White paper

Best Practices for Custody Transfer

Using API MPMS 18.2

EMERSON

Best Practices for Custody Transfer Using API MPMS 18.2

Abstract

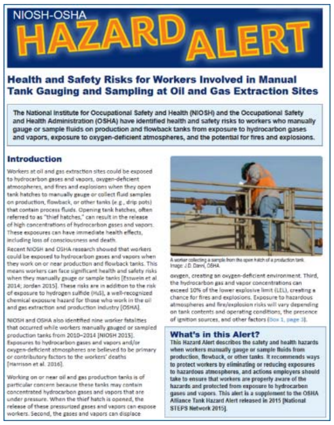
While manual tank gauging remains a common practice within custody transfer applications in the United States oil and gas industry, there are growing concerns about its effect on accounting accuracy, production losses, and worker safety. This white paper highlights the reasons for these concerns, but explains that until recently the only other method for small lease tank custody transfer was to install a lease automatic custody transfer (LACT) unit, which could be uneconomical on smaller sites. The paper goes on to describe how the American Petroleum Institute (API) has addressed this issue by releasing the new API MPMS Ch. 18.2 standard, which provides guidance on best practice in custody transfer from lease tanks using alternative measurement methods. The paper looks at how the standard aims to increase safety, and how the guidance now enables the use of technology, such as guided wave radar, within custody transfer applications. It concludes by examining how end users can decide which solution is right for them by calculating overall system uncertainty, and how they can determine their return on investment.

Safety

Until recently, the only small lease tank custody transfer method other than manual tank gauging per the API MPMS Ch. 18.1 standard was to install a LACT unit per API MPMS Ch. 6.1. However, this solution can be uneconomical on sites with low production volumes, so manual tank gauging is still prevalent within onshore oil and gas facilities in the United States. However, performing manual measurements presents a number of health, environmental, and safety concerns associated with personnel making frequent field trips, working under harsh seasonal weather conditions and being exposed to volatile organic compounds. A particular concern when performing manual tank gauging is the need to open tank thief hatches, which can expose workers to the rapid release of high concentrations of hydrocarbon gases and vapors. This may result in very low oxygen levels and high toxic H_2S levels, as well as flammable conditions around and over the thief hatch. Workers have experienced dizziness, fainting, headaches, nausea, and have even died whilst gauging tanks, collecting samples, or transferring fluids.

Between 2010 and 2014 there were nine fatalities associated with manual tank gauging and sampling operations. National Institute for Occupational Safety and Health (NIOSH) researchers and Occupational Safety and Health Administration (OSHA) officials are investigating these cases and a number of other reported worker deaths.

Figure 1. NIOSH-OSHA Hazard Alert



NIOSH-OSHA

HAZARD ALERT

Health and Safety Risks for Workers Involved in Manual Tank Gauging and Sampling at Oil and Gas Extraction Sites

The National Institute for Occupational Safety and Health (NIOSH) and the Occupational Safety and Health Administration (OSHA) have identified health and safety risks to workers who manually gauge or sample fluids on production and flowback tanks from exposure to hydrocarbon gases and vapors, exposure to oxygen-deficient atmospheres, and the potential for fires and explosions.

Introduction

Workers at oil and gas extraction sites could be exposed to hydrocarbon gases and vapors, oxygen-deficient atmospheres, and fires and explosions when they open tank hatches to manually gauge or collect fluid samples on production, flowback, or other tanks (e.g., drip pots) that contain process fluids. Opening tank hatches, often referred to as "thief hatches," can result in the release of high concentrations of hydrocarbon gases and vapors. These exposures can have immediate health effects, including loss of consciousness and death.

Recent NIOSH and OSHA research showed that workers could be exposed to hydrocarbon gases and vapors when they work on or near production and flowback tanks. This means workers can face significant health and safety risks when they manually gauge or sample tanks [Esswein et al 2014; Jordan 2015]. These risks are in addition to the risk of exposure to hydrogen sulfide (H_2S), a well-recognized chemical exposure hazard for those who work in the oil and gas extraction and production industry [OSHA].

