EXECUTIVE SUMMARY

Researchers assert that a significant portion of methane emissions are from a small number of large, temporally-dynamic emitters (Zavala-Araiza et al, 2018; Lyon et al., 2016; and Lavoie et al., 2017) that may be understated in national inventories. Gas carry-through to storage tanks due to leakage past drain valves into tank inlet headers, inefficient gas-liquid separation in upstream vessels, malfunctioning level controllers or leakage past the seat of level control valves, or unintentional storage of high vapour pressure liquids in atmospheric tanks are observed to be noteworthy sources at some sites and can be temporally-dynamic. Because uncontrolled storage tanks are designed to vent, Fugitive Emission Management Programs (FEMP) typically classify emissions as ‘process vents’ and **do not trigger remedial action**.

To inform mitigation efforts, this study investigates root-causes of fugitive (unintentional) as well as venting (intentional) emissions from fixed-roof storage tanks facilities located in Alberta and British Columbia. The work highlights the importance of fugitive emission diagnosis to enables effective repairs. Outcomes include a proposed troubleshooting decision tree for use during leak detection and repair (LDAR) surveys; a critical review of gas flashing estimation methods; and techno-economic assessments for ten storage tank emission mitigation options.

This study focuses on condensate, light crude oil and medium crude oil production at well sites. Cold heavy oil production (CHOP) is excluded because tank venting is driven by well behavior and beyond the scope of this project.

Methodology

Desktop investigations focused on fixed-roof storage tanks where infrared camera videos suggested fugitive and venting emissions were greater than the ECCC facility venting limit of 42 m^3/day (GC, 2018). Candidate tanks were selected from 2018 and 2019 field data collected during Energy Efficiency Alberta Baseline Opportunity Assessments and the British Columbia methane emissions field study. Participating companies voluntarily provided relevant site-specific and confidential data items that included:

- Tank and emission details collected during 2018 or 2019 field campaigns.
- Site process flow diagram (PFD)
- Storage tank piping and instrumentation diagram (P&ID). If P&IDs are not available, provide the maximum and minimum allowable working pressure for the subject tank (a photo of the tank nameplate is ideal).
- Operating pressure and temperature of vessel(s) immediately upstream of subject tank.
- Oil and gas disposition volumes relevant to the survey month.
- If the site has a treater, the pump rate (m^3/hr) for recycling slop oil.

- Laboratory analysis of relevant oil/condensate and gas streams.
- An explanation or copy of spreadsheet currently used to estimate storage tank emissions.

Based on these details, desktop reviews identified possible root-causes and defined specific questions for site operators to investigate for 47 tanks. In some cases, laboratory analysis of pressurized samples plus separator pressure, temperature and hydrocarbon liquid throughput were available and enabled quantification of flashing losses (using a process simulator). Comparing calculated emission rates to IR videos provided a qualitative indicator of whether the observed plume was strictly due to separator liquid flashing or whether other, unintentional mechanism(s) contributed.

Operators provided repair details, process data and/or equipment conditions that confirmed specific mechanism responsible for emissions observed by the IR camera. These mechanisms are broadly categorized by the following root-causes.

- Volatile liquid flashing (typically defined as venting emissions)
- Tank-top equipment component leaks (typically defined as fugitive emissions)
- Unintentional gas carry-through (typically defined as fugitive emissions)

Volatile Liquid Flashing Root-Cause Observations

Fixed-roof tanks located at primary production facilities are intended to store volatile hydrocarbon liquids from separators and treaters. Therefore it's not surprising that, of the tank emissions investigated by operators, approximately half were attributed to volatile liquid flashing. Provincial directives specify methods for quantifying gas flashing that provide reasonably representative emission rates for tanks not experiencing unintentional gas carry-through. For example, AER Directive 017 specifies the following to determine Gas-to-Oil Ratio (GOR) factors (that are multiplied by stock tank oil production for monthly associated gas volume accounting).

