SALT CREEK MIDSTREAM

Salt Creek Midstream's Standards pertain to both inventory and custody transfer measurements. Accurate measurements are to be performed in accordance with regulatory and industry measurement standards for quality and quantity determinations. Programs are to be established to ensure that measurement equipment is inspected maintained and calibrated. Adequate records of such inspection tests and calibrations are to be maintained by Field Operations. Measurements performed by others shall be periodically witnessed and documented by company representatives or independent inspectors to verify that proper measurement techniques are employed. There is to be segregation of responsibilities so that no one individual can control all phases of handling custody transfer and material balance transactions in a way that permits errors to go undetected. Material balance analyses are to be performed to ensure total and complete material accountability. Inventory shall be taken on the first of each month for accounting and material balance analyses. Each location shall have an approved security program that also covers inventories and movement of products and materials. Security measures are to be commensurate with the value and the vulnerability of the materials involved. Periodically each affiliate is to perform an independent review (self-assessment) and evaluate the implementation of measurement policies and practices by field units. These periodic reviews are intended to compliment the periodic evaluations of an affiliates overall system of control by the internal auditors.

This Measurement Manual defines measurement philosophies, policies, and procedures and is designed to assist in auditing, personnel training, and management control. It is the policy of Salt Creek Midstream's to provide transportation service to its shippers and other interested parties that is efficient, fair and impartial. Measurement of oil and other commodities as they are received into or delivered from Salt Creek Midstream's system is a critical operation in carrying out this policy. Salt Creek Midstream's encourages the development of improved procedures and equipment. It will adopt and use those that contribute to accuracy or efficiency. Salt Creek Midstream's will conform to applicable industry codes, standards and regulations of governmental agencies. The Measurement Manual, Quick Reference guide, and other CPLP measurement standard must be reviewed and updated no less than 3 year intervals

Contents

Chapter 1 - Manual Sampling in Tanks

Quick Reference

Safety

- Do not smoke during sampling.
- Before taking any measurements, ground your bare hands and tools by touching the handrail.
- Stand upwind and turn your face away when opening the tank hatch.
- Monitor H_2S while sampling.
- Never sample during an electrical storm.
- Wear appropriate personal protective equipment.
- When sampling hazardous liquids, follow the applicable safety procedures in the SCM Safety Manual.
- Dispose of all samples and security seals properly.
- Follow all applicable safety rules in the SCM Safety Manual.

Introduction

Manual sampling involves lowering a thief or bottle into the tank one or more times to get representative samples of the liquid. The purpose of sampling crude oil is to determine suspended and settled sediment and water, API gravity, and occasionally other properties like vapor pressure. Liquid petroleum products stored in tanks require sampling for APIgravity, vapor pressure, and other properties like flash, haze, and color. Manual sampling is necessary in tanks that do not use a LACT or ACT unit.

You take samples to determine S&W and API gravity in the field and return them to the laboratory for other types of testing (Other Tests for Crude and Products for more information).

Equipment You Will Need for Sampling

- Thief or sample bottles
- Cotton cord or brass chain for raising and lowering thief or sample bottle
- Graduated cylinder
- Sample containers for storing samples
- Solvent for washing sample containers
- Security seals and seal cutters

Procedures

Table 1.2 and Table 1.3 show how many samples to take in different tanks. Table 1.4 shows how to mix samples for different tests.

You must make sure the samples are representative of the entire volume in the tank, either by turning on mixers orby tnga greater number of samples.

Before You Sample Crude Oil

The contents of any large tank containing crude oil (except lease tanks) must be thoroughly mixed before sampling. Because different grades of crude require different mixing times, each facility must conduct tests to determine the ideal mixing time. Follow theseguidelines:

- Mix tanks that are less than 1/3 full for at least 2 hours (normal when receivingcrude).
- Mix tanks that are more than 1/3 full for 4 hours (normal when deliveringcrude).

Be sure to wait at least 2 hours after turning off the mixer before gauging the height of theliquid.

Types of Samples

This chapter gives procedures for taking the following types of samples:

- Spot sample—bottle or thief
- Composite spot sample—bottle or thief
- All-levels sample—bottle
- Running sample—bottle
- Sample cocks (taps) on tanks or pipes—bottle

Thief Spot Sampling Procedures

Use a thief for spot sampling and composite spotsampling.

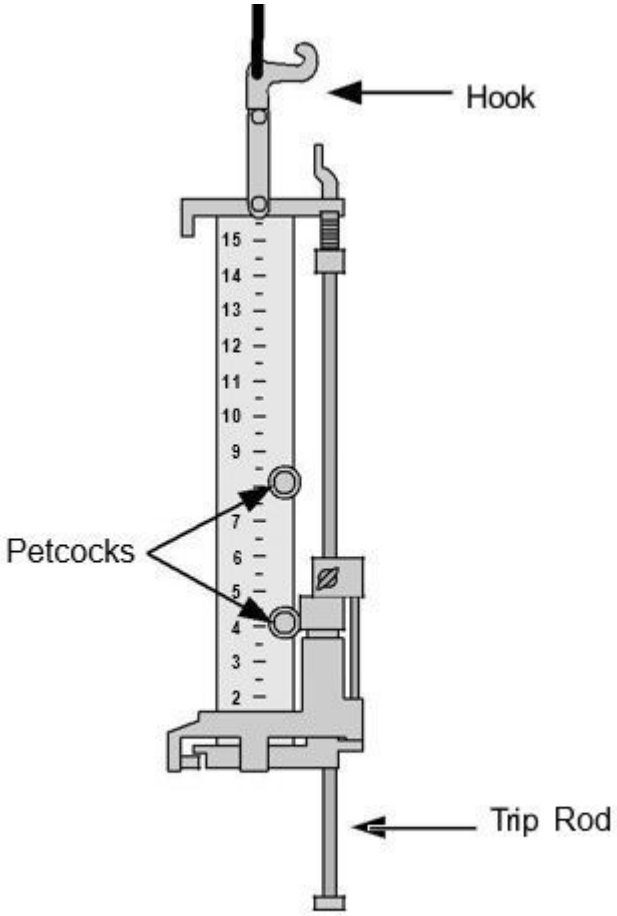


Figure 1.1. Thief

Safety Reminder

- Do not replace the sample cord with a cord containing synthetic materials. The cord must be 100% cotton to prevent a buildup of static electricity.
- Saturate new cotton cords with oil before using them the first time to assure that they are conductive.

Before sampling, assure that the conditions are safe, as listed under –Safety on the Quick Reference page. If you find any unsafe conditions or if the security of the tank has been compromised, do not take the samples and report these conditions to your supervisor.

Procedures for All Types of Tanks

1. Use clean, dry equipment.
    - Before using a thief, rinse it with Stoddard solvent or another naphtha of similar volatility. If necessary, use sludge solvents to remove all traces of sediment and sludge from previously used containers.
    - Wash the thief with a strong soap solution, rinse it thoroughly with tap water, then rinse it with distilled water. If you are sampling crude oil in the field,you may omit this step.
    - Dry the thief either by blowing a current of clean, warm air into it or by placing it in a hot, dust-free cabinet at 100°F or higher.
2. Cock the valve at the bottom of the thief in the open position and trip the hook in the eye of the trip rod.
    - Always lower the thief in the open position so that the thief fills from the bottom.
    - Always start at the top and work down so you disturb the oil as little as possible.
    - Do not disturb the cup case thermometer hanging inside the tank, if you are using one (see Gravity and Temperature Measurement in Tanks).
3. Lower the thief to the proper level.
    - For lease tanks, take an upper sample just below the surface of the liquid, a middle sample from the center of the liquid, and a lower sample just abovethe suction line.
    - For large tanks, see Table 1.2 and Figure 1.4 for proper sampling levels.
4. Jerk the cord sharply to close the bottom valve on the thief and trap the sample.
5. Pull the thief to the surface.
6. Pour about 6 inches of the liquid in the thief back into the tank.
7. Pour the sample into a small, clean sample container until it is about 3/4 full. Cap the sample container, wipe it clean, and label it as an –upper or –lower sample (see Figure 1.2). Put it into a compartment in your tool box.
8. If you are compositing samples, measure out the proper amount of sample into a graduated cylinder and put it in the sample container.
9. Pour the remaining liquid back into the tank.

Figure 1.2. Examples of labels on sample containers

Additional Procedures for Lease Tanks

When gauging a lease tank, use the upper and lower samples to determine the suspended S&W content (see Testing Crude Oil for Suspended Sediment and Water).

Use the middle sample to determine the API gravity.

1. To determine the API gravity and temperature of a sample in the thief, hang the thief containing the sample on the inside of the gauge hatch to test it (see Gravity and Temperature Measurement in Tanks fordetails).
2. When finished testing, fill the storage bottle 3/4 full, cap it, and place it in your toolbox.
3. Pour the remaining liquid back into the tank.

Take a bottom or outlet/clearance sample to determine the level of settled S&W.

4. Adjust the trip rod so that it will trip the thief shut when it is bumped on the tank bottom (normally at 4 inches).
5. Slowly lower the thief through the liquid and S&W until it touches the bottom of the tank.
6. Let the thief rest on the bottom to allow the S&W to reach its natural level inside the thief. Do not use a pumping motion to force the thief through the S&W.

7. Carefully raise the thief 2 to 4 inches and then allow it to bump the bottom hard enough to close the valve.
8. Pull the thief to the surface.
9. Slowly pour the contents over a glass plate or your gloved hand. Stop when you see S&W.
10. Return the thief to an upright position and measure the distance between the end of the trip rod and the surface of the S&W. This measurement is the depth of the S&W layer on the tank bottom.
11. Record the level of settled S&W.
12. Clean the thief.

Bottle Sampling Procedures

You can use a sample bottle for any sampling method.

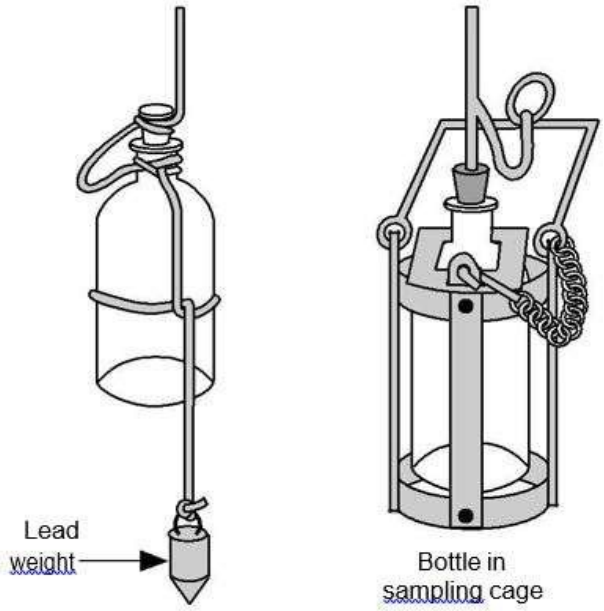


Figure 1.3. Sample bottle

First assure that the conditions are safe, as listed under ―Safety‖ on the Quick Reference page. If you find any unsafe conditions or if the security of the tank has been compromised, do not take the samples and report these conditions to your supervisor.

Spot Sampling Procedures

1. Use clean, dry equipment.

   - Before using a bottle, rinse it with Stoddard solvent or another naphtha of similar volatility. If necessary, use sludge solvents to remove all tracesof sediment and sludge from previously used containers.
   - Wash the bottle with a strong soap solution, rinse it thoroughly with tap water, then rinse it with distilled water. If you are sampling crude oil in the field, you may omit this step.
   - Dry the bottle either by blowing a current of clean, warm air into it or by placing it in a hot, dust-free cabinet at 100°F orhigher.

2. Estimate the liquid level in the tank.

3. Attach a weighted line to the bottle or place the bottle in a sample cage.
4. Put the stopper in the bottle.
5. Lower the weighted, stoppered bottle to the proper depth.
6. When the container reaches the selected level, pull out the stopper with a sharp jerk of the line and allow the bottle to fill completely.
7. When you judge that the container is full, raise the bottle.
8. If the bottle is not at least 3/4 full, pour out the contents and repeat steps 4–7.
9. If taking only one sample, pour off a small amount from the full bottle, and put the stopper in it immediately.
10. Repeat steps 5–8 for each sample needed.
11. Close the sample container, and return it to your toolbox.

Multiple Tank Composite Sample

Prepare a composite sample in the laboratory (not in the field) by mixing equal portions of the upper, middle, and lower samples. If samples are taken from multiple tanks used in a transfer, you will usually composite the samples in proportion to the volume of product in (or transferred from) each tank.

All-Levels Sample

1. Use clean, dry equipment.
    - Before using a bottle, rinse it with Stoddard solvent or another naphtha of similar volatility. If necessary, use sludge solvents to remove all traces of sediment and sludge from previously used containers.
    - Wash the bottle with a strong soap solution, rinse it thoroughly with tap water, then rinse it with distilled water. If you are sampling crude oil in the field, you may omit this step.
    - Dry the bottle either by blowing a current of clean, warm air into it or by placing it in a hot, dust-free cabinet at 100°F or higher.
2. Lower the weighted, stoppered bottle as near as possible to the draw-off level.
3. Pull out the stopper with a sharp jerk of the line, then raise the bottle at a uniform rate so that it is about 3/4 full as it emerges from the liquid.
    - For light products or deep tanks, a restricted opening may be needed to avoid filling the bottle before it reaches the surface of the liquid.
    - The bottle should not be more than 3/4 full.

4. If the container is full when it emerges from the liquid, pour the liquid back and try again.

- The goal is to get portions of sample from all levels of the tank. If the bottle is full, it did not sample any of the oil past the point that it filled.
- If you are unable to fill the sample container at the proper rate, use a different method, such as taking multiple spot samples, to obtain a representative sample.

Running Sample

1. Use clean, dry equipment.
    - Before using a bottle, rinse it with Stoddard solvent or another naphtha of similar volatility. If necessary, use sludge solvents to remove all tracesof sediment and sludge from previously used containers.
    - Wash the bottle with a strong soap solution, rinse it thoroughly with tap water, then rinse it with distilled water. If you are sampling crude oil in the field, you may omit this step.
    - Dry the bottle either by blowing a current of clean, warm air into it or by placing it in a hot, dust-free cabinet at 100°F or higher.
2. Lower the unstoppered bottle at a uniform rate as nearly as possible to the level of the bottom of the outlet connection or swing line.
3. Raise the bottle to the top of the oil at the same rate so that it is about 3/4 full when withdrawn from the liquid.
    - For light products or deep tanks, you may need a notched cork or other restricted opening to avoid filling the bottle too quickly.
    - The bottle should not be more than 3/4 full.
4. If the container is full when it emerges from the liquid, pour the liquid back and try again.
    - The goal is to get portions of sample from all levels of the tank. If the bottle is full, it did not sample any of the oil past the point that it filled.
    - If you are unable to fill the sample container at the proper rate, use a different method, such as taking multiple spot samples, to obtain a representative sample.

Summary of Sampling Procedures

- Take samples from the top down.
- Which tests are performed on which samples depends on the size of the tank, the liquid level, and whether it contains crude oil or a petroleum product
- If using a thief, pour about 6 inches of oil from the thief back into the tank before pouring the sample into the sample container.
- Pour the sample from the thief or bottle into the sample container or put the stopper in the bottle as quickly as possible to avoid losing light ends.
- Properly label all samples.

Number of Samples of Crude Oil to Take with a Bottle or Thief

The number of samples used for S&W testing depends on the size of the tank. Table 1.2 shows guidelines for obtaining samples from tanks of differentsizes.

Table 1.2. Samples for Determining S&W

Tank Capacity/Liquid Level	Number of Samples and Sampling Levels		
	Upper	Middle	Lower
1,000 barrels or less	1	1*	1
More than 1,000 barrels (no mixer) Liquid level less than 15 feet Liquid level more than 15 feet	 1 1	 1* 1**	 1 1
More than 1,000 barrels (with mixer)	1	1**	1

* The middle sample here is taken to determine the API gravity of the liquid. This sample is not included in the composite sample or in the tests for S&W.

** This middle sample may be used to determine the API gravity and then added to the composite sample for testingfor S&W, but normally all three samples are tested for gravity and S&W and the results averaged. Alternately the three

samples are composited and then tested.

Note: Additional tests may require additional samples.

In small tanks, test the upper and lower samples separately for suspended S&W. In addition to these samples, you may also take a bottom sample to determine the height of the settled S&W. Figure 1.4 shows where to take samples in a large tank.

