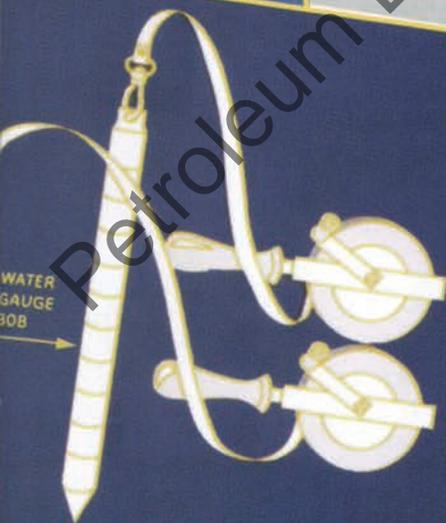


Primer of Oil and Gas Measurement

First Edition



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The University of Texas at Austin**

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CHAPTER 1

Tank Measurement

INTRODUCTION

Oil and oil products are often stored in large stationary tanks. Crude oil is stored in tanks near producing wells, at tank farms along the route to the refinery, and at the refinery itself. Oil products are stored in tanks in many areas, from the refinery to the petrochemical plant to the wholesale distributor. These liquids are stored for various reasons, but no matter what the reason, whenever they are kept in tanks, the amount stored must be accounted for and therefore must be measured precisely.

One way to measure the volume of a stored liquid is to determine the height of the liquid in the tank and then to refer to a *capacity table* computed specifically for that tank. This capacity table (also sometimes referred to as a tank table, a strapping table, or a gauge table) tells you the gross volume of liquid contained in a particular tank at any given level.¹ For example, in table 1.1 you can see that the height of the liquid is listed in one-inch increments. Opposite each height is the volume in barrels. Thus, if the liquid height in this tank is 25 feet, 6 inches, it holds 35,429.93 barrels of liquid.

If the liquid height includes a fraction of an inch, you consult the end of the table for the number of barrels for each fraction of liquid height. For example, if the liquid height is 25 feet, 6¼ inches, you look at the end of the table and find that for every quarter of an inch you add 29.16 barrels to the amount listed in the rest of the table. Thus, in this example, 25 feet, 6¼ inches equals 35,459.09 barrels of liquid.

A capacity table like the one shown in table 1.1 is developed from specific measurements taken from the storage tank. At various times during its life a storage tank is carefully measured by a professional independent contractor to obtain certain dimensions, including, among others, the depth of the tank (both inside and outside), the circumference of each ring of the tank and the height of the liquid, if any, in the tank. These measurements are then forwarded to the department that computes capacity tables. Measuring a tank so that its capacity can be computed is sometimes referred to as *tank strapping*. It is also frequently called *tank calibration*.

¹ To determine the *net* volume of liquid in a tank, and thus to determine tank liquid volume accurately, you must also know the height of the liquid, the temperature and gravity of the liquid, and the sediment and water content.

CHAPTER 2

Gauging Petroleum and Petroleum Product Heights in Stationary Tanks

INTRODUCTION

Measuring oil and oil products stored in stationary tanks is a fairly straightforward process. First you strap, or measure, the capacity of the tank. Next, you develop capacity tables that tell you the gross volume, in barrels, for any level of liquid. Finally, you gauge (i.e., measure) the height of the liquid from the bottom of the tank to the surface of the liquid. You gauge the height of the liquid to take inventory or to measure the amount of liquid transferred any time liquid enters or leaves the tank. If liquid is moving into or out of the tank, you gauge the height before the liquid enters or leaves and after the liquid enters or leaves the tank. The difference between the two measurements is the gross volume transferred.

In order to determine as closely as possible how many barrels of liquid are in the tank, you gauge the height of the liquid to the nearest eighth of an inch. On crude oil lease tanks holding one thousand barrels or less,

you gauge to the nearest quarter inch. Before you measure the liquid height, however, you need to make sure that the liquid has been in the tank long enough for the surface to be at rest and for any foam to have subsided. If you are gauging crude oil, you should also wait long enough for any entrained air to bubble out or water to settle out of the oil. And, if you are measuring liquid products and the tank has a mixer, you must be sure the mixer is shut off.