1. 24 hour test may be conducted such that all the applicable gas and oil volumes produced during the test are measured. The gas volume is divided by the oil volume to result in the GOR factor.
2. A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a pressure-volume-temperature (PVT) analysis can be conducted. The analysis should be based on the actual pressure and temperature conditions that the oil sample would be subjected to downstream of the sample point, including multiple-stage flashing. The GOR factor is calculated based on the volume of gas released from the sample and the volume of oil remaining at the end of the analysis procedure.
3. A sample of oil taken under pressure containing the gas in solution that will be released when the oil pressure is reduced may be submitted to a laboratory where a compositional

analysis can be conducted. A computer simulation program may be used to determine the GOR factor based on the compositional analysis.

Some circumstances permit operators to use correlations listed in the 2002 Canadian Association of Petroleum Producers (CAPP) Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities are also permitted. (CAPP, 2002). These correlations are desirable for predicting flashing loss contributions to emission inventories. However, correlations are unable to account for sample specific analyte fractions; stock tank liquid heating (that has an upward influence on GOR); or backpressure imposed by emission control overhead piping (that has a downward influence on GOR). Thus, correlations may be appropriate for estimating average emissions from a large number of tanks while more rigorous process simulation or direct measurement should be employed when accurate determination of site-specific venting is required (e.g., for designing vapour recovery systems or compliance with Directive 017).

In general, the accuracy of flash gas factors improves with modelling sophistication and process data granularity. Input data requirements for methods investigated by this study are indicated in Table ES-1. The AER 'Rule-of-Thumb' is the simplest and only requires knowledge of upstream pressure while process simulations are complex and require detailed process knowledge.

Table ES-1: Input process data required for selected flash gas estimation methods.

Input Parameter	**Correlations**			**Simulation**
	AER 'Rule-of-Thumb'	**Vazquez and Beggs**	**Valko and McCain**	**VapourSIM**
Stock tank oil density (API gravity)		**X**	**X**	**X**
Stock tank oil temperature				**X**
Stock tank oil RVP				**X**[1]
Local atmospheric pressure				**X**[1]
Stock tank vapour molecular weight		**X**		
Upstream separator pressure	**X**	**X**	**X**	**X**
Upstream separator temperature		**X**	**X**	**X**
C_1 to C_{30} analysis of pressurized liquid sample				**X**

[1] *Simulation users select flashing end point of interest (atmospheric pressure or RVP)*

To spot check how well Directive 017 site testing requirements align with correlations, flash gas factors are determined according to the methods presented in Table ES-1 and described in Appendix Sections 6.3.1 to 6.3.1. For example, GOR is calculated for a light crude oil (API Gravity 43.4°) over the range of separator pressures observed in the field dataset (and constant separator temperature of 10° C). Figure ES-1 presents GOR as a function of pressure and an insert of the pressure distribution. GOR determined by correlations are represented by trend lines. GOR determined by field measurements are plotted as brown boxes while GOR determined by VapourSIM are plotted as cross markers and used to spot check correlation results. Red font markers indicate a flash end point equal to atmospheric pressure and stock tank temperature (representative of instantaneous venting when pressurized liquid enters the tank). Green font markers indicate a flash end point equal to sales oil Reid Vapour Pressure (RVP) and representative of total venting due to instantaneous flashing plus weathering over a longer period of time. The difference between red and green simulated GOR is the contribution from working and breathing losses (i.e., weathering) that occurs over the entire period oil is stored in the tank (e.g., days, weeks or months).