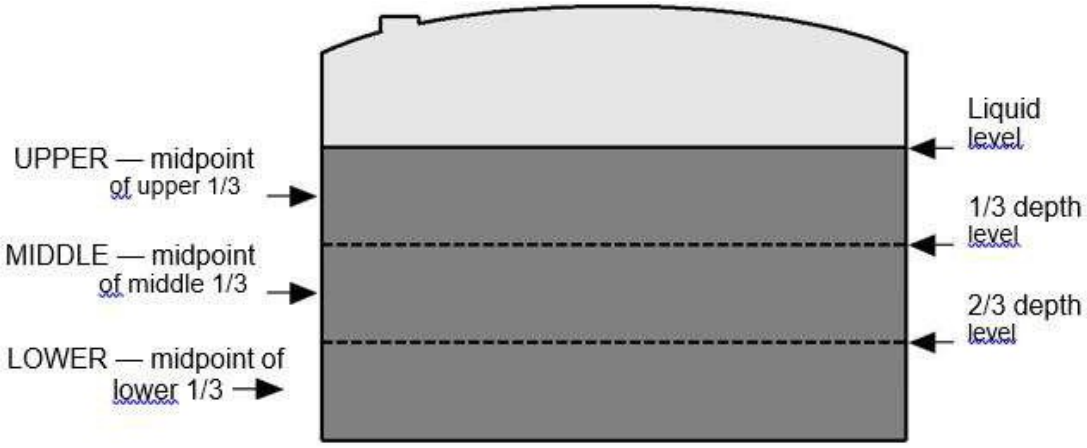


Figure 1.4. Where to take samples in a large tank

Mixing Samples

A sample may or may not need to be mixed before testing it, depending on the type of test and how homogeneous the sample is. Because an automatic sampling system takes samples over a period of many hours, some settling almost always occurs.

You can mix a sample with a stand-alone power mixer, with an internal mixer in the sample pot, or by shaking it. When using a stand-alone power mixer, be sure to use the correct type forthe container or pot you have, as the mixer/container combination has been tested and proven effective.

Table 1-4 lists the mixing recommendations for various tests.

Table 1.4. Recommended Mixing Procedures

Test Purpose*	Recommended Mixing Procedure		
	Power	Shaking	None
Density for crude and heavy fuels	X		
Sediment and water	X		
Density for other hydrocarbons		X	
Vapor pressure			X
Cloud point			X

* Sample transferred from a container. For tests not listed, refer to the specific test procedure.

Reference Documents

1. API Manual of Petroleum Measurement Standards, Chapter 3.1A
   -Standard Practice for the Manual Gauging of Petroleum and Petroleum Products

2. API Manual of Petroleum Measurement Standards, Chapter 8.1
   —Standard Practice for the Manual Sampling of Petroleum and Petroleum Products‖

3. API Manual of Petroleum Measurement Standards, Chapter 18.1 —Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck

4. SCM Safety Manual

Chapter 2 - Gauging tanks less than 1000 bbls

Safety

- Do not smoke during gauging.
- Ground your bare hands and equipment before gauging.
- Keep the gauge tape in contact with the hatch while gauging to prevent sparking.
- Stand upwind and turn your face away when opening the tank hatch.
- Check the condition of the ladder and catwalk before gauging.
- Determine whether you need to take precautions for H2S before gauging.
- Never gauge during an electrical storm.
- Dispose of all samples and security seals properly.
- Follow all applicable safety rules

Equipment You Will Need for Gauging Tanks

1. For gauging and manual sampling:
    - Steel gauge tape and bob (innage or outage)
    - Water-indicating paste (if applicable)
    - Gasoline-indicating paste (if applicable)
    - Thief or sample bottle
    - Cotton cord or chain for raising and lowering thief or sample bottle
    - Graduated cylinder
    - Sample containers (for storing samples
2. For gravity and temperature testing:
    - Thermohydrometer or
    - Hydrometer, hydrometer cylinder, filter paper, and constant-temperature bath
    - Cupcase woodback thermometer
    - Portable electronic thermometer (PET)
3. For S&W testing by the field centrifuge method:
    - Two verified 6-inch centrifuge tubes
    - Water-saturated toluene or Stoddard solvent
    - Demulsifier solution
    - Sample heater
    - Bimetal, pocket-type thermometer
    - Centrifuge
4. For security :
    - Seals for securing all pipeline connections
    - Side cutters for cutting and removing tank seal
    - Pliers

Procedures for Gauging by the Innage Method

The innage method of gauging directly measures the height of the liquid with a tape and bob that extend to the bottom of the tank.

First assure that the conditions are safe. If you find any unsafe conditions or if the security of the tank has been compromised, do not run the tank and report these conditions to your supervisor.

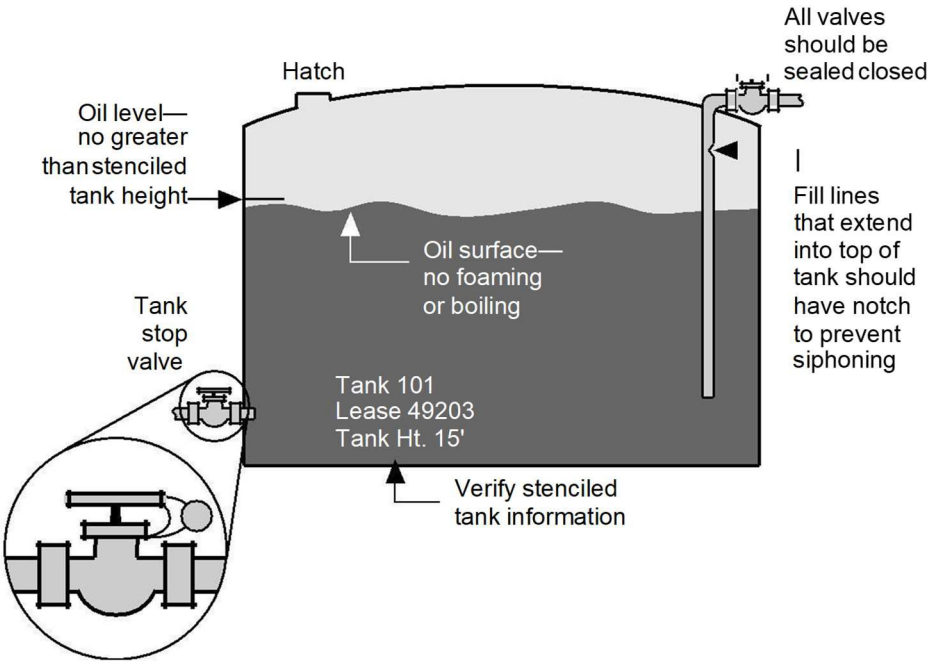


Figure 3.1. Checking the tank before gauging

Opening Gauge

If the conditions are safe, run the tank as follows:

1. Before taking the opening gauge, inspect the tank (see Figure 3.1):
   - Check the tank and valves for leaks or distortions.
   - Check the seal on the tank stop valve for any signs of tampering.
   - Check all bottom and side valves to make sure they are closed and have sealing devices for attaching seals.
   - Make sure the ladders and catwalk are safe.
   - Check the tank and lease numbers stenciled on the tank.
   - Ground yourself before climbing on the tank. Be especially cautious on dry days, since the potential forstatic electricity is greater in low humidity.
   - Check that the top valves are closed and can be sealed.
   - Open the hatch using all safety precautions. Wear an approved breathing apparatus if H2S is a potential hazard.
2. Suspend the cupcase thermometer, if used, at the midpoint of the tank.
3. Take an upper sample for S&W testing (see Testing Crude Oil for Suspended Sediment and Water).
   - Use clean, dry equipment.

- Cock the valve at the bottom of the thief in the open position and trip the hook in the eye of the trip rod.
- Lower the thief to just below the surface of the liquid.
- Jerk the cord sharply to close the bottom valve on the thief and trap the sample.
- Pull the thief to the surface.
- Pour about 6 inches of the liquid in the thief back into the tank.
- Pour the sample into a small, clean sample container until it is about 3/4 full. Cap the sample container, wipe it clean, and label the sample. Put it into a compartment in your tool box.
- If you are compositing samples, measure out the proper amount of sample into a graduated cylinder and put it in the sample container.
- Pour the remaining liquid back into the tank.

4. Take and test the middle sample for API gravity (see Gravity and Temperature Measurement in Tanks).
   - Hang the thief containing the sample on the inside of the gauge hatch.
   - Determine the API gravity of the oil.
   - Pour the remaining liquid back into the tank.
5. Follow the same procedures as under step 1 above to take a lower sample just above the suction line and test it for suspended S&W (see Testing Crude Oil for Suspended Sediment and Water).
6. Take an outlet/clearance sample (tank bottoms) to determine the level of settled S&W (see Figure 3.2).
   - Adjust the trip rod so that it will trip the thief shut when it is bumped on the tank bottom (normally at 4 inches).
   - Slowly lower the thief through the liquid and S&W until it touches the bottom of the tank.
   - Let the thief rest on the bottom to allow the S&W to reach its natural level inside the thief. Do not use a pumping motion to force the thief through the S&W. (The length of time depends on the type and temperature of S&W.)
   - Raise and trip the thief to trap an S&W sample.
   - Make sure the distance between the tank bottoms and the bottom of the P/L connection is greater than 4 inches

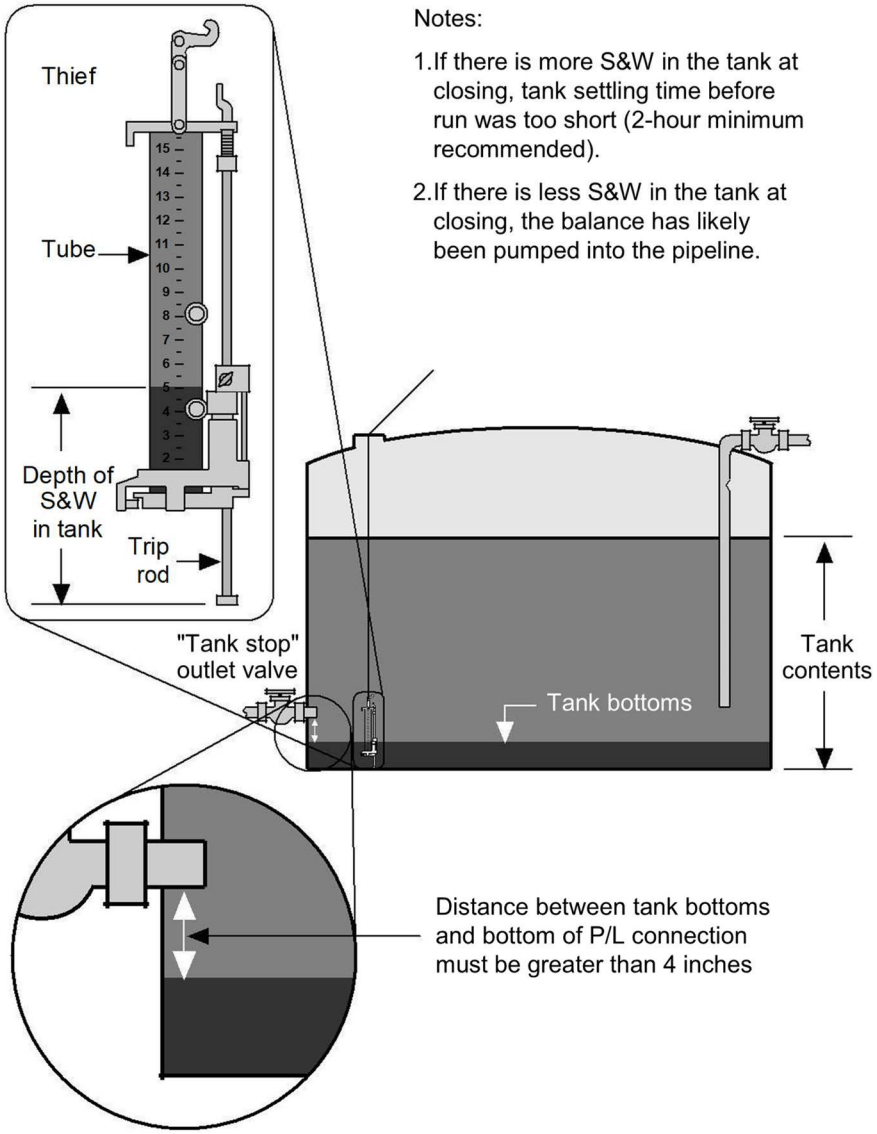


Figure 3.2. Checking the depth of settled S&W in the tank

7. Take the opening gauge to the nearest 1/4 inch. Two consecutive readings must be the same before recording the opening gauge on the measurement ticket (see Figure 3.3).
   - If necessary, apply a thin coat of water-indicating paste to the bob to read the free-water level.
   - Hold the gauge line over the hatch and allow the plumb bob to sink through the oil.
   - Be sure to keep the gauge tape in contact with the edge of the hatch to prevent dangerous sparking as the plumb bob enters the fluid. If the tape has a grounding wire, attach it to the tank.
   - Allow the plumb bob to penetrate the oil and S&W until it touches the tank bottom or datum plate. Don't let the bob tilt. (Use the known gauge height to estimate when the bob should reach bottom.)

- Always take the gauge reading from the same location or reference point on the hatch so the bob hits the same point on the tank bottom or datum plate. Using the same reference point for each gauging ensures a comparable gauge reading each time, even if the tank bottom is sloped.
- When using a water-indicating paste, leave the tape and bob in the liquid long enough for the paste to react with the water (usually 30 to 60 seconds). Slowly reel in the tape and stop when you see where the oilhas wet the tape.
- Read and record the measured liquid level and free-water level.
- To verify the measurement, wipe off about 2 feet of the oil-wetted tape and lower the tape again, repeating the procedures under step 6 until you get two consecutive readings that agree.
- When you have completed the opening gauge, clean the gauge tape and bob thoroughly before putting it away.

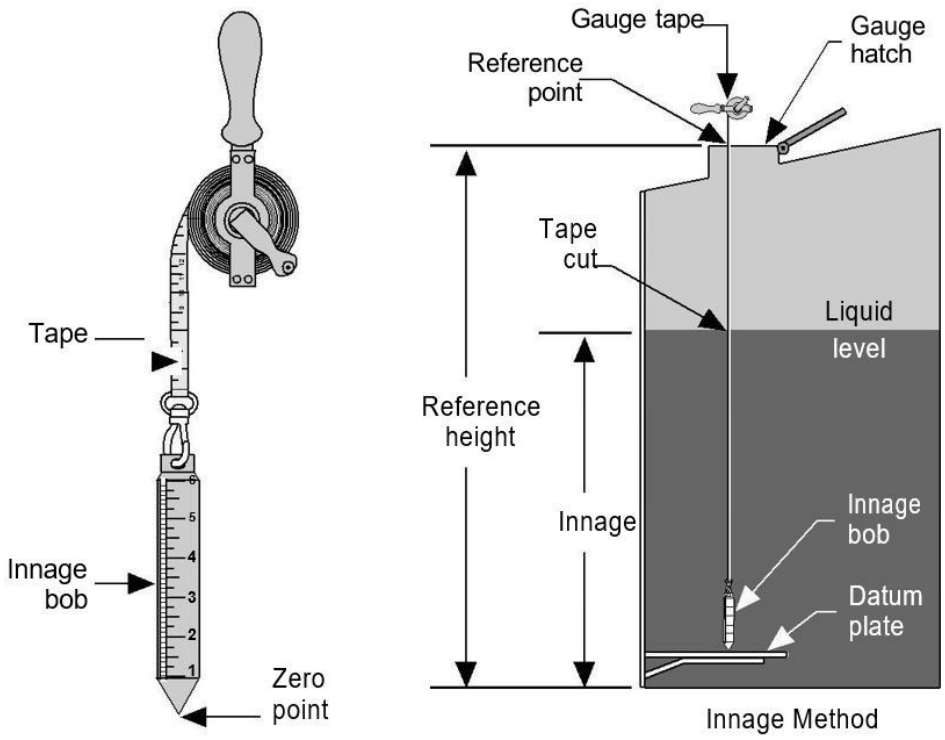


Figure 3.3. Innage method of gauging

8. Determine the temperature of the oil in the tank (see Gravity and Temperature Measurement in Tanks for details).
9. Record all of your readings.
10. Seal the equalizer and fill lines.
11. 11. Test the top and outlet samples for suspended S&W (see Testing Crude Oil for Suspended Sediment and Water).
12. Accept or reject the oil.