NIOSH and OSHA also identified nine worker fatalities that occurred while workers manually gauged or sampled production tanks from 2010–2014 [NIOSH 2015]. Exposures to hydrocarbon gases and vapors and/or oxygen-deficient atmospheres are believed to be primary or contributory factors to the workers' deaths [Harrison et al. 2016].

Working on or near oil and gas production tanks is of particular concern because these tanks may contain concentrated hydrocarbon gases and vapors that are under pressure. When the thief hatch is opened, the release of these pressurized gases and vapors can expose workers. Second, the gases and vapors can displace oxygen, creating an oxygen-deficient environment. Third, the hydrocarbon gas and vapor concentrations can exceed 10% of the lower explosive limit (LEL), creating a chance for fires and explosions. Exposure to hazardous atmospheres and fire/explosion risks will vary depending on tank contents and operating conditions, the presence of ignition sources, and other factors (Box 1, page 3).

A worker collecting a sample from the open hatch of a production tank. Image: J.D. Danni, OSHA

What's in this Alert?

This Hazard Alert describes the safety and health hazards when workers manually gauge or sample fluids from production, flowback, or other tanks. It recommends ways to protect workers by eliminating or reducing exposures to hazardous atmospheres, and actions employers should take to ensure that workers are properly aware of the hazards and protected from exposure to hydrocarbon gases and vapors. This alert is a supplement to the OSHA Alliance Tank Hazard Alert released in 2015 [National STEPS Network 2015].

The recent NIOSH-OSHA Hazard Alert (Figure 1) suggests that by utilizing automated technology to eliminate hand-gauging, trips to the top of the tank can be minimized. This helps to reduce the risk to workers and improve safety. Also, better insight into tank inventory levels can reduce the risk of spills and optimize transfer logistics, which leads to a reduction in road traffic hazards.

Lost production risk

Not only are there safety risks associated with manual tank gauging, but there is also significant risk of lost oil production. Manual tank gauging requires very high operator competency, is subject to human errors, and often must be performed within difficult weather conditions.

When oil is hauled off the lease site, the crude oil truck driver often must ensure that the volume to be delivered is not less than what was measured to be contractually compliant. This can lead to open- and end-level measurements being rounded off, which can introduce errors. A recent publication by the United States Bureau of Land Management (BLM) reported that typical manual tank gauging uncertainties ranged from 0.6% to 2.5%. Using a midpoint of 1.5% uncertainty and applying that to a well producing 600bbl/day of oil, at a sales price of $45 per barrel, this would result in a potential annual loss of $148,000.

Another potential problem area is that lack of visibility to production separator upsets will send oil to the water tank or water to the oil tank. If not detected, oil in the water tank will be lost, especially if using a third-party water hauler during water transfers. Unaccounted-for or unauthorized hauling of produced oil in the water tank from a multiple well pad facility could lead to significant losses.

How does API MPMS Ch. 18.2 help?

To address potential problems associated with manual tank gauging and provide a broader scope of economical solutions in addition to LACT unit solutions, API has released the new API MPMS Ch. 18.2 standard. The new standard provides guidance on crude oil custody transfer from lease tanks using alternative measurement methods. The aim of API MPMS Ch. 18.2 is to increase safety by allowing the use of technology and standards for custody transfer that do not require a thief hatch to be opened.

Defined zones

API Ch. 18.2 has defined three zones where the quantity and quality of oil being loaded from a lease tank to a truck trailer can be measured. The zones are depicted in Figure 2 and are defined as the tank zone, transition zone, and trailer zone.