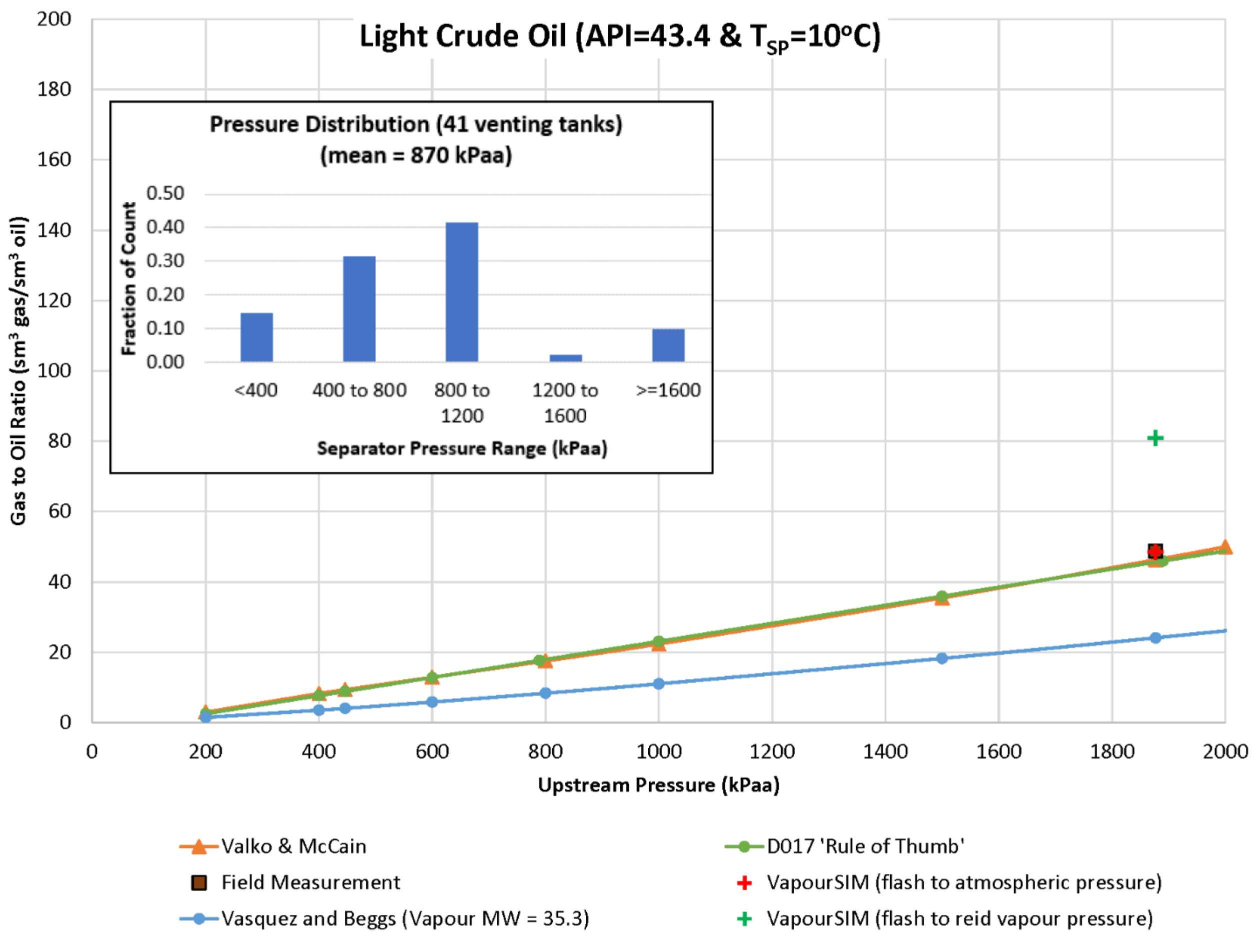

Figure ES-1: GOR correlation estimates over separator pressure range of 200 to 2,000 kPaa for light crude oil with API = 43.4º and separator temperature = 10 ºC.

The VapourSIM (flashed to atmospheric pressure) and measured GOR results are reasonably aligned with Valko and McCain results for the light crude oil example presented in Figure ES-1. This is expected because the pressure, temperature and API gravity of the subject oil stream is within the range of conditions the correlation was derived from. Similar observations are made for a medium oil example (API Gravity 30.1^o) but not for condensate examples. This is attributed to the condensate API gravity (66.4^o) being greater than the maximum API gravity (56.8^o) used to derive the Valko and McCain correlation.

Techno-Economic Assessment of Mitigating Actions

Tanks not experiencing unintentional gas carry-through but still exceeding provincial or federal methane regulation limits may require controls to reduce emissions. Design memorandums are developed for the ten mitigation approaches listed in Table ES-2 and broadly grouped into two categories: tank top versus flash vessel vapour capture. Storage tanks certified with a minimum and maximum allowable working pressure rating can be fitted with overhead piping that can capture 100 percent of tank-top vapours. However, many tanks are not rated for pressure or vacuum service and at risk of failure if tank-top vapour capture piping is installed. Therefore, options to install a flash vessel between separators and non-certified tanks are investigated. The applicability of each case depends on whether the subject site is connected to a natural gas gathering system; power distribution system; and or features sufficient lease area; certified tanks or a suitable well/reservoir for gas lift. Most UOG facilities operating in western Canada will satisfy one or more of the site requirements summarized in Table ES-2.