Closing Gauge

1. Before taking the closing gauge, inspect the tank:
    - Close and seal the tank stop valve. Record the seal number.
    - Inspect the pipeline, tank connections, seams, and the ground around the bottom of the tank for leaks or distortions.
    - Check all seals that were put on when the tank was run for tampering.
    - Make sure the seal numbers match the seal numbers written on the ticket.
    - Make sure that the ladders and catwalk are safe.
    - Ground yourself before climbing on the tank. Be especially cautious on dry days, since the potential forstatic electricity is greater in low humidity.
    - Open the hatch using all safety precautions, including an approved breathing apparatus if H2S is a potential hazard.
2. Determine the temperature of the oil remaining in the tank
3. Gauge the height of the remaining oil and free water (repeat the same steps as under step 6 of —Opening Gauge)

Reference Documents

1. API Manual of Petroleum Measurement Standards, Chapter 3.1A—Standard Prac0ce for the Manual Gauging of Petroleum and Petroleum Products
2. API Manual of Petroleum Measurement Standards, Chapter 7 —Temperature Determina0on
3. API Manual of Petroleum Measurement Standards, Chapter 11.1, Volume I, Table 5A —Generalized Crude Oils – Correction of Observed API Gravity to API Gravity at 60ºF
4. API Manual of Petroleum Measurement Standards, Chapter 11.1, Volume I, Table 6A—Generalized Crude Oils – Correction of Volume to 60ºF Against API Gravity at 60ºF
5. API Manual of Petroleum Measurement Standards, Chapter 12.1 —Calcula0on of Sta0c Petroleum Quantities, Part 1 – Upright Cylindrical Tanks and Marine Vessels
6. API Manual of Petroleum Measurement Standards, Chapter 18.1 —Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck
7. SCM Safety Manual

Chapter 3 - Gauging Tanks > 1000 bbls

Safety

- Do not smoke during gauging.
- Ground your bare hands and equipment before gauging.
- Keep the gauge tape in contact with the hatch while gauging to prevent sparking.
- Stand upwind and turn your face away when opening the tank hatch.
- Check the condition of the ladder and catwalk before gauging.
- Determine whether you need to take precautions for H2S before gauging.
- Never gauge during an electrical storm.
- Do not climb onto a floating roof if
  - liquid is being pumped into or out of the tank,
  - the tank mixer is running,
  - the roof is leaking or the floating roof seal is leaking, or
  - local regulations prohibit it.
- Follow OSHA's confined space regulations.
- Dispose of all samples and security seals properly.
- Follow all applicable safety rules.

Scope

This chapter describes the procedures for measuring the level of crude oil or liquid petroleum products in upright cylindrical tanks with a capacity of more than 1,000 barrels with fixed or floating roofs.

Tank gauges may be used for inventory or custody transfer purposes, but the preferred method is to use meters for custody transfer.

Equipment You Will Need for Gauging Tanks

1. For gauging and manual sampling:
   - Steel gauge tape and bob
   - Water-indicating paste (if applicable)
   - Gasoline-indicating paste (if applicable)
   - Thief or sample bottle
   - Cotton cord or chain for raising and lowering thief or sample bottle
   - Graduated cylinder
   - Sample containers (for storing samples)
2. For gravity and temperature testing:

- Thermohydrometer or
- Hydrometer, hydrometer cylinder,
- Cupcase woodback thermometer or Portable electronic thermometer (PET)

3. For S&W testing by the field centrifuge method:
   - Two verified 6-inch centrifuge tubes
   - Water-saturated toluene or Stoddard solvent
   - Demulsifier solution
   - Sample heater
   - Bimetal, pocket-type thermometer
   - Centrifuge

Gauging Tanks with an External Floating Roof

You can gauge an external floating roof tank from the platform or from the floating roof. If gauging from the roof, you must use the innage method. Since the roof of an external floating roof tank may be classified as a confined space, you must follow all appropriate safety procedures.

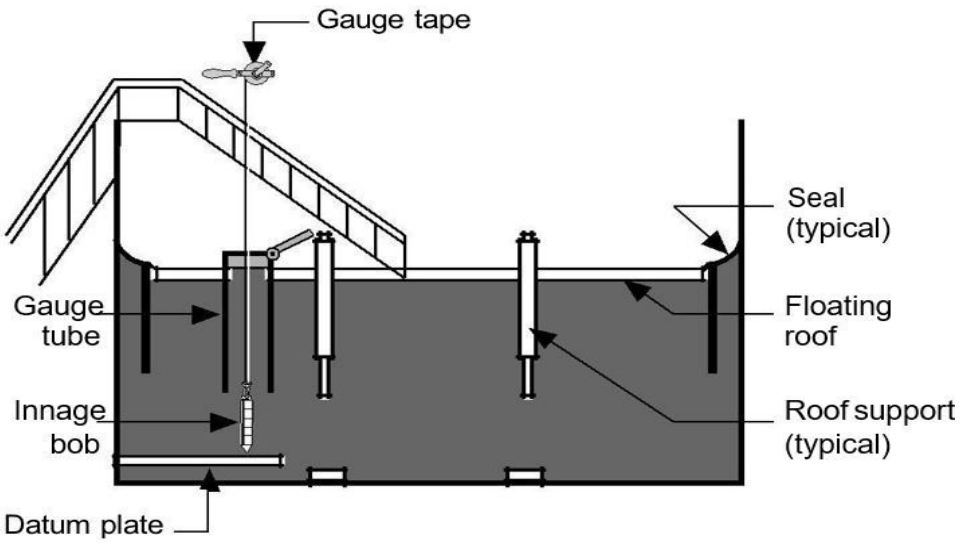


Figure 4.1. Gauging an external floating roof tank from the platform

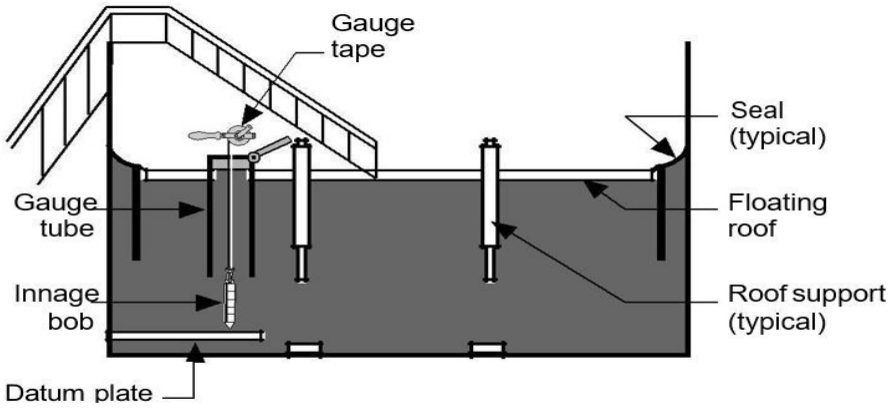


Figure 4.2. Gauging an external floating roof tank from the floating roof

To get an accurate reading, follow these precautions:

- For both the opening and closing gauges, the roof must be either floating freely or fully supported. For example, do not take the opening gauge while the roof is floating or the closing gauge while the roof is partly or completely resting on the bottom.
- If the roof is not floating, its legs must be resting directly on the tank bottom, not on the settled S&W.
- Do not gauge the tank for custody transfer if the roof is in the —cri0cal zone (the ver0cal range in which the level of the stored oil is high enough to lift a tank's floating roof off the tank floor but too low to make the entire roof float freely in a level position).
- The leg settings must match the settings listed on the tank table.
- The roof must be free of ice, snow, water, dirt, and scale.
- If possible, do not gauge on windy days.

- If the gauges will be used for custody transfer, the tank must have a recent tank calibration table calculated in accordance with API standards.

Gauging Tanks with an Internal Floating Roof

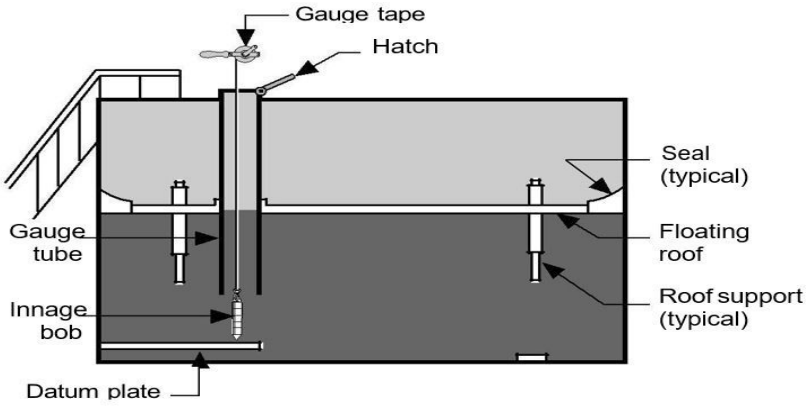


Figure 4.3. Gauging an internal floating roof tank

To get an accurate reading, follow these precautions:

- Since an internal floating roof is lighter than an external floating roof, the oil will continue to move longer than in an external floating roof tank.
- The roof must be either floating freely or fully supported for both gauges. For example, do not take the opening gauge while the roof is floating or the closing gauge while the roof is partly or completely resting on the bottom.
- If the roof is at rest, it must be resting directly on the tank bottom
- Do not gauge the tank for custody transfer if the roof is in the —cri0cal zone(the ver0cal range in which the level of the stored oil is high enough to lift a tank's floating roof off the tank floor but too low to make the entire roof float freely in a level position).

Procedures for Gauging tanks > 1000bbls

If the conditions are safe, gauge the tank as follows:

1. Before taking the opening gauge, inspectthe tank :
   - Check the tank and valves for leaks or distortions.
   - Check all bottom and side valves to make sure they are closed.
   - Make sure the ladders and catwalk are safe.
   - Check the tank number stenciled on the tank.
   - Ground yourself before climbing on the tank. Be especially cautious on dry days, since the potential for static electricity is greater in lowhumidity.
   - Open the hatch using all safety precautions.
2. Suspend the cupcase thermometer or PET at the midpoint of the tank.
3. Sample the liquid. The number and location of samples depends on the level of oil in the tank (see—Manual Sampling in Tanks fordetails).
4. Take the opening gauge to the nearest 1/8 inch. Two consecutive readings must be the same before recording the opening gauge on the measurement ticket (see Figure 4.5).
   - Apply a thin coat of water-indicating paste to the bob to read the free-water level.
   - Hold the gauge line over the hatch and allow the plumb bob to sink through the liquid.
   - Be sure to keep the gauge tape in contact with the edge of the hatch to prevent dangerous sparking as the plumb bob enters the fluid. If the tape has a grounding wire, attach it to the tank prior to lowering.
   - Allow the plumb bob to penetrate the liquid and S&W until it touches the tank bottom or datum

plate. Don't let the bob tilt. (Use the known gauge height to estimate when the bob should reach bottom.)

- Read the tape at the reference point.
  - Compare this reading to the reference gauge height (which should be indicated on the top of the tank).
  - A difference of more than 1/2 inch could indicate that the bob has not reached the bottom or datum plate
- Always take the gauge reading from the same location or reference point on the hatch so the bob hits the same point on the tank bottom or datum plate. Using the same reference point for each gauging ensures a comparable gauge reading each time, even if the tank bottom is sloped.
- If the tank does not have an indicated reference gauge point, gauge opposite the gauge hatch hinge.
- Read and record the measured liquid level and free-water level.
- To verify the measurement, wipe off about 2 feet of the wetted tape and lower the tape again, repeating the procedure above. Repeat the procedure until you get two consecutive readings that agree

5. Determine the temperature of the liquid in the tank (see Gravity and Temperature Measurement in Tanks for details).
   - Take the recommended number of temperature readings (see Gravity and Temperature Measurement in Tanks for details).
     - For greater than 10 feet of product, take 3 temperatures — middle of the upper, middle, and lower thirds of the liquid level
     - For less than 10 feet of product, take 1 temperature in the middle of the liquid level
6. Record all of your readings.
7. Test the samples for suspended S&W (see Testing Crude Oil for Suspended Sediment and Water for details)

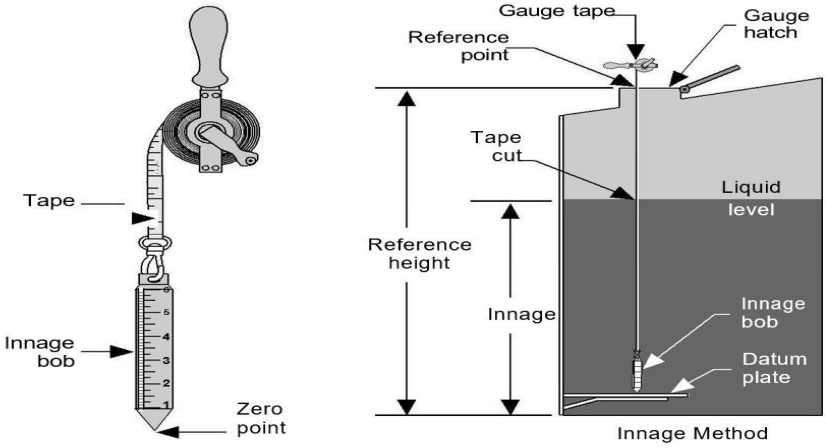


Figure 4.5.

Closing Gauge

1. Before taking the closing gauge, inspect the tank:
   - Close the tank isolation valve.
   - Inspect the pipeline, tank connections, seams, and the ground around the bottom of the tank for leaks or distortions.
   - Make sure that the ladders and catwalk are safe.
   - Check the tank number stenciled on the tank to be sure you are turning off the correct tank.
   - Ground yourself before climbing on the tank. Be especially cautious on dry days, since the charge of static electrical sparks is greater in low humidity.

- Open the hatch using all safety precautions, including an approved breathing apparatus if H2S is a potential hazard

2. Sample the liquid remaining in the tank (see Gravity and Temperature Measurement in Tanks for details).
3. Gauge the height of the remaining liquid and free water (repeat the same steps as under step 4 of —Opening Gauge)

Reference Documents

8. API Manual of Petroleum Measurement Standards, Chapter 3.1A—Standard Prac0ce for the Manual Gauging of Petroleum and Petroleum Products
9. API Manual of Petroleum Measurement Standards, Chapter 7 —Temperature Determina0on
10. API Manual of Petroleum Measurement Standards, Chapter 11.1, Volume I, Table 5A —Generalized Crude Oils – Correction of Observed API Gravity to API Gravity at 60ºF
11. API Manual of Petroleum Measurement Standards, Chapter 11.1, Volume I, Table 6A—Generalized Crude Oils – Correction of Volume to 60ºF Against API Gravity at 60ºF
12. API Manual of Petroleum Measurement Standards, Chapter 12.1 —Calcula0on of Sta0c Petroleum Quantities, Part 1 – Upright Cylindrical Tanks and Marine Vessels
13. API Manual of Petroleum Measurement Standards, Chapter 18.1 —Measurement Procedures for Crude Oil Gathered from Small Tanks by Truck
14. SCM Safety Manual

Chapter 4 – Gravity and Temperature Measurement in Tanks

Safety

- Do not smoke while working around tanks.
- Before taking any measurements, ground your bare hands and tools by touching the handrail.
- Stand upwind and turn your face away when opening the tank hatch.
- Monitor H2S while sampling.
- Never sample during an electrical storm.
- Dispose of all samples and security seals properly.
- Follow all applicable safety rules SCM Safety Manual.

Scope

This chapter includes the procedures for determining API gravity and temperature of crude oil and liquid petroleum products in non-pressurized tanks.

Summary of Gravity Procedures

- Use the middle sample to measure gravity in tanks that hold less than 1,000 barrels.
- Use the upper, middle, and lower samples to measure gravity in tanks that hold more than 1,000 barrels. These samples may be composited for testing, or they may be tested separately and the results averaged.
- For tanks of less than 1,000 barrels (lease tanks), use a clean thermohydrometer and leave it in the thief for at least 3 minutes (longer in heavier oils or during extreme heat or cold).
- For tanks holding more than 1,000 barrels, pour the samples into a hydrometer cylinder in the laboratory for testing with a thermohydrometer.
- When the liquid is opaque, deduct 0.1°API from the gravity reading to correct for the meniscus.
- Record the gravity to the nearest 0.1°API.
- Record the thermohydrometer temperature to the nearest 1.0°F.

Summary of Temperature Procedures

- Take one reading from the middle of tanks under 1,000 barrels.
- Take 3 readings, one each from the middle of the top, middle, and bottom thirds of tanks 1,000 bbls and larger. Report the average of the 3 readings as the temperature of the tank.
- SCM' preferred procedure for determining tank temperature for custody transfer is to use a portable electronic thermometer (PET); however, cupcase thermometers are acceptable for inventory purposes or for lease operations where only one middle temperature is required.
- When using a PET, keep the sensor probe in motion within the fluid by raising and lowering it 1 foot above and below the desired depth.
- Leave a cupcase thermometer in the liquid for at least 10 minutes before reading the temperature (15 minutes in heavier oils and when the ambient temperature is below 32°F). See Table 2.2 for additional information on recommended immersion times.
- Record the temperature to the nearest 0.1ºF when using a PET and 0.5ºF when using a cupcase thermometer.
- For safety reasons, the temperature of the liquid must be 120°F or less. If the tank is above 120ºF, notify your supervisor.

Introduction

After sampling the liquid in the tank, you will gauge the tank to determine the amount of liquid in it. Part of the gauging process includes measuring the API gravity and temperature of the liquid.

A tank's volume varies due to expansion and contraction of the liquid and the metal tank shell with changes in temperature. Each tank has a capacity table that is based on the volume at a certain temperature. Getting an accurate temperature reading allows you to correct the volume for the actual temperature of the liquid in the tank. Density, like volume, depends on temperature, and so you will also measure the temperature of the sample while determining the API gravity.

One purpose of measuring API gravity is to allow conversion of the volume you measure by gauging to the volume at the standard temperature of 60°F. API gravity is also a property of the oil that may affect the price paid for the oil.