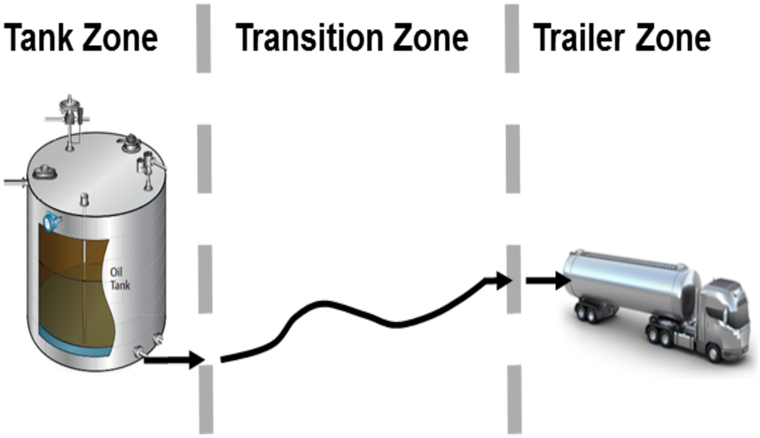
Tank zone

This is defined as the tank interior and any equipment attached to it. The tank zone ends at the outlet valve.

Transition zone

This is defined as the area between the tank and the truck during custody transfer. The transition zone ends at the inlet valve of the trailer.

Figure 2. Defined Tank Zones



Trailer zone

This is defined as the trailer interior after a product has left the transition zone. The trailer zone begins at the inlet valve of the trailer.

API MPMS Ch. 18.2 requires measurement of the following data for custody transfer, which can be done using equipment located in one or multiple zones:

- Merchantability
- Indicated/observed volume
- Product temperature
- API gravity and observed temperature
- Suspended S&W
- Calculated volume (GSV and NSV) (refer to API MPMS Ch. 12)

The API MPMS Ch. 18.2 standard recommends creating a list of existing and/or available equipment within each zone and documenting the equipment measurement uncertainty, which is then used to determine the quantity and quality of crude oil. Section 13.2 of the standard outlines procedures for determining the overall uncertainty in the custody transfer volumes of oil transferred from the lease tank to the truck. Once this has been determined, a method can then be developed that minimizes overall measurement uncertainty, while meeting contractual obligations.

There are many different types and possible permutations of measurement devices that can be applied. This white paper will focus on indicated volume measurement using the two most common methods; automatic tank gauging and LACT units.

API MPMS Ch. 18.2 and guided wave radar

Automatic tank gauging is applied within the tank and/or trailer zone. Although the existing API MPMS Ch. 3.1B standard addresses the use of automatic tank gauging for custody transfer measurement, this standard was developed for applications involving large storage tanks. For applications involving small lease tanks the accuracy requirements of the standard are financially prohibitive.

The API MPMS Ch. 18.2 standard addresses the unique requirements of small lease tanks and allows technology which is much better suited and economically viable to be installed, such as guided wave radar.

Figure 3. Guided Wave Radar

Guided wave radar instruments provide highly-accurate and reliable level measurements (see Figure 3). Guided wave radar has traditionally provided validation of well production rates, off-lease transfers of produced water and tank gauging for oil custody transfer. Many oil and gas operators have now standardized on guided wave radar technology and have an existing installed base of instruments.

Guided wave radar technology can eliminate nearly all trips to the top of the tank since GWR verification is typically only performed once per month. Technologies have been developed that allow the guided wave radar electronics to be verified without even having to open the vessel or remove the probe.

Figure 4. NIST-Traceable Verification Box

NIST-Traceable Verification Box used to verify instrument and generate Certificate of Compliance.

Having successfully applied the technology to broad range of applications, operators can now see the benefit of applying guided radar technology to custody transfer applications. For example, the diagnostic capabilities and interface measurements provided by guided wave radar technology can be utilized to detect if oil or water has been transferred to the wrong tank, to minimize lost production and provide insight to help correct separator problems. Guided wave radar also provides the ability to ensure that the water level in the oil tank is at least four inches below the outlet of the tank before transfer of crude oil begins, as recommended by API MPMS Ch. 18.2.

Many operators are now realizing the economic benefits of automated level measurement solutions, such as guided wave radar, to ensure accurate inventory measurements, prevent spills, optimize transfer logistics, and verify custody transfer measurements. The availability of wireless guided wave radar technology provides additional advantages in terms of reduced installation costs. For example, WPX Energy® was able to save as much $24,000 on the cost of installing a measurement solution to support a four-well pad, as noted in an article published in *World Oil Magazine* “In the Digital Oil Field “no wires” is a no-brainer”.