Once these conditions are met, you can use one of several methods to determine the liquid height in a stationary tank with a fixed roof: the *innage tape-and-bob procedure*; the *outage* (sometimes called *ullage*) *tape-and-bob procedure*; or a modified outage or ullage procedure. *Innage* refers to the liquid height in the tank. *Outage* refers to the space between the liquid and a reference point at the top of the tank.

CHAPTER 3

Measuring the Temperature, Density, and Suspended S&W Content of Liquids in Tanks

INTRODUCTION

To determine the net volume of liquid in a tank, you must know not only the height of the liquid and the settled S&W, but also the liquid's temperature, its density, and the amount of S&W suspended in it. All three of these factors directly affect the volume of liquid in a tank.

The temperature is important because petroleum liquids expand—take up more volume—when warm, and contract—take up less volume—when cold. How much they expand and contract depends not only on their temperature but also on their density. For example, crude oil does not expand or contract as much as kerosene, given the same deviation in temperature, because crude oil is denser than kerosene. To measure how much liquid a tank contains, then, you must measure the temperature and the density of the liquid.

You must also determine the amount of suspended S&W in the liquid. Suspended S&W is extraneous matter that remains trapped in the tank oil. It can be seen only after being physically or chemically separated from the oil. You must subtract the amount of *suspended* S&W from the liquid volume just as you do the amount of *settled* S&W. Producers and carriers agree to limit the total amount of suspended S&W to a certain percentage of the liquid because S&W can cause corrosion and problems in processing and transporting; may violate federal, state, or municipal regulations; and may not be acceptable to the pipeline transporting the liquid. If tests reveal a higher percentage than the one agreed on, the suspended S&W must be removed before the transfer takes place. Once you have measured the temperature, the density of the liquid in the tank, and the suspended S&W content, you can determine the net volume.

CHAPTER 4

Manual Sampling of Petroleum and Petroleum Products

INTRODUCTION

To the inexperienced, obtaining a sample of oil or product from a storage tank would not seem that difficult. Samples are relatively small, so why not just lower a suitable container into a tank, fill it, raise it to the surface and use the contents for whatever tests are needed?

If the liquids were anything but oil or oil products, this method might work. But oil and oil products are combinations of hydrocarbons and other substances. Storage tanks rarely contain homogeneous quantities of these liquids from top to bottom. The hydrocarbons and other materials tend to gravitate by weight into different strata throughout the tank. Just grabbing a sample from the top will not give you a good cross section of all of the vessel's contents—and obtaining a good cross section, or representative sample, is absolutely necessary. You use samples not only to test for API gravity and suspended sediment and water, but also to determine certain other physical and chemical characteristics that must be known before a custody transfer can take place or a price can be determined. For example, you use a sample to test the sulfur content of diesel fuels, the octane level of certain fuels, or to determine whether the product meets the buyer's or the government's specifications. If you do not have a sample that accurately represents the entire contents of the tank, then

all tests on that sample will give you erroneous information.

Automatic sampling of pipeline systems is preferred. Automatic systems are discussed in detail in chapter 5 of this book and in API *MPMS*, chapter 8, section 2, "Automatic Sampling of Petroleum and Petroleum Products." In general, an automatic system provides a constant, systematic withdrawal of small amounts of crude oil or product as the liquid leaves the tank and enters the pipeline. Automatic systems are not always available, however. API *MPMS*, chapter 8, section 1, "Manual Sampling of Petroleum and Petroleum Products," describes the conditions under which you can obtain an acceptable manual sample from an oil or product tank: if (1) the material you're sampling contains a heavy component, like sediment and water, which clearly separates from the oil or product; (2) the tank contains either a weir or a swing suction at the bottom of the tank to prevent the shipment of the heavy component; and (3) you take the sample so that none of the heavy component is included. The standard also details the procedures used to obtain that sample. These procedures can be used for a variety of vessels, including rail cars, pipelines, marine vessels, trucks, and lease tanks.