Equipment You Will Need for Determining Gravity and Temperature

- Thief or bottle containing a sample from the middle of the tank (small tanks) or the upper, middle, and lower samples (large tanks)
- Hydrometer cylinder, thermohydrometer (or hydrometer and glass thermometer), and a constant-temperature bath if the temperature of the sample is very different from the ambient temperature
- Portable electronic thermometer and ASTM glass thermometer for verifying the PET (preferred) or cupcase woodback thermometer
- Circulating bath and ice bath or PET calibrator (when verifying a PET)

Procedures

The contents of large tanks containing crude oil should be thoroughly mixed before you make temperature measurements (lease tanks do not have mixers). Because different grades of crude require different mixing times, a facility may conduct tests to determine the ideal mixing time for each grade it handles. Unless otherwise instructed, follow these guidelines:

- Mix tanks that are less than 1/3 full for at least 2 hours.
- Mix tanks that are more than 1/3 full for 4 hours.

Be sure to wait at least 2 hours after turning off the mixer before gauging the height of the liquid to allow the liquid to stop moving.

Procedures for Measuring API Gravity

Measure the gravity as soon as possible after collecting the sample(s) and after the temperature of the sample(s) has stabilized.

Thermohydrometer Method

1. Use a sample from the middle of the column of liquid (small tanks) or 3 samples from the top, middle, and bottom of the column of liquid (large tanks).
   - o For small tanks, you may hang the thief in the hatch and determine the gravity before transferring the sample to astorage container.
   - o For large tanks, transfer the sample, without splashing, to a clean hydrometer cylinder for the test.
2. Insert a clean thermohydrometer into the thief or hydrometer cylinder until it floats freely, and then push it down another 1/4 inch (see Figure 2.1).
3. Leave the thermohydrometer in the thief or hydrometer cylinder for at least 3 minutes to allow the temperature to stabilize.
   Note: Do not allow the thermohydrometer to touch the side of the thief.
4. After at least 3 minutes, read the observed gravity at eye level. Take the measurement at the bottom of the meniscus for clear liquids (see Figure 2.1).

5. When the liquid is too opaque to see the meniscus (for example, crude oil), deduct 0.1°API to correct for it
6. Record the gravity to the nearest 0.1°API.
7. Read the temperature at eye level.

Note: The thermohydrometer bulb must remain in the liquid while you are reading it.

8. Record the observed temperature to the nearest 1.0°F

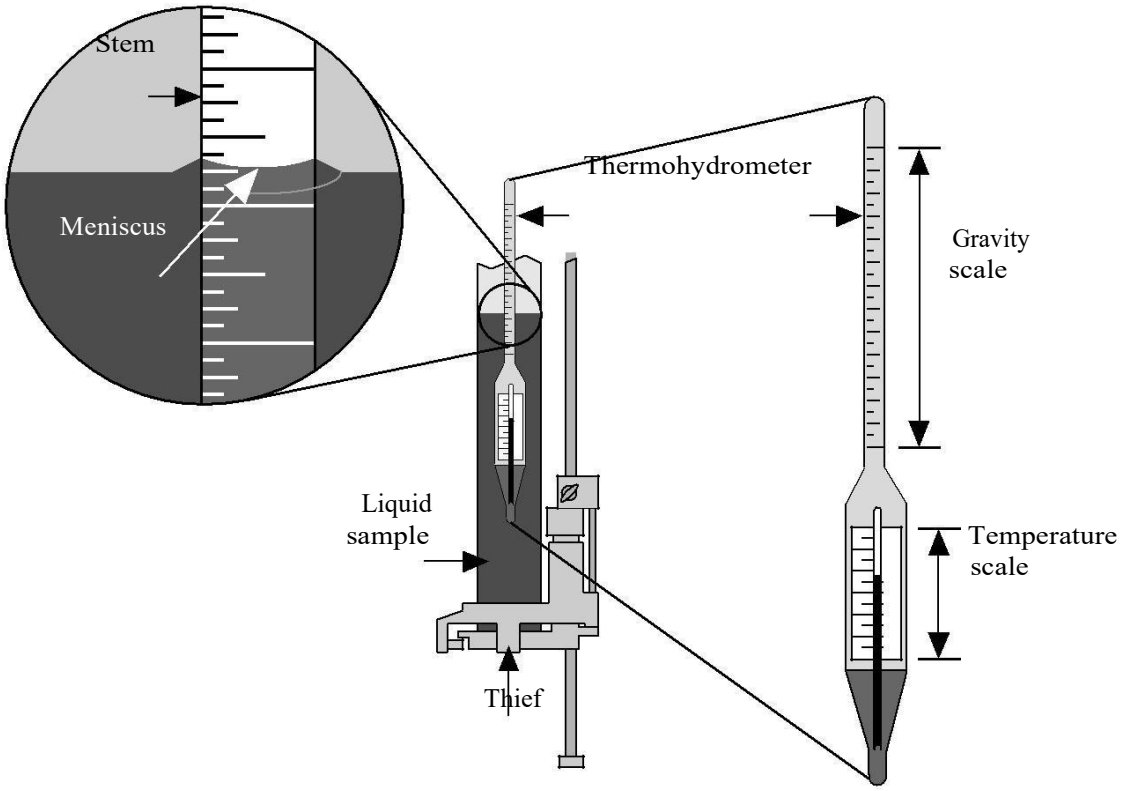


Figure 2.1. Using a thermohydrometer to measure API gravity

Where to Take Temperature Readings

In tanks where the liquid depth is more than 10 feet, take temperature readings at 3 levels: in the middle of the top, middle, and bottom third of the column of liquid. When the liquid depth is less than 10 feet, take 1 measurement in the middle of the column of liquid.

The temperature of a liquid in a storage tank can vary throughout its depth; therefore, when the difference in temperature between any two readings is greater than 2ºF, calculate an average temperature. Do this by taking temperatures at different levels that are equally spaced apart, averaging the readings, and rounding off the result to the nearest 0.1ºF. Report the result as the average temperature for the entire volume. In some cases, such as when a tank has a non-uniform cross-sectional area, it may be necessary to calculate a volume-weighted average temperature.

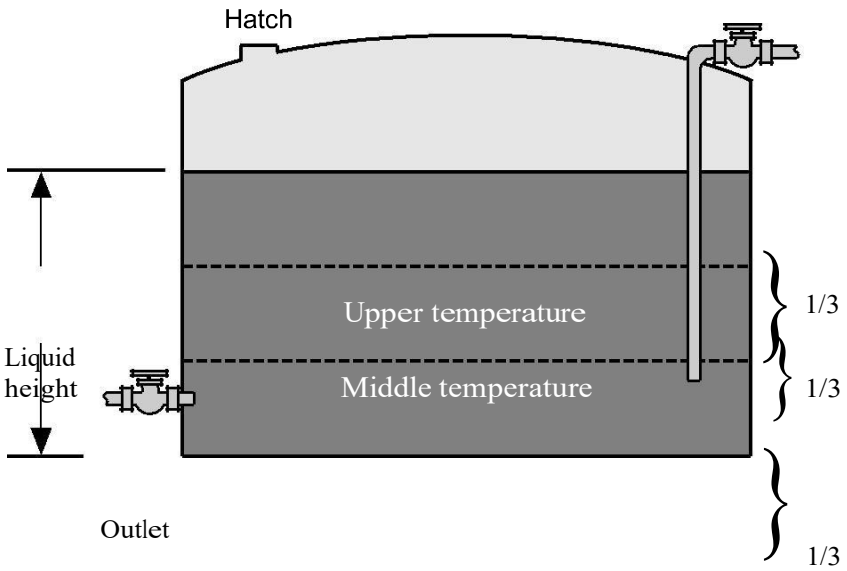


Figure 2.3. Locations for determining the temperature of the liquid in a large tankwith liquid height more than 15 feet

Procedures for Measuring Temperature

You may use a portable electronic thermometer (PET) or a cupcase woodback thermometer to measure temperature in tanks. PETs are preferred in all types of liquids

First assure that the conditions are safe, If you find any unsafe conditions or if the security of the tank has been compromised, do not take the measurements and report these conditions to your supervisor.

Portable Electronic Thermometer (PET)

See Table 2.1 and Table 2.2 for information about temperature measuring locations and thermometer immersion times.

1. Attach the grounding cable from the thermometer to the tank before opening the hatch.
2. Verify that the thermometer battery is working.
3. Set the temperature range selector.
4. Lower the sensing probe to the correct level. If taking more than one reading, start with the position closest to the top of the tank.
   - o Position the thermometer as far from the tank shell as practical.
5. Repeatedly raise and lower the probe about 1 foot in each direction until the temperature reading stabilizes; that is, when the readout varies by no more than 0.2°F for at least 30 seconds.
6. After the temperature has stabilized, read and record the temperature.
7. Repeat steps 4, 5, and 6 in large tanks for each level needed.
8. When taking more than one reading, average the readings, round to the nearest 0.1°F, and record the average.

$$\frac{T1 + T2 + T3}{\text{temperature 3}} = \text{average}$$

9. Clean the thermometer with a solvent and dry it with a cloth.

Safety Reminder

- The temperature must be 120°F or less. If the tank is above 120ºF, notify your supervisor.

Cupcase Woodback Thermometer

Because a cupcase woodback thermometer assembly takes so long to reach the temperature of the liquid in the tank (up to 1 hour, depending on the difference in temperature between the liquid and the air), you must immerse the thermometer when you first begin gauging and read the temperature after you finish. See Table 2.1 and Table 2.2 for locations of measurements and immersion times.

If the conditions are safe, begin as follows:

1. Attach the thermometer to a conductive lowering device (e.g., cotton cord, brass chain, or gauging tape).
2. If the atmospheric temperature differs by more than 20°F from the anticipated temperature of the liquid in the tank, immerse the thermometer twice just below the liquid's surface and empty the cup after each immersion.
3. Lower the thermometer to the correct level, keeping the lowering device in contact with the hatch.
   - Position the thermometer as far from the tank shell as practical.
   - Repeatedly raise and lower the thermometer about 1 foot to help stabilize the reading.
4. After the temperature has stabilized, pull the thermometer from the liquid.
   - Keep the assembly sheltered below the edge of the hatch to prevent the wind or air temperature from affecting the reading.
   - Make sure the cup is full while you are reading the temperature.
   - Do not hold the assembly by the brass cup, as heat from the hand may change the temperature of the oil.
   - Read the temperature to the nearest 0.5ºF immediately after pulling the thermometer out.
5. For a custody transfer repeat steps 3 and 4. For inventory or for small tanks, usually only one middle temperature reading is all that is required.
   - If the readings agree within 2°F, average them and record the average to the nearest 0.1ºF.

$$\frac{T1 + T2}{\text{temperature 2}} = \text{average}$$

   - If the readings differ by more than 2°F, take additional readings and average the results.
6. For tanks that hold 1,000 bbls or more, repeat steps 3, 4, and 5 at the top, middle, and bottom of the column of oil.
   - Average the 3 temperature readings:

$$\frac{T1 + T2 + T3}{\text{temperature 3}} = \text{average}$$

7. When taking readings from more than one location in the tank, average the readings, round to the nearest 0.5°F, and record the average.
8. After using the thermometer in a heavy, high-viscosity, or high-pour-point oil, clean all parts of the assembly.
   - Rinse the cupcase thermometer with Stoddard solvent or another naphtha of similar volatility. If necessary, use sludge solvents to remove all traces of sediment and sludge.

Procedures for Verifying Thermometers

Thermometers are precision instruments. Ensuring their accuracy is an important part of your job.

Verifying PETs

A PET must be calibrated in a laboratory before using it the first time and recalibrated once a year thereafter

Spot-check the PET before each use or once a day, and make a more thorough check monthly. Do not use a PET that does not pass these checks. Document the monthly checks and keep the documentation on file at the location for at least two years.

Monthly Check

1. Place the PET and a NIST-certified or equivalent thermometer side by side in a circulating hot-water bath, if available.
   - Leave them undisturbed for at least 10 minutes.
   - Compare the readings of the two thermometers. If they differ by more than 0.5°F, do not use the PET.
2. Place the PET and a NIST-certified or equivalent thermometer side by side in ice water.
   - Leave them undisturbed for at least 10 minutes.
   - Compare the readings of the two thermometers. If they differ by more than 0.5°F, do not use the PET.
3. If the PET is out of calibration, follow the manufacturer's procedures for recalibration.

Verifying a Glass Thermometer (including a Cupcase Thermometer)

A glass thermometer must be verified in a laboratory before using it the first time and reverified once a year thereafter. You should spot-check the thermometer before each use or once a day. Do not use it if it fails these checks.

1. Make sure the thermometer is clean. An oil film can insulate the thermometer and cause an inaccurate reading.
2. Check that the paint on the engraved scale is still present. Do not use a thermometer that has lost this paint. It is too difficult to see the reading.
3. Check that the liquid column has not separated. If the column separates, then rejoins, do not use the thermometer until it has been verified in a laboratory.
4. Compare the reading on the thermometer to that on a similar thermometer. If the readings differ by more than 1.0ºF, do not use the thermometer.

Table 2.1. Locations for Determining Temperature in Small and Large Tanks

Tank Capacity/Liquid Level	Number of Measurements	Locations of Measurements
1,000 barrels or less	1	Middle of liquid height
More than 1,000 barrels		
Liquid level under 10 feet	1	Middle of liquid height
Liquid level 10 to 15 feet	2	3 feet from top of liquid surface and 3 feet from bottom of tank
Liquid level over 15 feet	3	Middle of top third Middle of middle third Middle of bottom third

Table 2.2. Recommended Immersion Times for PETs and Cupcase Woodback Assemblies

	Recommended Immersion Times

API Gravity at 60°F	PET*	Cupcase Woodback Assembly**			
	In Motion	In Motion	Stationary	When Temperature Differential <5°F	
				In Motion	Stationary
>50°	30 seconds	5 minutes	10 minutes	5 minutes	10 minutes
40 to 49°	30 seconds	5 minutes	15 minutes	5 minutes	15 minutes
30 to 39°	45 seconds	12 minutes	25 minutes	12 minutes	20 minutes
20 to 29°	45 seconds	20 minutes	45 minutes	20 minutes	35 minutes
<20°	75 seconds	45 minutes	80 minutes	35 minutes	60 minutes

* While measuring, keep the sensor probe in motion by raising and lowering it 1 foot above and below the desired depth.

** Can be used in either an in-mo0on or a sta0onary mode. —In mo0onl is defined as repeatedly raising and lowering the assembly 1 foot above and below the desired depth.

If additional mass is placed in the liquid near the thermometer (such as a weight to make the cupcase woodback assembly sink), the immersion time of the assembly will be longer than those listed in this table. Immersion times should be established by testing, and all parties involved should agree on the times

Note: Immersion times are based on test procedures outlined in API MPMS Chapter 7. Failure to use these recommended times may result in incorrect temperature readings.

The following table, which is an excerpt from API Table 5A, can be used to correct the observed API gravity at the observed temperature to the standard API gravity at 60°F when gauging crude oil.

API Table 6A can be used to correct the observed API gravity at the observed temperature to the standard API gravity at 60ºF when gauging products.

Table 2.3. Correction of API Gravity to 60°F for Generalized Crude Oils

Temperature	API Gravity at the Observed Temperature (°API)*							
	30.0	30.5	31.0	31.5	32.0	32.5	33.0	33.5
	Corresponding API Gravity at 60°F (°API)							
40.5°F	31.4	31.9	32.4	32.9	33.4	33.9	34.5	35.0
41.0°F	31.3	31.9	32.4	32.9	33.4	33.9	34.4	34.9
41.5°F	31.3	31.8	32.3	32.8	33.4	33.9	34.4	34.9
42.0°F	31.3	31.8	32.3	32.8	33.3	33.8	34.3	34.9

* Round the observed gravity to the nearest 0.5°API.

Note: Based on API Table 5A.

Example:

If the observed gravity is 31.7 °API (round it to 31.5°API) and the observed temperature is 41.3°F (round it to 41.5°F), the API gravity is 32.8°API.

Take the difference between the observed gravity and API gravity in the table (31.7 - 31.5 = 0.2) The corrected API gravity is 32.8 + 0.2 = 33.0°API.
Note: API does not recommend interpolation of temperature.