To achieve the safety benefits realized by keeping workers off the tanks, operators must develop procedures for obtaining product quality measurements in the transition zone. API MPMS Ch. 18.2 Section 10.2 outlines various options and existing standards to determine oil quality.

LACT units for larger facilities

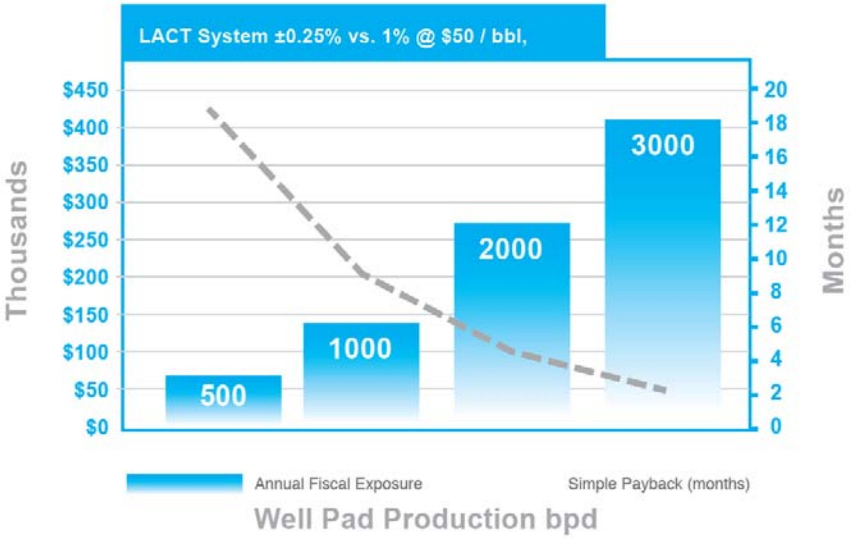
LACT units are skid-based solutions that automate measurement and control of the transfer of crude oil from production facilities to pipelines or trucks. These solutions offer many advantages over alternative custody transfer methods. For example, a LACT unit enables unattended measurement with a maintained accuracy of ±0.25 percent or better. In addition, it allows for better use of labor, better scheduling of runs to pipelines, elimination of measurement errors due to tank bottom build-up or encrustation, and reduced operating and maintenance costs.

LACT units use flowmeters to monitor the fluid and these must measure and quantify with a very high level of accuracy. The flowmeter must be insensitive to high viscosity values and maintain the requested level of accuracy and reliability even with changing conditions and operating parameters. Meter technologies, such as Coriolis, are designed to overcome these types of challenges and provide stable measurement and proving results over extensive service periods.

Effective validation through proving operations (pipe provers, compact provers) ensure ongoing meter accountability, while advanced in-situ diagnostics, available for Coriolis meters, help identify abnormal events that compromise measurement between validations. Because LACT units are usually installed in remote locations and are almost always unmanned, it is important to have remote accessibility to all data and operating conditions.

Operators are faced with a difficult decision as to when it makes economic sense to invest in a LACT unit rather than use manual tank gauging or automatic tank gauging. LACT units are often installed to reduce fiscal measurement uncertainty and help automate larger volume transfers when a field exceeds a company’s standard production rate.

Figure 5. LACT Unit Payback in Months



Based on annual fiscal exposure from different production levels, Figure 5 provides a simple way of determining the return on investment period of deploying a typical LACT Unit, offering ±0.25 percent accuracy, instead of manual gauging offering accuracy of 1 percent.

Although a one-percent error for manual gauging was used for this comparison, in many cases operators have reported errors of up to eight percent.