Table ES-2: Site features required for deployment of mitigating technologies.

Case # and Description	Connection to electric grid	Connection to gas gathering system	Certified tanks	Sufficient lease area	Well and reservoir suitable for gas lift
#1 Tank Top to Existing High Pressure Flare	X		X		
#2 Tank Top to Low Pressure Flare			X	X	
#3 Tank Top to Booster Compressor for Gas Lift	X		X	X	X
#4 Tank Top to Vapour Combustor	X		X		
#5 Flash Vessel to Electrical Generators	X			X	
#6 Tank Top to Electrical Generators	X		X	X	
#7 Flash Vessel to Existing High Pressure Flare					
#8 Flash Vessel to Vapour Combustor					
#9 Tank Top to VRU for Gas Sales	X	X	X	X	
#10 Flash Vessel to VRU for Gas Sales	X	X		X	

A description of installed equipment; process flow diagrams (PFD), total installed capital cost (TICC) details; and annual GHG emission reductions are developed for each mitigation case investigated. These are used for calculating Net Present Value (NPV with sensitivity analysis) and indicate whether an investor can expect to recover their capital and earn a nominal rate of return. Average abatement costs (in present value terms) are also developed to show the total lifecycle cost incurred by an operator (net of any revenue) to avoid the release of one tonne of CO_2E. As shown in Table ES-3, all options except case #3, have a negative NPV under the base venting rate of 500 m^3 per day and would not normally be implemented because there is no economic benefit to facility owners. Sensitivity analysis indicates all actions are highly sensitive to the monetization of GHG emission reductions. When re-calculated using the current federal carbon price (levelized value of $46 per t CO_2E), NPV is positive for all cases but #8 and #10.

Table ES-3: Summary of TICC, NPV, GHG reduction and average abatement costs for options to mitigate of 500 m^3 per day tank venting.

Case # and Description	TICC	NPV	GHG reduction over 10 years	Average Abatement Cost ($/t CO_2E)
#1 Tank Top to Existing High Pressure Flare	$195,000	-$311,000	11,180	28
#2 Tank Top to Low Pressure Flare	$155,000	-$245,000	11,180	22
#3 Tank Top to Booster Compressor for Gas Lift	$780,000	$283,000	17,500	16
#4 Tank Top to Vapour Combustor	$235,000	-$363,000	11,275	32
#5 Flash Vessel to Electrical Generators	$245,000	-$122,000	8,055	15
#6 Tank Top to Electrical Generators	$300,000	-$113,000	11,275	10
#7 Flash Vessel to Existing High Pressure Flare	$125,000	-$123,000	9,535	15
#8 Flash Vessel to Vapour Combustor	$200,000	-$307,000	8,055	38
#9 Tank Top to VRU for Gas Sales	$430,000	-$461,000	17,522	26
#10 Flash Vessel to VRU for Gas Sales	$525,000	-$620,000	12,517	50

Tank-Top Equipment Leaks Root-Cause Observations

Tank-top equipment leaks are the second root-cause category and are only relevant to controlled storage tanks where vapours are directed to a conservation or destruction system (but leak from associated equipment). Their root-cause can be malfunctioning equipment components or incorrectly set, undersized or blocked components that cause tank ullage pressures to exceed relief set-points. Tank-top equipment leaks are detected during LDAR surveys. Repairing components installed on controlled tanks typically requires a full or partial site shut-down and therefore aligned with other maintenance work or downstream facility outages (which can exceed some regulatory timelines). It involves planning the shutdown, emptying the tank, isolating (lock-out) the tank; purging with an inert gas (e.g., nitrogen); accessing with a manlift; disassembling/replacing/repairing the component; purging the tank with natural gas; removing lock-out and returning the tank to service.

Repair costs depend on materials (ranging from almost zero to thousands) and labour (ranging from $200 to thousands)) which depend on the nature of the problem and number of people involved. Valuing the cost of a site shut-down depends on throughput, current commodity prices and view on whether down time should be included in the repair cost.