CHAPTER 5

Automatic Sampling of Petroleum and Petroleum Products

INTRODUCTION

Millions of barrels of petroleum and petroleum products are produced and transported every day. Each fluid must be sampled in order to determine price and to test for such characteristics as the octane rating (gasolines), the sulfur content (diesel fuels), gravity (crudes), and S&W content (oil or products). The best way to obtain a representative sample of oil or product is to use an automatic sampling system.

Automatic sampling involves a constant, systematic withdrawal of small amounts from a liquid stream flowing through a pipe.

If the automatic sampling system is set up correctly and maintained properly, it will give you a more representative sample of the liquid than you would get if you manually sampled the liquid. The automatic system eliminates much of the risk of human error, can be used virtually anywhere (since it is installed on pipelines), provides a constant withdrawal from any liquid stream, and reduces the personnel time required to obtain a sample. In short, it is highly efficient and accurate.

CHAPTER 6

An Introduction to LACT Systems

INTRODUCTION

Manually measuring the millions of barrels of oil that are transferred from lease to pipeline each day could consume a lot of time and money. A more efficient method is to use a LACT—lease automatic custody transfer—unit. This unit measures the quantity and quality of oil (that is, it performs all the functions described in chapters 2–4) without a gauger or other personnel present. It saves the lease operator and the producing company time and money while providing a systematic means of monitoring all oil transferred from lease to carrier.

To transfer oil from lease to carrier, a LACT unit must perform three basic functions: (1) it must accurately measure the quantity of oil transferred; (2) it must sample the oil being transferred so that it can be tested to determine quality; and (3) it must monitor the S&W content to prevent the transfer of “bad oil.” Bad oil contains an unacceptable amount of S&W—an extraneous commodity that is worthless and that corrodes the pipe. Keeping the amount of S&W to a minimum is necessary. What constitutes an acceptable amount is usually established by the pipeline or other carrier and is typically a little less than 1% of the total volume transferred.

CHAPTER 7

Meters and Meter Proving

INTRODUCTION

A *meter* is a device that measures the volume of a fluid flowing through it. Many types are used in a variety of locations, from the lease to truck-loading racks, to measure oil or oil products, but the two most common types used to measure liquids are the displacement meter and the turbine meter. All meters, however, regardless of type or location, measure and register how much oil or product has been bought, sold, or transferred to another's custody. And they must measure this liquid volume accurately.

Even the best meter, no matter how well designed, installed, and maintained, does not always measure *exactly* the amount flowing through it. Each has a particular margin of error, whether the result of design limitations or of wear and tear.

Determining the meter's accuracy, or *proving* the meter, is a very important job in the oil industry. Each meter must be checked periodically, or proved, to determine its margin of error, that is, the difference between the amount registered and the true volume flowing through it. The registered volume can be corrected by manually adjusting, or calibrating, the meter, or by determining a numerical meter factor that is used in a mathematical formula to convert the meter's registered volume to volume indicated by the prover.

In this chapter the displacement meter and the turbine meter will be described as well as two of the most commonly used proving procedures—proving a meter with an open-tank prover, and proving a meter with a pipe prover.

CHAPTER 8

Orifice Meter Installations

INTRODUCTION

Measuring petroleum liquids, as described in chapter 7, is a straightforward process, but, because of the nature of natural gas, a direct measure of its volume is very difficult. Natural gas is a mixture of hydrocarbon gases with very low density and viscosity; as a result, a volume of gas expands and contracts easily, depending on the pressure and temperature. Natural gas distributes itself uniformly throughout a container and is also invisible, odorless, and lighter than air. (The odor we associate with natural gas is a sulfur compound called mercaptan. It is added to natural gas so that any leaks can be detected.) In other words, it is a devil of a substance to contain, much less to measure, since its density and volume change dramatically with any change in pressure and temperature. There is no gallon, or barrel, for that matter, of natural gas. Natural gas must, by its nature, be contained and measured in a very different way from liquids.

BEHAVIOR OF GAS MOLECULES

Gas molecules are in constant motion. They travel in a straight line until they collide with another molecule or a confining wall. They bounce off each other much the way billiard balls do when they strike. The pressure exerted by a gas depends on how hard and how often its molecules collide with the walls of the chamber in which it is confined. The fewer the gas molecules in a chamber, the fewer the molecular collisions, and thus the lower the exerted pressure. The greater the number of gas molecules in a confined space, the greater the number of collisions, and thus, the greater the pressure exerted by the gas.