Trailer mounted Coriolis custody transfer systems

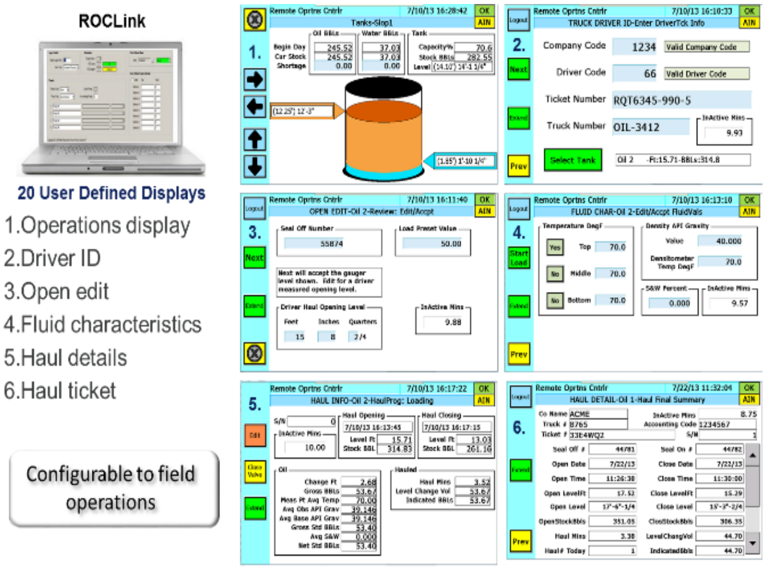
With the addition of API MPMS Ch. 18.2, another option now available to operators is the use of trailer mounted Coriolis custody transfer systems (Figure 6). These systems can reduce the capital cost of permanent skid-based LACT systems, and often the trucking company will make the capital investment instead of the operator. The trucking company sees the added benefit of increased accuracy and improved safety by not having to send the truck driver to the top of the tank for manual measurements. Also, the time required to purchase the oil is reduced significantly, enabling a cost benefit of faster delivery and higher truck utilization that justifies the purchase price and maintenance of the equipment. Although the standard sites that trailer-mounted systems are subjected to adverse conditions and hazards on oil field roads, many operators are using these systems and have documented no differences in Coriolis meter factor shift or reduction in measurements accuracy when compared to a stationary skid-based system. The North Dakota Industrial Commission (NDIC) is now allowing Coriolis based custody transfer systems mounted on the trailer to be used in North Dakota and other regional and federal regulatory agencies are evaluating approval of trailer-based systems.

Figure 6. Trailer Mounted Coriolis System

Automation systems

No matter which custody transfer method is chosen, measurement data and diagnostics from instruments and can be brought into a central controller or remote terminal unit (RTU) for remote access or direct access on site. Human machine interfaces can be used to automate haul transactions using manual or automatic tank gauging or LACT-based systems. Integrating functionality into automated production management and tank management programs has been proved to eliminate issues around production measurement compliance, as well as minimize lost and unaccounted-for production. A recent article in Automation World highlights where Marathon™ saved close to $15 million by formalizing and automating metering at their production tanks. Better insight and early identification of uncertainties can help contain ownership costs and reduce fiscal risk. Solutions for remote operations include flow computers and RTU platforms with flexible software applications and SCADA systems to monitor the process of fluid transportation (Figure 7).

Figure 7. Well Pad Tank Management Haul Interference



How do I determine ROI and which solution is right for my well pad?

Section 13 of API MPMS Ch. 18.2 details methods for calculating the measurement uncertainty. These calculations can be used to determine the most economical solution for each well pad based on the uncertainty and risk that is acceptable based on the facility production rates and/or contractual obligations.

In two scenarios below, we utilize the methods outlined in the standard to show a payback for a small and mid-sized facility.

Scenario 1

Consider the following facility:

- Single well
- Four oil and two water tanks (20 feet [6.10 m] 400 bbl each 1/4-in. [6.35-mm] strapping table)
- 600 bbl/day oil production
- 200 bbl/day water production

Figure 8. Low Production Rates

This facility (Figure 8) has a minimal installed base of equipment and the operator is using manual tank gauging per API MPMS Ch. 18.1 for oil hauls. The calculations assume that the uncertainty of the manual tank gauging operation is ± 1/4 in. (0.38%) per the 18.1 standard. Although this is the requirement of manual tank gauging operations, many operators have reported uncertainties that are much higher, in the range of 0.6% to 2.5%. For the purposes of this paper we are taking a very conservative approach to calculate the payback and risk associated with manual tank gauging. Using 1/4-in. uncertainty and $45 per barrel price of oil, this facility will have an annual risk of lost production totaling $36,458. The details for the calculations are summarized in Table 1 and Table 2.