Reference Documents

1. API Manual of Petroleum Measurement Standards, Chapter 3.1A—Standard Prac0ce for the Manual Gauging of Petroleum and Petroleum Products

2. API Manual of Petroleum Measurement Standards, Chapter 7 —Temperature Determina0on

3. API Manual of Petroleum Measurement Standards, Chapter—Manual Sampling of Petroleum and Petroleum Products

4. API Manual of Petroleum Measurement Standards, Chapter 9.1—Hydrometer Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products

5. API Manual of Petroleum Measurement Standards, Chapter 9.3—Thermohydrometer Test Method for Density and API Gravity of Crude Petroleum and Liquid Petroleum Products

6. API Manual of Petroleum Measurement Standards, Chapter 11.1, Volume I, Table 5A—Generalized Crude Oils – Correction of Observed API Gravity to API Gravity at 60ºF

7. SCM Safety Manual

Chapter 5 - Testing Crude Oil for Suspended Sediment and Water

Safety

- Stopper centrifuge tubes securely and keep them away from your face when mixing samples.
- Always balance the centrifuge before spinning by placing filled centrifuge tubes in opposite trunnion cups.
- Know the safety and health risks of chemicals used for testing. Xylene and toluene, for example, are extremely flammable and toxic to the skin, eyes, and lungs.
    - Do not handle chemicals with bare hands or breathe the vapors. Wear gloves and use a respirator.
    - Keep chemicals away from the mouth.
    - Keep chemical containers closed when you are not using them.
    - Keep your work area clean and well-ventilated.
    - Clean up spills promptly.
- Dispose of all samples and security seals properly.
- Follow all applicable safety rules

Equipment You Will Need for Determining S&W

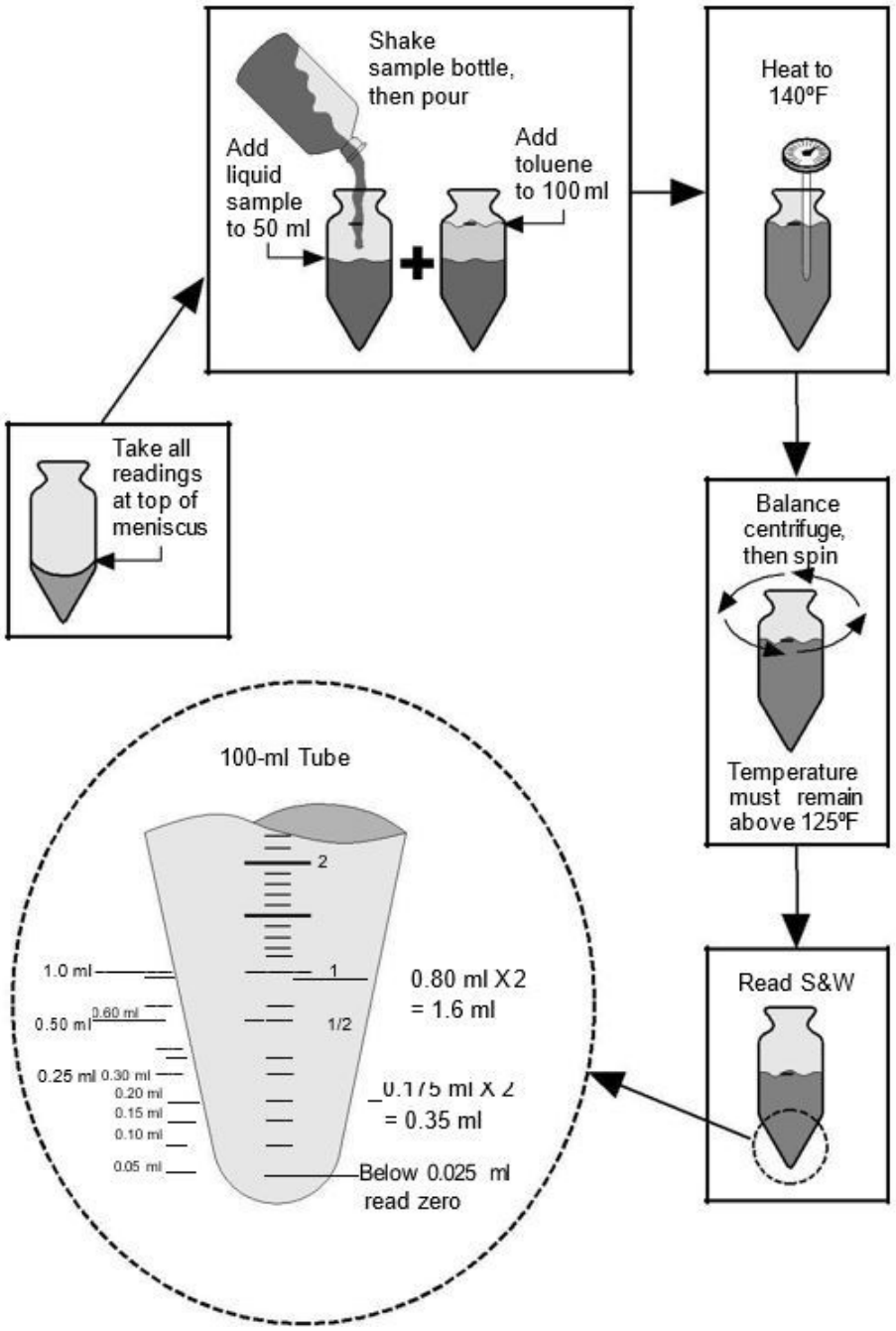
- Upper and lower samples from a small tank or
- Individual samples or a composite sample made from all samples from a large tank
- Sample containers (for storing samples)
- Two certified or verified 6-inch, 100-ml or 200-ml centrifuge tubes
- Diluent — water-saturated toluene or Stoddard solvent
- Sample heater
- Bimetal pocket thermometer
- Centrifuge

Procedures for Testing Suspended S&W in Samples from Large Tanks and Automatic Samplers by the Field Centrifuge Method

These procedures apply to 100-milliliter centrifuge tubes (Figure 5.3). Some use 200-part centrifuge tubes.

1. Fill each of two centrifuge tubes with exactly 50 milliliters of one of the samples.
2. Fill each tube from step 1 with solvent to the 100-ml mark.
3. Stopper the tubes tightly and shake them thoroughly, until the crude and solvent contents are mixed thoroughly. Shaking the tubes may cause excessive vapor pressure build up and break the tubes; shake the tubes well below eye level and wear gloves.
4. Loosen the stopper slightly.
5. Place the two tubes in the warmer pockets of the heated centrifuge (or preheater unit).
6. Heat the tubes until the fluids are 140 +/- 5□ □F.
7. Put the tubes in the centrifuge and spin for at least 5 minutes. Note: Make sure the tubes are balanced in the centrifuge.
8. Following the spin, do not let the temperature drop below 125 deg F; check it with the dial thermometer. If it does, the pre-spin temperature of 140 deg F shall be raised by the difference between the final spin temperature and 125 deg F. This difference must be added to the pre-spin sample temperature. For example, (125 deg F - final spin temp) + 140 deg F = revised final spin temperature. Reheat the sample to the revised final spin temperature and repeat the spin.
9. Remove the tubes from the centrifuge. Look straight on at the “cut line” between the combined volume of water and sediment at the bottom of the tube and the crude layer floating on top. Rotate the tube so you can see the graduation markings. Record the amount of the combined volume of water and sediment at the bottom of each tube to the nearest 0.05% times 2 on 100 ml tubes

10. Reheat the sample to 140° F, return the tubes without agitation to the centrifuge, and spin for an additional five minutes at the same rate. Repeat this operation until two consecutive identical readings are obtained for each tube.
11. For testing using 200 ml tubes, the percentage of water and sediment is the average of the values read directly from the two tubes.



Reference Documents

1. API Manual of Petroleum Measurement Standards, Chapter 10.4—Determina0on of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure)

Chapter 6 - Other Tests for Crude and Products

Quick Reference

Safety

Employees and contractors should be familiar with the hazards of the products and the test instruments associated with the particular test they are performing. Look in ASTM, API, and equipment manufacturers' manuals for safety precautions. Observe any hazardous material handling precautions stated in the MSDS or on the container of thecommodity.

Scope

This chapter gives an overview of the procedures for quality testing of crude and products.Most of these tests are done in a nonpipeline laboratory, but some are done onsite.

Summary of Tests

Crude Oil

- Sulfur content
- Mercaptan content
- Organic chloride content
- Reid vapor pressure
- Metals content
- Types and amount of light ends
- Hydrogen sulfide content
- Viscosity and pour point
- Boiling point range
- Neutralization number
- Nitrogen content

Introduction

Crude oils are tested for composition and characteristics other than gravity, S&W, and temperature that affect their quality and therefore their value. Since most of these tests are done in a (nonpipeline) laboratory, this chapter contains a general discussion of these tests rather than giving specific procedures. If you do the tests onsite, follow local procedures.

Tests for Crude Oil

Most tests on crude oil determine what it consists of, including contaminants. Other testsdetermine purely physical characteristics, such as Reid vapor pressure, viscosity, and pour point.

Sulfur

The test method for sulfur (ASTM D-4294) determines total sulfur in a crude oil from all its various forms. Sulfur is primarily present as organic sulfur (attached to hydrocarbon molecules) but can also be present as hydrogen sulfide, mercaptans (see ―Mercaptans‖ below), and inorganic salts (sulfates).

Test Summary

The common method used today to test samples for sulfur is by x-ray. A sample of crude oil is placed into a cup with a clear plastic Mylar window at the bottom. The cup is placed into the x-ray instrument and the sample is irradiated with x-rays. The signal received by the detector, coming from the sample, indicates the level of sulfur. The test result is total sulfur in weightpercent.

Table 6.1. Typical Sulfur Levels

Crude Designation	Sulfur Content
Sweet crude	< 0.50 wt%
A crude	0.40 to 0.60 wt%
Light sour	0.60 to 1.30 wt%
Medium sour	Not more than 2.70 wt%
Heavy	Not more than 3.50 wt%

Significance and Refinery Impact

The sulfur level of a crude oil is an indicator of its quality as a grade — sweet or sour — andaffects its value (see Table 6.1). Sulfur has a significant impact on refinery processing. The refinery needsto accurately know the sulfur level of the crude oil being refined, because of effects on product specifications and the cost of handling sulfur recovered from processing. The expense of refining operations increases drastically with increasing crude sulfur content. The sulfur level indicates how much treatment and removal are needed during the refining process. Refineries recover sulfur from the refining process to comply with environmental regulations on plant emissions. Many governmental regulations limit the sulfur content of refined products, thus limiting the types of crude oils that some refineries can process. In the case of contamination, increased sulfur levels can jeopardize a refinery's ability to comply with theseregulations. In general, high-sulfur crudes tend to be heavier (lower APIgravity).

On-Line and Portable Sulfur Analyzers

Some pipeline locations have on-line x-ray sulfur analyzers that help track crude oil sulfur content in real time on the pipeline. This assists with batch cutting and qualitymonitoring. Several pipeline stations also have portable sulfur analyzers that you can take into the field. This allows stations to quickly determine sulfur levels where needed and to do field testing atremote locations where a quality problem is being investigated.

Mercaptans

Mercaptans are naturally occurring sulfur compounds. Ethyl mercaptan is used to add odor to natural gas. Higher-molecular-weight mercaptans are a problem in jet fuel and gasolinesdue to specification levels of not more than 30 ppm in jet fuel product and not more than 40 ppm in gasolines.

Levels of mercaptans in crude oil vary and depend on the field from which the crude is produced.

Test Summary

A sample is diluted with isopropanol and titrated with silver nitratesolution.

Significance and Refinery Impact

Maximum mercaptan level in crude is limited by refinery treating capacity. A crude witha mercaptan level higher than expected can lead to a fuel product that is over specification on mercaptans. Many refineries use processes that either remove mercaptans(hydroprocessing) or convert them to less harmful disulfides (Merox, Bender, Doctor plants).
Mercaptans introduce odor and are corrosive to metal fuel system components. Jet A has a mercaptan specification of 0.003% (30 ppm). Gasoline products have a mercaptanspecification of 40 ppm.

Organic Chlorides

Organic chlorides are primarily chlorinated hydrocarbons that remain in the hydrocarbon phase and are not removed in the refinery desalting process. Also, certain refinery processesinject chloride chemicals for operational needs. They do not occur naturally in crude oil and indicate contamination of the crude stream, typically from solvents such as dry cleaning fluids,carburetor cleaners, and other halogenated hydrocarbons as well as transformer PCBs, degreasing agents, and used motor oils.

Test Summary

Testing for organic chlorides is a multistep process. First the crude oil is distilled tofractionate out the naphtha cut (initial boiling point to 400°F). Next the naphtha fraction is washed with caustic and then with water to remove inorganic chlorides, which can interfere in thedetection step. The final step is to quantify the chloride level by either titration orcombustion/coulometric analysis, both of which detect the level of organic chloride in ppm. The organic chloride levelof the whole crude is then calculated from the chloride level in the naphtha fraction and the percentage of the naphtha fraction in the crude oil.

Significance and Refinery Impact

Organic chlorides pose a hazard to refiners because they carry over into process streams where they break down under more severe process conditions and form corrosive compounds such as hydrochloric acid, primarily in the naphtha streams. These compounds attack piping, which can cause leaks and lead to fires or explosions. It does not require a great deal of contamination to cause serious problems, so specifications for organic chloride are set at a very low limit.

Typical Levels

Organic chlorides do not occur naturally in crude oils and indicate contamination. SCM has a specification for organic chloride of not more than 1 ppm by weight in the whole crude andnot more than 5 ppm by weight in the naphtha fraction.

Reid Vapor Pressure

Reid vapor pressure (RVP) is a laboratory measure of volatility, or how readilya compound evaporates at low temperatures.

Test Method

Testing for RVP is done by placing the sample in a fixed volume cell at 100°F. Whenstabilized, an automated analyzer uses a transducer to obtain the pressure. If the test is done manually, the sample is shaken several times and the pressure gauge is read.

Significance and Impact

RVP is a good indicator of the amount of light ends (C2 to C6 hydrocarbons) a crude contains and therefore the pressure the crude can create in an enclosed space such as a tank or pipeline. SCM' RVP specification is 9.5(or other determined by contract) psi for crude oils based upon NSPS (New Source Performance Standards) tank regulations.

Too much pressure from a crude oil can pop relief valves and cause pumping problems and meter errors. High RVP can lead to noncompliance with above-ground storage tank RVP limits. This includes unwanted hydrocarbon releases into the atmosphere, upsetting of tank roofs, and other undesirable tank problems.

Refineries are interested in RVP for similar reasons while crude is in tanks and duringinitial handling in desalting and in the distilling process. Refinery problems can include distillation tower upsets, overloading of the light-end unit separation, reaching gas compressor capacity limits, and a decrease in crude oil refining value when light ends are fraudulentlyblended.

Metals

Metals content generally refers to heavy metals in crude oil such as arsenic (As), iron (Fe), vanadium (V), and nickel (Ni). It may also refer to such metals as sodium, magnesium, and calcium. Table 6.2 shows the maximum amount of some of these metals allowed in crudes.

Test Summary

Metals in crude oil can be analyzed directly by x-ray spectroscopy, similar to the sulfuranalysis, or by an alternative lab method. A more detailed analysis for metals would include distillingthe crude to isolate either the 650°F+ reduced crude fraction or 1050°F+ resid fraction before doing the lab analysis.

Significance and Refinery Impact

Vanadium and nickel occur naturally in crude and are concentrated in the resid portion. Iron is often introduced into crude at the wellhead, during transportation by pipeline or vessel, or in tankage.

Metals poison catalysts used in the refining process for producing finished petroleumproducts (that is, they deactivate or decrease the reactivity of catalysts). This is a concern when resid is

being run on the fluid catalytic cracker unit, in platformers and magnaformers used ingasoline production, in hydrocrackers used in jet and gasoline production, and in hydrotreaters producing jet, gasoline, and diesel — these all use catalysts in the processing stage. Some vanadium compounds can damage turbine blades and refractory furnaces.

SCM' concern about metals in crude is to prevent contamination of low-metal crudes (West Texas intermediate/West Texas sour) with heavy high-metal crudes such as Mayan. This isone reason for small buffer batches of West Texas sour surrounding Mayan batches on the Cushing Chicago Pipeline System.

Table 6.2. Quality Guidelines for Metals in Crude Oils

Type of Crude	Metal Contaminant	Maximum Amount Allowed
Sweet crude	Iron Nickel Vanadium	Not more than 10 ppm Not more than 5 ppm Not more than 5 ppm
Sour and heavy crudes	Iron Nickel Vanadium	Not more than 40 ppm Not more than 30 ppm Not more than 75 ppm

Typical Levels

Metals content in crude oils varies widely. Mayan heavy has 700 ppm vanadium in the resid fraction, which equates to 260 ppm on a whole crude basis (37% resid). Arabian heavy crudeoil has much less vanadium, 180 ppm in the resid fraction, 50 ppm whole crude basis (28% resid). To make a valid comparison of metals content of two or more crude oils, make sure you know whether the amounts are for the whole crude or for the resid fraction.

Hydrogen Sulfide

Hydrogen sulfide (H_2S) is a poisonous gas that occurs naturally in crude oil and canbreak out from it. Higher H_2S levels are generally found in heavy sour crudes.

You must use respiratory protection when levels in the air reach 10 ppm. At 300 ppm H_2S is an Immediate Danger to Life and Health (IDLH).

Test Summary

In the laboratory, H_2S can be determined by gas chromatography or the wet chemical method. The wet chemical method involves driving the H_2S from the crude oil with nitrogen gas and heat, chemically trapping the H_2S, and then finishing with a titration to quantify the level.