Unintentional Gas Carry-Through Root-Cause Observations

Unintentional gas carry-through is the third root-cause category and of most interest because it presents low-cost methane reduction opportunities and may help explain discrepancies between bottom-up emission inventories and top-down observations.

The most common cause observed is from leakage of process gas or volatile product past valve seats connected to the product header leading to storage tanks. Hard substances (e.g., sand, wax or other debris) can deposit on a valve seat and prevent the disk fully sealing with its seat, as indicated in the Figure ES-2 globe valve example. The seat or disk can also be scoured or damaged to the point where a full seal is not possible. The most common instance of these problems are on liquid (hydrocarbon or water) control valves immediately downstream of separators or scrubbers (commonly referred to as 'dump-valves'). Other instances of this leak type are observed on manual by-pass valves that result in direct connection between high-pressure production fluids and atmospheric tanks. It's also possible for level controllers to malfunction and send a false output signal that keeps the dump-valve open (and passing gas to the storage tank). Malfunctioning can be due to a 'hung-up' float assembly or change in liquid density that prevents the assembly from returning to its expected level.

Overall, costs reported by operators to repair a passing dump-valve ranged from zero to $7,500 depending on the nature of the problem and number of people involved.

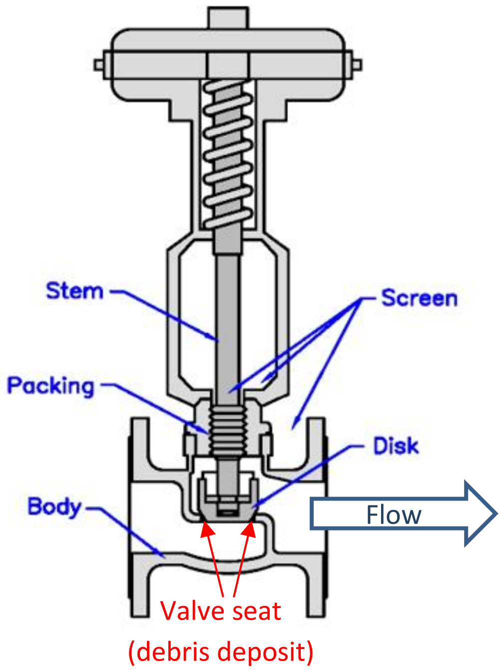

Figure ES-2: Globe control valve with debris deposit area indicated.

Inefficient separation of gas and liquid phases upstream of the tanks allowing some gas carry-through, by entrainment or in solution, to the tanks. Sustained high liquid levels in the separator will initiate frequent signals for the dump-valve to open resulting in continuous flow of pressurized hydrocarbon liquids to the storage tanks. This condition reduces residence time for separation of gas from the liquid phase and may cause storage tank flashing to exceed solution gas losses predicted by a simulator or correlation (strictly based on the subject liquid properties and separator conditions).

Although considered infrequent and not observed in the study dataset, piping anomalies can result in unintentional placement of gas or high vapour pressure product in tanks not equipped with appropriate vapour controls. Examples include:

- Liquids from 2nd and 3rd compression stage scrubbers being tied into storage tanks instead of recycled back to the 1st stage scrubber inlet.
- Recombining separator gas, after metering, into the liquid line connected to a tank.
- Purge gas supplied to a separator liquid line and connected to a storage tank.
- Oil well production casing connected to a storage tank.

Field Troubleshooting Decision Tree

To support first attempts at field level troubleshooting and root-cause identification, the decision tree depicted in Figure ES-3 is proposed. It is intended to identify equipment components or process conditions responsible for continuous venting from uncontrolled storage tanks. The decision tree is a systematic process for determining whether tank venting may be due to component malfunction (that can be repaired) or inherent to the pressurized hydrocarbons stored. The decision tree can be integrated into FEMP and completed by LDAR survey technicians (equipped with an IR camera and portable acoustic leak detector). It is applicable to continuous venting, observed by IR camera (or other detection method), from uncontrolled tanks storing hydrocarbons and/or water. It is **not** applicable to tank venting that occurs at an intermittent frequency corresponding to the separator dump frequency because this is an indicator of equipment components operating according to their design.[1] It is **not** applicable to tanks equipped with emission controls that conserve or combust the vapours.