Table 1. MTG Lost Production Risk

Description	Value	Units
Price of oil	$45.00	$/bbl
Daily pad production	600	bbl/day
Yearly pad production	219,000	bbl/year
Truck capacity	180	bbls
Number of hauls per year	1,217	hauls
MTG lost production risk	$36,458.14	USD

Table 2. Uncertainty in Units

Description	Value	Uncertainty	Units
Opening gauge	19.00	0.0208	ft
Closing gauge	10.10	0.0208	ft
Linearized strap at open	20.00	0.0104	1/ft
Linearized strap at closed	20.00	0.0104	1/ft
API gravity at 60F	42.5	0.1	0.1 API°
Observed temperature	85.0	85.0	1 °F
Observed pressure	5.5	5.5	0.2 psig
Measured sediment and water	0.20%	0.20%	0.02% vol%
Net standard volume	175.26	0.67	bbl/load

Uncertainty summary:

- 1/4-in. (6.35-mm) uncertainty on manual tank gauging measurement
- 0.1 °API uncertainty on gravity
- 1 °F on observed temp
- 0.38% or 0.67 barrel/load risk
- $36,458 risk per year

The operator has decided they would like to investigate updating this facility to include automatic tank gauging using guided wave radar to reduce their overall measurement uncertainty and minimize safety risk. The equipment needed to update the facility is included below.

Upgrade to API 18.2 using automatic tank gauging

- Two guided wave radars using equalized oil tanks $1,800 each = $3,600
- Battery + solar + remote display $1,700 + $800 = $2,500
- Load line spool piece with static mixer, temp transmitter, and sample system = $2,000
- Only local indication (manual ticketing, no RTU integration)
- Installation cost = $1,150
- Total installed cost = $9,250

With the installation of guided wave radar, the uncertainty analysis can now be updated as shown below. Based on going from 1/4- to 1/8-in. (6.35 mm to 3.17 mm), the risk of lost production per year is reduced by $12,953 and would result in a payback of 8.6 months, as seen in Table 3.

Table 3. Payback Guided Wave Radar

Description	Value	Units
Price of oil	$45.00	$/bbl
Daily pad production	600	bbl/day
Yearly pad production	219,000	bbl/year
Truck capacity	180	bbls
Number of hauls per year	1,217	hauls
MTG lost production risk	$36,458.14	USD
Reduced lost production risk oil transfer	$12,953.36	USD
Installation cost	$9,250.00	USD
Payback	8.6	Months

Uncertainty analysis

- 1/8-in. (3.17 mm) uncertainty on automatic tank gauging measurement
- 0.1 °API uncertainty on gravity
- 0.5 °F on observed temp
- 0.43 barrel/load risk
- $23,504.78 risk per year ($12,953 less)
- Payback 8.6 months

The calculations and payback assume that the uncertainty is biased as a loss and not a plus or minus analysis as you would consider in most uncertainty analyses. Based on many discussions with operators who have conducted their own independent evaluations of manual tank gauging operations, the tendency is for the crude oil truck driver to round the measurements so they do not deliver less crude than they reported on the run ticket and are therefore not accused of theft. This biases the measurement so that it is not in favor of the operator; therefore, showing it as a loss is appropriate. At a minimum, the calculations demonstrate the reduction in risk of lost production. There are many safety considerations that have not been included in the payback. If you consider that this facility would require 1,217 hauls per year, that is also 2,434 trips (Open/Close readings) to the top of the tank for manual tank gauging operations. That could be reduced by 99%, assuming a monthly field verification of the radar gauge (only 12 trips per year to the top of the tank).

Another consideration is to monitor water tanks to ensure that there are no salt water disposal overcharges and no oil is lost due to the water tank because of poor separator performance. Installing guided wave radar with interface detection can yield positive results. For this calculation, we have assumed that the risk of lost oil to the water tank is 0.25% of production. The payback is only 5.2 months (see Table 4). Even though these are water tanks, they have the same safety risks if the tank is manually gauged.