Hydrogen sulfide levels in the air can be determined using Draeger tubes or other H_2S detectors.

Significance and Impact

Crude oil sitting in tanks, sample bottles, etc. can release hydrogen sulfide, or H_2S can escape during refinery processing, causing an immediate danger. Knowledge of a crude oil's H_2S content is vital to prevent accidents and can aid a refinery in its ability to process the sulfur as a by-product from the refining process. Determination of the H_2S content is now a standard test when crude oils are analyzed in the laboratory for economic assays.

Viscosity and Pour Point

Viscosity is formally defined as the resistance to flow under gravity. It also refers to the time a fluid takes to move a specified distance and is a measure of the shear rate of crude.
Pour point is the lowest temperature at which a fluid will move. It is close to the solidification point.

Test Summary

Viscosity is tested by measuring how long it takes a crude oil to move through a calibrated capillary tube at a specified temperature. This is done in a constant temperature bath.
Pour points of petroleum products are tested in a low-temperature refrigerated bath. The sample is tested until solid. The pour point is the temperature at which flow was last observed — generally 5°F above the solidification point.

Significance and Impact

The high viscosity of heavier crudes decreases its flow rate in the pipeline, can increase line pressure, and therefore extends the time to move a batch of crude oil. On some pipeline systems, crude oils having too high a viscosity are penalized, with higher tariffs, for the extra time it takes to move them through the system.

Pour point is necessary information to know for a crude oil, especially in the winter. If a crude solidifies in the line, then steps need to be taken to get it moving. This could involve adding chemicals to liquefy the crude at lower temperatures (pour point depressants). A high pour point can also increase line pressure. Condensate or other lighter crude oils may be added to some heavy crudes to make it possible to transport them through the pipeline without solidifying.
—dumbbell‖ crudes both cause incorrect product yields and result in shortages or overages for market demands, which leads to profit losses for the refinery.

Similarly, distillation determines resid content (fraction boiling at 1050°F or more, invol%). High resid levels may indicate fraudulent blending.

Nitrogen

Nitrogen in crude refers to the amount of —organic‖ nitrogen that is bound (attached) to

hydrocarbon molecules.

Test Summary

The test for organic nitrogen is performed by first diluting the crude oil into a solvent. This mixture is then injected into a combustion furnace, which burns the sample under controlled conditions. The products of this process are swept by a flowing gas stream into a reaction chamber where the level of nitrogen is determined by the response of the detectormodule.

Significance and Impact

Nitrogen is a concern as a catalyst poison to refiners when it is present in naphtha feed streams to isomerization, reformers (platformers), and ultraformer units. These units use expensive catalysts (which contain precious metals such as platinum and others) that can lose reactivity when poisoned. Lower catalyst reactivity increases refinery processing expense. Catalyst poisoning also decreases the life of the catalyst, which leads to the expense of replacing it earlier than scheduled.

Chapter 7 - Seals and Security

Quick Reference

Safety

- Exercise care when handling seals and side cutters to prevent cuts.
- Follow all applicable safety rules in the SCM Safety Manual.

Scope

These procedures apply to lease tanks and LACT/ACT unit systems (including theELM).

When and Where to Use Seals and Security

- Seal tanks when making new connections, when welding, when oil is being delivered, and when the tank is on line.
- Seal LACT/ACT units at the prover connector valves, S&W monitor, sampler system, back-pressure valve, meter and meter accessory stack, control panel and power panels, temperature averagers, head switches and level controls, diverter valves, and piping and control conduits.

Note: At some locations, the seals may be installed by the other party. Also some ACT meters, depending on location, manning, and products, may not be sealed.

- Flow computers shall be password protected.

What to Do If a Seal Is Broken

While the tank is still on line:

- Seal off the tank.
- Take a closing gauge.
- Write the ticket as usual, but do not fill in the closing gauge.
- Attach a note to the ticket giving the reason for not completing it; include the closing gauge and temperature at the time of sealing.
- Make a full report to your team leader.

When you find a seal on a LACT/ACT system broken:

- Replace the boxcar seal with a wire seal.
- Do not transfer oil to/from that facility until your supervisor instructs you to do so.
- Conduct an immediate investigation and report your findings to your supervisor.

Introduction

Seals protect the company and the operator by assuring that no one has tampered with the oil run. They are placed on any part of a lease tank or LACT unit that could be tampered with. Seals are also part of assuring safety when working on tanks—for example, when welding a line. Electronic liquid measurement (ELM) flow computers require security in the form of software password protection, as well as physical locking of the area where they are located.

Equipment You Will Need for Working with Seals

- Boxcar seals
- Wire seals
- Pliers
- Side cutters

Procedures

The purpose of using seals and security procedures is to make sure that the equipment containing and monitoring crude or product has not been not tampered with.

The following will give you an overview of where you should check for seals and how to use them.

Using Seals

The two types of seals are boxcar seals and wire seals (see Figure 8.1 under "More About It" at the end of this chapter). Boxcar seals are numbered; record the numbers as a reference on the run ticket.

- Use a wire seal if you encounter a defective boxcar seal. Attach the defective boxcar seal to the wire seal, and record both seal numbers on the run ticket.
- If you find that a boxcar seal has been used where a wire seal should have been used, replace the boxcar seal with a wire seal or use the boxcar seal with a wire seal attached to it.
- Replace any seals that were broken during LACT/ACT checkout, as well as any missing seals and any seals showing signs of deterioration.

When and Where to Seal a Tank

1. When making new connections:
    - Seal tank stops closed when new tanks are connected to the SCM gathering system or when a new gathering system is brought on line.
    - Seal tank stops closed after tanks have been connected to a SCM system.
2. When oil is being delivered by tank truck:
    - Seal pipeline connections on lease tanks used for receiving oil delivered by tank truck.
    - Close and seal all draw-off connections when the tank is on line.
    - Request the operator to make sure that the tank's gauge and thieving hatches can be sealed while still allowing venting.
    - Seal the tank's gauge and thieving hatches.
3. When the tank is on line — to make sure that unwanted hydrocarbons or contaminants cannot be introduced or removed from the pipeline system undetected — do the following:
    - Seal all closed valves on draw-off connections, filling lines, overflow lines, and equalizer lines.

Where To Seal LACT/ACT Units

The following list is an overview of where you should check for seals to ensure that noone has tampered with LACT/ACT components.

1. Prover connector valves
    - Place a lock bar with seals across prover valves. On gate valve installations, use a lock and chain along with the seals.
2. S&W monitor and probe
    - Seal each connection on the probe and detector. Also, seal the electronic module at the hinges, cover latch, and at any other connections.
3. Sampler system
    - Place a seal at any point where tampering may affect the system's accuracy. All container openings, valves, pipe unions, pump drains, and other locations on the system should be sealed.
4. Back-pressure valve
    - Seal back-pressure valves through the adjustment bolt.
5. Meter and meter accessory stack
    - Seal the following on the meter and meter stack: the main meter body bolting, temperature and pressure averagers, right-angle drive dust cover, and meter totalizer.
6. Control panel and power panels
    - All electronic devices are wired through the control box and can be disabled

by entry into the panels. Seal all electronic devices at hinges, latches, andother points of access.

7. Tank head switches and level controls

    - Seal the high- and low-level switches as well as the low-level limit switch just above the sales outlet.

8. Diverter valves

    - Seal the diverter valve in such a way as to prevent tampering and the sale of —bad oil

9. Piping and control conduits

    - Seal all pipe couplings and screwed plugs located downstream from the meter to guard against the removal of metered liquid from the pipeline.

Signs of Tampering

Look for the following signs of tampering each time you check the LACT/ACT or gauge a tank:

- Forced entry
- Broken SCM security seals or seals that have been tampered with
- Electrical connections that have been tampered with (e.g., jumper wires)
- Small holes drilled in the weatherproof box housing the electronics (possible signs of an attempt to insert wires for manipulating controls)
- Monitor alarm and trip set points that don't agree with previous settings

In addition to checking the unit for signs of tampering, be sure to pick up and dispose of all security seals and wires you have removed.

Procedures When a Seal Has Been Broken

When you find a broken seal on a foreign line while the tank is still online:

- Seal off the tank.
- Take a closing gauge.
- Write the ticket as usual, but do not fill in the closing gauge.
- Attach a note to the ticket giving the reason for not completing it; include the closing gauge and temperature at the time of sealing.
- Make a full report to your supervisor.

The supervisor may authorize you to run oil from other tanks on the lease, but do not run any oil from the tank with the broken seal until you have permission from the District Manager.

When you find a broken seal on a pipeline connection:

- Replace the boxcar seal with a wire seal.
- Do not run oil from that tank or any other tank on the lease until your supervisor instructs you to.
- Conduct an immediate investigation and report your findings to your supervisor. Specifics of the investigation will depend on the circumstances, location, etc.

Other Security Measures

SCM prefers that flow lines enter a tank through the roof at a point near the regular gauge hatch. If the flow line extends through the roof into the liquid contents, a hole or slot must be cut in the pipe at a point not lower than the top of the tank shell. This precaution prevents the liquid from being siphoned from one tank to another.

On older locations where the flow lines enter the tank so far from the gauge hatch that thegauger cannot make a fingertip inspection, SCM will not require the operator to change the location of the lines, provided the tank can be inspected to see that the line has an opening no lower thanthe top of the tank shell. On future installations, SCM will advise the operator to locate theselines close enough to the gauge hatch that SCM personnel can inspect them from the hatch.

Some operators prefer that flow lines enter the tank through the shell, usually near groundlevel. This is acceptable; however, any filling line that enters through the shell of the tank must havea valve or stop with an approved and conveniently accessible sealing device. It must be sealed closed whenever the tank is on line.

Security for ELM Systems

The flow computer is the main component of an ELM system that requires securitymeasures.

Software Security

Passwords provide security for software. The first level of security allows measurement personnel to enter routine data from gauging, metering, and proving.

Higher levels of security allow only the appropriate personnel to change basic data(for example, tank strapping data, meter data, and prover calibration data), computational procedures, and/or algorithms.

Physical Security

The computer should be maintained in a secure location by locking the cabinet, house, orarea where it is located. If this is not possible, then other means should be used to make the equipment inaccessible to tampering.

Some other equipment, like temperature/pressure averagers, may be sealed to preventtampering.

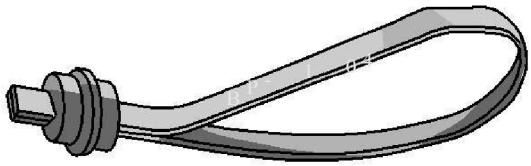


Figure 8.1. Boxcar seal

Reference Documents

1. SCM Safety Manual

Chapter 8 - Proving a Meter

Quick Reference

Safety

- Make sure the portable prover is grounded to prevent static electricity buildup.
- Follow all applicable safety rules SCM Safety Manual.

Scope

These procedures apply to proving meters on crude and product pipelines, using pipe provers or small-volume provers.

Summary of Procedures for LACT Units

- Prove LACT meters quarterly or every 75,000 barrels, whichever comes first unless
  - ◊ directed otherwise by regulatory or contractualobligations,
  - ◊ the fluid characteristics and operation require more frequent proving,
  - ◊ the flow rate increases or decreases by 15% or more, or
  - ◊ the gravity significantly changes.
- Prove after replacing or repairing the meter.
- The meter factor is calculated from 5 consecutive runs, out of a maximum of 10 runs, that agree (highest to lowest) towithin 0.05%.
- The new meter factor must be within ±0.0025 of the previous meter factor (under the same operating conditions).
- In most locations, apply the meter factor to the entire ticket period (often the entiremonth).

Summary of Measurement Procedures for Flowing Liquids

1. Check the operation of the LACT/ACT unit and ELM system or meter installation
2. Check meter operation
3. Mix and withdraw samples
4. Analyze the samples as required for thespecific type of transaction and product
5. Prove the meter
6. Calibrate temperature and pressure devices
7. Verify/calibrate the densitometer, as appropriate.
8. Record all results

Summary of Procedures for ACT Units

- Prove ACT meters at least monthly on each product, or more often
  if ◊ the flow rate changes by 15% or more,
  ◊ the temperature changes by 5°F, or
  ◊ the gravity changes by 5°API.
- The meter factor is calculated from 5 consecutive runs, out of a maximum of 10 runs, that agree (highest to lowest) to within 0.05%.
- The new meter factor must be within ±0.0015 of the previous meter factor (under the same operating conditions).

Summary of Preventive Maintenance for Provers

- Monthly:
  ◊ Verify temperature and pressure indicators and transmitters.
  ◊ Verify that all valves are sealingproperly.
  ◊ For bidirectional provers, verify that the four-way valve is sealing properly.
  ◊ For unidirectional provers, verify that the interchange is sealingproperly.
- Every six months:
  ◊ Pull the prover sphere and inspect it fordamage.
  ◊ Verify that the size is still the same as during the last prover calibration.

Equipment You Will Need for Measuring Flowing Liquids

For checking LACT/ACT units:

- Inspection form or checkout list
- Stopwatch
- Security seals and seal cutters
- Tools for checking the meter and accessories
- Equipment for calibrating or verifying temperature and pressure transducers and/or signal-receiving devices
- Equipment for gravity and temperature testing (see below)
- For LACT units, equipment for determining S&W (see below)

For automatic sampling:

- Sample containers (cans or bottles)
- Portable receivers, when applicable
- Sample(s)
- Solvent for washing sample containers
- Security seals and seal cutters

For gravity and temperature testing:

- Thermohydrometer
  or
  Hydrometer, hydrometer cylinder, filter paper, and constant-temperature bath
- Cupcase woodback thermometer
- Portable electronic thermometer (PET)
- Circulating bath and ice bath or PET calibrator (for verifying a PET)

For S&W testing by the field centrifuge method:

- Two verified 6-inch centrifuge tubes
- Water-saturated toluene or Stoddard solvent
- Demulsifier solution
- Sample heater
- Bimetal, pocket-type thermometer
- Centrifuge

For S&W testing by the laboratory centrifuge method:

- Two verified 8-inch centrifuge tubes
- Water-saturated toluene or Stoddard solvent
- Demulsifier solution
- Sample heater
- Bimetal, pocket-type thermometer
- Centrifuge

For water testing by the Karl Fischer titration method:

- Nonaerating, high-speed shear mixer
- Clean glass syringes
- Reagent-grade xylene
- Karl Fischer reagents
- Karl Fischer coulometric titrator

For security (lease tanks):

- Seals for securing all pipeline connections
- Side cutters for cutting and removing seals
- Pliers

Introduction

No meter can be absolutely accurate. To know the correct amount of oil being measured bya meter, it is necessary to determine how well a particular meter is performing under real operating conditions by proving it.

Proving involves measuring the liquid flow through the meter and through a prover and comparing the two volumes. The two volumes are used to calculate the meter factor. All parties involved in a custody transfer use the meter factor to correct any inaccuracy in the meter's measurements until the next scheduled proving.

The type of prover used depends on the volume of liquid to be measured and the nature of the transfer.

When to Prove aMeter

In general, prove LACT meters quarterly or every 75,000 barrels, whichever comes first, unless directed otherwise by regulatory or contractual obligations. The fluid characteristics and operation may require more frequent proving; for example, if the flow rate changes by 15% or more or the gravity significantly changes. In addition, prove after replacing or repairing themeter.

Prove ACT meters at least monthly or more often if the flow rate changes by 15% or more, the temperature changes by 5°F, or the gravity changes by 5°API.

Procedures

Calibrate provers regularly, normally every year to three years (see Chapter 16, —Waterdraw Calibration). Keep provers in top mechanical condition to ensure accurate results. See –Troubleshooting below for details about maintaining provers.

During proving, the fluid properties (for example, API gravity), flow rate, pressure, and temperature should be similar to those during normal operating conditions for the meter. The specific procedure for proving a meter varies according to the type of proving device. For each proving, however, follow the same procedure under the same operating conditions for each proving run so that you can produce repeatable results.

Preliminary Procedures for Stationary Provers

Follow these procedures before beginning the first proving run.

1. If a flow computer is not used for proving, record all data on a notepad for later entry into TICKETING SYSTEM.
2. To establish flow through the prover, open the inlet and outlet blockvalves.
3. Make sure the block-and-bleed valve on the main line is closed and the four-

way diverter valve (on bidirectional provers) is open to one side of the prover.

- Check the block-and-bleed valve for leaks. Open the bleed valve to ensure that oil is not leaking past the seals on the valve.
- Observe the pressure indicated on the cavity gauge of the four-way valve so you will notice any rise in pressure during proving, which indicates a leak.