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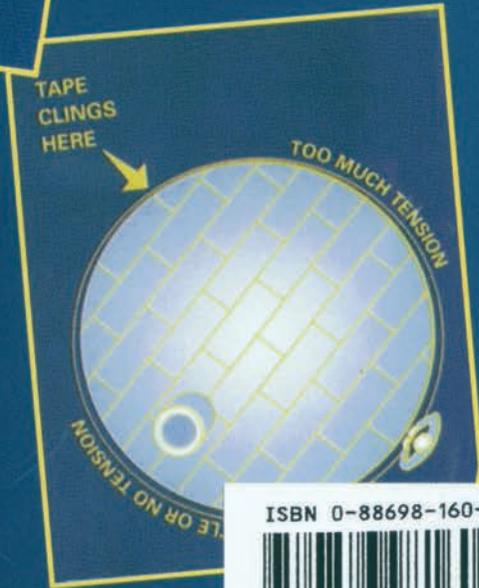
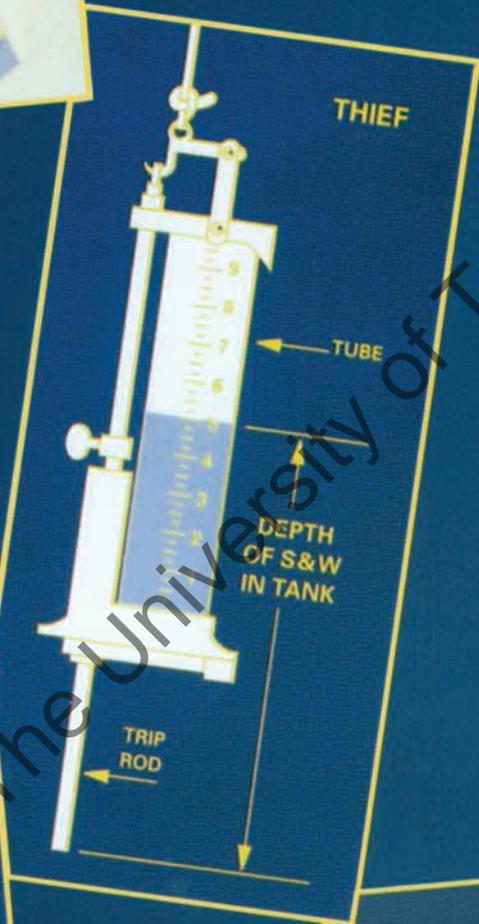
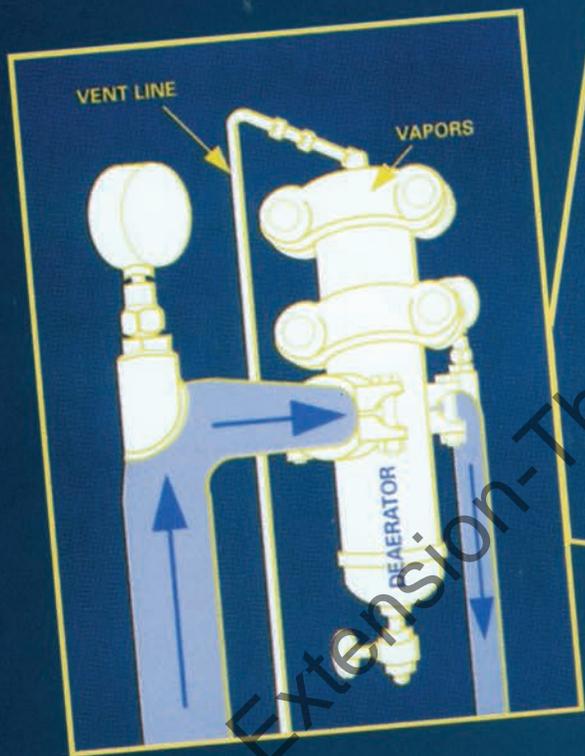
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