Table 4. Payback with Guided Wave Radar/Interface Detection

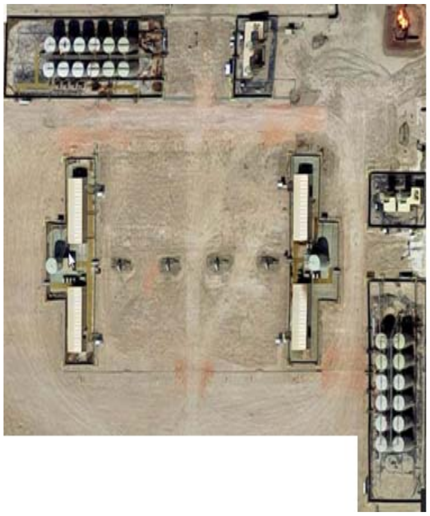
Description	Value	Units
Disposal cost	$2.00	$/bbl
Daily pad water production	200	bbl/day
Yearly pad water production	73,000	bbl/year
Truck capacity	160	bbls
Number of hauls per year	456	hauls
MTG SWD over charge risk	$607.64	USD
ATG SWD over charge risk	$391.75	USD
Oil skim loss prevention (0.25%)	$24,637.50	USD
Reduced risk (water disposal + skim)	$24,853.39	USD
Reduced lost production risk oil transfer	$12,953.36	USD
Total reduced risk	$37,806.75	USD
Installation cost	$16,500.00	USD
Payback	5.2	Months

- Water disposal cost $2.00 per bbl
- Estimated 0.25% oil skim loss to water tank
- Add two guided wave radar level devices with interface detection on water tanks ($7,250 installed cost)
- Reduce ~ $25k risk of oil loss and SWD overcharges
- Payback 5.2 months (includes oil loss risk, skim loss, and SWD overcharge risk in payback)
- Interface detection (oil/water in the tank)

Scenario 2

For Scenario 2, we will consider a larger facility (Figure 9) and conduct a similar analysis, but additional automation will be required and we will compare an automatic tank gauging installation with that of a LACT system.

Figure 9. Mid-sized Facility



Facility profile:

- Four-well pad
- 16 oil tanks (20 feet [6.10 m] 400 bbl each 1/4-in. [6.35-mm] strapping table)
- 8 water tanks (20 feet [6.10 m] 400 bbl each 1/4-in. [6.35-mm] strapping table)
- 2,400 bbl/day oil production
- 1,200 bbl/day water production
- Low-cost level instrument installed for inventory measurement only.

For this well pad, the operator is also using manual tank gauging, but has an existing legacy float-based system installed. The same uncertainty analysis per Scenario 1 is calculated.

Uncertainty analysis:

- ¼-in. (6.35-mm) uncertainty on manual tank gauging measurement
- 0.1 °API uncertainty on gravity
- 1 °F on observed temp
- 0.38% or 0.67 barrel/load risk
- $145,832.55 risk per year

For this installation, we will replace all the legacy tank gauges with guided wave radar and include a tank management system to automate the haul tickets (see Table 5).

Table 5. Payback with Guided Wave Radar/Tank Management System

Description	Value	Units
Price of oil	$45.00	$/bbl
Daily pad production	2,400	bbl/day
Yearly pad production	876,000	bbl/year
Truck capacity	180	bbls
Number of hauls per year	4,867	hauls
MTG lost production risk	$145,832.55	USD

Facility update per API 18.2:

- Replace legacy level devices with 16 guided wave radar $1,800 each = $28,800
- Guided wave radar installation, two people
- Labor 32 hrs and $50 per hr = $3,200
- Qty 4, load line spool piece with static mixer, temp transmitter, and sample system = $8,000 installed cost
- Automated haul tickets, RTU and Tank Manager $7,000 installed cost.

With the installation of guided wave radar, the uncertainty analysis can now be updated. Based on going from 1/4- to 1/8-in. (6.35 mm to 3.17 mm), the risk of lost production per year is reduced by $51,813 and would result in a payback of 10.9 months. Additional savings by not having to manually enter ticket data have not been included, but should be considered by the operator (see Table 6).