Using the decision tree begins at the offending tank and involves tracing pipe to the upstream vessel(s) responsible for delivering liquids (or walking directly to the vessel(s) if predetermined from P&IDs or identified by the site operator). These vessels can be separators, treaters, scrubbers, or drain sumps. If equipped with a level gauge, the vessel liquid level and dump-frequency can be monitored as follows.

- Sustained high-liquid level and frequent/continuous dump events are an indicator of inlet liquid flows greater than separator design capacity. Under these conditions, there may be insufficient residence time for gas to fully disengage from liquids before delivery to the tank.
- Sustained low-liquid level (or empty vessel) and frequent/continuous dump events are an indicator of a malfunctioning level controller. Under these conditions, the controller may be sending a false signal for the dump valve to remain open.
- Sustained mid-liquid level or rising/descending levels (that align with dump frequency) are an indicator of sufficient separator capacity and intended level control. Under these conditions, the offending component may be the dump-valve. This is checked with an acoustic leak detector by placing a probe on the valve body. If liquids or gas are passing through the closed valve, vibrations (noise) are generated and an acoustic signal is observed by the instrument. An empirical correlation is then used to estimates the leak rate based on the signal strength, valve type and pressure differential across the valve.

If these troubleshooting steps don't identify a root-cause then the subject vessel is unlikely to be the source of continuous venting. The same steps should be repeated for all other vessels

[1] When viewed by an IR camera, intermittent tank venting should appear as a large plume; associated with instantaneous flashing when pressurized liquids enter the tank; that decreases in magnitude until the next dump event. The plume may not decrease to 'zero' because of residual weathering of oil between dumping events. If dumping events are infrequent (e.g., occurring once per hour or more), a very small or zero plume may be observed which is an indicator of intermittent venting.

connected to the tank. Locating connected scrubbers and drain sumps can be more difficult than identifying upstream separators or treaters. It requires patient pipe walks and/or consultation with site operators and P&IDs (especially if pipe racks are insulated). If all connected vessels are checked and no problems identified, then the root-cause may be due to an abnormal piping configuration or the flashing of volatile liquid hydrocarbons.