4. After diverting the oil into the prover, allow time for the prover temperature to stabilize. The temperature is considered to be stabilized when the prover outlet temperature is constant and agrees closely with the meter temperature.
5. To adjust the flow rate back to normal, lower the back-pressure setting on the meter. Reset the back-pressure when you are finished proving.
6. If the meter is new or has been recently repaired, verify that the number of pulses generated per barrel matches the meter manufacturer's specifications as indicated on the Meter Proving Report.
   - Reset the electronic pulse counter to zero.
   - Start the electronic pulse counter with the remote switch attached to the counter.
   - Open the flow through the meter. After 10 barrels have been registered, stop the electronic pulse counter. Read the counter.
   - Using the following formula, calculate the pulses per barrel:

$$\text{pulses per barrel} = \frac{\text{total pulses}}{\text{closing meter reading} - \text{opening meter reading}}$$

7. Take a sample of the flowing oil and determine its gravity using a hydrometer. Record the results so you can enter them later on the Meter Proving Report.
8. Reset the electronic pulse counter to zero.
9. Set the four-way valve and launch the sphere for the first pass.
10. For a unidirectional prover, record the number of pulses at the end of the sphere (or displacer) pass.
11. For a bidirectional prover, reverse the four-way valve to allow the sphere to change directions, and record the number of pulses for the round trip.
12. Note the temperature and pressure of the prover and record the readings for this run. If both inlet and outlet thermometers are available, average the two readings.
13. For a bidirectional prover, record the meter temperature (unless temperature-compensated) and meter pressure.
14. Reset the prover counter and repeat steps 9-13 until you have accumulated data for 5 consecutive runs.
    - If the results of the 5 runs meet SCM requirements of 0.05% repeatability (see —Repeatability Requirements below), stop.
    - If not, continue the proving runs until you obtain 5 consecutive runs that are repeatable. If you make 10 runs without meeting the repeatability

requirements, stop and determine the problem (see ―Troubleshooting‖ below).

15. Return the flow through the LACT or ACT to normal.
16. Reset the back-pressure setting on the meter.
17. Complete the Meter Proving Report on your laptop.
18. Compare the new meter factor with the previous one. If the new meter factor varies from the previous one by more than ±0.0015 for ACTs or more than ±0.0025 for LACTs, identify the problem (see ―Troubleshooting‖ below).

Procedures for Proving with a Portable Prover

If you are using a portable prover, follow these additional steps.

1. Ground the prover.
2. Hook up the hoses on the prover to the prover connections.
   - Inspect the hoses for signs of wear or damage and make sure they have the correct pressure rating.
   - When removing the protective dust caps on the prover connections, loosen the caps slowly to allow any built-up pressure to dissipate.
   - If the prover is equipped with a vent valve, bleed the pressure before removing the caps.
3. Establish flow through the prover and check for leaks.
4. Launch the prover sphere and bleed air from the vent valves while the sphere is in motion. Be sure to bleed both prover chambers.
5. Verify that the prover counter is receiving signals from the pulse generator. Launch the sphere a few times to make sure that the detector switches are gating properly.
6. Clear the counter and then follow steps 7-16 under ―Proving with Stationary Provers‖ above.
7. Block in and bleed pressure from the prover.
8. Disconnect the prover and reset the counter.
9. Stow all equipment and bleed pressure from the prover.
10. Clean the area.
11. Complete the Meter Proving Report on your laptop.
12. Compare the new meter factor with the previous one. If the new meter factor varies from the previous one by more than ±0.0015 for ACTs or more than ±0.0025 for LACTs, identify the problem (see ―Troubleshooting‖ below).

Repeatability Requirements

The results of a meter proving must meet specific criteria that demonstrate repeatability.

These requirements are as follows:

- Calculate a meter factor using the average number of pulses from a series of 5 consecutive round trips.
- Within the series, the total pulse counts must not vary by more than 0.05% between the highest and lowest reading.
- If you cannot meet the criteria for repeatability in 10 round trips, stop and determine the problem before continuing (see ―Troubleshooting‖ below).
- For ACT locations, the new meter factor must be within ±0.0015 of the last meter factor for this product. For LACT meters in crude oil service, the tolerance is ±0.0025. The previous meter factor is shown on the Meter Proving Report.
- The meter factors should be trended, using the utility program in TICKETING SYSTEM, to monitor meter performance and condition.

Troubleshooting

When results from a meter proving are unacceptable or when there is other evidence that the meter or the proving equipment is malfunctioning, you must determine the cause of the problem. This section describes some of the most common difficulties that you may encounter in the proving process and suggests ways of correcting them.

Proving problems tend to fall into two broad categories:

1. The pulse counts vary by more than 0.05% between the highest and lowest reading in 5 consecutive runs (nonrepeatability).
2. The new meter factor varies from the previous meter factor by more than ±0.0025 for LACTs or more than ±0.0015 for ACTs. (These tolerances are valid only if the meter was proved under the same operating conditions.)

Nonrepeatability

Nonrepeatability can have the following causes:

- Air or gas in the prover
- Unstable temperature
- Unstable flow rates
- Bad detector switches
- A nearby electrical field, two-way radios, or radio repeater stations, which can produce stray pulses
- A defective prover sphere
- A leaking four-way valve (bidirectional prover)
- A leaking diverter valve (unidirectional prover)

The procedures for these checks are given below in ―Procedures for Troubleshooting

Changing Meter Factor

A changing meter factor can often be traced to the followingproblems:

- Meter wear
- Deposits in the meter
- Flow rate of the oil
- Viscosity of the oil
- Temperature and pressure of the oil
- Air and vapor in the oil
- An overinflated or underinflated sphere

Use good judgment in evaluating widely divergent meter factors at a particular location. Repairing or replacing a meter is expensive, so evaluate the meter thoroughly and perform extensive troubleshooting procedures to prevent unnecessary costs. Table 14.1 summarizes some of the most common causes of a fluctuating meter factor.

Table 14.1. Causes of Meter Factor Fluctuation

Cause	Effect	Meter Factor
Incrustation	Lower meter registration	Increases
Prover temperature too high	Higher meter registration	Decreases
Prover temperature too low	Lower meter registration	Increases
Air or gas in oil	Higher meter registration	Decreases
Leaking valve	Higher meter registration	Decreases
Piston wear	Higher meter registration	Decreases
Stray pulses to counter	Higher meter registration	Decreases
Loss of pulses to counter	Lower meter registration	Increases
Leakage around sphere	Higher meter registration	Decreases

Procedures for Troubleshooting

Check the following components and circumstances to investigate a changing meter factor or repeatability problems.

1. Liquid changes
    - When there is an unacceptable discrepancy between the new meter factor and the previous one, review the characteristics of the oil. If there have been considerable changes in the liquid since the previous proving, the new meter factor may be valid. The changes may be in gravity, temperature, or type of crude/product.
2. Prover displacers
    - Inspect prover displacers regularly for over- or underinflation. A deflated sphere causes liquid to leak past the sphere, and the meter factor drops. Overinflated spheres may cause the sphere to jump, which will produceuneven meter pulses. The sphere should be 2-3% oversized.
    - Overinflation causes increased wear and distortion of the sphere as well as jumping of the sphere, which produces erratic pulse counts. Underinflation causes high pulse counts and results in a meter factor that is too low.
3. Four-way diverter valve
    - Check the four-way diverter valve prior to proving and then at least once during proving.
    - If the valve is sealing properly, the gauge should remain at a pressure significantly lower than the prover pressure. Any rise in pressure indicatesthat the valve is leaking.
    - Leakage through the four-way valve causes an increase in pulse counts and thus a lower meter factor.
4. Detector switches
    - If you remove either switch on a prover, contact the Measurement Team, as the prover must be recalibrated (waterdrawn) before using it again.
    - Consult the manufacturer's instructions before attempting any adjustments or repairs to the switches.
5. Prover isolation valve (block-and-bleed valve)
    - During proving operations, check all connecting valves for leaks. Make sure the total flow from the meter (and only that flow) is flowing through the prover while you are proving the meter.
    - Any leakage causes higher pulse counts, resulting in a lower meter factor.

6. Meter back-pressure
    - API recommends that the back-pressure be no less than 2 times the pressure drop across the meter at the maximum operating flow rate plus 1.25 times the equilibrium vapor pressure at measurement temperature. For crude oil, this means that the system should be operated above 20 psi.
    - Improper back-pressure causes the liquid to separate or flash, producing cavitation in the meter. The meter will become very erratic under these conditions.
7. Check for air or vapor in the system.
8. Check pressure, temperature, and density-sensing devices for error.
9. Check all electrical equipment for any failures, including the pulse generator, counters, coil, preamplifiers, signal transmission system, power supply,and all readout devices.
10. Check for leakage from all isolation and diversion valves.
11. Check for proper gearing in the meter accessory drive.

Preventive Maintenance for Provers

Follow these procedures for maintaining a prover. At

least monthly:

4. Verify temperature and pressure indicators and transmitters.
5. Verify that all valves are sealing properly by checking bleeders.
    - Check the body bleed on block-and-bleed valves.
    - Check the bleeder between double block valves.
6. For bidirectional provers, verify that the four-way valve is sealing properly by checking the differential pressure or by opening the body bleeder.
7. For unidirectional provers, verify that the interchange is sealing properly by checking the differential pressure or opening the cavity bleeder.

Every six months:

1. Pull the prover sphere and inspect it for damage. Replace it with a new sphere if damage is extensive.
2. Verify that the size is still the same as during the last prover calibration.
    - Measure the sphere around two axes (the seam and fill ports). The two readings should agree within 1%. See Table 16.2 for the acceptable tolerance for various sizes of spheres.
    - If the sphere needs to be resized, use a 50-50 mix of water and antifreeze.
3. Reinstall provers with adjustable sphere ramps according to the

manufacturer's recommendations to prevent sphere damage.

Reference Documents

1. API Manual of Petroleum Measurement Standards, Chapter 4 —Proving Systems‖

2. SCM Safety Manual

Chapter 9 - Tickets

Definition

Run ticket refers to the evidence of receipt or delivery of oil issued by a pipeline, other carrier, or purchaser. The amount of oil transferred from storage is recorded on a run ticket. The amount of payment for oil is based upon information contained in the run ticket

A. At a minimum, each meter measurement ticket shall include the following information:

1. Date(s) and time(s) of start and end of batch
2. Delivery location
3. Name of shipper
4. Name of carrier
5. Start totalizer or accumulator (in barrels,gallons, lbs, scf,mcf, mmcf)
6. Ending totalizer or accumulator (in barrels,gallons, lbs, scf,mcf, mmcf)
7. Indicated quantity of product transferred
8. Gross quantity of product transferred (in barrels,gallons, lbs, scf,mcf, mmcf)
9. Net quantity of product transferred (in barrels,gallons, lbs, scf,mcf, mmcf)
10. Weighted average temperature (degrees F to tenth decimal point)
11. Weighted average density (degrees API to tenth decimal point)
12. Weighted average pressure (psig to tenth decimal point)
13. Meter factor (to the ten-thousands decimal point)
14. BS&W % (composite sample) for crude oil
15. Persons name(s) who performed measurement activity

BLM (Bureau of Land Management – Department of the Interior) requires all Run tickets meet the following:

§ 3174.12 Measurement tickets.

(a) Tank gauging. After oil is measured by tank gauging under §§ 3174.5 and 3174.6 of this subpart, the operator, purchaser, or transporter, as appropriate, must complete a uniquely numbered measurement ticket, in either paper or electronic format, with the following information:

(1) Lease, unit PA, or CA number;

(2) Unique tank number and nominal tank capacity;

(3) Opening and closing dates and times;

(4) Opening and closing gauges and observed temperatures in °F;

(5) Observed volume for opening and closing gauge, using tank specific calibration charts (see § 3174.5(c));

(6) Total gross standard volume removed from the tank following API 11.1 (incorporated by reference, see § 3174.3);

(7) Observed API oil gravity and temperature in °F;

(8) API oil gravity at 60 °F, following API 11.1 (incorporated by reference, see § 3174.3);

(9) S&W content percent

(10) Unique number of each seal removed and installed;

(11) Name of the individual performing the tank gauging; and

(12) Name of the operator.

(b) LACT system and SCM.

(1) At the beginning of every month, and, unless the operator is using a flow computer under § 3174.10, before conducting proving operations on a LACT system, the operator, purchaser, or transporter, as appropriate, must complete a uniquely numbered measurement ticket, in either paper or electronic format, with the following information:

(i) Lease, unit PA, or CA number;

(ii) Unique meter ID number;

(iii) Opening and closing dates;

(iv) Opening and closing totalizer readings of the indicated volume;

(v) Meter factor, indicating if it is a composite meter factor;

(vi) Total gross standard volume removed through the LACT system or SCM;

(vii) API oil gravity. For API oil gravity determined from a composite sample, the observed API oil gravity and temperature must be indicated in °F and the API oil gravity must be indicated at 60 °F.

(viii) The average temperature in °F;

(ix) The average flowing pressure in psig;

(x) S&W content percent;

(xi) Unique number of each seal removed and installed;

(xii) Name of the purchaser's representative; and

(xiii) Name of the operator.

(2) Any accumulators used in the determination of average pressure, average temperature, and average density must be reset to zero whenever a new measurement ticket is opened.

Other system requirements

System should

1. Calculate volumes from strapping tables (system should have ability to have tables uploaded into system from csv file)
2. Compatible with Modbus and Hart protocols.
3. API 21 compliant
4. Meet API 12.2 and other API calculation standards
5. Meet AGA standards

Chapter 10 – LACT DESIGN

GENERAL

SCOPE

A. The purpose of this specification is to cover the design, fabrication, testing and preparation from shipment of skid mounted Lease Automatic Custody Transfer (LACT) Units.
B. Requirements on equipment performance, facility design and control of custody transfer equipment are included in this standard.

CODES AND STANDARDS REQUIREMENTS

A. The primary reference document of this standard is the API Manual of Petroleum Measurement Standards (API MPMS). API Specification 11N (Spec 11N), API RP 500, and all recognized industry codes and standards pertaining to the design of custody transfer measurement shall be followed. This includes, but is not limited to, publications by the National Institute of Standards and Technology (NIST), American Society for Testing and Materials (ASTM), National Fire Prevention Association (NFPA), National Electric Code Association (NECA), and National Association of Corrosion Engineers (NACE).
B. Pressure vessels and tanks associated with a LACT unit shall be designed and fabricated in accordance with the ASME Boiler and Pressure Vessel Code.
C. Piping shall be designed and fabricated per ANSI B31.4 Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia and Alcohols.
D. All applicable environmental and safety regulations and guidelines shall be observed. All local, state and federal regulations shall be followed within their jurisdictional limits.

DESIGN

A. All equipment shall be in compliance with the performance and accuracy provisions of API MPMS. Each LACT Unit shall be capable of demonstrating a traceability to NIST standards.
B. All LACT Units shall be designed for fail safe operation in cases of failure or malfunction so that un-sampled, off specification, or unmeasured liquids will not flow through custody transfer facilities. Status and failure indicators (alarms) shall be provided to facilitate identification of equipment failures and malfunctions.
C. All equipment shall be designed and installed to be easily accessible for inspection, testing, calibration, and routine maintenance. This includes the recommended use of flexible conduit at least 18 inches long to connect each electrical device to rigid conduit. For piping components, it includes the use of isolation valves and unions, clamped couplings, or flanged connection for removal of equipment.

D. All materials used in custody transfer equipment shall be compatible with the internal and external environments. Materials shall not experience excessive corrosion embrittlement, degradation, or physical property changes that affect the serviceability of the equipment.
E. Materials containing crude oil under pressure shall also be ductile and resistant to fire exposure. Nonmetallic materials, such as plastics, shall not be used. Cast Iron, brass, bronze, copper, aluminum and zinc shall not be used in pressure containing components.
F. A typical LACT Schematic is shown in Appendix A, Figure A-1.
G. Each LACT Unit skid shall have, as a minimum, the following components:
    1. Charge Pump: See section CHARGE PUMP for complete description.
    2. Basic Sediment and Water (BS&W) Monitor: See section BS&W MONITOR for complete description.
    3. Diverter Valve: A three-way, two position valve or two mechanically interlocked valves shall be provided on all LACT Units where excess BS&W liquids are to be circulated for retreating. Flow shall be normally directed to the diverted (wet) discharge piping for fail- safe hookup. This valve shall be activated by the BS&W monitor such that the valve moves to divert flow to the clean oil discharge only when it receives a positive signal and it fails "safe" with flow to the wet oil discharge in the absence of a positive signal. If a diverter valve is not used, the wiring shall be configured to shut down oil delivery upon failure to receive a "clean oil" signal from the monitor.
    4. Strainer and Air/Gas Eliminator: The air/gas eliminator and strainer, as separate or integral units, shall be located upstream from the meter in a horizontal pipe. The air/gas eliminator shall be installed higher than the meter, at or near the highest location in the LACT Unit piping. The strainer element shall be equipped with a 4-mesh basket with a finer mesh lining. A 20-mesh or finer liner shall be furnished for use during the first 24 hours of operation.
    5. Static Mixer: An in-line static mixer shall be installed upstream of the sample probe.
    6. Sample Systems: See section SAMPLE SYSTEMS for complete design.
    7. Back Pressure Valve[s]: An adjustable back pressure valve may be located downstream of the meter Prover connections. The valve shall be a spring loaded or electrically actuated, globe or angle style valve with a resilient seat and corrosion resistant trim. It shall be closed under no flow conditions and shall fail in a closed position. If re-treating line present, a back pressure valve or other restriction device shall be provided on the re-treating line and shall have the same pressure setting as the outlet control valve.
    8. Check Valve: A check valve shall be installed at the outlet of each meter run, downstream of the back pressure valve.
    9. Meter: See section METER for a complete description.
    10. Flow Computer: See section FLOW COMPUTER for a complete description.
    11. Prover Manifold: See section PROVER MANIFOLD for a complete design.