Uncertainty analysis:

- 1/8-in. (6.35 mm) uncertainty on automatic tank gauging measurement
- 0.1 °API uncertainty on gravity
- 0.5 °F on observed temp
- 0.43 barrel/load risk
- $94,019.10 risk per year (reduced from $145,832)
- Payback 10.9 months

Table 6. Payback with Guided Wave Radar

Description	Value	Units
Price of oil	$45.00	$/bbl
Daily pad production	2,400	bbl/day
Yearly pad production	876,000	bbl/year
Truck capacity	180	bbls
Number of hauls per year	4,867	hauls
MTG lost production risk	$145,832.55	USD
ATG lost production risk	$94,019.10	USD
Reduced risk	$51,813.44	USD
Installation cost	$47,000.00	USD
Payback	10.9	Months

Applying the same methodology in Scenario 1 and adding guided wave radar to minimize oil skim and overcharges for salt water disposal can reduce the payback to 5.5 months, as indicated in the table below in Table 6.

Table 7. Payback with Guided Wave Radar

Description	Value	Units
Disposal cost	$2.00	$/bbl
Daily pad water production	1,200	bbl/day
Year pad water production	438,000	bbl/year
Trunk capacity	160	bbls
Number of hauls per year	2,738	hauls
MTG SWC over charge risk	$3,645.81	USD
ATG SWC over charge risk	$2,350.48	USD
Oil skim loss prevention (0.25%)	$98,550.00	USD
Reduced risk (water disposal + skim)	$99,845.34	USD
Reduced lost production risk oil transfer	$51,813.44	USD
Total reduced risk	$151,658.78	USD
Installation cost	$69,400.00	USD
Payback	5.5	Months

Another option to consider is the installation of a LACT unit. LACT units have the lowest overall uncertainty, but do have a higher initial capital cost. For this well pad we have assumed a LACT unit with automated haul tickets will have an installation cost of approximately $113,000. This is a general estimate for the cost of a LACT unit. Prices can vary by geographic region, size, and technology used. Based on the reduction in uncertainty, the LACT system will have a payback in 16 months. The uncertainty analysis is shown below in Table 8.

Table 8. Payback with LACT System

Description	Value	Units
Price of oil	$45.00	$/bbl
Daily pad production	2,400	bbl/day
Yearly pad production	876,000	bbl/year
Truck capacity	180	bbls
Number of hauls per year	4,867	hauls
MTG lost production risk	$145,832.55	USD
ATG lost production risk	$94,019.10	USD
LACT lost production risk	$60,938.33	USD
Reduced risk	$84,894.22	USD
Installation cost	$113,000.00	USD
Payback	16.0	months

Uncertainty analysis:

- 0.1 °API uncertainty on gravity
- 0.5 °F on observed temp
- 0.28 barrel/load risk
- $60,938.33 risk per year (reduced from $145,832.55)
- Payback 16 months

Conclusions

The application of wired or wireless automatic tank gauging technology, such as guided wave radar, for continuous level monitoring improves safety and production management by enhancing operations. Continuous insight into actual inventory levels helps avoid reactive operator events associated with high-level alarms, well shut-ins, or a tank overfill situation. Oil losses to water storage tanks and diminished storage capacity due to excessive water levels in oil tanks are minimized through oil/water interface detection. With the publication of API MPMS Ch. 18.2, there is now an industry-acceptable path that uses guided wave radar for crude oil custody transfer from small lease tanks.

Where economical, the installation of a LACT-based custody transfer system can pay for itself with reduced measurement uncertainty and better use of labor. With the addition of API MPMS Ch. 18.2, many operators are also implementing trailer mounted Coriolis custody transfer systems that reduce the capital cost of flow measurement-based systems.

Leveraging automation systems and standards-based applications for well pad tank management has the added benefit of bringing all the measurement systems together to maximize overall efficiency and reduce fiscal risk.

To learn more about Emerson’s solutions for small lease tank custody transfer, visit Emerson’s Produced Fluids Management website.

If you would like to speak with an Emerson representative about the ROI calculator used in these scenarios and customize the calculations for your well pad design, please feel free to contact us.

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