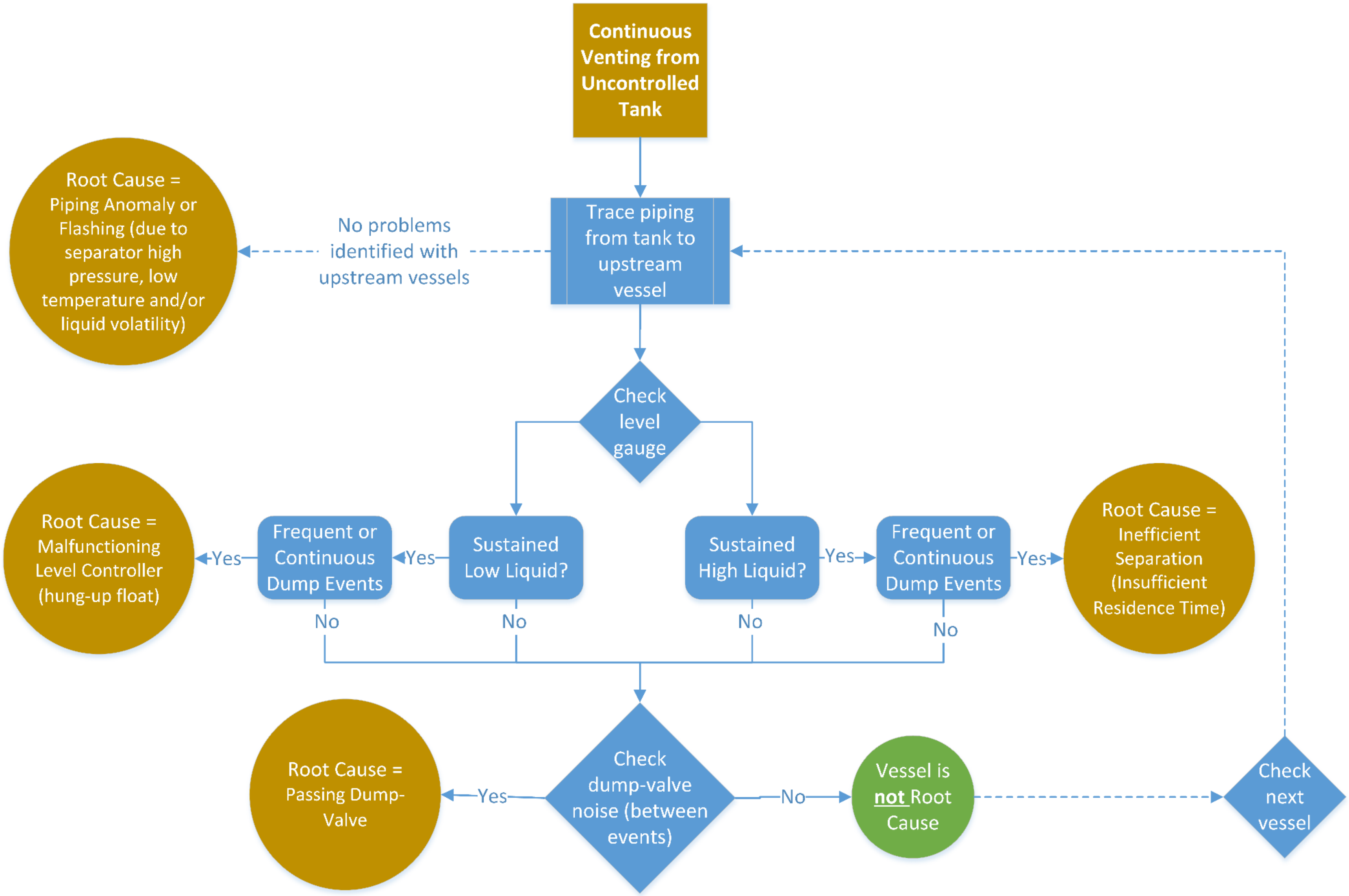

Figure ES-3: Decision tree for troubleshooting the root-cause of continuous venting from uncontrolled storage tanks.

Key conclusions and recommendations from this study include the following:

- Evidence collected by this study indicates separator and scrubber dump-valve leakage is contributing to fugitive emissions from storage tanks. However, this source is not accounted in provincial or national inventories. To resolve this data gap, a field measurement campaign should be implemented to develop component counts and population-average emission factors.
- A decision tree for identifying the root-cause of venting from uncontrolled storage tanks is proposed as a first troubleshooting attempt during LDAR surveys. Outcomes are intended to alert maintenance personal to equipment that may be malfunctioning and unknowingly contributing to tank venting.
- The key benefit of correlations is their simplicity and minimal input data requirements. However, they are unable to account for sample specific analyte fractions; stock tank liquid heating (that has an upward influence on GOR); or backpressure imposed by emission control overhead piping (that has a downward influence on GOR). When accurate determination of peak venting is required (e.g., for designing vapour recovery systems or compliance with Directive 017), more rigorous process simulation should be applied to account for site specific conditions.
- To improve laboratory analysis data reliability the steps recommended by Colorado regulators (described in Section 6.3.1), when performing and verifying flash gas liberation analysis on pressurized liquid hydrocarbon samples, should be considered (CAPCD, 2017).
- For emission inventory purposes, the Valko and McCain correlation is recommended when determining flash gas factors for crude oils within the range of parameters stated in Table 20. This is based on alignment with GORs determined with VapourSIM (flashed to atmospheric pressure) and measured spot checks plus its use in Colorado for determining flash gas factors (SLR, 2018). The Valko and McCain correlation is not recommended for lighter condensates with API gravity greater 56.8^o. Instead, the Vasquez & Beggs and D017 'Rule of Thumb' correlations provide more reasonable GOR estimates for condensates with API gravity greater 56.8^o.
- Techno-economic assessments are completed for ten storage tank emission mitigation options. Results indicate all but one option have a negative NPV when venting equals 500 m^3 per day. Unless alternative revenue opportunities (e.g., offset credits, royalty credits, energy efficiency incentives, etc) are available, current commodity prices and limited economic benefit to facility owners will challenge implementation of mitigation options. Of particular vulnerability are existing sites that require retrofits and may be forced to shut-in if incentives are not available. This outcome diminishes economic activity and Canada's capacity to implement climate solutions.