12. Control Panel: Controls for the LACT facilities shall be in an enclosure that is resistant to the elements, tampering, vandalism and fire exposure. The control panel shall have separate power and control enclosures. See section CONTROL PANEL for a complete description.
13. Mounting Skid: The equipment components should be mounted on a sliding type, welded, oil-field style, structural steel skid designed with sufficiently sized members and bracing to provide a completely portable unit.

H. All equipment components should be rigidly attached to the skid and braced as necessary, using suitable connections for those items likely to require future removal for normal repairs and maintenance.

PRODUCTS

1. Crude Oil

HYDRAULIC ASSEMBLY

A. The hydraulic assembly shall be made of Schedule 40 steel line pipe and fittings.
B. Piping size for all elements directly in the main flow stream shall be no less than the nominal size of the meter.
C. The hydraulic assembly of the main flow stream shall be connected using raised face flanges unless otherwise specified by the user.
D. All piping and structural components should be commercially blasted, and painted with at least one coat of metal primer.

CHARGE PUMP AND MOTOR

A. Pump shall be electrically driven, rated for a discharge pressure and rate that are compatible with the rating for the meter used, and sized to assure turbulent flow in the main stream piping.
B. A centrifugal pump shall be supplied. The pump shall conform to ANSI B73.1 or other applicable standard governing the pump type and design.
C. The pump shall be capable of providing 20 psig minimum over the RVP of the metered product at the LACT unit discharge at the maximum flow rate.
D. The pump should be directly coupled to the motor with a flexible coupling, complete with guard.
E. The pump should have a mechanical seal.
F. A drip pan and drain piping shall be provided under the pump for spill protection in the event of a seal leak.
G. The common base plate for the pump and motor should allow vertical and horizontal adjustment for alignment relative to each other without moving the base plate on the skid.
H. Pump internal materials shall be appropriate for the specified service.
I. An eccentric reducer shall be used if the inlet pipe is larger than the inlet connection of the pump.

BASIC SEDIMENT AND WATER (BS&W) MONITOR:

A. Probe installation is required in a vertical run of pipe as close downstream of the charge pump, static mixer, or other mixing element as is possible. End connections (if applicable) are required to facilitate removal of the probe for internal inspection and cleaning.
B. The instrument shall have:
   1. Adjustable range: 0-3 percent water in increments of 0.1 percent water.
   2. Time delay for diverter action: 0-2 minutes (adjustable when specified).
   3. Means for field calibration.

C. Meters and push buttons for performing operational checks and field calibration shall be provided. The monitor shall provide an indication of whether merchantable oil or excess BS&W is in the probe.
D. The monitor chassis shall be either explosion proof or mounted in a weatherproof, dust tight enclosure. The limit setting and graduated indicator shall be visible when the monitor is sealed or locked.

SAMPLING SYSTEM

A. Sample Probe Location.
   1. The probe may be installed in either a vertical or horizontal pipe run.
      a. In a vertical pipe run, the probe shall be installed with at least three pipe diameters of straight pipe upstream and two pipe diameters of straight pipe downstream of the probe. The static mixer shall be installed within two pipe diameters of the probe.
      b. In a horizontal pipe run, the static mixer shall be installed within one to two pipe diameters of the probe.
   2. A manual sample probe shall be installed three pipe diameters downstream of the automatic sample probe in order to take hand samples.
B. Sample Probe Design
   1. The sample probe shall be located only in the horizontal plane and it shall extend such that the tip opening is located in the middle one-third of the pipe facing upstream.
   2. Acceptable sampling tip designs include:
      a. Open end with 45 degree bevel.
      b. Open end 90 degree tube turn reamed to a sharp entrance edge.
      c. Closed end with round orifice entrance near the tip.
      d.
C. Sample Extraction System

   1. The sample probe shall be connected to a three-way solenoid valve with a volume regulator as close as practical but not greater than 10 inches. The piping shall be level or slope down to the valve and shall be a minimum 3/8 inch in diameter. Refer to the Typical LACT Schematic in Appendix A, Figure A-1.
   2. The sample probe shall be connected to a sample extractor as close as practical, but not greater than 10 inches. The piping shall be level or slope down to the valve and shall be 3/8 inch in diameter. Upstream of the sample valve shall be a circulating loop that discharges upstream of the LACT charge pump.
   3. The sampler shall be flow responsive (proportional) type, actuated by an impulse switch driven by the meter counter. Unless otherwise specified, the impulse switch shall give one impulse per barrel (adjustable).

4. The tubing between the three-way valve [sample extractor] outlet and the sample container shall be stainless steel, as short as practical, and shall be 3/8 inch in diameter, and continuously slope downward to the container without sags or loops.
5. Fluid shall flow through three-way solenoid valve [sample extractor and circulating loop piping] at a velocity at leastequal to the primary piping velocity.
6. The piping shall contain a check valve to prevent back flow from the sample container.

D. Sample container and circulating system.

1. A sample container shall be designed and installed to prevent vaporization of the stored sample.
   a. The container shall be epoxy [plastic] coated (or equal) to minimize wax deposits and container corrosion. The sample container coating shall be of a color to allow effective inspection and cleaning.
   b. The container shall be designed to withstand an internal pressure of 20 psig and be hydrotested for at least one hour to verify pressure containment capability.
   c. The container shall be equipped with a quick opening type, vapor proof top inspection hatch designed to hold the sample under a pressure sufficient to prevent the escape ofvapor.
   d. The container shall be properly sized with respect to the expected volume per batch or ticket period at a fill volume of 80% of container volume capacity.
   e. An internal spray bar to "wash" the container tip and sides and promote circulation of liquids within the container shall be provided.
   f. The bottom of the container shall be so constructed that there are no voids in which a portion of the sample can be entrapped so that it is not subject to mixing by the circulation pump.
   g. A level indicating transmitter may be installed to indicate the volume of the sample contained.
   h. A full length sight glass, protected to avoid breakage, shall be installed along with a graduated scale with graduations of 0.1 gallons orsmaller.
   i. A pressure relief valve shall be provided and set to the design pressure of the container.
   j. Pressure required for controlling vaporization may be provided by means of an internal flexible diaphragm that is vapor impervious upon which a regulated gas pressure is maintained. Under no condition shall gas pressure from an outside source be applied in direct contact with the sample.
   k. A pressure gauge shall beprovided.
   l. A vacuum breaker to permit liquid withdrawal shall be installed.
   m. A high level sensor shall be installed that shall alarm on high level and discontinue operation of the charge pump. The high level switch shall be installed at the 75-80% fill volume level.
2. A circulation pump shall be installed below the sample container to allow a complete blending of the sample into a homogeneous mixture before and during the withdrawal of a portion of the sample for testing.
3. The pump shall be an electric motor driven rotary displacement or centrifugal pump with a capacity equal to the sample container size per minute, i.e., five GPM for a five-gallon container.
4. The pump suction shall be connected to the bottom most point of the sample container and the discharge shall be connected to the internal spray bar. The piping shall be 3/4

inch or larger on both the suction and discharge of the mixing pump.

5. An in-line static mixer on the discharge of the mixing pump shall be installed.
6. A sample draw valve and fill connection shall be located as close as possible to the mixing pump [in-line static mixer].
7. Piping shall be included to completely drain the container and discharge into the LACT charging pump suction after the sample analysis is concluded.

METERS

A. The custody transfer meter shall be a Coriolis mass flow type meter selected for the planned service conditions of working pressure and flow capacity. The wetted parts of the meter shall be stainless steel.
B. The meter case and trim specifications shall be selected for the planned service conditions of working pressure and flow capacity and be made of corrosion-resistant materials.
C. Meters shall have a repeatability of plus or minus 0.05 percent (0.0005), and a linearity of plus or minus 0.25 percent (0.0025) over the range of operating flow rates.
D. The meter shall have a failure logic function to discontinue and lock out flow through the meter.
E. Low and high flow rate alarm logic shall be provided.

METER TEMPERATURE DEVICES

A. Temperature transmitters shall have a range suitable for the operating conditions and shall have an accuracy within 0.2 °F under all operating conditions and an output resolution of 0.1 °F or better.
B. The transmitter wiring shall be continuous between the transmitter and the PLC control unit.
C. Temperature devices and thermowells shall be mounted to allow a filling with a conductive fluid, extend into the center third of the pipe, installed in the same size pipe as the meter piping within 12 inches from the meter outlet flange.
D. Test thermowells shall be located within 8-12 inches of the transmitter thermowells.

FLOW COMPUTER/PLC CONTROL UNIT

A. The equipment shall perform the following functions:
   1. Temperature displayed to a resolution of 0.01°F to facilitate calibration of sensors.
   2. Pressure displayed to a resolution 0.1 psi to facilitate calibration of sensors.
   3. Pulse generation and counting for proving.
   4. Failure detection.
   5. Non-Resettable totalization
   6. Low/high flow rate alarms.
   7. Sample pacing.
   8. Flow accumulation.
   9. Capability for diagnostic activities including display of all units, conversion factors, correction factors, and outputs.
   10. Capable of providing Flow weighted average Temperature, Pressure, Gravity
   11. Meet API MPMS Chapter 21 standards

B. Flow computers used for custody transfer registration shall display an accumulated volume within one barrel of the metered flow.

PROVER MANIFOLD

A. A three-valve arrangement is required for single meter installations including:
   1. One isolation valve on the inlet and outlet lines to the prover with full opening design no smaller than the line size.
   2. A block and bleed (center) valve that shall be a full opening double block design with internal bleed for leakage check. Valve shall have a full opening design no smaller than the line size
   3. Cam and groove connections with dust caps for quick coupling to portable proving equipment. (Note : on Ansi 300# or higher ratings a hammer type connection is required)
   4. Drain capability at each connection.
   5. Drain pan under or enclosure around the prover connections to collect any leaks.

B. All piping components shall be designed to minimize flow restriction during proving operation.

LOCKS AND/OR SEALS

A. Locks and/or seals shall be used to restrict the unauthorized entry to equipment involved with the quality or quantity measurement of custody transfer liquids. All means of entry into the operating stream, downstream of the charge pump, shall be locked and/or sealed to restrict or indicate unauthorized entry.

B. Acceptable sealing devices are: padlocks, numbered lead wire seals, numbered ribbon car seals, epoxy or other hardenable inert sealing compound (for tubing and conduit fitting only), and rigid covers that are sealable.

C. All equipment that could affect measurement quality or quantity except the charge pump, shall be sealed and/or locked.

INSTRUMENTATION AND ELECTRICAL

A. See site specific requirements

MARKING

A. LACT units shall be identified by a name plate securely attached to the power control panel in a conspicuous place. Markings shall be either raised or stamped at least 1/8 inch high. The name plate shall contain the following information:

B. Fabricator's name.

C. Design flow rate in GPM or B/D.

D. Date of fabrication.

METER OPERATIONS AND PROVING

OPERATION

A. For batched operations the meter shall be operated within the following conditions from the previous proving or shall be recalibrated to capture the new operating conditions.

1.	Gravity	+/- 5° Corrected API
2.	Flow Rate	+/- 15%
3.	Pressure	+/- 20% or 50 PSIG whichever is less
4.	Temperature	+/- 10° F
5.	Volume	Not above manufactures specs

B. For lease operations measurement equipment shall be verified and / or calibrated by the following guidelines.
   1. Per contract or regulations
C. For truck receipt locations the same guidelines shall apply with the addition that the meter proving shall be performed at no more than 5° corrected API gravity from the previous sample pots corrected API gravity.

ELECTRICAL WIRING

A. All electrical wiring shall be in accordance with the National Electric Code (latest revision). Instrumentation and control wiring shall be routed separately and away from AC power cables and electrical noise generating equipment such as power transformers. Wire shall be 2, 3, 4 or more pair, as required for the specific field instrument.
B. A spare pair is recommended with each wiring circuit. Each pair shall be labeled with durable material on each with loop and service designations. Wiring pairs shall be individually shielded and coated. Minimum wire size shall be No. 16 AWG cable or larger, except for the BS&W monitor cable. Multiple pairs shall be twisted at least twice per foot and shall be color-coded. Shielding shall be maintained to within one inch of the terminal connections.
C. Terminal strips shall be used for all signal and power terminations. Terminations shall be made with tin-plated components and shall be labeled, numbered, or otherwise identified to give pertinent functional information.
D. Electronic transmitters with analog circuits shall be installed in temperature controlled enclosures or incorporate temperature compensation capability to minimize the effects of ambient temperature changes to the electronics.
E. Junction boxes shall be designed for pulling cable without the use of terminations. Splices, terminations, or solder connections shall not be allowed between the device and the sensor, except as required for field connections. Use only the coaxial cable length provided with the BS&W monitor. Modification of the cable length will require a full recalibration by the manufacturer.
F. All panel mounted instruments and shields shall be individually grounded to the facility ground system using insulated N0. 14 AWG, or larger copper ground wires. Shields shall

not be grounded at the individual instruments. Each individual electronic device shall have power transient (lightning) protection devices. Flow computers and electronic 76 averaging devices shall have appropriate surge protectors on each input circuit.

G. Primary electric power shall be furnished from a regulated power supply with surge protection.

CONTROLS

A. The following automatic control functions shallbe provided:

B. Start and stop the charging pump on receipt of signals from the respective surge tank level control(s) or SCADA start/stop

C. If re-treating line is included, divert clean oil to delivery discharge only on receipt of a positive signal from the BS&W, and deliver to the wet oil discharge otherwise.

D. Restart on receipt of full power following a power outage period.

E. Stop on receipt of signal indicating either (a) low flow rate, (b) meter failure, (c) monitor failure, (d) ESD, or (e) high pressure limit exceeded, and remain locked out until a manual reset is activated.

APPENDIX - TYPICAL LACT UNIT

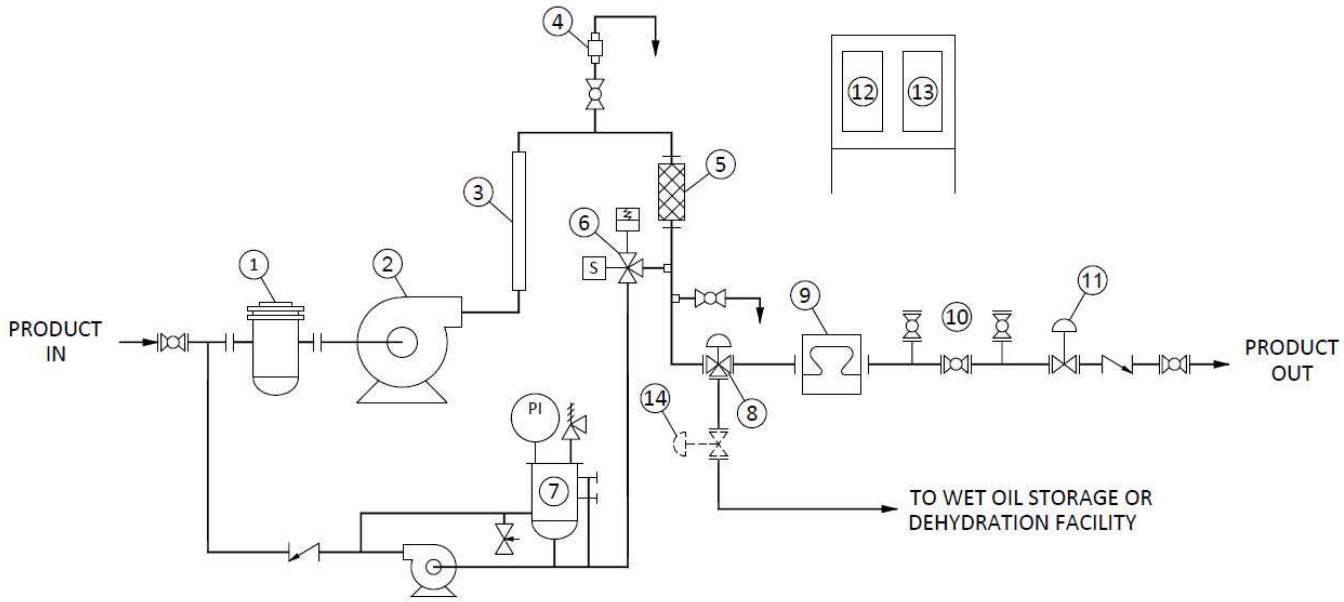


Figure A-1: Typical LACT Unit Schematic