined spaces.

A1.1.3 INFORMATION REGARDING PARTICULAR MATERIALS AND CONDITIONS SHOULD BE OBTAINED FROM THE EMPLOYER, THE MANUFACTURER OR SUPPLIER OF THAT MATERIAL OR THE MATERIAL SAFETY DATA SHEET.

A1.2 Safety and Health Consideration

A1.2.1 *General*—Potential health effects can result from exposure to any chemical and are dependent on the toxicity of the chemical, concentration, and length of the exposure. Everyone should minimize his or her exposure to work place chemicals. The following general precautions are suggested:

(1) Minimize skin and eye contact and breathing of vapors.

(2) Keep chemicals away from the mouth; they can be harmful or fatal if swallowed or aspirated.

(3) Keep containers closed when not in use.

(4) Keep work areas as clean as possible and well ventilated.

(5) Clean spills promptly and in accordance with pertinent safety, health, and environmental regulations.

(6) Observe established exposure limits and use proper protective clothing and equipment.

NOTE A1.1—Information on exposure limits can be found by consulting the most recent editions of the Occupational Safety and Health Standards, 29 Code of Federal Regulations Part 1910.1000 and following and the ACGIH publication "Threshold Limit Values for Chemical Substances and Physical Agents in the Work Environment."[8]

A1.2.1.1 INFORMATION CONCERNING SAFETY AND HEALTH RISKS AND PROPER PRECAUTIONS WITH RESPECT TO PARTICULAR MATERIALS AND CONDITIONS SHOULD BE OBTAINED FROM THE EMPLOYER, THE MANUFACTURER OR THE MATERIAL SAFETY DATA SHEET.

[8] Available from American Conference of Governmental Industrial Hygienists, Inc. (ACGIH), 1330 Kemper Meadow Dr., Cincinnati, OH 45240, http://www.acgih.org.

A2. THEORETICAL CALCULATIONS FOR SELECTING THE SAMPLER PROBE LOCATION

A2.1 Introduction

A2.1.1 This annex describes calculation procedures for estimating the dispersion of water-in-oil at a sampling location. These procedures have a very simple theoretical base with many of the equations not being strictly applicable; therefore, they should be used with extreme caution in any practical application. A conservative approach is strongly recommended when estimating the acceptable limits for adequate dispersion (steam conditioning).

NOTE A2.1—From IP Petroleum Measurement Manual, Part IV Sampling:

A2.1.2 The equations contained in this annex have been shown to be valid for a large number of field data. The range of the field data covered the following correlating parameters:

Relative density	0.8927–0.8550 (27°–34° API)
Pipe diameter	40 cm–130 cm (16 in.–52 in.)
Viscosity	6–25 cSt at 40°C
Flowing velocity	>0–3.7 m/s (>0–12 ft/s)
Water concentration	<5 %

NOTE A2.2—Use caution when extrapolating outside of these ranges.

A2.1.3 When evaluating if dispersion is adequate or not in a given system, using the worst case conditions is recommended.

A2.1.4 When calculating the dispersion rate E in A2.4, it should be noted that dispersion energies of different piping elements are not additive in regard to dispersion, that is, when a series of elements is present, the element that should be considered is the one that dissipates energy the most.

A2.1.5 As an aid in determining the element most likely to provide adequate dispersion, Fig. A2.1 has been developed. When using Fig. A2.1, it is important to consider it as a guide only and that particular attention should be paid to the notes. Fig. A2.1 does not preclude the need for a more detailed analysis of these elements, within a given system, shown by the table to be the most effective.

A2.2 *Symbols* —The symbols used in Annex A2 are presented in Table A2.1.

A2.3 Dispersion Factors

A2.3.1 As a measure of dispersion, the ratio of water concentration at the top of a horizontal pipe C_1 to that at the bottom C_2 is used. A C_1/C_2 ratio of 0.9 to 1.0 indicates very good dispersion while a ratio of 0.4 or smaller indicates poor dispersion with a high potential for water stratification. Calculations giving ratios less than 0.7 should not be considered reliable as coalescence of water droplets invalidates the prediction technique.

A2.3.2 The degree of dispersion in horizontal pipes can be estimated by:

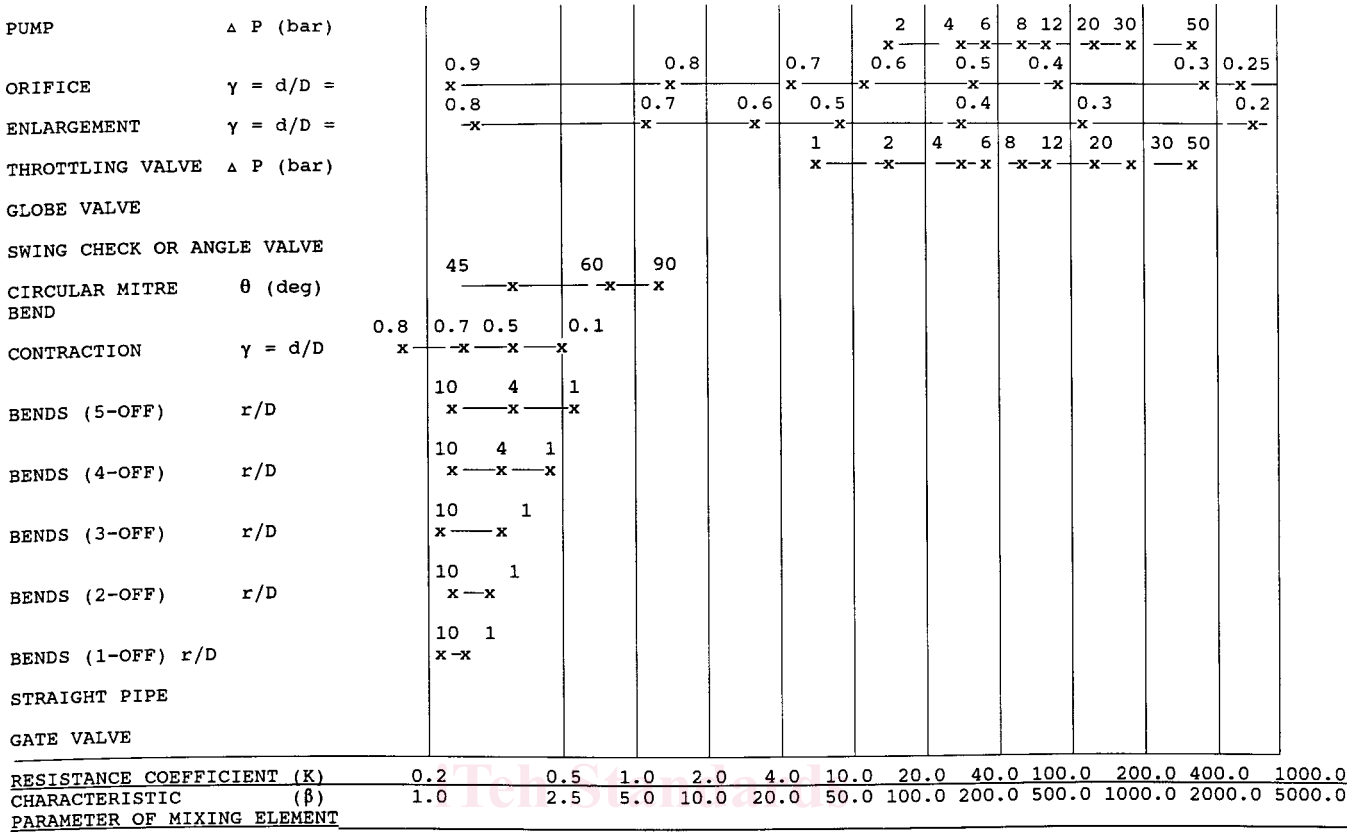
$$\frac{C_1}{C_2} = \exp\left(\frac{-W}{\varepsilon/D}\right) \quad \text{(A2.1)}$$

where:

C_1/C_2 = the ratio of water concentration at the top (C_1) to that at the bottom (C_2),
W = the settling rate of the water droplets, and
ε/D = the turbulence characteristic, where ε is the eddy diffusivity and D the pipe diameter.

A2.3.3 An alternative measure of dispersion, G, can be defined in Eq A2.2. Table A2.2 presents the relationship of C_1/C_2 with G.

$$G = \frac{\varepsilon/D}{W} \quad \text{(A2.2)}$$



NOTE 1—The table has been compiled assuming the same pipeline diameter downstream of any device. If the downstream diameter of any two devices is not identical, comparisons using Fig. A2.1 cannot be performed.

NOTE 2—It is not intended that Fig. A2.1 be used to ascertain β or K values but only to provide a comparison of the likely mixing effects of devices.

NOTE 3—For centrifugal pumps and throttling valves, the dissipation energies, which are defined without the use of β values (see Table A2.4), the comparison has been done using an assumed β equal to E/E_o and the following typical values— $D = 0.4$ m; $\nu = 16$ cSt; $\rho = 900$ kg/m^3; $V = 5.6$ m/s.

FIG. A2.1 Comparison of Mixing Devices

A2.3.4 It is important to note that the uncertainty of the calculations is such that errors in G of more than 20 % may result at low values of G. For this reason, it is recommended that no reliance be placed upon calculated G values of less than 3 and that additional energy dissipation calculated G value.

A2.4 Determination of Energy Dissipation

A2.4.1 Two different techniques are given for determining the rate of energy dissipation.

A2.4.2 Method A uses the relationship in Eq A2.3.

$$E = \frac{\Delta P V}{\Delta X \rho} \tag{A2.3}$$

where:

ΔP = the pressure drop across the piping element,
V = the flow rate at the pipe section in which energy is dissipated, and
ΔX = a characteristic length which represents the distance in which energy has been dissipated.

In most cases ΔX is not known with any confidence. Wherever possible, the value to be used should be supported by experimental data.

NOTE A2.3—If ΔX is not known, a substitute value of $\Delta X = 10D$ may be used as a very rough approximation for devices of low mixing efficiency such as those in Table A2.3. For specially designed high efficiency static mixers the value ΔX will be small and should be obtained from the designer.

NOTE A2.4—If ΔP is not known, calculate it from Eq A2.4.

$$\Delta P = \frac{K \rho V^2}{2} \tag{A2.4}$$

where:

K = the resistance coefficient of the piping element under consideration.

Suggested values of K for different piping elements are given in Table A2.3.

A2.4.3 Method B uses the relationship $E = \beta E_0$, where β is a characteristic parameter of a mixing element and E_0 is the rate of energy dissipation in a straight pipe. E_0 is calculated from Eq A2.5.

$$E_0 = 0.005 \nu^{0.25} D^{-1.25} V^{2.75} \tag{A2.5}$$

where: ν is given in mm^2/s (cSt).

A2.4.4 Suggested values of β and tentative relationships for E (other than $E = \beta E_0$) are given in Table A2.4 and Table A2.5 respectively.

A2.5 *Contraction* —Contraction effects can be calculated with Eq A2.6.